Exhibit No.	Name/Citation	Description
1	Ex. 1 Lyons Affidavit	Affidavit of Martin J. Lyons
2	Ex. 2 Alonso Affidavit	Affidavit of Mario E. Alonso
3	Ex. 3	Illinois Annual Air Quality Report 2011—location of plants and air monitoring stations
4	Ex. 4	Ameren's comment in USEPA Docket QA-OAR-2012-0233
5	Ex. 5 MPS Group Emission Data	MPS Group 2012 Emission Data
6	Ex. 6 MPS Group Information	Addresses, IEPA ID numbers, permit application numbers, and other info of 7 Energy Centers
7	Ex. 7 Group Exhibit	Group Exhibit of Five Memoranda provided by Development Strategies
8	Ex. 8 Thompson Affidavit	Affidavit of Daniel P. Thompson
9	Ex. 9 Bilicic Affidavit	Affidavit of George W. Bilicic
10	Ex. 10 Table 1 & Table 2	Table 1 & Table 2 Ameren MPS Group Variance SO2 Limit Comparison to the Current MPS
11	Ex. 11 Diericx Affidavit	Affidavit of Aric D. Diericx
12	Ex. 12AECOM Memorandum	Health Effects Report provided by AECOM
13	Ex. 13 Whitworth Affidavit	Affidavit of Steven C. Whitworth
14	Ex. 14	Newton FGD Construction Permit

EXHIBIT 1

AFFIDAVIT OF MARTIN J. LYONS

TESTIMONY OF MARTIN J. LYONS

I. BACKGROUND AND QUALIFICATIONS

1. My name is Martin J. Lyons, Jr. I am employed by Ameren Corporation ("Ameren") as Executive Vice President and Chief Financial Officer. My business address is 1901 Chouteau Avenue, St. Louis, Missouri, 63103. I am responsible for corporate planning, business and commodity risk management, internal audit, treasury, tax, investor relations, accounting and financial reporting. I received my Bachelor of Science in Business Administration degree, with a major in Accountancy, from St. Louis University. I received my Master of Business Administration degree from Washington University in St. Louis. I was named to my current position in 2009.

2. Before joining Ameren, I served as a partner in PricewaterhouseCoopers LLP's St. Louis office providing auditing services to companies in a variety of industries. In 2001, I joined Ameren Corporation as the Controller. I was named Vice President and Controller in 2003 and in 2008 became Senior Vice President and Chief Accounting Officer.

II. AMEREN CORPORATION'S DECISION TO EXIT MERCHANT GENERATION BUSINESS

3. Ameren is a public utility holding company whose primary assets are the common stock of its subsidiaries, including Ameren Missouri, Ameren Illinois, Ameren Transmission Company and Ameren Energy Resources ("AER"). Ameren's subsidiaries are separate, independent legal entities with separate businesses, assets, and liabilities. Dividends to Ameren stockholders depend on distributions made to it from its subsidiaries. Ameren's core business and source of earnings is its utility operations (rate-regulated natural gas delivery, rate- regulated transmission and rate-regulated generation and delivery). AER has not made a distribution to Ameren since 2009.

4. AER's financial prospects have been increasingly dire. A depressed power price market, increasing fuel and transportation costs, Midwest economic malaise, and burdensome interest costs associated with AER long-term debt, including debt obligations of AER subsidiary Ameren Energy Generating Company ("AEG" or "GENCO"), have all contributed to AER's poor financial performance. AER's net income plummeted from $238 million in 2009 to $ (396) million in 2012 and cash flow from operations for AER over this same period dropped 44% from $339 million in 2009 to $191 million in 2012. Net income for GENCO[1], the owner of the Newton Energy Center and a Securities and Exchange Commission (SEC) registrant, plummeted from $162 million in 2009 to $(40) million in 2012, as summarized below:

	Year Ended December 31,			
	2009	**2010**	**2011**	**2012**
Net income/(loss) in millions	$ 162	$ (36)	$ 45	$ (40)

5. In addition, cash flow from operations over this same period dropped 45%, from $253 million in 2009 to $139 million in 2012. The erosion of income and cash flows has had a direct and adverse impact on GENCO's creditworthiness and ability to fund capital investment. Over the last fourteen months, credit rating agencies (Standard & Poor's, Moody's and Fitch) have downgraded the ratings of GENCO's bonds several notches, such that they are now deep within "junk" status, indicating increasing uncertainty as to whether or not GENCO will be able to meet its ongoing debt obligations[2]. The chart below summarizes credit rating actions since 2009.

[1] AER subsidiary and AmerenEnergy Resources Generating (AERG) are not publicly registered companies. GENCO's financial predicament, however, is reflective of AER and AERG's financial status.

[2] Investment grade ratings are BBB- and above (Baa3 Moody's) while BB+ (Ba1 Moody's) and below are considered speculative investments. GENCO's bond ratings fall within the speculative or "junk" category. Fitch defines "CC" and "CCC" ratings as follows: CCC: "Default is a real possibility"; CC: "Default of some kind is

Ameren Energy Generating Company Rate Changes
(January 2009 – June 2013)

	Fitch		Moody's		S&P		
	Unsecured	Issuer	Unsecured	Issuer	Unsecured	Issuer	Rating Change
As of 01/01/09	BBB+	BBB+	Baa3	NR	BBB-	BBB-	
07/30/10	BBB	BBB					Downgrade
03/01/11			Ba1	NR			Downgrade
05/23/11	BB+	BB+					Downgrade
01/27/12	BB-	BB-					Downgrade
02/28/12					BB	BB	Downgrade
02/29/12			Ba2	NR			Downgrade
03/05/12					BB-	BB-	Downgrade
04/12/12			Ba3	NR			Downgrade
11/26/12					B+	B	Downgrade
12/21/12	B+	B-			B	B-	Downgrade
01/10/13			B2	NR			Downgrade
01/28/13	CCC-	CC					Downgrade
02/08/13					CCC+	CCC+	Downgrade
03/14/13			B3	NR			Downgrade

6. Under generally accepted accounting standards[3], all entities must perform impairment assessments when events and circumstances suggest that the value of an asset (or group of assets) has declined such that its carrying costs may not be recoverable. For example, a dramatic change in market conditions could trigger a requirement to perform an impairment assessment. If the carrying cost or book value exceeds the undiscounted future cash flows of the asset(s), an impairment charge must be recognized in the company's financial statements. On December 30, 2011, the United States D.C. Circuit Court of Appeals issued a stay of USEPA's Cross-State Air Pollution Rule "CSAPR".[4] Following the stay, in early 2012 natural gas prices declined sharply. As a result of these events, Ameren performed an impairment evaluation of its merchant generation assets. Upon conclusion of such evaluation, impairment charges of $628

probable." Moody's defines a "B" rating as follows: "Obligations rated B are considered speculative and subject to high credit risk." Genco's rating is the lowest within the category. Standard & Poor's defines a "CCC" rating as follows: "Currently vulnerable and dependent on favorable business, financial and economic conditions to meet financial commitments". All of the ratings indicate the dire financial situation of Genco.

[3] Accounting Standards Codification (ASC) 360 Property, Plant and Equipment.

[4] The Court ultimately vacated the CSAPR in its entirety.

million pre-tax were recorded in the first quarter of 2012 to reduce the book value of AERG's Duck Creek to its estimated fair market value. However, under applicable accounting guidance, the estimated undiscounted future cash flows of the remainder of the merchant assets retained sufficient value at the time of the assessment to avoid impairment charges. See *Note 17 – Impairment and Other Charges, Ameren Corporation 2012 Form 10k.* As 2012 progressed, however, market conditions and outlook for the business continued to erode, forcing Ameren to make a fundamental decision regarding its business operations. The volatility and bleak outlook for earnings and cash flow from the merchant segment threatened to impede Ameren's ability to focus on and invest in its core rate-regulated operations. Accordingly, in a Form 8K filed on December 20, 2012, with the SEC, Ameren announced its intent to exit the merchant generation business and affirmed that "a change in circumstances had occurred regarding its expected duration of ownership of its Merchant Generation business segment's energy centers" and that cash flows would be insufficient to recover the total carrying value of the energy centers. As a consequence, and under applicable accounting guidance, Ameren recorded an impairment charge of $1.95 billion related to its merchant business segment indicating their value had deteriorated well below the cost of these assets reflected on Ameren's books. The specific method of exit was not identified, but the options cited in Ameren's 2012 10K included either sale of all or parts of Ameren's merchant generation business or the restructuring of all or a portion of Ameren's equity position in GENCO.

7. Prior to Ameren's decision to exit its merchant business, Ameren had taken several measures to preserve liquidity and manage its credit profile with the goal of weathering the power market downturn. Specifically, AER reduced capital and operating & maintenance

expenditures, divested select non-coal generating plants, and established an internal "Put Option" mechanism to provide CENCO with emergency standby liquidity.

III. Divestiture of AER Business Segment to Dynegy (IPH)

8. Shortly after that public announcement, Dynegy, Inc. ("Dynegy") contacted Ameren regarding the potential acquisition of the AER merchant generating business segment. Dynegy owns and operates through two if its subsidiaries coal and natural gas fired power plants in Illinois. Due to its Illinois presence and its ownership of a variety of merchant generation assets throughout the country, Dynegy was viewed as a strategic buyer for the AER assets. (During the summer and fall of 2012, other firms expressed interest in the merchant business, but those discussions did not culminate in a viable transaction for Ameren.)

9. By agreement dated March 14, 2013, Ameren agreed to convey to Illinois Power Holdings, LLC (IPH), an indirect subsidiary of Dynegy, its equity interest in AER (once reorganized). AER, through its various operating subsidiaries (AERG, AEG, EEI), owns the following coal-fired energy centers: Joppa, Edwards, Newton, Coffeen, Duck Creek, Meredosia and Hutsonville. However, not all assets and liabilities of AER are part of the IPH transaction. As directly relevant to the variance, Ameren will initiate a reorganization of AER by moving the five operating energy centers (Joppa, Edwards, Newton, Coffeen, and Duck Creek) into a subsidiary of AER ("New AER"). The reorganized company is referred to as "new AER" in the Transaction Agreement and is the entity that IPH will be acquiring. In addition, the shuttered energy centers, Meredosia and Hutsonville, will be transferred from AER but to an existing indirect subsidiary of Ameren, AmerenEnergy Medina Valley Cogen LLC ("Medina Valley") so that Ameren can continue to manage ongoing environmental responsibilities for these plants.

After closing occurs, the reorganized company acquired by IPH will be renamed and will no longer operate under the name of "Ameren" or any other similarly derived name.

10. The Put Option Agreement described in testimony and during the public hearing in PCB 12-126 has been modified and exercised by GENCO. As the Board may recall from the testimony of Gary Rygh (Barclay's Capital) and Ryan Martin (Ameren) in PCB 12-126, the Put Option Agreement was designed as a mechanism to provide cash liquidity to GENCO. Based on GENCO's current and expected liquidity position, the GENCO Board of Directors determined exercising the Put Option was in the best interest of GENCO. In essence, GENCO agreed to transfer ownership of the Elgin, Gibson City and Grand Tower natural gas plants in exchange for an irrevocable commitment that, upon exercise of the Put Option, the remittance of $100 million would immediately be made by Ameren to GENCO indirectly through a cash infusion into AERG. GENCO would subsequently receive additional funds to the extent appraised values of the three natural gas plants was determined to be greater than $100M. As part of the negotiations with Dynegy, Ameren and GENCO agreed to modify the Put Option Agreement and substituted Medina Valley in place of AERG as a party to that agreement. GENCO has exercised the option, and Ameren, through Median Valley, has remitted $100 million to GENCO. Following approval from FERC, ownership of the three natural gas facilities will be transferred from AEG to Medina Valley. The gas plant facilities are being marketed and will be sold by Medina Valley as soon as practicable. The Put Option proceeds represent GENCO's primary source of reserve liquidity, since it no longer has access to third party external financing, and can be used to support the volatile short-term working capital and cash needs associated with continued operation of the GENCO energy centers, including funding operations and potential losses and to

pay interest. Copies of the Put Option Agreements and Amendments thereto are appended to my testimony.

IV. WORKING CAPITAL REQUIREMENTS OF THE AER MERCHANT BUSINESS

11. On-going operations of AER require relatively large amounts of working capital. Specifically, the marketing activity associated with AER's generation business necessitates the availability of working capital sufficient to support the settlement of fuel purchases, power purchase and sale transactions, and any related credit assurance required under agreements with trading partners. The overall timing of all cash receipts and payments impacts ongoing working capital and cash needs. These needs varied by up to $75 million in 2012 on a daily basis within any month. Through short-term inter-company loans, Ameren Corporation extended capital to AER (including GENCO) to cover cash obligations until the settlement of power sale transactions permitted such proceeds to be remitted back to the parent company. The average daily amount of short-term debt extended to AER during the year ended March 31, 2013 was $80 million. The largest daily debt balance during this period was $132 million.

12. Ameren has historically provided credit and cash collateral support for AER's business. As of March 31, 2013, this support totaled $223 million of credit guarantees and $31 million of cash collateral support. In its December 20, 2012 announcement, Ameren indicated it planned to reduce and ultimately eliminate this support. Due to its weak financial state, AER and its subsidiaries may be required to provide cash collateral to support its ongoing business. Without a bank credit facility, parental credit support, or the ability to obtain debt from external sources, such cash collateral, would have to be funded with on-hand cash balances.

13. Future AER operations and cash needs may vary depending upon a variety of factors including the following: cash collateral requirements for new or existing contracts, the

future price of electricity, the dispatch of the generation stations, the price of fuel, changes in fuel inventory levels, future operations and maintenance expenses and capital expenditure requirements. Accordingly, while the cash position of GENCO has benefitted from the exercise of the Put Option, such proceeds must be reserved by GENCO to provide adequate ongoing liquidity and manage short-term cash volatility. The funds are not available to fund significant capital investment, including the completion of the Newton FGD. The use of GENCO's primary liquidity source to fund long-term projects that do not generate additional revenues would be financially imprudent and could threaten GENCO's ability to continue as a going concern.

14. Assuring adequate liquidity is a challenge for AER and GENCO due a number of factors described previously in the testimony of Gary Rygh (Barclay's Capital) and Ryan Martin (Ameren) and noted by the Board in PCB 12-126. GENCO cannot secure its own independent source of additional liquidity due to restrictions in certain bond indenture covenants. Outside of specific borrowing restrictions, liquidity for unregulated generation companies continues to be very limited and, if available at all, expensive given declining business conditions and operating results. Note that under IPH ownership, GENCO would continue to be subject to the indenture provisions that currently restrict its ability to secure third party financing or pay dividends.

V. COMPLIANCE OBLIGATIONS UNDER BOARD ORDER (PCB 12-126)

15. As indicated above, to facilitate the transaction, Ameren will reorganize AER to segregate the assets to be conveyed from those to be retained by Ameren through Medina Valley. Along with the natural gas plants identified above, and just prior to the closing of the IPH transaction, as noted above, ownership of the Hutsonville and Meredosia energy centers will be transferred to Medina Valley. I am the Executive Vice President and Chief Financial Officer of Medina Valley and a member of its Board of Managers. I can confirm and represent that under

the current AER variance (PCB 12-126) and in the event the Board grants IPH's proposed request for variance, neither Hutsonville nor Meredosia will operate its generating units, consistent with the Board's Order in PCB 12-126.

16. Should the Board deny the pending request for variance relief presented to the Board by IPH and Medina Valley, AER would continue to comply with the Board's Order in PCB 12-126. I simply wish to reiterate that Ameren is committed to exiting the merchant generation business in an orderly fashion so as to focus on its core utility operations. Ameren does not foresee a circumstance under which it would continue to own and operate merchant generating assets in Illinois. Should the IPH transaction not close, Ameren would continue to explore exit possibilities, which could include the sale of assets, the restructuring of debt and equity in GENCO, or some combination thereof. Under a restructuring scenario, control and operation of the merchant business would be dependent on negotiations with the GENCO bondholders and, ultimately, the result of such restructuring proceedings thereby creating uncertainty for employees, suppliers and local communities. In Ameren's view, the conveyance of the merchant business to IPH represents the best path forward for the continued operation of the energy center facilities which are an integral part of the Southern and Central Illinois economy. Dynegy already has a significant operating presence in Illinois and is well-positioned through its subsidiaries to achieve the necessary economies of scale required to operate these energy centers during uncertain and distressed power market conditions. We have no reason to believe that any other potential buyer would be willing to acquire the energy centers without the variance, unless such buyer intended to close one or more plants.

FURTHER, Affiant sayeth not.

DATED: 7/18/13

Name: Martin J. Lyons, Jr.
Title: Executive Vice President and Chief Financial Officer

Subscribed and swore to before me
this 18th day of July, 2013

Notary Public

Debby Anzalone - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #10435722
My Commission Expires 5/23/2014

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EXHIBIT 2

AFFIDAVIT OF MARIO E. ALONSO

AFFIDAVIT OF MARIO E. ALONSO

I. BACKGROUND AND QUALIFICATIONS

1. My name is Mario E. Alonso and I am the Vice President Strategic Development for Dynegy Inc. ("Dynegy"). I also am a member of Dynegy's Executive Management Team and am Vice President Strategic Development for Illinois Power Holdings, LLC ("IPH"), a wholly owned, indirect subsidiary of Dynegy. My business address is 601 Travis Street, Suite 1400, Houston, Texas 77002. I provide this affidavit in support of the Petition for Variance filed by IPH, AmerenEnergy Medina Valley Cogen, L.L.C. ("Medina Valley"), and Ameren Energy Resources, LLC ("AER") ("Petition"). I make this affidavit based on personal knowledge or on knowledge I have obtained through inquiry of individuals employed by Dynegy or its affiliates.

2. As Dynegy's Vice President Strategic Development, I am responsible for leading Dynegy's strategic planning and corporate development activities, including long-term strategic planning and mergers and acquisitions. Prior to taking on this role in July 2012, I served as Dynegy's Treasurer from August 2011 to July 2012. I previously served as Vice President, Mergers and Acquisitions from 2008-2011 and held various other key roles in Mergers and Acquisitions and Treasury at Dynegy from 2001 to 2008. Prior to joining Dynegy in 2001, I worked as an associate with Enron Corporation. I received my undergraduate business degree from the University of Virginia in 1993 with a major in finance. I received my MBA from the University of Virginia in 1999.

3. I am familiar with the planned transaction between IPH and Ameren Corporation ("Ameren"). I have read and am familiar with the September 20, 2012 Opinion and Order by the Illinois Pollution Control Board (the "Board" or "IPCB"), PCB 12-126, granting AER variance

relief from the sulfur dioxide ("SO_2") emission rates in the multi-pollutant standard ("MPS") rules applicable to the Ameren MPS Group.

II. ILLINOIS POWER HOLDINGS, LLC

4. IPH is a Delaware limited liability company owned directly by Illinois Power Holdings II, LLC, a Delaware limited liability company ("Holdings II"). Holdings II is a directly wholly owned subsidiary of Dynegy. IPH is a non-recourse entity formed with the purpose of acquiring the equity interest in Ameren's merchant utilities (as further discussed below), pursuant to the Transaction Agreement, dated March 14, 2013, between Ameren and IPH (the "Transaction Agreement"). As of the date of this affidavit, IPH does not own any assets or conduct any business in the state of Illinois.

5. No entity in Dynegy's corporate structure, outside of Holdings II and Dynegy, holds any direct or indirect interest in IPH and IPH maintains corporate separateness from Dynegy and Dynegy's existing subsidiaries. A core pillar of the transaction is that the Acquired Merchant Utilities (as defined below) must be economically viable on their own and be independent, self-sustaining, self-funding businesses. Attached Affidavit Exhibit 1 is a simplified corporate organization diagram for Dynegy Inc. as would exist upon closing of the transaction, including IPH's position as a parent company of the Acquired Merchant Utilities. Each of Dynegy's subsidiaries is an independent legal entity with separate assets and liabilities.

6. Following closing under the Transaction Agreement, IPH will own all of Ameren's interest in Ameren Energy Generating Company ("GENCO", also referred to as "AEG"), AmerenEnergy Resources Generating Company ("AERG"), Ameren Energy Marketing Company ("Ameren Marketing"), Electric Energy, Inc. ("EEI"), and Midwest Electric Power, Inc. ("MEPI") (GENCO, AERG, Ameren Marketing, EEI, and MEPI, collectively, the

"Acquired Merchant Utilities"). IPH and each of the Acquired Merchant Utilities will maintain corporate separateness from all of Dynegy's current legal entities.

III. THE ACQUISITION OF NEW AER

7. The transaction between IPH and Ameren is functionally a straightforward sale of equity interests in the company owning the generating assets. At the closing of the transaction and after a reorganization of AER that, to IPH's understanding, Ameren intends to undertake prior to closing (the reorganized company is referred to in the Transaction Agreement as "New AER"), Ameren will transfer 100 percent of its equity interest in New AER to IPH with the result that IPH will acquire all of Ameren's interests in the Acquired Merchant Utilities and the operating generating facilities they hold at closing, specifically the: (i) Coffeen Plant (located in Coffeen, Illinois), (ii) Duck Creek Plant (located in Canton, Illinois), (iii) E.D. Edwards Plant (located in Bartonville, Illinois), (iv) Newton Power Plant (located in Newton, Illinois), and (v) Joppa Generating Station (located in Joppa, Illinois) (collectively, the "Acquired Plants").

8. The closing of the transaction is expected to occur during the fourth quarter of 2013. IPH's obligation to close is subject to two specific conditions relevant to the Petition. The first is the transfer to IPH, or such other legally binding approval by the Board which has the effect of making applicable immediately after closing of the transaction to IPH, of the variance relief, Docket PCB 12-126, granted by the Board on September 20, 2012 to AER (the "Variance Relief") without material change. The second is the successful transfer of the Grand Tower, Gibson City and Elgin natural gas-fired energy centers (collectively, the "Put Assets") to Petitioner Medina Valley. IPH insisted its obligations to close the acquisition from Ameren be conditioned upon the applicability of variance relief after the transaction because the Acquired Plants will simply not be financially viable without the relief from the MPS rules applicable to

the Ameren MPS Group. If the variance relief from the MPS rules requested in the Petition is not granted, and IPH nonetheless moves forward with the transaction, IPH's only option to comply with the MPS would be to shut down a combination of the Newton, E.D. Edwards and Joppa Energy Centers by January 1, 2015. In IPH's analysis, the E.D. Edwards and Joppa Energy Centers would be shut down by January 1, 2015.

IV. WITHOUT THE REQUESTED VARIANCE RELIEF, COMPLIANCE WITH THE 2015 AND 2017 MPS OVERALL SO_2 ANNUAL EMISSION RATES WOULD IMPOSE AN UNREASONABLE SIGNIFICANT HARDSHIP ON IPH

9. Compliance with the Ameren MPS Group Multi-Pollutant Standard rule's 2015 and 2017 overall SO_2 annual emission rates would impose an arbitrary and unreasonable hardship on IPH as the owner of the Acquired Merchant Utilities. The hardship derives from two key factors: continuing significant federal regulatory uncertainty and historically depressed power prices. As a result of these intertwined factors, IPH and the Acquired Merchant Utilities will simply not be financially viable to comply with the MPS without the requested variance relief.

10. First, USEPA has not announced formal plans or a timeline for developing a valid replacement rule for the Cross State Air Pollution Rule ("CSAPR"). While the United States Supreme Court recently decided to review the appellate court's decision vacating CSAPR, the future of CSAPR remains uncertain. President Obama's recent announcement directing USEPA to develop carbon standards for existing power plants creates additional regulatory uncertainty for long-term planning involving the Acquired Merchant Utilities and the Acquired Plants. Importantly, in the absence of an effective federal SO_2 and NO_x program that "levels the playing field" among competitors in the electric generation market, the Illinois-specific MPS

requirements continue to place the Acquired Merchant Utilities and the Acquired Plants at a competitive disadvantage with electric generators in nearby states that have not deregulated their energy markets (and, thus, in contrast to the Acquired Plants, are able to recover environmental costs through revenues from a captive rate base) and have not required electric generators to significantly reduce SO_2 and NO_x emissions.

11. Second, based on information provided by an independent third-party reporting service[1] and as shown in the table below, power prices remain depressed and are not expected to improve over the next several years. As a merchant generator, the source of revenues for IPH and the Acquired Merchant Utilities is the sale of electricity; thus, IPH and Acquired Merchant Utilities are largely dependent on the commodity price of electricity. The table below summarizes future expected natural gas and power prices as of late June 2013. The prices in the table below represent hub pricing for natural gas and power in the Midcontinent Independent System Operator ("MISO") region, where the Acquired Plants are located and sell almost all of their power.[2] MISO participants include both regulated utilities and merchant generators. For purposes of comparison, in 2006-2007, the power price relevant to the Acquired Plants was approximately $60 per megawatt hour,[3] and the natural gas price was approximately $6.70 per mmBtu.[4] The data clearly shows objective market expectations that for the next several years power prices will remain depressed and natural gas prices will remain at distressed levels.

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[1] SunGard Kiodex LLC (Kiodex). Kiodex surveys a variety of market sources in creating its daily market assessments and, therefore, generates a reliable unbiased market expectation.

[2] In table column "2013", June 28, 2013 power prices represent the balance of 2013 and June 28 gas prices include August to December 2013. Power prices are around the clock (ATC) prices.

[3] See *AER v. IEPA*, PCB 12-126, Opinion and Order, 61 (Sept. 20, 2012).

[4] Average Chicago Citygate price over the 2006-2007 period, based on information reported by Platts Gas Daily.

MISO Gas Price ($/mmBtu)	**2013**	**2014**	**2015**	**2016**	**2017**
6/28/2013	$3.70	$3.96	$4.17	$4.37	$4.61
MISO Power Price ($/MWhr)	**2013**	**2014**	**2015**	**2016**	**2017**
6/28/2013	$31.85	$30.67	$31.78	$33.14	$34.47

12. IPH has analyzed several financing alternatives, including self-funding, third party financing and financing through its parent company, Dynegy, in each case as described below. No viable funding mechanism exists for IPH to complete the Newton flue gas desulfurization ("FGD") project or otherwise meet the MPS 2015 and 2017 compliance deadlines.

13. IPH and the Acquired Merchant Utilities, as AER under Ameren, must be self-funding and support their own expenses through their own operating revenues. Under IPH, the Acquired Merchant Utilities will remain in the merchant power generation market without a rate base, meaning that environmental or other compliance costs cannot be recovered by rates from captive consumers. IPH and the Acquired Merchant Utilities will face significant exposure to market prices, swings in load demand, and commodity price volatility; and power prices remain at historically depressed levels.

14. In acquiring New AER, IPH will inherit the near term balance sheet challenges currently faced by AER. In the first quarter of 2013, AER had a $151 million net income loss, which follows its $396 million net income loss in 2012.[5] As stated in a recent Standard & Poor's update, GENCO, AER's largest subsidiary, "has less than adequate liquidity" and "poor standing

[5] Dynegy Inc., Prospectus, SEC Form 424B(3) filed June 5, 2013, Annex A: Financial Statements Relating to AER.

in the credit markets".[6] Notably, GENCO has approximately $825 million in long-term public bond debt outstanding, with approximately $300 million of this debt maturing in 2018 and $250 million maturing in 2020. GENCO's existing debt requires approximately $59 million in annual interest payments. GENCO's failure to repay the bonds when due would constitute a default under the GENCO bond indenture, which would likely lead to a GENCO bankruptcy. After IPH acquires New AER and its subsidiary GENCO, GENCO will continue to be responsible for repayment of that $825 million debt, including the annual $59 million interest payment obligation. Given depressed power prices, GENCO's existing debt and the significant capital expenditure needed to complete the Newton FGDs, New AER will not have the financial resources or liquidity at closing to complete construction of the Newton FGDs to comply with the MPS rule's 2015 and 2017 system-wide SO_2 annual emission rate limits.

15. Third party external financing also is not available to IPH or the Acquired Merchant Utilities. Neither IPH nor its subsidiaries will likely be able to access credit markets to obtain third-party financing due to the distressed power market in which the Acquired Merchant Utilities operate. Indeed, prior to entering the Transaction Agreement, Dynegy approached several financial institutions to inquire about the possibility of obtaining a credit facility to support the Acquired Plants once transferred to IPH. Given the low cash flow profile, negligible lien capacity of the assets, existing debt and weak credit profile of the Acquired Merchant Utilities, the financial institutions contacted replied that they would not extend a credit facility. In addition, because IPH, New AER and AERG (as with AER and AERG currently) will not be

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[6] Standard & Poor's, *Research Update: Ameren Energy Generating Co. Ratings Lowered to 'CCC+' On Weak Power Prices; Outlook Negative*, at 2, 3 (Feb. 8, 2013).

publicly registered companies and will not be rated by the credit rating agencies, they will have limited financing options.

16. Moreover, GENCO is currently prohibited by its debt covenants from obtaining external financing. While IPH generally would seek to refinance GENCO's existing $825 million bond obligation in the public market at some point in the future in order to extend the maturity dates, covenants in GENCO's bond indenture restrict GENCO's ability to incur additional indebtedness from external sources if GENCO's interest coverage ratio is less than 2.5 or its leverage ratio is greater than a specified maximum. As GENCO disclosed in a recent filing with the U.S. Securities and Exchange Commission ("SEC"), during the first quarter of 2013, GENCO's interest coverage ratio fell to a level less than the specified minimum level required for external borrowings. Further, as also disclosed in GENCO's SEC filing, due to the decline in GENCO's earnings and operating cash flows resulting from depressed power prices, GENCO's interest coverage ratio is expected to remain less than this minimum level through at least 2015. As a result, GENCO's ability to borrow additional funds from external, third-party sources is restricted. Moreover, given GENCO's poor financial health, even after GENCO regains the ability under its existing debt agreements to borrow external funds, refinancing may not be possible as a practical matter due to the onerous terms that likely would be imposed by external lenders.

17. Finally, credit pressures prevent Dynegy from financially supporting IPH and the Acquired Merchant Utilities. As part of its diligence process prior to entering the Transaction Agreement, Dynegy contacted the credit rating agencies (Moody's and Standard & Poor's) to understand the transaction's implications, if any, on Dynegy's credit rating. Both credit rating

agencies agreed that, as structured, the transaction was a credit neutral event because of the non-recourse nature of IPH. However, the credit rating agencies made clear that the transaction would have a negative effect on the credit rating of Dynegy if the acquired entities were to be absorbed into the Dynegy capital structure or if Dynegy were to provide financial support to the Acquired Merchant Utilities other than limited amounts of working capital.

18. A downgrade in Dynegy's credit rating would mean less favorable terms and conditions for Dynegy's financing (*e.g.*, increased interest rates for borrowing, more restrictive covenants) and loss of investor confidence, ultimately jeopardizing Dynegy's balance sheet and liquidity. In fact, Dynegy very recently completed a refinancing, in which Dynegy made clear to the rating agencies and equity and debt investors that IPH would be non-recourse to the Dynegy balance sheet. Today, Dynegy is recognized as having a good balance sheet within the industry and, thus, is able to obtain the benefits of this, as demonstrated by the recent favorable refinancing. Simply stated, Dynegy will not -- and, in effect, cannot -- endanger its balance sheet or its credit rating by integrating IPH and the Acquired Merchant Utilities into the Dynegy capital structure. Thus, Dynegy has publicly communicated to investors that the Acquired Merchant Utilities must stand on their own financially. Confidence from its investor base (both debt and equity) is key to Dynegy's future success and Dynegy cannot, without jeopardizing Dynegy's financial future, backtrack on its commitment to the non-recourse nature of IPH, particularly in the context that Dynegy emerged from bankruptcy in late 2012 through which it was able to restructure its balance sheet.

19. While Dynegy's new refinancing agreement would allow Dynegy to make certain investments in its subsidiaries, including IPH, Dynegy cannot invest funds under the refinancing

agreement in IPH without risking its credit rating. Nor could Dynegy invest funds under the refinancing agreement in IPH without risking its credibility with investors. Moreover, because Dynegy must balance the investment needs of all of its current and future subsidiaries, Dynegy could not commit funds under the refinancing agreement to the extent needed to complete the Newton FGDs, even if doing so would not imperil Dynegy's credit rating and credibility.

20. Upon closing of the transaction, IPH and the Acquired Merchant Utilities will not have sufficient liquidity to fund the immediate or accelerated installation of the Newton FGD project or other large environmental capital projects. At closing, IPH, New AER and its consolidated subsidiaries will have approximately $220 million in cash,[7] of which $203 million will be at GENCO and approximately $17 million at AERG/Ameren Marketing. Depending on the results of the sale process of the Put Assets, the total cash figure at closing for GENCO could be higher. However, depending largely on volatile commodity markets, the majority of this approximate $220 million in cash available at closing will be utilized over the next several years to fund operations/potential losses, pay interest, and provide some working capital and credit support. Moreover, in two years when Ameren's obligation under the Transaction Agreement to provide credit support to New AER terminates, New AER will need to replace its credit support, which may be a significant amount. In fact, if the existing credit support were to be replaced today, a substantial amount of the $220 million in cash available at closing would be used up.

21. While the exercise of the put option has infused additional capital into GENCO, the proceeds from exercising the put option (a minimum of $133 million) are part of the approximately $220 million in cash that New AER and its subsidiaries will have at closing.

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[7] The approximate nature of the $220 million amount reflects uncertainty regarding certain real estate sales. Depending on the outcome of those real estate sales, the cash at closing may be up to approximately $226 million.

However, as explained above, this cash is needed to fund operations/losses and pay interest at GENCO over the next several years, and there are no excess funds to accelerate installation of the Newton FGD project or make any other MPS compliance alternatives feasible. In addition, this cash would also be used for purposes of replacing New AER's credit support in two years.

22. At closing, New AER and its consolidated subsidiaries also will have approximately $160 million in net working capital. This does not, however, mean that the Acquired Merchant Utilities will have an incremental $160 million of liquidity to spend above the approximate $220 million in cash available at closing. This $160 million of net working capital is tied up in the business as the typical capital required to simply run the business day to day and maintain appropriate fuel (coal) inventory and materials/supplies (*e.g.*, spare parts). In fact, the majority of this $160 million net working capital is for maintaining adequate levels of fuel inventory and materials/supplies.

23. Importantly, IPH expects that the gradual recovery of power prices (anticipated to begin after April 2015) will provide New AER with sufficient cash flow and liquidity to complete construction of the Newton FGDs by year end 2019. Dynegy has made clear in its public statements that it believes power prices will begin to recover when compliance with the federal Mercury and Air Toxics Standards ("MATS") tightens supply as environmentally noncompliant or uneconomic generation units in the Midwest continue to retire. The MATS compliance deadline is April 16, 2015, but the rule allows electricity generating units to obtain one-year, and in some cases two-year, extensions of the compliance deadline.

24. As publicly stated, Dynegy expects New AER will not generate free cash flow until 2015. However, free cash flow in 2015 by New AER does not mean that New AER would have sufficient liquidity or financial resources in 2015 to spend the significant capital needed to

complete construction of the Newton FGDs or otherwise comply with the MPS. The recovery of power prices will not be immediate in 2015, nor will market recovery in 2015 be sufficient to generate the cash flow and liquidity needed to accelerate completion of the Newton FGDs in time to meet the 2017 MPS overall SO_2 annual emission limit. Rather, IPH expects the recovery of power prices and associated generation of positive cash flows to occur gradually over time. Thus, the five-year term of the requested variance is critical to allowing adequate time for both recovery of power prices and New AER and its subsidiaries to accumulate the significant financial resources needed to fund completion of the Newton FGDs, while at same time meeting their existing debt obligations, operating costs and credit support requirements.

25. In evaluating the contemplated transaction, Dynegy's position has always been that, given the depressed commodity markets and volatile nature of the merchant energy business, at the closing of the transaction, New AER must have sufficient liquidity for the next several years to meet its needs of funding operations/potential losses, paying interest, and providing some working capital and credit support. Furthermore, without the approximate $60 million in annual operational synergies that Dynegy estimates it will realize in this transaction by 2015, the approximate $220 million in cash at closing would not be sufficient to fund operations over the next several years. Those synergies will result from gross margin and cost improvements at New AER based on the successful implementation of Dynegy programs addressing, among others, reduction in forced outage rates to improve in-market availability, fuel and rail procurement practices, vendor optimization, and the combination of Dynegy's engineering, maintenance, and outage planning expertise. Implementation of Dynegy's PRIDE initiative (Producing Results through Innovation by Dynegy Employees) at New AER is also

expected to result in significant margin and cost improvements, as it has at Dynegy over the past two years, by continuously improving performance wherever possible based on the advice of our employees, the experts who see these opportunities first-hand. Both the upfront cash at closing and the synergies are required to provide comfort that the business will have the necessary liquidity over the next several years, particularly given the volatile nature of the markets. Simply stated, it is not feasible over the next several years to simultaneously have adequate liquidity necessary to continue operating the Acquired Plants and also spend hundreds of millions on capital investments to accelerate installation of the Newton FGD project, install alternative air pollution controls or otherwise comply with the MPS without the requested variance relief. Consistent with Dynegy's need to protect its credit rating and the commitments Dynegy has made to the credit rating agencies, as well as to Dynegy's creditors and investors, that IPH would not be integrated into Dynegy's capital structure, financial support from Dynegy to IPH, if any, will be limited in amount and targeted only to providing necessary working capital support. This limited support will not be for the purposes of making capital investments at the Acquired Plants (*e.g.*, pollution controls, equipment replacements) and, in any event, would only be a small fraction of the significant capital needed for a large scale capital project such as the Newton FGD project. As part of the Transaction Agreement, Dynegy also has provided a $25 million guarantee to Ameren for two years after closing for certain pre-closing payments of IPH and certain post-closing indemnification and reimbursement obligations of IPH. That guarantee is not available for making capital investments at the Acquired Plants and, again, in any event would not be sufficient to fund completion of the Newton FGD project.

26. Finally, as solely a merchant generation company without any regulated rate-based subsidiaries, Dynegy has had to face several years of economic challenges caused by depressed power pricing and a weakened national economy. Dynegy filed for Chapter 11 bankruptcy protection in July 2012 and, while successfully emerging from bankruptcy in October 2012, Dynegy continues to face near-term economic challenges posed by depressed power prices. For example, Dynegy reported operating losses of $104 million for the fourth quarter of 2012 and $142 million for the first quarter of 2013. Thus, in a very real sense, while Dynegy expects power pricing and market conditions to improve gradually over the longer-term beginning in 2015, Dynegy is not a "deep pocket" with limitless funds that could now or in the next several years be made available to IPH to complete construction of the Newton FGDs.

27. In short, at closing, IPH and the Acquired Merchant Utilities are expected to have sufficient liquidity and collateral support to meet expected operating obligations, including sufficient funds to continue construction of the Newton FGD project in accordance with the schedule in the requested variance relief, as well as to maximize the existing FGD systems at Duck Creek and Coffeen and utilize low sulfur coal at the other Acquired Plants. IPH and the Acquired Merchant Utilities will not, however, have sufficient funds to meet the MPS requirements without the requested variance relief or to accelerate installation of the Newton FGD project.

V. CONCLUSION

28. I have read the Petition and the facts stated therein with regard to subject matters of this affidavit are true and correct to the best of my knowledge and belief.

FURTHER, Affiant sayeth not.

DATED: July 19, 2013

Mario E. Alonso

Subscribed and swore to before me
this 19th day of July, 2013

Katherine D. Fisher
Notary Public

KATHERINE D. FISHER
Notary Public
STATE OF TEXAS
My Comm. Exp. November 18, 2016

EXHIBIT 3

MAP DEPICTING LOCATIONS OF ENERGY CENTERS AND IPEA AIR QUALITY MONITORING STATIONS

Illinois Environmental Protection Agency, *Illinois Annual Air Quality Report* (2011) (including map depicting Agency air quality monitoring stations with the locations of the Ameren MPS Group superimposed).

State of Illinois
Illinois Environmental Protection Agency

Annual Air Quality Report

Illinois

❖

2011

November 2012

ILLINOIS ANNUAL AIR QUALITY REPORT 2011

Illinois Environmental Protection Agency
Bureau of Air
1021 North Grand Avenue, East
P.O. Box 19276
Springfield, IL 62794-9276

Printed on recycled paper

2011
EXECUTIVE SUMMARY

This report presents a summary of air quality data collected throughout the State of Illinois during the calendar year - 2011. Data is presented for the six criteria pollutants (those for which air quality standards have been developed - particulate matter (PM_{10} and $PM_{2.5}$), ozone, sulfur dioxide, nitrogen dioxide, carbon monoxide, and lead) along with some heavy metals, nitrates, sulfates, volatile organic and toxic compounds. Monitoring was conducted at 75 different site locations collecting data from more than 170 instruments.

In terms of the Air Quality Index (AQI) air quality during 2011 was either good or moderate 92 percent of the time throughout Illinois. There were no days when air quality in some part of Illinois was considered Unhealthy (category Red). This compares with zero Unhealthy days in 2010. There were 31 days (25 for 8-hour ozone, 4 for $PM_{2.5}$ and 2 for both 8-hour ozone and $PM_{2.5}$) when air quality in some part of Illinois was considered Unhealthy for Sensitive Groups (category Orange). This compares with 32 Unhealthy for Sensitive Groups days reported in 2010. Air quality trends for the criteria pollutants are continuing to show downward trends or stable trends well below the level of the standards. Percentage changes over the ten year period 2002 – 2011 are as follows: 24-hour Particulate Matter (PM_{10}) 15 percent decrease, annual Particulate Matter ($PM_{2.5}$) 20 percent decrease, 1-hour Sulfur Dioxide 47 percent decrease, annual Nitrogen Dioxide 29 percent decrease, 8-hour Carbon Monoxide 48 percent decrease, Lead 33 percent decrease, and 8-hour Ozone 5 percent decrease.

Stationary point source emission data has again been included. The data in the report reflects information contained in the Emission Inventory System (EIS) as of December 31, 2011. Emission estimates are for the calendar year 2011 and are for the pollutants: particulate matter, volatile organic material, sulfur dioxide, nitrogen oxides and carbon monoxide. Emission trends of these pollutants have been given for the years 1998 to the present. Emissions reported with the Annual Emissions Report have been provided starting with 1998 and are currently available through 2010. In general there has been a trend toward decreasing emissions over this time period.

SECTION 2: STATEWIDE SUMMARY OF AIR QUALITY FOR 2011

OZONE

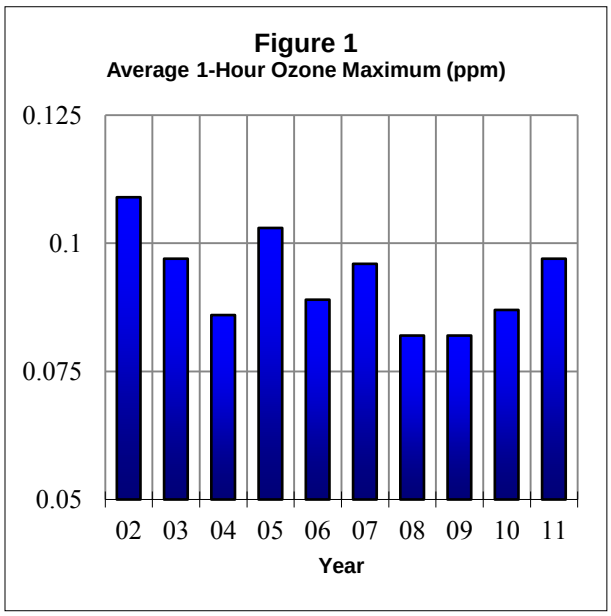
Monitoring was conducted at 34 locations during at least part of the April-October "ozone season" and at least 75 percent data capture was obtained at 34 sites.

Two sites recorded hourly concentrations above the former 0.12 parts per million (ppm) 1-hour standard. University of Chicago recorded the highest 1-hour concentration of 0.139 ppm followed by Zion with a concentration of 0.126 ppm. This compares with the highest concentration of 0.100 ppm in 2010 at both Lemont and Zion. The highest value in the St. Louis Metro East area was 0.109 ppm recorded at Jerseyville compared with a high in 2010 of 0.115 ppm at East St. Louis.

Data is also presented to compare with the 8-hour standard of 0.075 ppm. The appropriate statistic for comparison with the 8-hour standard is the fourth highest value, which is averaged over a three year period. There were 11 sites in Illinois that had a fourth high value above 0.075 ppm in 2011 compared with two sites in 2010. The highest fourth high value was 0.081 ppm at both Maryville and Wood River. The highest level in the Chicago area was 0.079 ppm at the South Water Filtration Plant. For the three year period 2009 – 2011, two sites had a fourth high average above 0.075 ppm (Table B4).

Figure 1 shows for each year the statewide average of each site's highest hourly ozone value for the ten year period 2002-2011. The graph shows some year-to-year fluctuation with high years in 2002 and 2005 and low years in 2004, 2008 and 2009. The statewide average for 2011 was 0.097 ppm compared with 0.087 ppm in 2010 and 0.082 ppm in 2009.

Statewide, the total number of 1-hour excursion days in 2011 was two compared with zero in 2010 and zero in 2009.



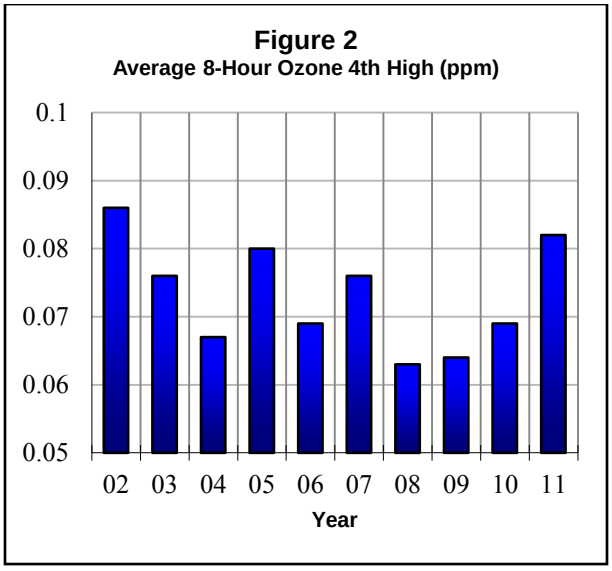


Figure 2 shows for each year the statewide average of the 4th highest 8-hour ozone value for the same period 2002-2011. The statewide average for 2011 was 0.082 ppm

compared with 0.069 ppm in 2010 and 0.064 in 2009.

Overall, Illinois' weather was much above normal in terms of meteorological conditions favorable to ozone formation and transport statewide.

July was the most conducive month in terms of meteorological conditions statewide. In terms of conducive days, the Chicago area and the Metro-East area both had much above average numbers.

PARTICULATE MATTER

Monitoring was conducted at 34 sites for $PM_{2.5}$. Valid annual averages were obtained for 32 of the 34 sites. No sites recorded an average above 15.0 ug/m^3, the level of the annual standard, compared with zero sites in 2010 and zero sites in 2009. The Statewide average of the annual averages was 11.2 ug/m^3 in 2011 compared with 11.6 ug/m^3 in 2010 and 10.6 ug/m^3 in 2009. **Figure 3** shows the trend of the Statewide annual averages for $PM_{2.5}$ for the period 2002-2011. There were 6 exceedances of the 24-hour standard of 35 ug/m^3 in 2011 compared with 31 exceedances in 2010. The Statewide peak of 39.9 ug/m^3 was recorded at Chicago Mayfair Pump Station. The Statewide average of the 98th percentile of 24-hour averages was 25.5 ug/m^3 in 2011 compared with 26.9 ug/m^3 in 2010 and 24.3 ug/m^3 in 2009.

In 2011 there were 5 sites monitoring PM_{10}. The Statewide annual average was 23 ug/m^3 compared with 23 ug/m^3 in 2010 and 20 ug/m^3 in 2009.

For PM_{10} the Statewide average of the maximum 24-hour averages in 2011 was 69 ug/m^3 compared with 62 ug/m^3 in 2010 and 56 ug/m^3 in 2009. **Figure 4** depicts this trend for the period 2002-2011.

No sites exceeded the former primary annual standard of 50 ug/m^3. The highest annual average was 31 ug/m^3 in Granite City. The lowest annual was 13 ug/m^3 in Northbrook. There were no exceedances of the 24-hour primary standard of 150 ug/m^3. The highest 24-hour average was recorded in Lyons Township with a value of 92 ug/m^3 compared with a high 24-hour value of 106 ug/m^3 in Granite City in 2010.

Figure 3
Particulate Matter ($PM_{2.5}$) Annual Trends (ug/m^3)

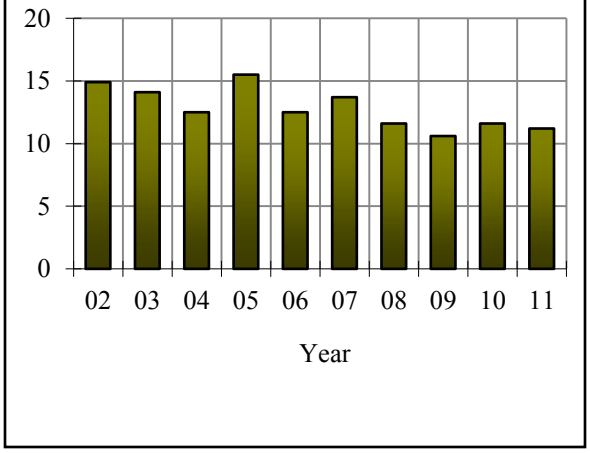
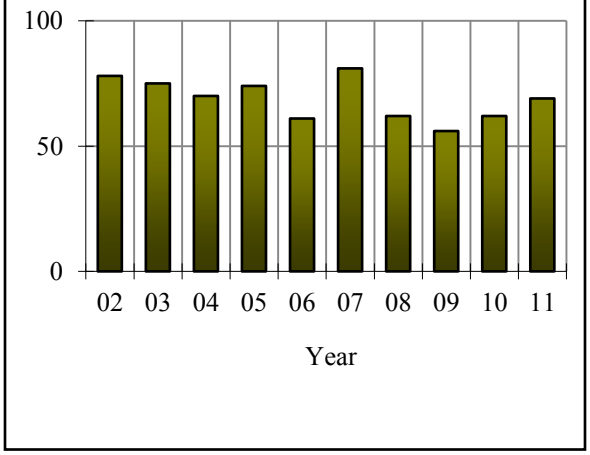


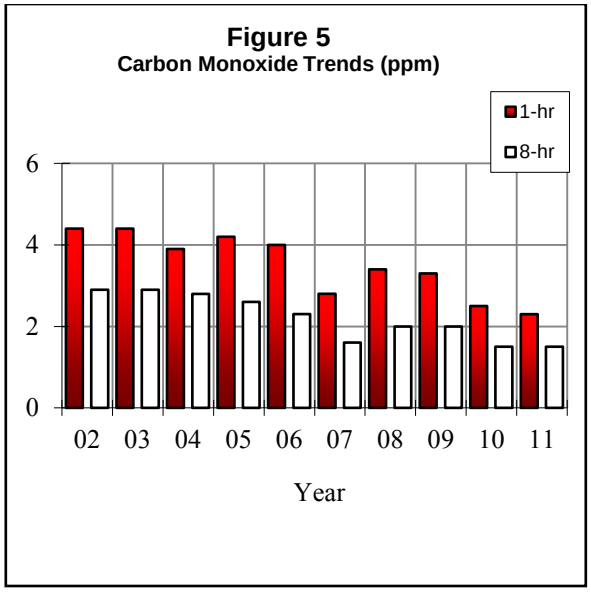
Figure 4
Particulate Matter (PM_{10}) 24-Hour Trends (ug/m^3)



CARBON MONOXIDE

There were no exceedances of either the 1-hour primary standard of 35 ppm or the 8-hour primary standard of 9 ppm in 2011. The highest 1-hour average was 3.3 ppm recorded at Chicago Transit Authority. The highest 8-hour average was 2.0 ppm recorded in Maywood and Peoria.

Figure 5 shows the trend for the period 2002-2011 for the statewide average of the 1-hour and 8-hour high CO values. The overall trend for both averages is downward. The statewide average of the 1-hour high was 2.3 ppm in 2011 compared with 2.5 ppm in 2010. The statewide average for the 8-hour high was 1.5 ppm in 2011 compared with 1.5 ppm in 2010.



SULFUR DIOXIDE

There were 42 exceedances of the new 1-hour primary standard of 75 ppb in 2011 compared with 50 exceedances in 2010. There were no exceedances of the 3-hour secondary standard of 500 ppb in 2011. The annual and 24-hour primary standards were revoked by USEPA in 2010. The highest 1-hour average was 262 ppb recorded in Pekin compared with 331 ppb in Pekin in 2010. The statewide average of the 1-hour high in 2011 was 63 ppb. This compares with 75 ppb in 2010 and 81 ppb in 2009. The highest 3-hour average of 176 ppb was recorded in Pekin in 2011 compared with 223 ppb in Pekin in 2010. There were two sites over the primary 1-hr standard of 75 ppb for the 2009-2011 period compared to four sites for the 2008-2010 period (Table B17).

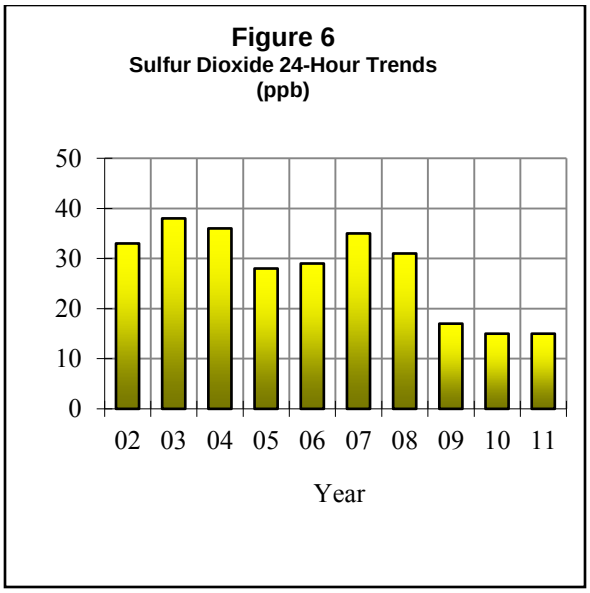
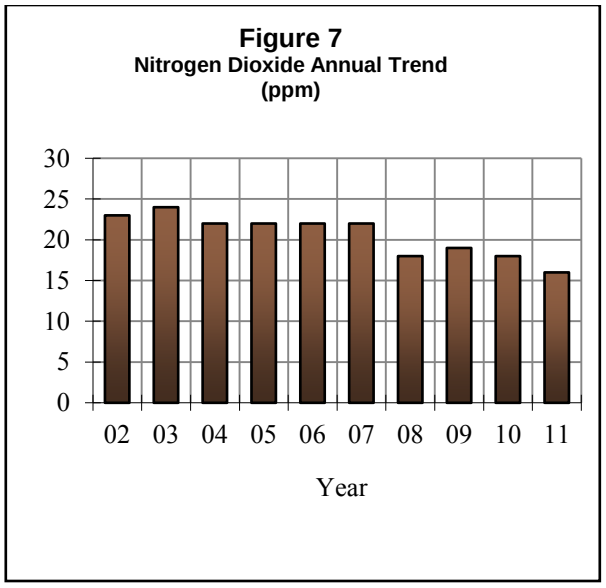


Figure 6 shows the statewide trend for the maximum 24-hour averages for the period 2002-2011. The 24-hour average trend has been overall downward; however a greater degree of year-to-year fluctuations have occurred. The statewide average for 2011 was 15 ppb compared with the 2010 average of 15 ppb. Statewide 1-hour average maximums have also declined. The 2011 average was 63 ppb compared to 75 ppb in 2010.

NITROGEN DIOXIDE

There were no violations of the annual primary standard of 53 ppb recorded in Illinois during 2011. The highest annual average of 23 ppb was recorded at Schiller Park. The Statewide average for 2011 was 16 ppb compared with 18 ppb in 2010 and 19 ppb in 2009. There were no violations of the new 1-hour primary standard in 2011 as well. This compares to zero violations in 2010. There were no sites over the 1-hour primary standard of 100 ppb for the 2009-2011 period compared to zero sites for the 2008-2010 period (Table B20).

One site operated only during part of the ozone season as PAMS. **Figure 7** depicts the trend of statewide averages from 2002-2011. The trend has been generally stable for the period ranging from 16 ppb to 24 ppb. There have been no violations of the annual standard since 1980.



LEAD

Perhaps the greatest success story in controlling criteria pollutants is lead. As a direct result of the Federal Motor Vehicle Control Program which has required the use of unleaded gas in automobiles since 1975, lead levels have decreased by more than 90 percent statewide. Based on new health studies the lead standard was revised in 2008 from a quarterly mean of 1.5 ug/m^3 to a rolling 3-month maximum mean of 0.15 ug/m^3.

There were no violations of the former quarterly lead standard of 1.5 ug/m3. There were three violations of the new rolling 3-month maximum mean standard for the 2009 to 2011 period. Violoations were recorded at Granite City - 15th & Madison with a value of 0.42 ug/m^3, Chicago Perez with a value of 0.29 ug/m^3 and Decatur Mueller with a value of 0.20 ug/m^3. This compares with a statewide high of 0.42 ug/m^3 for 2008 to 2010 at Granite City 15th & Madison.

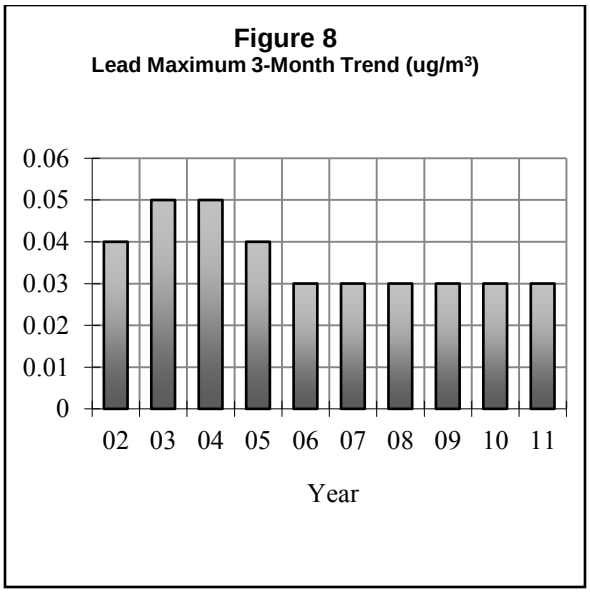


Figure 8 shows the trend of the statewide non-source maximum monthly averages from 2002-2011. The chart shows a general flat trend of ambient lead levels over the last several years. In 2010, several source oriented monitors were installed and one non-source monitor was discontinued. Currently, not enough data exists for the source oriented sites to establish a trend. However, the statewide average for all sites was 0.08 ug/m^3 in 2011 compared to 0.12 ug/m^3 in 2010.

FILTER ANALYSIS RESULTS

The TSP samples analyzed, in addition to lead, for specific metals, sulfates and nitrates. Several of the metals analyzed (arsenic, beryllium, cadmium, chromium, manganese, and nickel) have known toxic properties. Other metals such as iron can be used as tracers to help identify sources of high particulate values. Sulfates and nitrates are precursors of acid precipitation/deposition and add to the understanding of this inter-regional problem. They are also important constituents of the $PM_{2.5}$ values. There are currently no State or Federal ambient air quality standards for these parameters.

The areas with the highest metals concentrations in Illinois are generally the heavy industrialized areas of the Metro-East (Granite City and East St. Louis) and South Chicago, especially for iron and manganese. The highest 24-hour average for arsenic was 0.464 ug/m^3 measured in Granite City. The highest annual average of 0.011 ug/m^3 was also recorded at Granite City. There were no measurable beryllium 24-hour averages recorded statewide. Chicago Perez recorded the highest cadmium concentrations with a maximum 24-hour average of 0.022 ug/m^3. The highest annual average of 0.002 ug/m^3 was also recorded at Chicago - Washington. The highest 24-hour chromium average was 0.092 ug/m^3 recorded at Maywood. Maywood had the highest annual average at 0.023 ug/m^3. The highest iron and manganese values were recorded in South Chicago and the high traffic areas of Maywood. The highest 24-hour average for nickel was recorded at Maywood with a value of 0.016 ug/m^3. The highest annual average was in Maywood with an average of 0.008 ug/m^3. For nitrates, the highest 24-hour average was 34.0 ug/m^3 recorded at Chicago - Washington. The highest annual average was 4.1 ug/m^3 recorded at Maywood, Cermak and Chicago – Washington. For sulfates, the highest 24-hour average was 17.7 ug/m^3 recorded at Maywood. The highest annual average was 7.5 ug/m^3 at Chicago - Washington. In general, metals, nitrate and sulfate values were slightly higher in 2011 than in 2010.

TOXIC COMPOUNDS

Sampling for toxic compounds other than metals (see Filter Analysis Section) was conducted at Northbrook and Schiller Park. Most compounds were below the method detection limits. The highest compounds were toluene, mercury, benzene, acrolein and formaldehyde.

$PM_{2.5}$ SPECIATION

$PM_{2.5}$ samples are also analyzed for numerous constituents at 5 sites. The major constituents (inorganic elements, ammonium, nitrate, sulfate, elemental and organic carbon) are listed in **Table B26**. In general, approximately 62% is ammonium nitrate and ammonium sulfate, 32% is elemental and organic carbon and 6% is inorganic elements.

Statewide Air Monitoring Site Locations

ID	NAME	XCOORD	YCOORD	AQS CODE
1	Quincy John Wood Community College	642227.44	4419695.50	170010007
2	Champaign	394297.22	4442244.68	170190006
3	Thomasboro	398939.77	4455622.22	170190007
4	Bondville SWS Climate Station	382927.63	4434458.00	170191001
5	Alsip Village Garage	439028.14	4613506.98	170310001
6	Chicago Washington H.S.	455116.70	4615183.98	170310022
7	Chicago Cermak Pump Station	446450.82	4635956.70	170310026
8	Chicago South Water Filtration Plant	454702.37	4622802.04	170310032
9	Chicago Mayfair Pump Station	437859.32	4646216.44	170310052
10	Chicago Springfield Pump Station	440063.88	4640354.22	170310057
11	Chicago CTA Building	447307.81	4636384.48	170310063
12	Chicago University of Chicago	450011.00	4626726.33	170310064
13	Chicago Jardine Water Plant	449590.78	4638386.72	170310072
14	Chicago Comm ED	440680.96	4622421.39	170310075
15	Perez Elementary School	445348.00	4633988.00	170310110
16	Chicago Taft H.S.	434390.00	4648367.48	170311003
17	Lyons Township Village Hall	430877.97	4628036.70	170311016
18	Lemont IEPA Trailer	417538.46	4613403.03	170311601
19	Blue Island Eisenhower H.S.	442015.58	4612496.03	170312001
20	Schiller Park IEPA Trailer	427390.48	4646283.31	170313103
21	Summit Graves Elementary School	433134.91	4626002.30	170313301
22	Cicero IEPA Trailer	437539.20	4633977.22	170314002
23	Des Plaines Regional Office Building	428543.56	4656797.86	170314007
24	Northbrook Water Plant	433953.24	4665668.78	170314201
25	Maywood 1500 Maybrook Drive Platform	431442.48	4635917.35	170316003
26	Maywood Comm ED Maintenance	431199.07	4635910.07	170316004
27	Cicero Liberty School	437852.27	4634984.05	170316005
28	Maywood 4th District Court Building	431466.96	4635994.08	170316006
29	Evanston Water Pumping Station	444223.82	4656857.88	170317002
30	Naperville City Hall	404209.07	4625007.66	170434002
31	Lisle Morton Arboretum	410890.26	4629582.92	170436001
32	Effingham Central Junior H.S.	366000.19	4325369.00	170491001
33	Knight Prairie Township	357489.72	4216177.00	170650002
34	Jerseyville Illini Junior H.S.	731349.00	4332451.50	170831001
35	Elgin McKinley School	394074.74	4656164.53	170890003
36	Elgin Larsen Junior H.S.	394651.06	4656017.29	170890005
37	Aurora Health Department	389528.14	4626729.16	170890007
38	Zion Camp Logan	433408.66	4702013.37	170971007
39	Oglesby IEPA Trailer	328401.31	4573311.00	170990007
40	Cary Grove H.S.	397480.49	4675110.16	171110001
41	Normal ISU Physical Plant	330837.53	4487250.50	171132003
42	Decatur IEPA Trailer	335319.94	4414769.00	171150013
43	Decatur Mueller	333988.00	4414303.00	171150110
44	Nilwood IEPA Trailer	258043.88	4364498.50	171170002
45	Alton Clara Barton Elementary School	747358.56	4308458.00	171190008
46	Granite City Air Products	747522.88	4286713.50	171190010
47	Granite City Gateway Medical	748300.44	4287426.50	171190024
48	Granite City Fire Station 1	748727.63	4287873.00	171191007
49	Maryville Southwest Cable TV	242682.59	4290595.00	171191009
50	South Roxana Grade School	755353.88	4301836.50	171191010
51	Edwardsville RAPS Trailer	757101.44	4298007.00	171192007
52	Alton SIU Dental Clinic	747734.94	4309900.00	171192009
53	Wood River Water Treatment Plant	751122.13	4305295.00	171193007
54	Peoria Fire Station 8	279707.38	4507329.50	171430024
55	Peoria Commercial Building	279203.50	4508748.50	171430036
56	Peoria City Office Building	281616.22	4508336.50	171430037
57	Bartonville Pump Station	276515.00	4503674.00	171430110
58	Mapleton Caterpillar Plant	267429.00	4493834.00	171430210
59	Peoria Heights H.S.	281679.94	4513723.50	171431001
60	Houston Baldwin Site 2 - IEPA Trailer	255745.52	4229049.50	171570001
61	Rock Island Arsenal	707169.75	4598886.00	171613002
62	East St. Louis RAPS Trailer	747238.69	4277551.00	171630010
63	Springfield Sewage Treatment Plant	278158.03	4408840.50	171670006
64	Springfield Federal Building	273312.59	4408832.50	171670008
65	Springfield Illinois Agriculture Building	273728.00	4412449.00	171670012
66	Springfield Illinois Building	274003.78	4412395.53	171670014
67	Pekin Fire Station 3	275274.31	4492892.00	171790004
68	Mount Carmel Division Street	432441.06	4250177.00	171850001
69	Sterling Sauk Medical Clinic	275084.00	4629822.00	171950110
70	Joliet Pershing Elementary School	406854.40	4597853.20	171971002
71	Braidwood Comm ED Maintenance	400173.37	4564033.85	171971011
72	Rockford City Hall	327811.72	4681606.50	172010011
73	Rockford Winnebago County Health Department	327392.16	4681107.00	172010013
74	Rockford J. Rubin and Company	327440.00	4678637.00	172010110
75	Loves Park Maple Elementary School	332121.41	4688981.00	172012003

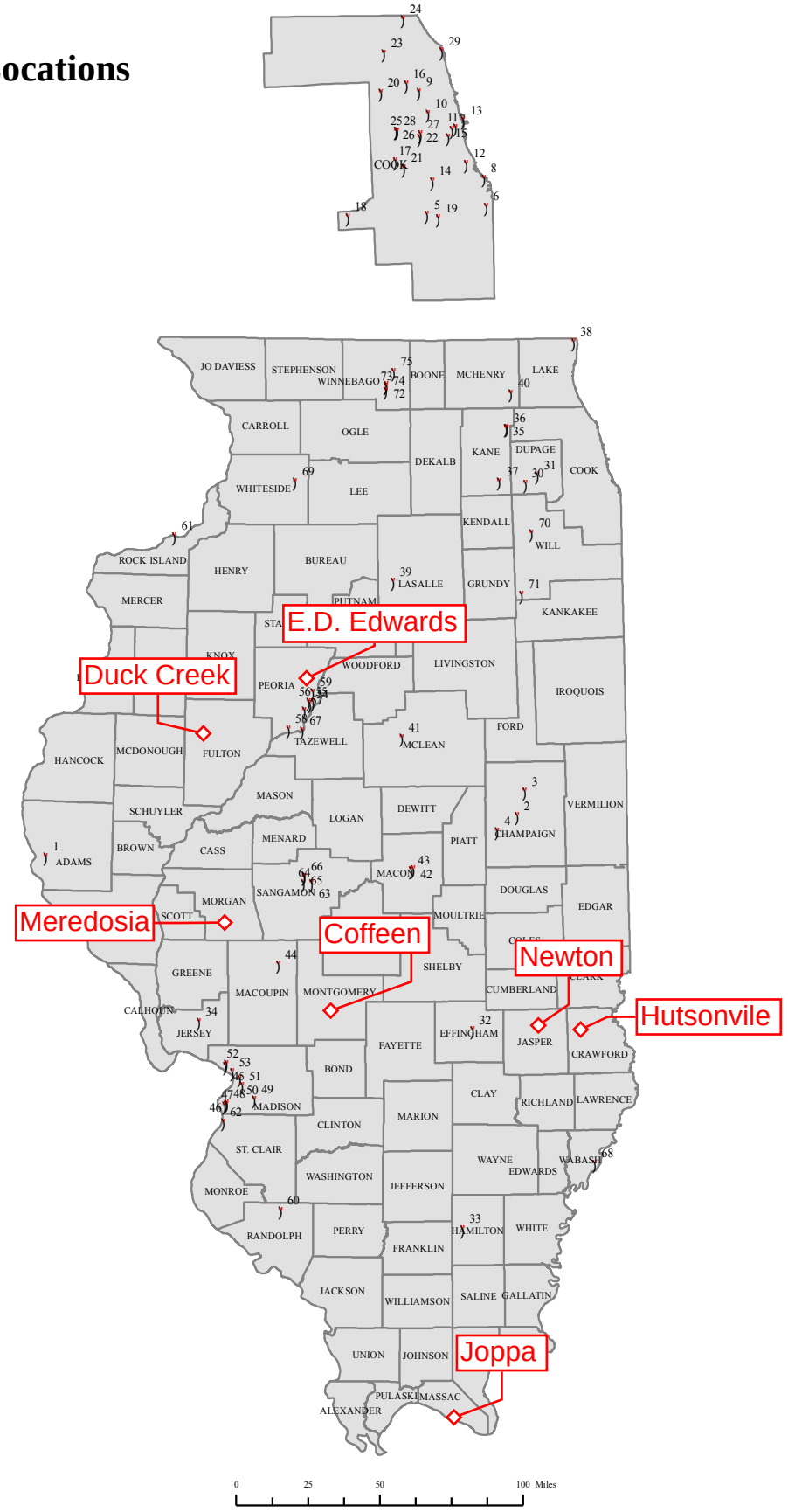


EXHIBIT 4

USEPA DOCKET QA-OAR-2012-0233

March 15, 2013

United States Environmental Protection Agency
Air Docket
Attention Docket ID No. EPA-HQ-OAR-2012-0233
Mail Code 6102T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Dear Sirs,

Ameren appreciates the opportunity to comment on the US EPA recommendations for the Pekin, IL SO_2 nonattainment area. Ameren Corporation ("Ameren") is based in St. Louis, MO, and through its operating companies serves 2.4 million electric and nearly one million natural gas customers across a 64,000-square-mile area in Illinois and Missouri. Ameren companies' net generating capacity is more than 16,400 megawatts. Our power plants use a variety of fuels to generate electricity—principally coal, nuclear, hydro and natural gas.

Specifically Ameren disagrees with the inclusion of the Hollis Township in Peoria County to the Pekin, IL SO_2 non-attainment area for the following reasons:

1) The Pekin area map displayed in Figure 2 of the Illinois EPA's technical support document[1] shows that the Hollis Township (in particular the Ameren Edwards Energy Center) is located almost directly north of the exceeding Pekin SO_2 monitor. Figure 3 in that same document shows the wind rose for the nearby Peoria Regional Airport. This figure indicates that winds from the north account for less than 5% of total direction occurrences. US EPA makes the following statement in their response to the Illinois technical support document:

> "The wind rose provided by Illinois suggests that winds come most frequently from the south, and somewhat frequently from the northwest, but winds come from all directions with sufficient frequency to suggest that meteorology is not a significant factor in defining this nonattainment area."[2]

This statement is misleading. With such a low percentage of winds from the north the probability of facilities located north of the exceeding monitor having a significant impact is expected to be low.

2) Figure 4 of the Illinois technical support document[1] shows the pollution rose for the years 2008-2010. This figure shows that over 90% of the occurrences of hours with $SO_2 > 75$ ppb occurred for wind directions from the West to Southwest. The remaining hours with $SO_2 > 75$ ppb occurred for wind directions from the East to South-Southwest. Figure 1 below and Attachment I shows a more detailed picture of this pollutant rose.[3] This figure uses data from the Tazewell county SO_2 monitor and meteorology from the Greater Peoria Regional Airport (see Attachment I). The enhanced pollutant rose

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[1] Technical Support Document: Recommended Attainment/Nonattainment Designations in Illinois for the 2010 Revised Primary 1-Hour SO_2 National Ambient Air Quality Standard (AQPSTR 11-02); June 2, 2011

[2] Draft Technical Support Document Illinois Area Designations For the 2010 SO2 Primary National Ambient Air Quality Standard; US EPA February 2013.

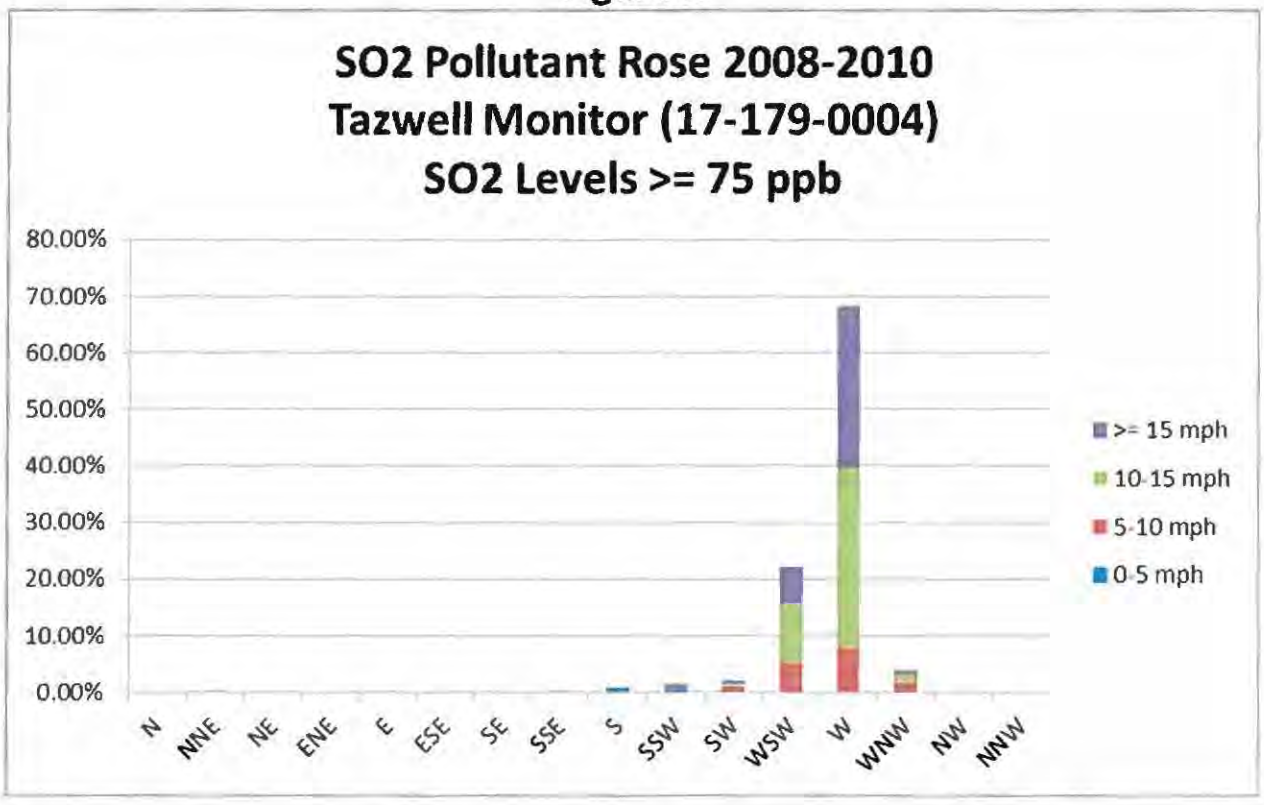
[3] See references in Attachment I for data sources

shown in Figure 1 demonstrates that for the 3 year period 2008-2010 there were no contributions from facilities located north of the Tazewell county monitor for measured SO_2 levels greater than or equal to 75 ppb. Actually over 99% of the measured SO_2 levels 75 ppb or larger occurred for winds from the South-Southeast to West-Northwest. The majority of these occurred with winds from the West and West-Southwest.

3) Further evaluation of Figure 1 (as well as the detailed hourly data in Attachment I) indicates that the meteorology associated with elevated SO_2 levels was occurring a majority of the time with wind speeds greater than 10 mph. These relatively high wind speeds can cause plumes from relatively short stacks to experience significant downwash. Such stacks exist just west of the Tazewell county SO_2 monitor.

4) US EPA in its response to Illinois' analysis for designating the Pekin, IL area nonattainment insinuates that just because there is a significant SO_2 emitting source north of the monitor that it automatically contributes to the higher levels monitored. This assumption is false based on the analysis described above. In addition as US EPA surely knows that the level of emissions emitted is not the only factor that should be considered. US EPA needs to consider the actual location of the source relative to the monitor and area's meteorology (as discussed above); the sources stack height; sources stack flow and temperature; and the sources other relevant operating characteristics. It is presumptuous of US EPA to assume that a source that emits SO_2 automatically contributes to the exceedances measured without considering all relevant information.

Figure 1



Based on this analysis and Illinois EPA's analysis the facilities located north of the Tazewell monitor did not contribute to any of the measured exceedances of the one hour SO_2 standard in Tazewell County. US EPA has not sufficiently demonstrated that Hollis Township, Peoria County should be included in the Pekin, IL SO_2 nonattainment area and thus Hollis Township should be removed from US EPA's recommendation.

If you have any questions please don't hesitate to contact me at 314-544-2089.

Sincerely,

Kenneth Anderson
Managing Supervisor – Air Quality Management

Attachment

Attachment I

Hourly SO_2 Data from the Tazewell Monitor and Wind Data from the Peoria Airport for Measured SO_2 Levels >= 75 ppb 2008-2010

SO2 and Wind Data for Tazewell Area 2008

Date	Hour	SO2 (ppb)	Wind Speed (mph)	Wind Direction (deg)
12/27/2008	21:00	277	5	200
11/08/2008	0:00	260	17	260
12/28/2008	0:00	256	18	260
05/02/2008	18:00	243	15	260
12/27/2008	23:00	231	24	270
11/08/2008	2:00	229	14	260
12/28/2008	3:00	225	15	260
12/28/2008	2:00	211	20	260
11/07/2008	23:00	207	14	260
			14	260
			17	260
12/28/2008	1:00	205	18	260
12/28/2008	6:00	181	13	260
11/07/2008	22:00	165	15	270
12/27/2008	22:00	164	15	270
			22	270
12/28/2008	4:00	164	11	250
			21	270
04/12/2008	5:00	160	11	270
03/25/2008	15:00	155	20	280
05/03/2008	8:00	155	20	260
03/25/2008	16:00	143	15	270
04/12/2008	4:00	143	11	250
04/12/2008	2:00	142	15	260
			16	260
05/03/2008	9:00	140	20	270
11/08/2008	1:00	136	14	260
04/26/2008	8:00	119	16	250
			15	260
			16	250
12/29/2008	11:00	119	14	270
10/02/2008	14:00	118	11	260
01/17/2008	22:00	117	10	260
04/26/2008	13:00	115	18	280
04/07/2008	12:00	114	16	270
03/21/2008	13:00	112	11	220
12/02/2008	1:00	112	8	250
			9	260
12/28/2008	7:00	111	9	270

01/17/2008	21:00	110	11	260
			14	260
10/02/2008	15:00	109	7	280
11/08/2008	9:00	105	20	270
04/26/2008	5:00	103	14	270
04/07/2008	11:00	102	14	290
01/17/2008	16:00	100	15	270
04/12/2008	1:00	97	16	260
04/26/2008	10:00	96	15	260
04/12/2008	6:00	95	16	280
04/26/2008	7:00	90	15	250
			20	260
12/02/2008	2:00	90	8	260
			7	260
			8	260
03/25/2008	14:00	89	22	260
04/26/2008	11:00	87	15	260
11/07/2008	18:00	86	13	250
12/28/2008	5:00	85	5	230
04/26/2008	12:00	81	18	270
04/26/2008	9:00	80	15	240
05/04/2008	16:00	80	9	260
12/28/2008	8:00	80	15	260
11/10/2008	12:00	79	0	0
06/28/2008	16:00	78	14	290
03/26/2008	12:00	77	3	VR
04/12/2008	3:00	77	11	250
06/28/2008	11:00	77	10	250
10/02/2008	16:00	77	7	280
05/02/2008	19:00	76	10	250
11/08/2008	4:00	76	13	260

SO2 and Wind Data for Tazewell Area 2009

Date	Hour	SO2 (ppb)	Wind Speed (mph)	Wind Direction (deg)
03/31/2009	17:00	352	22	260
12/09/2009	7:00	282	28	260
			28	260
			22	260
			26	260
10/23/2009	16:00	263	14	250
			14	260
12/09/2009	9:00	262	25	260
			29	260
			29	260
			26	260
			29	270
12/09/2009	8:00	252	29	260
			30	260
			28	260
			31	260
			26	260
10/23/2009	17:00	235	14	260
			13	260
			15	260
			11	260
			10	270
			10	270
10/30/2009	23:00	233	18	260
			13	260
04/30/2009	10:00	231	17	280
			14	280
12/28/2009	2:00	230	10	260
05/21/2009	11:00	229	15	210
08/20/2009	15:00	202	16	270
12/09/2009	10:00	198	31	270
			28	260
			24	280
03/31/2009	18:00	197	15	250
03/10/2009	18:00	193	20	290
			14	290
10/31/2009	3:00	187	15	250
10/31/2009	2:00	183	15	260

03/08/2009	14:00	181	31	270
08/20/2009	17:00	175	7	250
10/31/2009	0:00	173	14	250
			13	280
01/17/2009	15:00	171	18	290
12/28/2009	4:00	170	10	260
			11	270
04/30/2009	14:00	169	14	270
			11	260
			11	250
04/30/2009	9:00	163	18	280
			18	270
			17	260
			15	260
06/01/2009	11:00	161	8	250
05/21/2009	10:00	160	17	260
10/31/2009	7:00	160	13	260
08/20/2009	14:00	155	17	240
12/03/2009	21:00	155	13	260
10/03/2009	3:00	154	10	260
			11	250
			11	250
12/27/2009	23:00	151	11	270
			11	260
10/31/2009	5:00	149	8	260
05/30/2009	14:00	148	5	290
10/31/2009	4:00	147	13	260
05/29/2009	11:00	146	3	VR
03/08/2009	13:00	144	28	280
05/31/2009	11:00	144	3	160
03/24/2009	21:00	144	11	250
10/23/2009	15:00	142	14	260
			15	260
			13	250
05/14/2009	11:00	142	13	280
10/06/2009	16:00	141	18	270
10/03/2009	5:00	140	10	260
			10	260
08/20/2009	16:00	139	14	250
12/10/2009	12:00	138	18	260
12/09/2009	6:00	138	25	260
			25	260
			23	260

12/10/2009	6:00	138	14	270
10/23/2009	14:00	137	13	260
			13	250
			11	250
06/09/2009	12:00	137	0	0
10/24/2009	10:00	137	9	270
06/01/2009	12:00	134	11	280
12/28/2009	3:00	134	11	260
10/24/2009	12:00	133	10	280
10/02/2009	21:00	130	14	240
			15	250
10/31/2009	1:00	129	13	270
			14	270
10/30/2009	22:00	129	25	260
			21	260
08/20/2009	13:00	127	18	240
10/03/2009	4:00	127	10	250
			10	260
05/29/2009	10:00	126	5	280
03/31/2009	16:00	125	26	270
10/03/2009	8:00	125	14	250
06/28/2009	23:00	125	6	260
10/03/2009	11:00	123	8	260
			9	250
06/01/2009	15:00	120	8	270
10/24/2009	13:00	119	10	250
04/08/2009	10:00	119	9	290
06/05/2009	9:00	118	8	230
11/25/2009	19:00	118	10	270
08/21/2009	12:00	113	13	270
10/31/2009	8:00	113	14	280
			14	270
12/09/2009	13:00	112	20	270
			28	270
11/25/2009	11:00	112	14	280
			11	260
			14	270
05/31/2009	12:00	112	6	VR
10/23/2009	20:00	112	17	270
			10	270
			10	260
12/10/2009	23:00	110	7	260
05/30/2009	12:00	109	13	250

12/10/2009	21:00	108	13	270
05/10/2009	14:00	107	13	310
08/21/2009	11:00	107	8	260
			14	260
04/25/2009	15:00	105	8	260
05/30/2009	11:00	105	13	260
10/06/2009	14:00	104	17	280
10/30/2009	20:00	103	15	250
03/25/2009	12:00	102	11	240
12/10/2009	7:00	102	13	260
12/28/2009	1:00	101	11	260
03/25/2009	14:00	100	13	250
05/11/2009	9:00	99	5	VR
10/04/2009	14:00	98	5	260
10/24/2009	11:00	98	14	260
			9	280
05/21/2009	13:00	97	9	240
11/04/2009	11:00	97	10	270
06/19/2009	10:00	97	18	250
03/25/2009	10:00	97	15	250
			16	260
			14	260
			15	260
02/07/2009	13:00	96	13	250
03/08/2009	15:00	95	29	270
05/23/2009	8:00	95	0	0
06/01/2009	10:00	95	9	240
03/25/2009	11:00	94	10	260
12/04/2009	9:00	94	11	260
05/14/2009	10:00	94	13	260
12/10/2009	22:00	93	10	270
11/25/2009	18:00	91	10	260
			11	260
04/30/2009	13:00	91	11	270
04/25/2009	14:00	91	6	270
05/14/2009	12:00	91	13	260
11/25/2009	13:00	90	16	270
06/20/2009	14:00	90	9	260
10/23/2009	18:00	89	14	260
			15	280
12/28/2009	0:00	87	13	260
12/03/2009	17:00	85	10	260
07/31/2009	13:00	85	7	280

12/03/2009	20:00	85	11	260
12/10/2009	13:00	84	14	280
07/15/2009	12:00	84	11	290
06/09/2009	13:00	83	6	280
05/29/2009	12:00	83	5	250
10/23/2009	21:00	83	14	270
			14	260
			11	280
06/05/2009	12:00	82	8	240
03/25/2009	15:00	80	11	250
			11	280
05/21/2009	9:00	80	11	260
12/11/2009	0:00	80	7	260
10/06/2009	15:00	79	16	270
04/01/2009	13:00	79	16	270
06/01/2009	19:00	79	0	0
11/04/2009	10:00	79	10	270
03/25/2009	1:00	79	3	210
04/09/2009	10:00	78	0	0
11/25/2009	21:00	78	15	280
12/26/2009	21:00	78	10	260
			10	270
05/27/2009	11:00	77	11	270
11/03/2009	12:00	76	5	230
07/31/2009	10:00	76	10	280
06/05/2009	17:00	75	9	240
05/29/2009	9:00	75	5	300

SO2 and Wind Data for Tazewell Area 2010

Date	Hour	SO2 (ppb)	Wind Speed (mph)	Wind Direction (deg)
05/13/2010	15:00	331	21	250
06/02/2010	8:00	254	10	260
01/25/2010	11:00	241	16	270
09/07/2010	9:00	228	15	260
09/07/2010	11:00	224	20	260
10/27/2010	13:00	220	22	250
09/07/2010	10:00	217	21	260
09/07/2010	14:00	210	15	270
09/07/2010	12:00	202	24	260
10/20/2010	16:00	198	9	250
10/20/2010	14:00	196	18	260
09/07/2010	13:00	195	20	260
05/13/2010	14:00	190	14	260
04/07/2010	14:00	179	14	260
01/25/2010	12:00	178	17	280
			17	260
			16	270
			21	270
			22	270
			17	280
			17	270
			17	260
03/18/2010	13:00	177	9	240
01/24/2010	12:00	174	10	250
			11	270
10/20/2010	15:00	173	13	270
10/30/2010	13:00	172	16	260
04/21/2010	20:00	170	10	260
11/13/2010	23:00	167	15	270
01/24/2010	11:00	161	11	270
10/14/2010	12:00	160	8	260
11/13/2010	18:00	151	17	250
01/25/2010	6:00	150	11	260
			10	250
11/30/2010	8:00	149	13	260
			13	260
			15	260
			14	260

10/20/2010	13:00	145	17	260
11/13/2010	20:00	144	21	270
11/30/2010	6:00	144	13	260
11/26/2010	7:00	138	10	260
11/30/2010	12:00	137	16	270
11/26/2010	2:00	134	6	240
04/15/2010	11:00	134	16	250
10/20/2010	17:00	127	7	250
11/30/2010	10:00	125	16	270
11/14/2010	3:00	122	10	260
11/13/2010	19:00	122	20	270
10/14/2010	14:00	120	13	260
03/11/2010	20:00	117	9	250
11/26/2010	8:00	116	13	270
04/15/2010	12:00	116	15	230
06/19/2010	13:00	115	7	290
11/13/2010	21:00	114	13	260
02/19/2010	11:00	114	3	190
11/30/2010	5:00	114	15	270
			11	260
11/30/2010	11:00	114	20	270
11/30/2010	2:00	113	20	270
			14	270
11/26/2010	14:00	111	15	260
10/26/2010	15:00	111	17	250
09/12/2010	13:00	110	14	250
04/21/2010	15:00	109	0	0
03/19/2010	12:00	108	14	250
10/14/2010	13:00	108	14	280
03/23/2010	14:00	108	15	210
10/27/2010	12:00	107	21	250
07/28/2010	13:00	107	13	260
05/11/2010	12:00	106	15	270
10/20/2010	12:00	105	13	270
11/14/2010	13:00	104	13	240
05/09/2010	12:00	104	7	VR
04/03/2010	11:00	102	14	290
09/16/2010	6:00	102	13	260
			11	260
			11	260
			13	260
11/13/2010	17:00	102	17	250
12/31/2010	23:00	99	20	260

10/06/2010	15:00	98	13	260
05/09/2010	14:00	97	3	VR
05/13/2010	16:00	97	16	270
10/01/2010	13:00	97	6	300
04/15/2010	13:00	97	15	230
10/27/2010	16:00	96	22	270
11/30/2010	14:00	95	21	270
11/30/2010	9:00	95	13	250
07/28/2010	12:00	94	13	250
09/12/2010	11:00	92	9	280
01/25/2010	10:00	91	13	260
			14	250
			13	260
12/31/2010	22:00	91	16	260
02/03/2010	12:00	89	3	170
01/17/2010	1:00	89	3	10
			5	40
			5	20
			3	20
			0	0
12/11/2010	20:00	88	13	250
06/27/2010	14:00	87	13	280
06/27/2010	13:00	87	15	260
01/24/2010	13:00	86	13	280
05/03/2010	14:00	86	13	280
03/11/2010	15:00	82	15	240
12/11/2010	19:00	81	14	270
03/19/2010	13:00	81	13	240
05/03/2010	17:00	81	10	280
06/19/2010	14:00	80	11	260
10/30/2010	14:00	77	11	250
02/19/2010	10:00	77	0	0
01/25/2010	5:00	77	10	260
11/30/2010	7:00	77	14	260
02/23/2010	14:00	75	9	270
05/14/2010	10:00	75	10	260
11/30/2010	4:00	75	21	270
11/30/2010	3:00	75	13	270

Note:

1. Zero for wind speed/direction indicates calm

2. Multiple wind speed/direction readings indicate more than one reading was taken for that hour because of changing conditions.
3. VR – variable
4. SO_2 data from US EPA AirData – Tazewell monitor (ID: 17-179-0004) Pekin, IL
5. Wind Speed/Direction data from NOAA – Quality Controlled Local Climatological Data (QCLC) Greater Peoria Regional Airport – Station ID: 14842/PIA

EXHIBIT 5

MPS GROUP 2012 EMISSION DATA

Michael L. Menne
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Environmental Services
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T 314.554.2816
F 314.554.4182
mmenne@ameren.com

February 6, 2013

CERTIFIED MAIL 7009 0820 0001 4250 1690

Mr. Jim Ross, Manager
Division of Air Pollution Control
Bureau of Air
Illinois Environmental Protection Agency
1021 North Grand Avenue East
P. O. Box 19726
Springfield, IL 62794-9276

RE: Illinois Multi-Pollutant Standard – Annual Emission Rate Report for 2012

Dear Mr. Ross:

In accordance with 35 Illinois Administrative Code Part 225 Subpart B Section 225.233(e)(4), Ameren Energy Resources, as authorized agent for Ameren Energy Generating Company, Ameren Energy Resources Generating Company and Electric Energy Inc., submits this Annual Emission Rate Report for 2012. This report encompasses the electric generating units that are members of Ameren's Multi-Pollutant Standard (MPS) group as contained in Ameren's "Notice of Intent" dated December 27, 2007. Below is a list of the units contained in Ameren's MPS group:

Ameren Energy Generating Company

Facility	Facility I. D.	Emission Unit
Coffeen	135803AAA	01
Coffeen	135803AAA	02
Hutsonville	033801AAA	05
Hutsonville	033801AAA	06
Meredosia	137805AAA	01
Meredosia	137805AAA	02
Meredosia	137805AAA	03
Meredosia	137805AAA	04
Meredosia	137805AAA	05
Newton	079808AAA	1
Newton	079808AAA	2

Ameren Energy Resources Generating Company

Facility	Facility I. D.	Emission Unit
Duck Creek	057801AAA	1
E. D. Edwards	143805AAG	1
E. D. Edwards	143805AAG	2
E. D. Edwards	143805AAG	3

Electric Energy, Inc.

Facility	Facility I. D.	Emission Unit
Joppa	127855AAC	1
Joppa	127855AAC	2
Joppa	127855AAC	3
Joppa	127855AAC	4
Joppa	127855AAC	5
Joppa	127855AAC	6

Section 225.233(e)(3)(B)(iii) requires the Ameren MPS Group comply with an overall NOx annual emission rate of no more than 0.11 #/mmBtu. Ameren's MPS Group achieved an overall NOx annual emission rate of 0.11 #/mmBtu for 2012. Unit specific emission data is included in Attachment 1.

By order of the Illinois Pollution Control Board (IPCB) on September 20, 2012(PCB-12-126, Variance-Air) for 2012 the Ameren MPS Group must comply with an overall SO2 annual emission rate of no more than 0.38 #/mmBtu. Ameren's MPS Group achieved an overall SO2 annual emission rate of 0.36 #/mmBtu for 2012. Unit specific emission data is included in Attachment 2.

Please contact Donald Schuh at (314) 554-2658 if you have any questions concerning this submittal or if additional information is required.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Sincerely,

Michael L. Menne

Michael L. Menne

Attachments

bcc: M. L. Menne
S. C. Whitworth
M. T. Curtis
K. J. Kersting
K. J. Anderson
M. J. Hutcheson
R. H. LaPlaca
B. Parker
D. H. Schuh
R. L. Robertson
S. C. Hughes
File: AQ 5.6.2

Multi-Pollutant Standard Demonstration of Compliance
2012 NOx Annual Emission Rates
Required by 35 IAC 225 Subpart B Section 225.233(e)(4)

Ameren Energy Generating Company				
Facility	**Emission Point**	**NOx (tons)**	**Heat Input (mmBtu)**	**NOx Emission Rate (#/mmBtu)**
Coffeen	01	703	19,425,264	0.072
Coffeen	02	1,270	34,734,221	0.073
Hutsonville	05	0	0	0.000
Hutsonville	06	0	0	0.000
Meredosia	CS0001 (01, 02, 03, 04)	0	0	0.000
Meredosia	05	0	0	0.000
Newton	1	1,946	35,688,036	0.109
Newton	2	1,057	20,336,868	0.104

Ameren Energy Resources Generating Company				
Facility	**Emission Point**	**NOx (tons)**	**Heat Input (mmBtu)**	**NOx Emission Rate (#/mmBtu)**
Duck Creek	1	1,247	25,219,961	0.099
E D Edwards	CS0001 (1, 2)	2,698	25,327,583	0.213
E D Edwards	3	611	18,872,502	0.065

Electric Energy, Inc.				
Facility	**Emission Point**	**NOx (tons)**	**Heat Input (mmBtu)**	**NOx Emission Rate (#/mmBtu)**
Joppa Steam	CS1 (1, 2)	1,532	25,030,782	0.122
Joppa Steam	CS2 (3, 4)	1,261	23,650,130	0.107
Joppa Steam	CS3 (5, 6)	1,272	22,902,466	0.111

Ameren MPS Weighted Average	13,598	251,187,813	**0.108**
Ameren MPS Group Mult-Pollutant Standard Per 225.233(e)(3)(B)(iii)			**0.114**

Note: Emissions data monitored and reported in accordance with 40 CFR Part 75.

Attachment 2

Multi-Pollutant Standard Demonstration of Compliance
2012 SO2 Annual Emission Rates
Required by 35 IAC 225 Subpart B Section 225.233(e)(4)

Ameren Energy Generating Company				
Facility	**Emission Point**	**SO2 (tons)**	**Heat Input (mmBtu)**	**SO2 Emission Rate (#/mmBtu)**
Coffeen	01	43	19,425,264	0.00
Coffeen	02	60	34,734,221	0.00
Hutsonville	05	0	0	0.00
Hutsonville	06	0	0	0.00
Meredosia	CS0001 (01, 02, 03, 04)	0	0	0.00
Meredosia	05	0	0	0.00
Newton	1	10,538	35,688,036	0.59
Newton	2	5,982	20,336,868	0.59

Ameren Energy Resources Generating Company				
Facility	**Emission Point**	**SO2 (tons)**	**Heat Input (mmBtu)**	**SO2 Emission Rate (#/mmBtu)**
Duck Creek	1	296	25,219,961	0.02
E D Edwards	CS0001 (1, 2)	6,845	25,327,583	0.54
E D Edwards	3	4,958	18,872,502	0.53

Electric Energy, Inc.				
Facility	**Emission Point**	**SO2 (tons)**	**Heat Input (mmBtu)**	**SO2 Emission Rate (#/mmBtu)**
Joppa Steam	CS1 (1, 2)	5,924	25,030,782	0.47
Joppa Steam	CS2 (3, 4)	5,734	23,650,130	0.48
Joppa Steam	CS3 (5, 6)	5,333	22,902,466	0.47

Ameren MPS Weighted Average	45,712	251,187,813	**0.36**
Ameren MPS Group Mult-Pollutant Standard Per September 20, 2012 IPCB Order			**0.38**

Note: Emissions data monitored and reported in accordance with 40 CFR Part 75.

February 1, 2013

Michael L. Menne
Vice President
Environmental Services
Ameren Services
T 314.554.2816
F 314.554.4182
mlmenne@ameren.com

October 29, 2012

CERTIFIED MAIL 7004 2890 0003 6374 3693

Mr. Jim Ross, Manager
Division of Air Pollution Control
Bureau of Air
Illinois Environmental Protection Agency
1021 North Grand Avenue East
P. O. Box 19726
Springfield, IL 62794-9276

RE: Illinois Mercury Rule Multi-Pollutant Standard – Seasonal Report for 2012

Dear Mr. Ross:

In accordance with 35 Illinois Administrative Code Part 225 Subpart B Section 225.233(e)(4), Ameren Energy Resources, as authorized agent for Ameren Energy Generating Company, Ameren Energy Resources Generating Company and Electric Energy Inc., submits this seasonal 2012 compliance report. This report encompasses the electric generating units that are members of Ameren's Multi-Pollutant Standard (MPS) group as contained in Ameren's "Notice of Intent" dated December 27, 2007. Below is a list of the units contained in Ameren's MPS group:

Ameren Energy Generating Company

Facility	Facility I. D.	Emission Unit
Coffeen	135803AAA	01
Coffeen	135803AAA	02
Hutsonville	033801AAA	05
Hutsonville	033801AAA	06
Meredosia	137805AAA	01
Meredosia	137805AAA	02
Meredosia	137805AAA	03
Meredosia	137805AAA	04
Meredosia	137805AAA	05
Newton	079808AAA	1
Newton	079808AAA	2

Ameren Energy Resources Generating Company

Facility	Facility I. D.	Emission Unit
Duck Creek	057801AAA	1
E. D. Edwards	143805AAG	1
E. D. Edwards	143805AAG	2
E. D. Edwards	143805AAG	3

Electric Energy, Inc.

Facility	Facility I. D.	Emission Unit
Joppa	127855AAC	1
Joppa	127855AAC	2
Joppa	127855AAC	3
Joppa	127855AAC	4
Joppa	127855AAC	5
Joppa	127855AAC	6

Section 225.233(e)(3)(B)(i) requires the Ameren MPS Group comply with an overall NOx seasonal emission rate of no more than 0.11 #/mmBtu. Ameren's MPS Group achieved an overall NOx seasonal emission rate of 0.109 #/mmBtu for the 2012 ozone season. Unit specific emission data is included in Attachment 1.

I am authorized to make this submission on behalf of the owners and operators of the affected units for which this submission is made. Please contact Donald Schuh at (314) 554-2658 if you have any questions concerning this submittal or if additional information is required.

Sincerely,

Michael L. Menne

Michael L. Menne

Attachment

Attachment 1

Multi-Pollutant Standard Demonstration of Compliance
2012 NOx Ozone Season Emission Rates
Required by 35 IAC 225 Subpart B Section 225.233(e)(4)

Ameren Energy Generating Company				
Facility	**Emission Point**	**NOx (tons)**	**Heat Input (mmBtu)**	**NOx Emission Rate (#/mmBtu)**
Coffeen	01	290	8,589,844	0.068
Coffeen	02	547	14,158,471	0.077
Hutsonville	05	0	0	0.000
Hutsonville	06	0	0	0.000
Meredosia	CS0001 (01, 02, 03, 04)	0	0	0.000
Meredosia	05	0	0	0.000
Newton	1	886	16,004,071	0.111
Newton	2	481	9,035,849	0.106

Ameren Energy Resources Generating Company				
Facility	**Emission Point**	**NOx (tons)**	**Heat Input (mmBtu)**	**NOx Emission Rate (#/mmBtu)**
Duck Creek	1	531	10,020,339	0.106
E D Edwards	CS0001 (1, 2)	1131	10,913,845	0.207
E D Edwards	3	240	7,875,766	0.061

Electric Energy, Inc.				
Facility	**Emission Point**	**NOx (tons)**	**Heat Input (mmBtu)**	**NOx Emission Rate (#/mmBtu)**
Joppa Steam	CS1 (1, 2)	618	10,102,220	0.122
Joppa Steam	CS2 (3, 4)	474	9,057,909	0.105
Joppa Steam	CS3 (5, 6)	516	9,043,370	0.114

Ameren MPS Weighted Average	5714	104,801,684	**0.109**
Ameren MPS Group Mult-Pollutant Standard Per 225.233(e)(3)(B)(i)			**0.114**

Note: Emissions data monitored and reported in accordance with 40 CFR Part 75.

October 25, 2011

bcc: M. Curtis
S. C. Whitworth
K. J. Anderson
B. Parker
S. C. Hughes
File: AQ 5.6.1

EXHIBIT 6

MPS GROUP INFORMATION
(§104.204(b))

General Information Responsive to 35 Ill. Adm. Code 104.204(b): Addresses; Boiler and Sizes; Pollution Control Equipment; SO_2 Emissions; Permits.

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes		Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Coffeen Energy Center (I.D. No. 135803AAA)					
134 CIPS Lane Coffeen, Illinois Montgomery County	Unit 1 Nominal 3,282 mmBtu/hr (1965)	Unit 2 nominal 5,544 mmBtu/hr (1972)	OFA[3] SCR[4] ESP[5] with FGC[6] FGD[7] Mercury Controls	2012 SO_2 emission rate = 0.004 lb/MMBtu 2012 SO_2 mass emissions = 103 tons	<u>State Operating Permits</u>: February 13, 2004 App. No. 73020002 Unit 1 February 13, 2004 App. No. 73020001 Unit 2

[1] All units unless otherwise indicated.

[2] Note that listed here are construction permit issued in or after 2005 through the present and that during this period, Ameren has been issued other construction permits for projects not pertinent to this request for variance.

[3] Overfire Air

[4] Selective Catalytic Reduction

[5] Electrostatic Precipitator

[6] Flue Gas Conditioning

[7] Flue Gas Desulfurization (scrubber)

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes		Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Coffeen Energy Center (I.D. No. 135803AAA)					
					Construction Permits: December 21, 2007 App. No. 07090069 New ESP for Unit 2 December 15, 2006; revised October 23, 2007 App. No. 06090019 New FGD for Unit 1 and Unit 2 June 22, 2009 App. No. 06090019 Revised WFGD System – Limestone Handling June 22, 2011 App. No. 11060016 Fuel Additives System for Unit 1 and Unit 2 March 2, 2012; revised March 21, 2013 App. No. 12020019 Temporary Mercury Re-Emission Reduction System

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes		Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Coffeen Energy Center (I.D. No. 135803AAA)					
					October 30, 2012 App No 12070042 Permanent Steag Mercury Control System CAAPP Permit: September 29, 2005 App. No. 95090009 Appealed November 3, 2005 (PCB 06-064) Stayed February 16, 2006 Partial Stay September 20, 2012 Reissued permit with partial stay September 20, 2012; expiration September 20, 2017

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes	Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Duck Creek Energy Center (I.D. No. 057801AAA)				
17751 North CILCO Road Canton, Illinois Fulton County	Unit 1 Nominal 3,713 mmBtu/hr (1976)	LNB[8] SCR ESP FGD Mercury Controls	2012 SO_2 emission rate = 0.02 lb/MMBtu 2012 SO_2 mass emissions = 296 tons	State Operating Permit: November 13, 1995 App. No. 78020006 Construction Permits: November 22, 2006; revised May 23, 2008 App. No. 06070049 New WFGD[9] system February 16, 2007 App. No. 06070048 Boiler project; New ESP May 7, 2007; revised January 31, 2008 App. No. 07030025 Pilot Air Quality Control System

[8] Low NOx Burner

[9] Wet FGD

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes	Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Duck Creek Energy Center (I.D. No. 057801AAA)				
				August 15, 2011 App. No. 11080047 Canton Fuels Company Reduced Emission Fuel (REF) Production Facility May 8, 2013 App. No. 13040048 Pilot Testing of Fuel Additives <u>CAAPP Permit</u>: September 29, 2005 App. No. 95070025 Appealed November 3, 2005 (PCB 06-066) Stayed February 16, 2006

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes			Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
E.D. Edwards Energy Center (I.D. No. 143805AAG)						
7800 South CILCO Lane Bartonville, Illinois Peoria County	Unit 1 Nominal 1,523 mmBtu/hr (1960)	Unit 2 Nominal 3,321 mmBtu/hr (1968	Unit 3 Nominal 4,594 mmBtu/hr (1972)	LNB ESP with FGC OFA on Unit 2 New LNB and OFA + SCR on Unit 3 Sorbent Injection	2012 SO_2 emission rate = 0.53 lb/MMBtu 2012 SO_2 mass emissions = 11,803 tons	<u>State Operating Permit</u>: July 1, 2004 App. No. 73010724 <u>Construction Permits</u>: March 9, 2007 App. No. 07030026 LNB and OFA for Unit 3 August 24, 2008 App. No. 08080029 LNB and OFA for Unit 2 September 9, 2009 App. No. 08100002 Sorbent Injection System for Units 1, 2, 3 March 30, 2011 App. No. 11030003 Pilot System for HBr injection (Mercury Control) for Unit 3

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes			Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
E.D. Edwards Energy Center (I.D. No. 143805AAG)						
						CAAPP Permit: September 29, 2005 App. No. 95070026 Appealed November 3, 2005 (PCB 06-067) Stayed February 16, 2006

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes		Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Hutsonville Energy Center (I.D. No. 033801AAA)					
15142 East 1900th Ave. Hutsonville, Illinois Crawford County	Unit 5 Nominal 695 mmBtu/hr (1952)	Unit 6 Nominal 695 mmBtu/hr (1953)	ESP	2012 SO_2 emission rate = 0.00 lb/MMBtu 2012 SO_2 mass emissions = 0 tons	<u>State Operating Permit</u>: February 17, 2005 App. No. 73020017 Unit 5 February 17, 2005 App. No. 73020018 Unit 6 <u>Construction Permits</u>: May 14, 2006 App. No. 06040014 Pilot Evaluation of Fuel Additives for SO_2 and mercury control April 3, 2008 App. No. 08030017 Pilot Evaluation of Water Injection for PM Control on Unit 5

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes		Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Hutsonville Energy Center (I.D. No. 033801AAA)					
					August 18, 2008 App. No. 08080015 Pilot OFA Evaluation for Units 5 and 6 CAAPP Permit: September 29, 2005 App. No. 95080105 Appealed November 3, 2005 (PCB 06-070) Stayed February 16, 2006

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes	Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Joppa Energy Center (I.D. No. 127855AAC)				
2100 Portland Road Joppa, Illinois Massac County	Units 1-6 Nominal 1,800 mmBtu/hr each (Units 1 and 2 1953) (Units 3 and 4 1954) (Units 5 and 6 1955)	ESP OFA on Units 1, 3, 4, 5 and 6 Sorbent Injection	2012 SO_2 emission rate = 0.48 lb/MMBtu 2012 SO_2 mass emissions = 16,991 tons	State Operating Permit: June 7, 2005 App. No. 73010757 Construction Permits: March 3, 2005 App. No. 05020008 OFA system for Unit 6 December 5, 2005 App. No. 05020011 OFA system for Unit 5 November 30, 2006 App. No. 0600057 OFA system for Unit 3 October 24, 2007 App. No. 07090035 OFA system for Unit 1

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes	Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Joppa Energy Center (I.D. No. 127855AAC)				
				October 31, 2008 App. No. 08100052 OFA system for Unit 4 March 31, 2006 App. No. 06020085 Pilot for Mercury Control December 5, 2006; revised October 30, 2007 and August 27, 2008 App. No. 06110002 Pilot for Mercury Control July 18, 2008; revised December 1, 2009 App. No. 08020070 Sorbent Injection System October 20, 2008; revised April 21, 2009 App. No. 08090057 Pilot for SNCR for NOx Control for Unit 3

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes	Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Joppa Energy Center (I.D. No. 127855AAC)				
				April 28, 2010 App. No. 11060053 Pilot for Injection System for SO_2 Control June 30, 2011; revised February 24, 2012 App. No. 11060053 Additives Injection System <u>CAAPP Permit</u>: September 29, 2005 App. No. 95090120 Appealed November 3, 2005 (PCB 06-065) Stayed February 16, 2006

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes			Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Meredosia Energy Center (I.D. No. 137805AAA)						
800 South Washington Street Meredosia, Illinois Morgan County	Units 1 and 2 Nominal 505 mmBtu/hr each (1945)	Units 3 and 4 Nominal 505 mmBtu/hr each (1946)	Unit 5 Nominal 2,784 mmBtu/hr (1957)	ESP FGC on Units 1-4 LNB, FGC and Sorbent Injection on Unit 5	2012 SO_2 emission rate = 0.0 lb/MMBtu 2012 SO_2 mass emissions = 0 tons	<u>State Operating Permits</u>: May 22, 1996 App. No. 73020005 Unit 1 May 22, 1996 App. No. 73020009 Unit 2 May 22, 1996 App. No. 73020008 Unit 3 May 22, 1996 App. No. 73020006 Unit 4 July 23, 2003 App. No. 73020007 Unit 5

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes			Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Meredosia Energy Center (I.D. No. 137805AAA)						
						Construction Permits: July 17, 2008 App. No. 08050025 Sorbent Activation Process Demonstration Project February 15, 2007 App. No. 06120072 FGC System for Boilers 1, 2, 3 and 4 December 1, 2009 App. No. 08070022 Sorbent Injection System for Unit 3/Boiler 5 August 24, 2009 App. No. 09080018 Low NOx Burners and OFA System for Boiler 5

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes			Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Meredosia Energy Center (I.D. No. 137805AAA)						
						CAAPP Permit: September 29, 2005 App. No. 95090010 Appealed November 3, 2005 (PCB 06-069) Stayed February 16, 2006

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes		Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Newton Energy Center (I.D. No. 079808AAA)					
6725 North 500th Street Newton, Illinois	Unit 1 Nominal 5,500 mmBtu/hr (1972)	Unit 2 Nominal 5,500 mmBtu/hr (1975)	LNB OFA ESP with FGC Sorbent Injection	2012 SO_2 emission rate = 0.59 lb/MMBtu 2012 SO_2 mass emissions = 16,520 tons	<u>State Operating Permits</u>: July 30, 1998 App. No. 78080036 Unit 1 June 29, 2001 App. No. 83020010 Unit 2 <u>Construction Permits</u>: June 8, 2009 App. No. 09050032 Pilot Evaluation of Fuel Additives for Mercury Control December 1, 2009 App. No. 08010049 Sorbent Injection Systems for Units 1 and 2

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes		Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Newton Energy Center (I.D. No. 079808AAA)					
					December 20, 2010 App. No. 10070051 Flue Gas Desulfurization (FGD) Systems for Unit 1 and Unit 2 February 25, 2011 App. No. 08010049 Revised Sorbent Injection System and Alternative Control Technology for Hg Control for Unit 1 June 30, 2011 App. No. 11060023 Additive Injection System for Mercury Control on Unit 2 July 28, 2011 App. No. 11070007 Fuel Additives System for Unit 1 November 28, 2011 App. No. 11070007 Fuel Additives for Unit 1 and Unit 2

Exhibit 6
Ameren MPS Group Information
(§ 104.204(b))

Address	Boilers and Sizes		Pollution Control Equipment[1]	SO_2 Emissions in Rate and TPY	Permits issued, issuance dates, application numbers, and any other relevant information[2]
Newton Energy Center (I.D. No. 079808AAA)					
					CAAPP Permit: September 29, 2005 App. No. 95090066 Appealed November 3, 2005 (PCB 06-068) Stayed February 16, 2006

EXHIBIT 7

ECONOMIC IMPACT: *DEVELOPMENT STRATEGIES MEMORANDA*

Five Memoranda Providing Economic Data and Analysis Specific to the five operating Energy Centers in the Ameren MPS Group.

Memorandum

To: Daniel P. Thompson, Vice President, Illinois Power Holdings, LLC

From: Robert Lewis, Brian Licari, and Yash Yedavalli

Date: July 12, 2013

Re: Economic Impacts of Coffeen Energy Center of Illinois and Surrounding Labor Market Area

In April, 2012, Development Strategies (DS) was commissioned by Ameren Energy Resources Corporation (AER) to conduct an independent analysis of the economic impact that the operations of AER's Coffeen Energy Center (Montgomery County) have on the Illinois economy and on its respective multi-county economic region. Development Strategies has since been commissioned by Illinois Power Holdings to update this analysis with the latest available data as of July, 2013, from both AER/Ameren Services and appropriate state and federal economic data sources. Development Strategies is pleased to submit this analysis of the direct and indirect economic impacts for this facility.

Direct economic impacts are the estimated dollars spent by AER at and in operational support of the energy center facility. For the purpose of this analysis, spending includes capital expenditures, non-payroll operations expenditures, and salaries paid to employees.

There are 162 total jobs at the Coffeen Energy Center, 161 of whom live in Illinois. We determined which counties in the "region" of the energy center are home to a large majority of those employees and this determined the facility's primary economic impact region for our impact analysis. We then calculated economic impacts within that impact region. Four Illinois counties make up the primary economic impact region in the case of Coffeen, which is home to 113 of its 162 employees. See accompanying map "AER: Coffeen Energy Center Labor Market Area" for the local labor market area boundaries.

Indirect economic impacts measure the "ripple effect" of wages and expenditures associated with AER's direct spending. For instance, Coffeen employees who live in Illinois will spend a large proportion of their earnings within the state of Illinois for housing and at local businesses such as retail stores, restaurants, mechanics, and others. Thus, each job at Coffeen will contribute to additional job support across many sectors in the community and, consequently, the state of Illinois. Likewise, much of the non-labor operational spending by the energy center is initially spent within the state, thus supporting additional income and jobs in the immediately surrounding counties and throughout the state.

To calculate these indirect impacts, multiplier coefficients are applied to the direct impact dollars; these multipliers also automatically take into account the amount of "leakage" from the local and state economies because some wages and expenditures will be spent outside of the regions in which they are initiated. For this reason, multiplier coefficients are finite and, therefore, measureable.

METHODOLOGY

The analysis of the direct and indirect economic impacts of the Coffeen Energy Center relied on spending and workforce information provided by AER, and on the U.S. Department of Commerce's Regional Input-Output Multiplier System (RIMS-II). RIMS-II provides multiplier coefficients for every county in the United States. These multipliers can also be aggregated for larger regions composed of counties, such as states and, in this case, the primary economic impact region around the energy center. Multiplier coefficients for sub-county geographies are not available. The multipliers are determined separately for, and are unique to, each county and region for key economic sectors. The RIMS-II multipliers are updated annually by the Bureau of Economic Analysis (BEA).

The economic impact analysis focuses on the multi-county region noted above and on the state as a whole. That is, the Coffeen Energy Center has two economic impact tables associated with it: the state and its own primary economic impact region. There are three principal multipliers for each sector:

- **Economic Output:** This is defined as the total dollar change in the regional or state economy due to direct expenditures by AER at the energy center. Economic output is a similar measure as the nation's gross domestic product but, unlike the GDP, it also includes all the intermediate values added during the production process.

- **Earnings:** The earnings multiplier measures the added household earnings for the regional and state labor force triggered by AER's direct spending at the energy center.

- **Employment:** This is defined as the added jobs in the county per $1,000,000 of direct spending by AER in addition to the jobs at the energy center.[1]

Multipliers are provided for various economic sectors. The direct, non-labor, operational spending by AER at the energy center falls within the Utilities sector; the employee earnings paid by AER fall within the Households sector; and capital expenditures fall within the Construction sector. The RIMS-II multipliers for the selected regions are summarized below. To calculate the indirect economic impacts:

- The *construction* multiplier coefficients for the state and region are applied to the *capital expenditure* figures of the energy center,

- The *utilities* multiplier coefficients for the state and region are applied to the *operational expenditures* of the energy center, and

- The *households* multiplier coefficients for the state and region are applied to the *employee compensation* figures of the energy center. Employee compensation is calculated by applying the average labor expenditure to the number of workers who reside in the state and region. For the purposes of this analysis, employee compensation includes salary, benefits, and any other labor related costs; therefore, the average labor expenditure per employee does not necessarily reflect the average wage.

- DS estimated a weighted *fuel* multiplier based on the *mining (except oil and gas)*, *truck transportation*, and *rail transportation* multipliers. Approximately 20 percent of the fuel cost was for transportation; therefore, the fuel multiplier was weighted accordingly.[2]

The respective direct and indirect impacts are then summed to calculate the total indirect impacts.

CONCLUSIONS

DS estimates that the Coffeen Energy Center has an economic impact on the Illinois economy and its primary economic impact region as shown on the following tables. Each table summarizes AER's direct spending at the Coffeen Energy Center (top line in the table), the multipliers for Illinois or the market area, the multiplier effects resulting from AER's operational spending, and the total direct and indirect economic impacts generated.

[1] The multipliers derived from U.S. Department of Labor data, however, are based on 2008 economic activity and data. So the model used in this report inflates the million dollars from 2008, or jobs per $1,081,940 in 2013 dollars, using the Consumer Price Index (CPI).

[2] A portion of AER's coal comes from out-of-state sources, but since this study focuses on the impacts within the state of Illinois, only the expenditures for Illinois-sourced coal were considered. The Coffeen Energy Center uses Illinois-sourced coal; therefore, the impacts of these fuel expenditures were included in the state-wide analysis. A small portion of Coffeen's Illinois-sourced coal comes from within its impact region; therefore, the fuel expenditures from Crown Mine in Macoupin County were considered for the economic impact region analysis.

IMPACTS ON THE STATE OF ILLINOIS

Annual Economic Impact of AER's Coffeen Energy Center Operations on the State of Illinois

	Annual Average in 2013 Dollars[1]				
	Fuel Expenditures	*Capital Expenditures*	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 5,001,000	$ 128,878,000	$ 19,922,000	$ 16,336,000	$ 170,137,000
MULTIPLIERS					
Output	2.2263	2.3293	1.5022	1.4416	2.1442
Household Earnings	0.5273	0.7145	0.2856	0.3968	0.6283
Employment[3]	10.5826	15.5885	4.6006	10.4217	13.6361
ADDED ECONOMIC IMPACT ON ILLINOIS					
Output	$ 11,134,000	$ 300,196,000	$ 29,927,000	$ 23,550,000	$ 364,807,000
Household Earnings	$ 2,637,000	$ 92,083,000	$ 5,690,000	$ 6,482,000	$ 106,892,000
Indirect Jobs Held by Illinois Residents	50	2,010	90	170	2,320
TOTAL ECONOMIC IMPACT ON ILLINOIS					
Output (Total Economic Activity)					$ 534,944,000
Household Earnings					$ 123,228,000
Direct Jobs at Coffeen Energy Center (Illinois residents)					161
Total Direct and Indirect Jobs at Coffeen Energy Center					2,481

[1] *Actual operating data from 2008-2012 adjusted to 2013 dollar amounts using the Consumer Price Index (CPI) and averaged.*

[2] *Estimate based on number of employees who reside in Illinois (161 of 162) and overall average labor expenditure per employee.*

[3] *Employment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multiplier presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows the direct expenditures by AER at the Coffeen Energy Center averaging approximately $170.1 million per year from 2008 to 2012 in 2013 dollars. Employee compensation is an estimate based on the number of Coffeen employees that live in Illinois (161 of 162). Additional results are discussed below:

- The $170.1 million spent by AER at Coffeen Energy Center triggered an additional $364.8 million in value added activity in Illinois, of which $106.9 million was household earnings that another supported 2,320 jobs.
- The estimated total output (economic activity) triggered by Coffeen Energy Center's direct operations ($170.1 million) and the added multiplier effects ($364.8 million) were $534.9 million for the Illinois economy.
- Of that amount, Coffeen Energy Center's operations triggered nearly $123.2 million in household earnings for workers in Illinois, including $16.3 million in direct compensation for employees and $106.9 million in added earnings from the multiplier effects.
- In total, Coffeen Energy Center's operations supported and annual average of 2,481 jobs for Illinois residents, including 161 direct jobs and approximately 2,320 jobs added through the multiplier effects.

IMPACTS ON THE MULTI-COUNTY REGION

Annual Economic Impact of AER's Coffeen Energy Center Operations on Labor Market Area

	Annual Average in 2013 Dollars[1]				
	Fuel Expenditures	*Capital Expenditures*	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 273,000	$ 128,878,000	$ 19,922,000	$ 11,466,000	$ 160,539,000
MULTIPLIERS					
Output	1.4367	1.4958	1.3635	0.6683	1.4202
Household Earnings	0.3328	0.4634	0.2920	0.1711	0.4210
Employment[3]	5.6576	9.8700	3.8628	4.5419	8.7206
ADDED ECONOMIC IMPACT ON MARKET AREA					
Output	$ 392,000	$ 192,776,000	$ 27,164,000	$ 7,663,000	$ 227,995,000
Household Earnings	$ 91,000	$ 59,722,000	$ 5,817,000	$ 1,962,000	$ 67,592,000
Indirect Jobs Held by Market Area Residents	-	1,270	80	50	1,400
TOTAL ECONOMIC IMPACT ON MARKET AREA					
Output (Total Economic Activity)					$ 388,534,000
Household Earnings					$ 79,058,000
Direct Jobs at Coffeen Energy Center (market area residents)					113
Total Direct and Indirect Jobs at Coffeen Energy Center					1,513

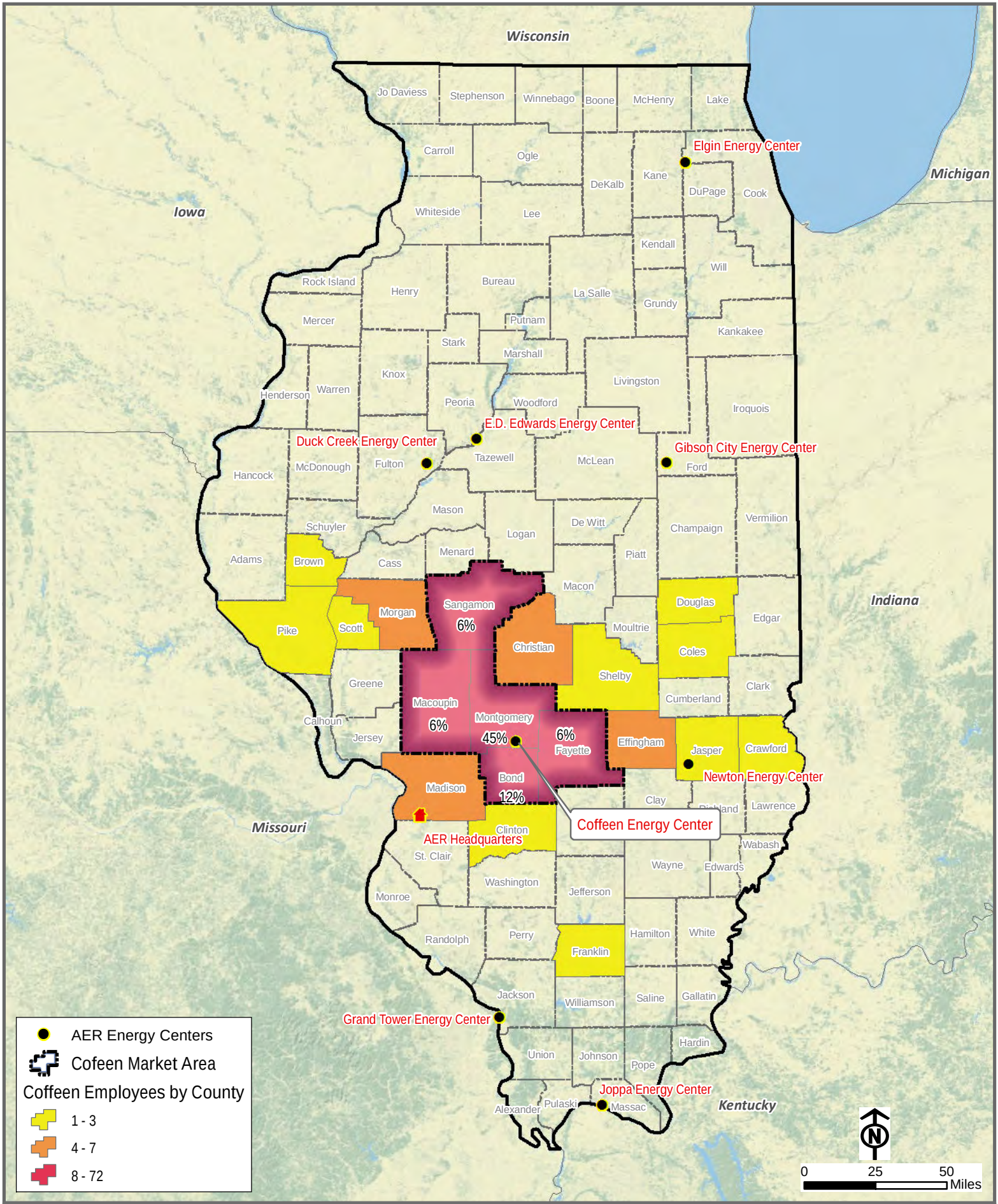
[1] *Actual operating data from 2008 to 2012 adjusted to 2013 dollar amounts using the Consumer Price Index (CPI) and averaged.*

[2] *Estimate based on number of employees who reside in labor market area (113 of 162) and overall average labor expenditure per employee.*

[3] *Employment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multiplier presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows that the direct expenditures by AER at the Coffeen Energy Center in the market area averaged approximately $160.5 million per year from 2008 to 2012 in 2013 dollars. This is less than for the state as a whole because employees outside of the market area are excluded. Employee compensation is an estimate based on the number of Coffeen employees that live in the labor market area (113 of 162). Additional results are discussed below:

- The $160.5 million spent by AER at Coffeen Energy Center triggered an additional $228.0 million in value added activity in the market area, of which $67.6 million was household earnings that supported 1,400 jobs. The multipliers vary for different types of major expenditures shown at the top of the table.
- The estimated total output (economic activity) triggered by Coffeen Energy Center's direct operations ($160.5 million) and the added multiplier effects ($228.0 million) were $388.5 million for the market area.
- Of that amount, Coffeen Energy Center's operations triggered nearly $79.1 million in household earnings for other workers in the market area, including $11.5 million in direct compensation for employees and $79.1 million in added earnings from the multiplier effects.
- In total, Coffeen Energy Center's operations supported an annual average of1,513 jobs for residents of the market area, including 113 direct jobs and approximately 1,400 jobs added through the multiplier effects.



AER: Coffeen Labor Market Areas

Source: Ameren provided employment counts by work location and county of residence, as of June 26, 2013

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July 2013

Memorandum

To: Daniel P. Thompson, Vice President, Illinois Power Holdings, LLC

From: Robert Lewis, Brian Licari, and Yash Yedavalli

Date: July 12, 2013

Re: Economic Impacts of Duck Creek Energy Center of Illinois and Surrounding Labor Market Area

In April, 2012, Development Strategies (DS) was commissioned by Ameren Energy Resources Corporation (AER) to conduct an independent analysis of the economic impact that the operations of AER's Duck Creek Energy Center (Jasper County) have on the Illinois economy and on its respective multi-county economic region. Development Strategies has since been commissioned by Illinois Power Holdings to update this analysis with the latest available data as of July, 2013, from both AER/Ameren Services and appropriate state and federal economic data sources. Development Strategies is pleased to submit this analysis of the direct and indirect economic impacts for this facility.

Direct economic impacts are the estimated dollars spent by AER at and in operational support of the energy center facility. For the purpose of this analysis, spending includes capital expenditures, non-payroll operations expenditures, and salaries paid to employees.

There are 66 total jobs at the Duck Creek Energy Center, 65 of whom live in Illinois. We determined which counties in the "region" of the energy center are home to a large majority of those employees and this determined the facility's primary economic impact region for our impact analysis. We then calculated economic impacts within that impact region. Three Illinois counties make up the primary economic impact region in the case of Duck Creek, which is home to 52 of its 66 employees. See accompanying map "AER: Duck Creek Energy Center Labor Market Area" for the local labor market area boundaries.

Indirect economic impacts measure the "ripple effect" of wages and expenditures associated with AER's direct spending. For instance, Duck Creek employees who live in Illinois will spend a large proportion of their earnings within the state of Illinois for housing and at local businesses such as retail stores, restaurants, mechanics, and others. Thus, each job at Duck Creek will contribute to additional job support across many sectors in the community and, consequently, the state of Illinois. Likewise, much of the non-labor operational spending by the energy center is initially spent within the state, thus supporting additional income and jobs in the immediately surrounding counties and throughout the state.

To calculate these indirect impacts, multiplier coefficients are applied to the direct impact dollars; these multipliers also automatically take into account the amount of "leakage" from the local and state economies because some wages and expenditures will be spent outside of the regions in which they are initiated. For this reason, multiplier coefficients are finite and, therefore, measureable.

METHODOLOGY

The analysis of the direct and indirect economic impacts of the Duck Creek Energy Center relied on spending and workforce information provided by AER, and on the U.S. Department of Commerce's Regional Input-Output Multiplier System (RIMS-II). RIMS-II provides multiplier coefficients for every county in the United States. These multipliers can also be aggregated for larger regions composed of counties, such as states and, in this case, the primary economic impact region around the energy center. Multiplier coefficients for sub-county geographies are not available. The multipliers are determined separately for, and are unique to, each county and region for key economic sectors. The RIMS-II multipliers are updated annually by the Bureau of Economic Analysis (BEA).

The economic impact analysis focuses on the multi-county region noted above and on the state as a whole. That is, the Duck Creek Energy Center has two economic impact tables associated with it: the state and its own primary economic impact region. There are three principal multipliers for each sector:

- **Economic Output:** This is defined as the total dollar change in the regional or state economy due to direct expenditures by AER at the energy center. Economic output is a similar measure as the nation's gross domestic product but, unlike the GDP, it also includes all the intermediate values added during the production process.

- **Earnings:** The earnings multiplier measures the added household earnings for the regional and state labor force triggered by AER's direct spending at the energy center.

- **Employment:** This is defined as the added jobs in the county per $1,000,000 of direct spending by AER in addition to the jobs at the energy center.[1]

Multipliers are provided for various economic sectors. The direct, non-labor, operational spending by AER at the energy center falls within the Utilities sector; the employee earnings paid by AER fall within the Households sector; and capital expenditures fall within the Construction sector. The RIMS-II multipliers for the selected regions are summarized below. To calculate the indirect economic impacts:

- The *construction* multiplier coefficients for the state and region are applied to the *capital expenditure* figures of the energy center,

- The *utilities* multiplier coefficients for the state and region are applied to the *operational expenditures* of the energy center, and

- The *households* multiplier coefficients for the state and region are applied to the *employee compensation* figures of the energy center. Employee compensation is calculated by applying the average labor expenditure to the number of workers who reside in the state and region. For the purposes of this analysis, employee compensation includes salary, benefits, and any other labor related costs; therefore, the average labor expenditure per employee does not necessarily reflect the average wage.

- DS estimated a weighted *fuel* multiplier based on the *mining (except oil and gas)*, *truck transportation*, and *rail transportation* multipliers. Approximately 20 percent of the fuel cost was for transportation; therefore, the fuel multiplier was weighted accordingly.[2]

The respective direct and indirect impacts are then summed to calculate the total indirect impacts.

CONCLUSIONS

DS estimates that the Duck Creek Energy Center has an economic impact on the Illinois economy and its primary economic impact region as shown on the following tables. Each table summarizes AER's direct spending at the Duck Creek Energy Center (top line in the table), the multipliers for Illinois or the market area, the multiplier effects resulting from AER's operational spending, and the total direct and indirect economic impacts generated.

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[1] The multipliers derived from U.S. Department of Labor data, however, are based on 2008 economic activity and data. So the model used in this report inflates the million dollars from 2008, or jobs per $1,081,940 in 2013 dollars, using the Consumer Price Index (CPI).

[2] A portion of AER's coal comes from out-of-state sources, but since this study focuses on the impacts within the state of Illinois, only the expenditures for Illinois-sourced coal were considered. The Duck Creek Energy Center uses Illinois-sourced coal; therefore, the impacts of these fuel expenditures were included in the state-wide analysis. Duck Creek's Illinois-sourced coal does not come from within its impact region; therefore, the fuel expenditures are not considered for the regional analysis.

IMPACTS ON THE STATE OF ILLINOIS

Annual Economic Impact of AER's Duck Creek Energy Center Operations on the State of Illinois

	Annual Average in 2013 Dollars[1]				
	Fuel Expenditures	*Capital Expenditures*	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 19,883,000	$ 59,091,000	$ 11,123,000	$ 7,666,000	$ 97,763,000
MULTIPLIERS					
Output	2.2263	2.3293	1.5022	1.4416	2.1446
Household Earnings	0.5273	0.7145	0.2856	0.3968	0.6027
Employment[3]	10.5826	15.5885	4.6006	10.4217	12.8883
ADDED ECONOMIC IMPACT ON ILLINOIS					
Output	$ 44,265,000	$ 137,641,000	$ 16,709,000	$ 11,051,000	$ 209,666,000
Household Earnings	$ 10,484,000	$ 42,221,000	$ 3,177,000	$ 3,042,000	$ 58,924,000
Indirect Jobs Held by Illinois Residents	210	920	50	80	1,260
TOTAL ECONOMIC IMPACT ON ILLINOIS					
Output (Total Economic Activity)					$ 307,429,000
Household Earnings					$ 66,590,000
Direct Jobs at Duck Creek Energy Center (Illinois residents)					65
Total Direct and Indirect Jobs at Duck Creek Energy Center					1,325

[1] *Actual operating data from 2008-2012 adjusted to 2013 dollar amounts using the Consumer Price Index (CPI) and averaged.*

[2] *Estimate based on number of employees who reside in Illinois (65 of 66) and overall average labor expenditure per employee.*

[3] *Employment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multipliers presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows the direct expenditures by AER at the Duck Creek Energy Center averaging approximately $97.8 million per year from 2008 to 2012 in 2013 dollars. Employee compensation is an estimate based on the number of Duck Creek employees that live in Illinois (65 of 66). Additional results are discussed below:

- The $97.8 million spent by AER at Duck Creek Energy Center triggered an additional $209.7 million in value added activity in Illinois, of which $58.9 million was household earnings that supported another 1,260 jobs.
- The estimated total output (economic activity) triggered by Duck Creek Energy Center's direct operations ($97.8 million) and the added multiplier effects ($209.7 million) were $307.4 million for the Illinois economy.
- Of that amount, Duck Creek Energy Center's operations triggered nearly $66.6 million in household earnings for workers in Illinois, including $7.7 million in direct compensation for employees and $58.9 million in added earnings from the multiplier effects.
- In total, Duck Creek Energy Center's operations supported 1,325 jobs for Illinois residents, including 65 direct jobs and approximately 1,260 jobs added through the multiplier effects.

IMPACTS ON THE MULTI-COUNTY REGION

Annual Economic Impact of AER's Duck Creek Energy Center Operations on Labor Market Area

	Annual Average in 2013 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 59,091,000	$ 11,123,000	$ 6,132,000	$ 76,346,000
MULTIPLIERS				
Output	1.613	1.218	0.813	1.491
Household Earnings	0.492	0.199	0.218	0.428
Employment[3]	10.758	2.847	6.219	9.300
ADDED ECONOMIC IMPACT ON MARKET AREA				
Output	$ 95,332,000	$ 13,542,000	$ 4,985,000	$ 113,859,000
Household Earnings	$ 29,096,000	$ 2,217,000	$ 1,337,000	$ 32,650,000
Indirect Jobs Held by Market Area Residents	640	30	40	710
TOTAL ECONOMIC IMPACT ON MARKET AREA				
Output (Total Economic Activity)				$ 190,205,000
Household Earnings				$ 38,782,000
Direct Jobs at Duck Creek Energy Center (market area residents)				52
Total Direct and Indirect Jobs at Duck Creek Energy Center				762

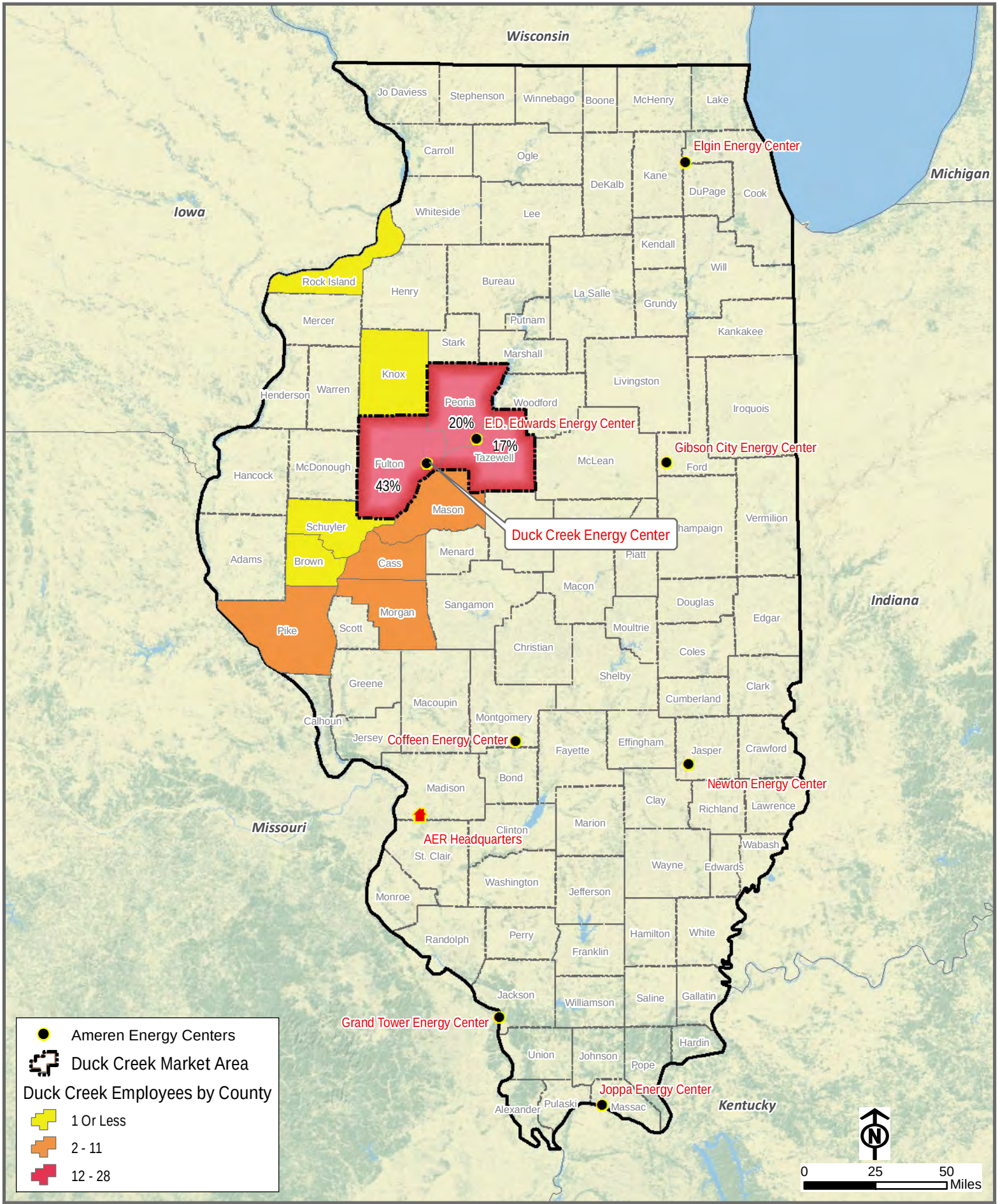
[1] *Actual operating data from 2008 to 2012 adjusted to 2013 dollar amounts using the Consumer Price Index (CPI) and averaged.*

[2] *Estimate based on number of employees who reside in labor market area (52 of 66) and overall average labor expenditure per employee.*

[3] *Employment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multiplier presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows that the direct expenditures by AER at the Duck Creek Energy Center in the market area averaged approximately $76.3 million per year from 2008 to 2012 in 2013 dollars. This is less than for the state as a whole because employees outside of the market area are excluded. Employee compensation is an estimate based on the number of Duck Creek employees that live in the labor market area (52 of 66). Additional results are discussed below:

- The $76.3 million spent by AER at Duck Creek Energy Center triggered an additional $113.9 million in value added activity in the market area, of which $32.7 million was household earnings that supported 710 jobs. The multipliers vary for different types of major expenditures shown at the top of the table.
- The estimated total output (economic activity) triggered by Duck Creek Energy Center's direct operations ($76.3 million) and the added multiplier effects ($113.9 million) were $190.2 million for the market area.
- Of that amount, Duck Creek Energy Center's operations triggered nearly $38.8 million in household earnings for other workers in the market area, including $6.1 million in direct compensation for employees and $32.7 million in added earnings from the multiplier effects.
- In total, Duck Creek Energy Center's operations supported an annual average of 762 jobs for residents of the market area, including 52 direct jobs and approximately 710 jobs added through the multiplier effects.



AER: Duck Creek Labor Market Areas

Source: Ameren provided employment counts by work location and county of residence, as of June 26, 2013

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July 2013

Memorandum

To: Daniel P. Thompson, Vice President, Illinois Power Holdings, LLC

From: Robert Lewis, Brian Licari, and Yash Yedavalli

Date: July 12, 2013

Re: Economic Impacts of E.D. Edwards Energy Center of Illinois and Surrounding Labor Market Area

In April, 2012, Development Strategies (DS) was commissioned by Ameren Energy Resources Corporation (AER) to conduct an independent analysis of the economic impact that the operations of AER's E.D. Edwards Energy Center (Peoria County) have on the Illinois economy and on its respective multi-county economic region. Development Strategies has since been commissioned by Illinois Power Holdings to update this analysis with the latest available data as of July, 2013, from both AER/Ameren Services and appropriate state and federal economic data sources. Development Strategies is pleased to submit this analysis of the direct and indirect economic impacts for this facility.

Direct economic impacts are the estimated dollars spent by AER at and in operational support of the energy center facility. For the purpose of this analysis, spending includes capital expenditures, non-payroll operations expenditures, and salaries paid to employees.

There are 111 total jobs at the E.D. Edwards Energy Center, all of whom live in Illinois. We determined which counties in the "region" of the energy center are home to a large majority of those employees and this determined the facility's primary economic impact region for our impact analysis. We then calculated economic impacts within that impact region. Three Illinois counties make up the primary economic impact region in the case of Edwards, which is home to 95 of its 111 employees. See accompanying map "AER: E.D. Edwards Energy Center Labor Market Area" for the local labor market area boundaries.

Indirect economic impacts measure the "ripple effect" of wages and expenditures associated with AER's direct spending. For instance, Edwards employees who live in Illinois will spend a large proportion of their earnings within the state of Illinois for housing and at local businesses such as retail stores, restaurants, mechanics, and others. Thus, each job at Edwards will contribute to additional job support across many sectors in the community and, consequently, the state of Illinois. Likewise, much of the non-labor operational spending by the energy center is initially spent within the state, thus supporting additional income and jobs in the immediately surrounding counties and throughout the state.

To calculate these indirect impacts, multiplier coefficients are applied to the direct impact dollars; these multipliers also automatically take into account the amount of "leakage" from the local and state economies because some wages and expenditures will be spent outside of the regions in which they are initiated. For this reason, multiplier coefficients are finite and, therefore, measureable.

METHODOLOGY

The analysis of the direct and indirect economic impacts of the E.D. Edwards Energy Center relied on spending and workforce information provided by AER, and on the U.S. Department of Commerce's Regional Input-Output Multiplier System (RIMS-II). RIMS-II provides multiplier coefficients for every county in the United States. These multipliers can also be aggregated for larger regions composed of counties, such as states and, in this case, the primary economic impact region around the energy center. Multiplier coefficients for sub-county geographies are not available. The multipliers are determined separately for, and are unique to, each county and region for key economic sectors. The RIMS-II multipliers are updated annually by the Bureau of Economic Analysis (BEA).

The economic impact analysis focuses on the multi-county region noted above and on the state as a whole. That is, the E.D. Edwards Energy Center has two economic impact tables associated with it: the state and its own primary economic impact region. There are three principal multipliers for each sector:

- **Economic Output:** This is defined as the total dollar change in the regional or state economy due to direct expenditures by AER at the energy center. Economic output is a similar measure as the nation's gross domestic product but, unlike the GDP, it also includes all the intermediate values added during the production process.

- **Earnings:** The earnings multiplier measures the added household earnings for the regional and state labor force triggered by AER's direct spending at the energy center.

- **Employment:** This is defined as the added jobs in the county per $1,000,000 of direct spending by AER in addition to the jobs at the energy center.[1]

Multipliers are provided for various economic sectors. The direct, non-labor, operational spending by AER at the energy center falls within the Utilities sector; the employee earnings paid by AER fall within the Households sector; and capital expenditures fall within the Construction sector. The RIMS-II multipliers for the selected regions are summarized below. To calculate the indirect economic impacts:

- The *construction* multiplier coefficients for the state and region are applied to the *capital expenditure* figures of the energy center,

- The *utilities* multiplier coefficients for the state and region are applied to the *operational expenditures* of the energy center, and

- The *households* multiplier coefficients for the state and region are applied to the *employee compensation* figures of the energy center. Employee compensation is calculated by applying the average labor expenditure to the number of workers who reside in the state and region. For the purposes of this analysis, employee compensation includes salary, benefits, and any other labor related costs; therefore, the average labor expenditure per employee does not necessarily reflect the average wage.

The respective direct and indirect impacts are then summed to calculate the total indirect impacts.

Note: Fuel expenditures for coal were not considered for this analysis. AER's coal comes from in-state and out-of-state sources. In the case of Edwards Energy Center, all of its coal comes from out-of-state sources. Since this study focuses on the impacts within the state of Illinois, only the expenditures for Illinois-sourced coal should be considered. Though a small portion of Edwards's fuel expenditures likely occur within Illinois (e.g. transportation costs), the vast majority of these expenditures occur outside of Illinois; therefore, we are uncomfortable assuming that the standard RIMS-II multipliers account for this scale of immediate leakage. Including fuel expenditures in this analysis, therefore, could overstate the local and statewide impacts.

CONCLUSIONS

DS estimates that the Edwards Energy Center has an economic impact on the Illinois economy and its primary economic impact region as shown on the following tables. Each table summarizes AER's direct spending at the Edwards Energy Center (top line in the table), the multipliers for Illinois or the market area, the multiplier effects resulting from AER's operational spending, and the total direct and indirect economic impacts generated.

[1] The multipliers derived from U.S. Department of Labor data, however, are based on 2008 economic activity and data. So the model used in this report inflates the million dollars from 2008, or jobs per $1,081,940 in 2013 dollars, using the Consumer Price Index (CPI).

IMPACTS ON THE STATE OF ILLINOIS

Annual Economic Impact of AER's Edwards Energy Center Operations on the State of Illinois

	Annual Average in 2013 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 12,864,000	$ 14,488,000	$ 11,893,000	$ 39,245,000
MULTIPLIERS				
Output	2.3293	1.5022	1.4416	1.7549
Household Earnings	0.7145	0.2856	0.3968	0.4599
Employment[3]	14.4079	4.2522	9.6324	9.1731
ADDED ECONOMIC IMPACT ON ILLINOIS				
Output	$ 29,964,000	$ 21,764,000	$ 17,145,000	$ 68,873,000
Household Earnings	$ 9,191,000	$ 4,138,000	$ 4,719,000	$ 18,048,000
Indirect Jobs Held by Illinois Residents	190	60	110	360
TOTAL ECONOMIC IMPACT ON ILLINOIS				
Output (Total Economic Activity)				$ 108,118,000
Household Earnings				$ 29,941,000
Direct Jobs at Edwards Energy Center (Illinois residents)				111
Total Direct and Indirect Jobs at Edwards Energy Center				471

[1] *Actual operating data from 2008-2012 adjusted to 2013 dollar amounts using the Consumer Price Index (CPI) and averaged.*

[2] *All of the employees at Edwards Energy Center live in the state of Illinois (111 total).*

[3] *Employment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multipliers presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows the direct expenditures by AER at the E.D. Edwards Energy Center averaging approximately $39.2 million per year from 2008 to 2012 in 2013 dollars. Employee compensation is the total labor cost at the energy center since all of the employees live in Illinois. Additional results are discussed below:

- The $39.2 million spent by AER at E.D. Edwards Energy Center triggered an additional $68.9 million in value added activity in Illinois, of which $18.0 million was household earnings that another supported 360 jobs.
- The estimated total output (economic activity) triggered by E.D. Edwards Energy Center's direct operations ($39.2million) and the added multiplier effects ($68.9 million) were $108.1 million for the Illinois economy.
- Of that amount, E.D. Edwards Energy Center's operations triggered nearly $29.9 million in household earnings for workers in Illinois, including $11.9 million in direct compensation for employees and $18.0 million in added earnings from the multiplier effects.
- In total, E.D. Edwards Energy Center's operations supported 471 jobs for Illinois residents, including 111 direct jobs and approximately 360 jobs added through the multiplier effects.

IMPACTS ON THE MULTI-COUNTY REGION

Annual Economic Impact of AER's Edwards Energy Center Operations on Market Area

	Annual Average in 2013 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 12,864,000	$ 14,488,000	$ 10,179,000	$ 37,531,000
MULTIPLIERS				
Output	1.6128	1.2198	0.8047	1.2419
Household Earnings	0.4988	0.2052	0.2175	0.3092
Employment[3]	10.8857	2.9230	6.1929	6.3947
ADDED ECONOMIC IMPACT ON MARKET AREA				
Output	$ 20,747,000	$ 17,672,000	$ 8,191,000	$ 46,610,000
Household Earnings	$ 6,417,000	$ 2,973,000	$ 2,214,000	$ 11,604,000
Indirect Jobs Held by Area Residents	140	40	60	240
TOTAL ECONOMIC IMPACT ON MARKET AREA				
Output (Total Economic Activity)				$ 84,141,000
Household Earnings				$ 21,783,000
Direct Jobs at Edwards Energy Center (market area residents)				95
Total Direct and Indirect Jobs at Edwards Energy Center				335

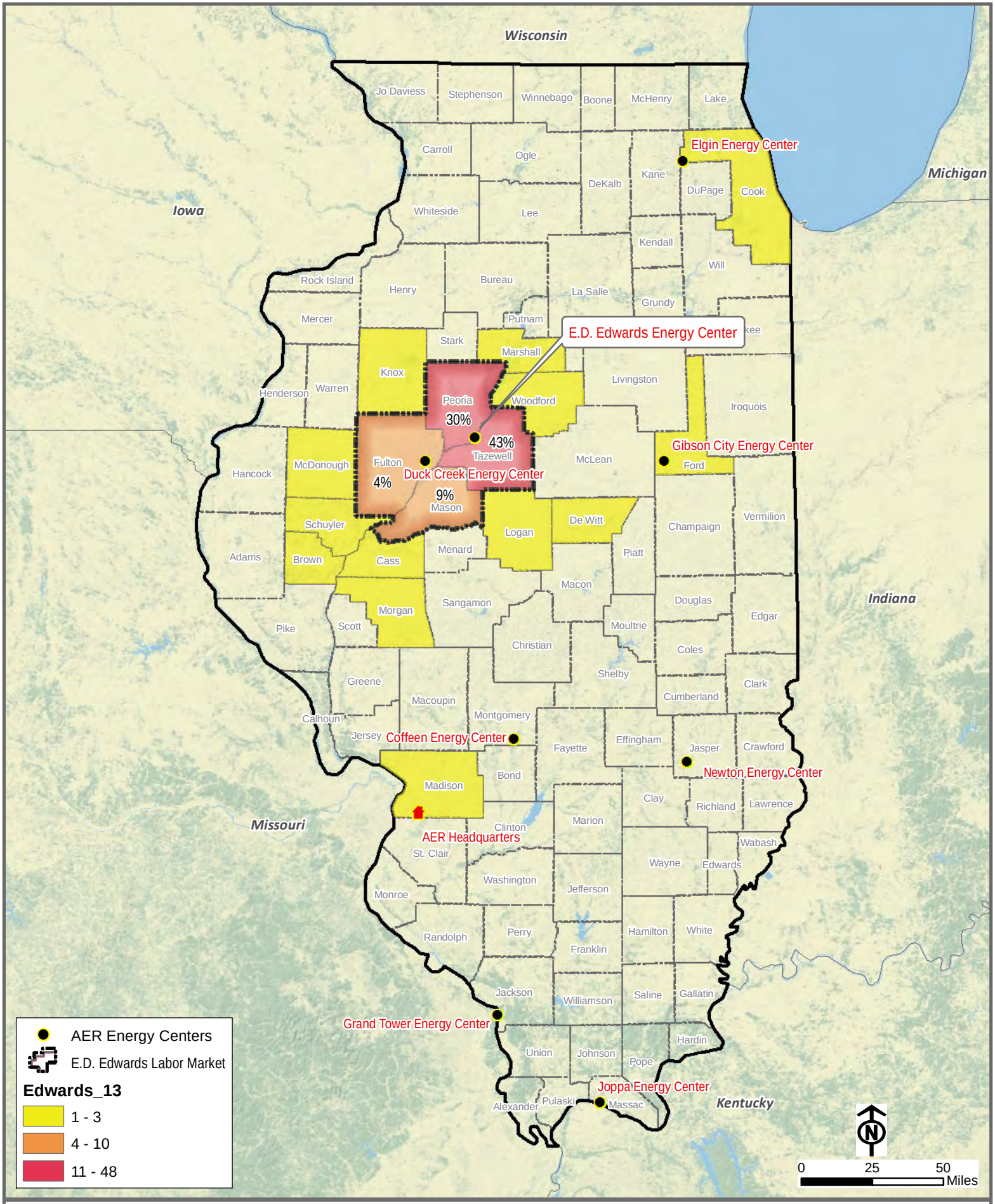
[1] *Actual operating data from 2008-2012 adjusted to 2013 dollar amounts using the Consumer Price Index (CPI) and averaged.*

[2] *Estimate based on number of employees who reside in market area (95 of 111) and overall average labor expenditure per employee.*

[3] *Employment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multiplier presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows that the direct expenditures by AER at the E.D. Edwards Energy Center in the market area averaged approximately $37.5 million per year from 2008 to 2012 in 2013 dollars. This is less than for the state as a whole because employees living outside of the market area are excluded. Employee compensation is an estimate based on the number of Edwards employees that live in the labor market area (95 of 111). Additional results are discussed below:

- The $37.5 million spent by AER at E.D. Edwards Energy Center triggered an additional $46.6 million in value added activity in the market area, of which $11.6 million was household earnings that supported 240 jobs. The multipliers vary for different types of major expenditures shown at the top of the table.
- The estimated total output (economic activity) triggered by E.D. Edwards Energy Center's direct operations ($37.5 million) and the added multiplier effects ($46.6 million) were $84.1 million for the market area.
- Of that amount, E.D. Edwards Energy Center's operations triggered nearly $21.8 million in household earnings for other workers in the market area, including $10.2 million in direct compensation for employees and $11.6 million in added earnings from the multiplier effects.
- In total, E.D. Edwards Energy Center's operations supported an annual average of 335 jobs for residents of the market area, including 95 direct jobs and approximately 240 jobs added through the multiplier effects.



AER: E.D. Edwards Labor Market Areas

Source: Ameren provided employment counts by work location and county of residence, as of June 26, 2013

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July 2013

Memorandum

To: Daniel P. Thompson, Vice President, Illinois Power Holdings, LLC

From: Robert Lewis, Brian Licari, and Yash Yedavalli

Date: July 12, 2013

Re: Economic Impacts of Joppa Energy Center of Illinois and Surrounding Labor Market Area

In April, 2012, Development Strategies (DS) was commissioned by Ameren Energy Resources Corporation (AER) to conduct an independent analysis of the economic impact that the operations of AER's Joppa Energy Center (Massac County) have on the Illinois economy and on its respective multi-county economic region. Development Strategies has since been commissioned by Illinois Power Holdings to update this analysis with the latest available data as of July, 2013, from both AER/Ameren Services and appropriate state and federal economic data sources. Development Strategies is pleased to submit this analysis of the direct and indirect economic impacts for this facility.

Direct economic impacts are the estimated dollars spent by AER at and in operational support of the energy center facility. For the purpose of this analysis, spending includes capital expenditures, non-payroll operations expenditures, and salaries paid to employees.

There are 176 total jobs at the Joppa Energy Center, 125 of whom live in Illinois. We determined which counties in the "region" of the energy center are home to a large majority of those employees and this determined the facility's primary economic impact region for our impact analysis. We then calculated economic impacts within that impact region. Three Illinois counties make up the primary economic impact region in the case of Joppa, which is home to 109 of its 143 employees; additionally, Joppa has 51 of its 176 employees residing in the neighboring state of Kentucky See accompanying map "AER: Joppa Energy Center Labor Market Area" for the local labor market area boundaries.

Indirect economic impacts measure the "ripple effect" of wages and expenditures associated with AER's direct spending. For instance, Joppa employees who live in Illinois will spend a large proportion of their earnings within the state of Illinois for housing and at local businesses such as retail stores, restaurants, mechanics, and others. Thus, each job at Joppa will contribute to additional job support across many sectors in the community and, consequently, the state of Illinois. Likewise, much of the non-labor operational spending by the energy center is initially spent within the state, thus supporting additional income and jobs in the immediately surrounding counties and throughout the state.

To calculate these indirect impacts, multiplier coefficients are applied to the direct impact dollars; these multipliers also automatically take into account the amount of "leakage" from the local and state economies because some wages and expenditures will be spent outside of the regions in which they are initiated. For this reason, multiplier coefficients are finite and, therefore, measureable.

METHODOLOGY

The analysis of the direct and indirect economic impacts of the Joppa Energy Center relied on spending and workforce information provided by AER, and on the U.S. Department of Commerce's Regional Input-Output Multiplier System (RIMS-II). RIMS-II provides multiplier coefficients for every county in the United States. These multipliers can also be aggregated for larger regions composed of counties, such as states and, in this case, the primary economic impact region around the energy center. Multiplier coefficients for sub-county geographies are not available. The multipliers are determined separately for, and are unique to, each county and region for key economic sectors. The RIMS-II multipliers are updated annually by the Bureau of Economic Analysis (BEA).

The economic impact analysis focuses on the multi-county region noted above and on the state as a whole. That is, the Joppa Energy Center has two economic impact tables associated with it: the state and its own primary economic impact region. There are three principal multipliers for each sector:

- **Economic Output:** This is defined as the total dollar change in the regional or state economy due to direct expenditures by AER at the energy center. Economic output is a similar measure as the nation's gross domestic product but, unlike the GDP, it also includes all the intermediate values added during the production process.

- **Earnings:** The earnings multiplier measures the added household earnings for the regional and state labor force triggered by AER's direct spending at the energy center.

- **Employment:** This is defined as the added jobs in the county per $1,000,000 of direct spending by AER in addition to the jobs at the energy center.[1]

Multipliers are provided for various economic sectors. The direct, non-labor, operational spending by AER at the energy center falls within the Utilities sector; the employee earnings paid by AER fall within the Households sector; and capital expenditures fall within the Construction sector. The RIMS-II multipliers for the selected regions are summarized below. To calculate the indirect economic impacts:

- The *construction* multiplier coefficients for the state and region are applied to the *capital expenditure* figures of the energy center,

- The *utilities* multiplier coefficients for the state and region are applied to the *operational expenditures* of the energy center, and

- The *households* multiplier coefficients for the state and region are applied to the *employee compensation* figures of the energy center. Employee compensation is calculated by applying the average labor expenditure to the number of workers who reside in the state and region. For the purposes of this analysis, employee compensation includes salary, benefits, and any other labor related costs; therefore, the average labor expenditure per employee does not necessarily reflect the average wage.

The respective direct and indirect impacts are then summed to calculate the total indirect impacts.

Note: Fuel expenditures for coal were not considered for this analysis. AER's coal comes from in-state and out-of-state sources. In the case of Joppa Energy Center, all of its coal comes from out-of-state sources. Since this study focuses on the impacts within the state of Illinois, only the expenditures for Illinois-sourced coal should be considered. Though a small portion of Joppa's fuel expenditures likely occur within Illinois (e.g. transportation costs), the vast majority of these expenditures occur outside of Illinois; therefore, we are uncomfortable assuming that the standard RIMS-II multipliers account for this scale of immediate leakage. Including fuel expenditures in this analysis, therefore, could overstate the local and statewide impacts.

CONCLUSIONS

DS estimates that the Joppa Energy Center has an economic impact on the Illinois economy and its primary economic impact region as shown on the following tables. Each table summarizes AER's direct spending at the Joppa Energy Center (top line in the table), the multipliers for Illinois or the market area, the multiplier effects resulting from AER's operational spending, and the total direct and indirect economic impacts generated.

[1] The multipliers derived from U.S. Department of Labor data, however, are based on 2008 economic activity and data. So the model used in this report inflates the million dollars from 2008, or jobs per $1,081,940 in 2013 dollars, using the Consumer Price Index (CPI).

IMPACTS ON THE STATE OF ILLINOIS

Annual Economic Impact of AER's Joppa Energy Center Operations on the State of Illinois

	Annual Average in 2013 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 22,380,000	$ 33,226,000	$ 14,696,000	$ 70,302,000
MULTIPLIERS				
Output	2.3293	1.5022	1.4416	1.7528
Household Earnings	0.7145	0.2856	0.3968	0.4454
Employment[3]	14.4079	4.2522	9.6324	8.5346
ADDED ECONOMIC IMPACT ON ILLINOIS				
Output	$ 52,130,000	$ 49,912,000	$ 21,186,000	$ 123,228,000
Household Earnings	$ 15,991,000	$ 9,489,000	$ 5,831,000	$ 31,311,000
Indirect Jobs Held by Illinois Residents	320	140	140	600
TOTAL ECONOMIC IMPACT ON ILLINOIS				
Output (Total Economic Activity)				$ 193,530,000
Household Earnings				$ 46,007,000
Direct Jobs at Joppa Energy Center (Illinois residents)				125
Total Direct and Indirect Jobs at Joppa Energy Center				725

[1] *Actual operating data from 2008-2012 adjusted to 2013 dollar amounts using the Consumer Price Index (CPI) and averaged.*

[2] *Estimate based on number of employees who reside in Illinois (125 of 176) and overall average labor expenditure per employee*

[3] *Employment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multipliers presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows the direct expenditures by AER at the Joppa Energy Center averaging approximately $70.3 million per year from 2008 to 2012 in 2013 dollars. Employee compensation is an estimate based on the number of Joppa employees that live in Illinois (125 of 176). Additional results are discussed below:

- The $70.3 million spent by AER at Joppa Energy Center triggered an additional $123.2 million in value added activity in Illinois, of which $31.3 million was household earnings that another supported 600 jobs.
- The estimated total output (economic activity) triggered by Joppa Energy Center's direct operations ($70.3 million) and the added multiplier effects ($123.2 million) were $193.5 million for the Illinois economy.
- Of that amount, Joppa Energy Center's operations triggered nearly $46.0 million in household earnings for workers in Illinois, including $14.7 million in direct compensation for employees and $31.3 million in added earnings from the multiplier effects.
- In total, Joppa Energy Center's operations supported 725 jobs for Illinois residents, including 125 direct jobs and approximately 600 jobs added through the multiplier effects.

IMPACTS ON THE MULTI-COUNTY REGION

Annual Economic Impact of AER's Joppa Energy Center Operations on Market Area

	Annual Average in 2013 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 22,380,000	$ 33,226,000	$ 11,757,000	$ 67,363,000
MULTIPLIERS				
Output	1.2842	1.1111	0.3814	1.0412
Household Earnings	0.3295	0.1606	0.0867	0.2038
Employment[3]	6.8812	1.9310	2.7508	3.5628
ADDED ECONOMIC IMPACT ON MARKET AREA				
Output	$ 28,740,000	$ 36,917,000	$ 4,484,000	$ 70,141,000
Household Earnings	$ 7,374,000	$ 5,336,000	$ 1,019,000	$ 13,729,000
Indirect Jobs Held by Area Residents	150	60	30	240
TOTAL ECONOMIC IMPACT ON MARKET AREA				
Output (Total Economic Activity)				$ 137,504,000
Household Earnings				$ 25,486,000
Direct Jobs at Joppa Energy Center (market area residents)				100
Total Direct and Indirect Jobs at Joppa Energy Center				340

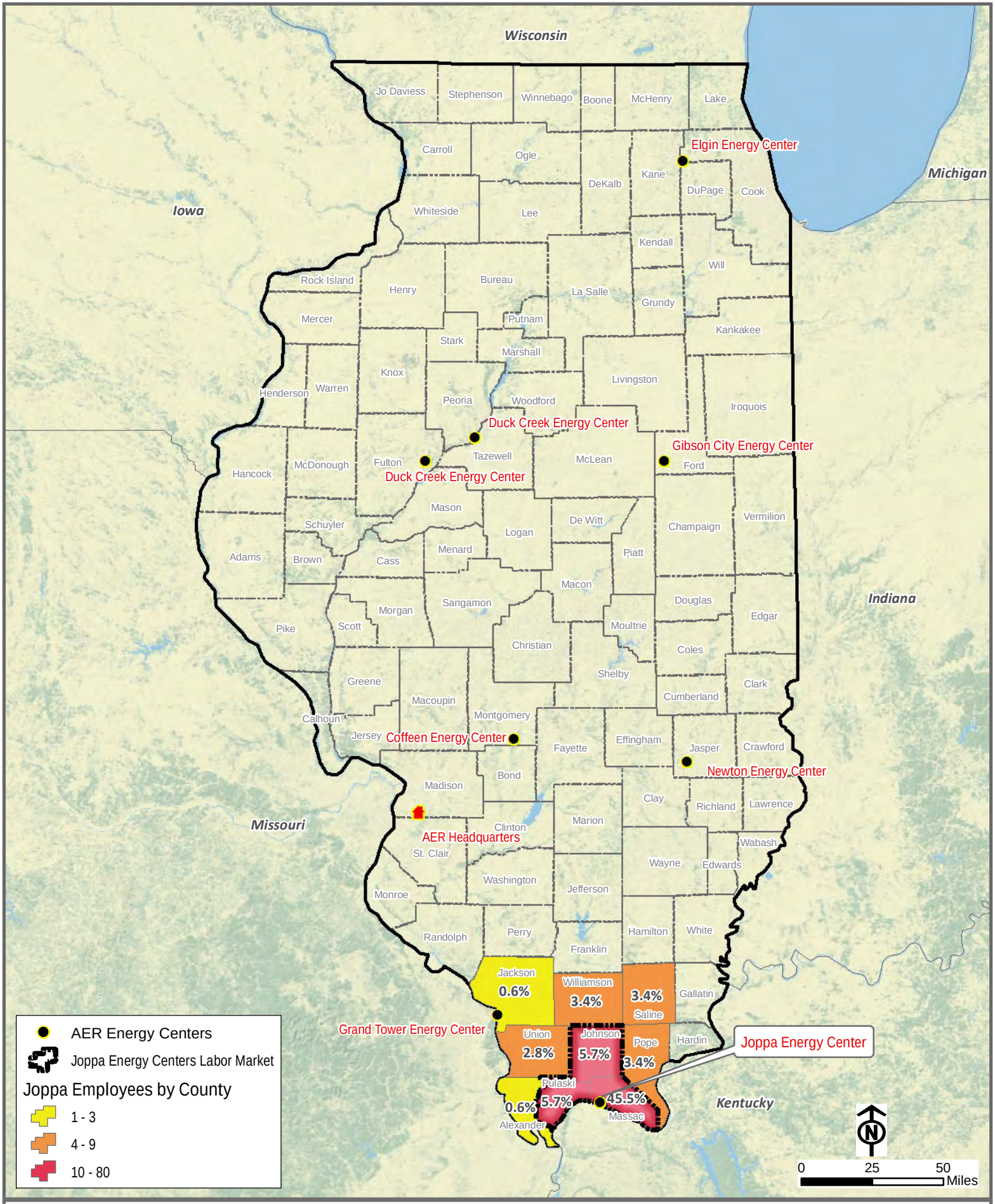
[1] *Actual operating data from 2008-2012 adjusted to 2013 dollar amounts and averaged.*

[2] *Estimate based on number of employees who reside in market area (100 of 176) and overall average labor expenditure per employee.*

[3] *Employment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multiplier presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows that the direct expenditures by AER at the Joppa Energy Center in the market area averaged approximately $67.4 million per year from 2008 to 2012 in 2013 dollars. This is less than for the state as a whole because employees outside of the market area are excluded. Employee compensation is an estimate based on the number of Joppa employees that live in the labor market area (100 of 176). Additional results are discussed below:

- The $67.4 million spent by AER at Joppa Energy Center triggered an additional $70.1 million in value added activity in the market area, of which $13.7 million was household earnings that supported 240 jobs. The multipliers vary for different types of major expenditures shown at the top of the table.
- The estimated total output (economic activity) triggered by Joppa Energy Center's direct operations ($67.4 million) and the added multiplier effects ($70.1 million) were $137.5 million for the market area.
- Of that amount, Joppa Energy Center's operations triggered nearly $25.5 million in household earnings for other workers in the market area, including $11.8 million in direct compensation for employees and $13.7 million in added earnings from the multiplier effects.
- In total, Joppa Energy Center's operations supported an annual average of 340 jobs for residents of the market area, including 100 direct jobs and approximately 240 jobs added through the multiplier effects.



AER: Joppa Labor Market Areas

Source: Ameren provided employment counts by work location and county of residence, as of June 26, 2013

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July 2013

Memorandum

To: Daniel P. Thompson, Vice President, Illinois Power Holdings, LLC

From: Robert Lewis, Brian Licari, and Yash Yedavalli

Date: July 12, 2013

Re: Economic Impacts of Newton Energy Center of Illinois and Surrounding Labor Market Area

In April, 2012, Development Strategies (DS) was commissioned by Ameren Energy Resources Corporation (AER) to conduct an independent analysis of the economic impact that the operations of AER's Newton Energy Center (Jasper County) have on the Illinois economy and on its respective multi-county economic region. Development Strategies has since been commissioned by Illinois Power Holdings to update this analysis with the latest available data as of July, 2013, from both AER/Ameren Services and appropriate state and federal economic data sources. Development Strategies is pleased to submit this analysis of the direct and indirect economic impacts for this facility.

Direct economic impacts are the estimated dollars spent by AER at and in operational support of the energy center facility. For the purpose of this analysis, spending includes capital expenditures, non-payroll operations expenditures, and salaries paid to employees.

There are 143 total jobs at the Newton Energy Center, 142 of whom live in Illinois. We determined which counties in the "region" of the energy center are home to a large majority of those employees and this determined the facility's primary economic impact region for our impact analysis. We then calculated economic impacts within that impact region. Three Illinois counties make up the primary economic impact region in the case of Newton, which is home to 109 of its 143 employees. See accompanying map "AER: Newton Energy Center Labor Market Area" for the local labor market area boundaries.

Indirect economic impacts measure the "ripple effect" of wages and expenditures associated with AER's direct spending. For instance, Newton employees who live in Illinois will spend a large proportion of their earnings within the state of Illinois for housing and at local businesses such as retail stores, restaurants, mechanics, and others. Thus, each job at Newton will contribute to additional job support across many sectors in the community and, consequently, the state of Illinois. Likewise, much of the non-labor operational spending by the energy center is initially spent within the state, thus supporting additional income and jobs in the immediately surrounding counties and throughout the state.

To calculate these indirect impacts, multiplier coefficients are applied to the direct impact dollars; these multipliers also automatically take into account the amount of "leakage" from the local and state economies because some wages and expenditures will be spent outside of the regions in which they are initiated. For this reason, multiplier coefficients are finite and, therefore, measureable.

METHODOLOGY

The analysis of the direct and indirect economic impacts of the Newton Energy Center relied on spending and workforce information provided by AER, and on the U.S. Department of Commerce's Regional Input-Output Multiplier System (RIMS-II). RIMS-II provides multiplier coefficients for every county in the United States. These multipliers can also be aggregated for larger regions composed of counties, such as states and, in this case, the primary economic impact region around the energy center. Multiplier coefficients for sub-county geographies are not available. The multipliers are determined separately for, and are unique to, each county and region for key economic sectors. The RIMS-II multipliers are updated annually by the Bureau of Economic Analysis (BEA).

The economic impact analysis focuses on the multi-county region noted above and on the state as a whole. That is, the Newton Energy Center has two economic impact tables associated with it: the state and its own primary economic impact region. There are three principal multipliers for each sector:

- **Economic Output:** This is defined as the total dollar change in the regional or state economy due to direct expenditures by AER at the energy center. Economic output is a similar measure as the nation's gross domestic product but, unlike the GDP, it also includes all the intermediate values added during the production process.

- **Earnings:** The earnings multiplier measures the added household earnings for the regional and state labor force triggered by AER's direct spending at the energy center.

- **Employment:** This is defined as the added jobs in the county per $1,000,000 of direct spending by AER in addition to the jobs at the energy center.[1]

Multipliers are provided for various economic sectors. The direct, non-labor, operational spending by AER at the energy center falls within the Utilities sector; the employee earnings paid by AER fall within the Households sector; and capital expenditures fall within the Construction sector. The RIMS-II multipliers for the selected regions are summarized below. To calculate the indirect economic impacts:

- The *construction* multiplier coefficients for the state and region are applied to the *capital expenditure* figures of the energy center,

- The *utilities* multiplier coefficients for the state and region are applied to the *operational expenditures* of the energy center, and

- The *households* multiplier coefficients for the state and region are applied to the *employee compensation* figures of the energy center. Employee compensation is calculated by applying the average labor expenditure to the number of workers who reside in the state and region. For the purposes of this analysis, employee compensation includes salary, benefits, and any other labor related costs; therefore, the average labor expenditure per employee does not necessarily reflect the average wage.

The respective direct and indirect impacts are then summed to calculate the total indirect impacts.

Note: Fuel expenditures for coal were not considered for this analysis. AER's coal comes from in-state and out-of-state sources. In the case of Newton Energy Center, all of its coal comes from out-of-state sources. Since this study focuses on the impacts within the state of Illinois, only the expenditures for Illinois-sourced coal should be considered. Though a small portion of Newton's fuel expenditures likely occur within Illinois (e.g. transportation costs), the vast majority of these expenditures occur outside of Illinois; therefore, we are uncomfortable assuming that the standard RIMS-II multipliers account for this scale of immediate leakage. Including fuel expenditures in this analysis, therefore, could overstate the local and statewide impacts.

CONCLUSIONS

DS estimates that the Newton Energy Center has an economic impact on the Illinois economy and its primary economic impact region as shown on the following tables. Each table summarizes AER's direct spending at the Newton Energy Center (top line in the table), the multipliers for Illinois or the market area, the multiplier effects resulting from AER's operational spending, and the total direct and indirect economic impacts generated.

[1] The multipliers derived from U.S. Department of Labor data, however, are based on 2008 economic activity and data. So the model used in this report inflates the million dollars from 2008, or jobs per $1,081,940 in 2013 dollars, using the Consumer Price Index (CPI).

IMPACTS ON THE STATE OF ILLINOIS

Annual Economic Impact of AER's Newton Energy Center Operations on the State of Illinois

	Annual Average in 2013 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 65,705,000	$ 12,553,000	$ 15,636,000	$ 93,894,000
MULTIPLIERS				
Output	2.3293	1.5022	1.4416	2.0709
Household Earnings	0.7145	0.2856	0.3968	0.6042
Employment[3]	14.4079	4.2522	9.6324	12.2479
ADDED ECONOMIC IMPACT ON ILLINOIS				
Output	$ 153,047,000	$ 18,857,000	$ 22,541,000	$ 194,445,000
Household Earnings	$ 46,946,000	$ 3,585,000	$ 6,204,000	$ 56,735,000
Indirect Jobs Held by Illinois Residents	950	50	150	1,150
TOTAL ECONOMIC IMPACT ON ILLINOIS				
Output (Total Economic Activity)				$ 288,339,000
Household Earnings				$ 72,371,000
Direct Jobs at Newton Energy Center (Illinois residents)				142
Total Direct and Indirect Jobs at Newton Energy Center				1,292

[1] *Actual operating data from 2008 to 2012 adjusted to 2013 dollar amounts using the Consumer Price Index (CPI) and averaged.*

[2] *Estimate based on number of employees who reside in Illinois (142 of 143) and overall average labor expenditure per employee.*

[3] *E mployment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multipliers presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows the direct expenditures by AER at the Newton Energy Center averaging approximately $93.9 million per year from 2008 to 2012 in 2013 dollars. Employee compensation is an estimate based on the number of Newton employees that live in Illinois (142 of 143). Additional results are discussed below:

- The $93.9 million spent by AER at Newton Energy Center triggered an additional $194.4 million in value added activity in Illinois, of which $56.7 million was household earnings that another supported 1,150 jobs.
- The estimated total output (economic activity) triggered by Newton Energy Center's direct operations ($93.9 million) and the added multiplier effects ($194.4 million) were $288.3 million for the Illinois economy.
- Of that amount, Newton Energy Center's operations triggered nearly $72.4 million in household earnings for workers in Illinois, including $15.6 million in direct compensation for employees and $56.7 million in added earnings from the multiplier effects.
- In total, Newton Energy Center's operations supported 1,292 jobs for Illinois residents, including 142 direct jobs and approximately 1,150 jobs added through the multiplier effects.

IMPACTS ON THE MULTI-COUNTY REGION

Annual Economic Impact of AER's Newton Energy Center Operations on Labor Market Area

	Annual Average in 2013 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 65,705,000	$ 12,553,000	$ 12,002,000	$ 90,260,000
MULTIPLIERS				
Output	1.4919	1.2710	0.5804	1.3400
Household Earnings	0.4231	0.2295	0.1442	0.3591
Employment[3]	8.3442	2.7410	3.8597	6.9798
ADDED ECONOMIC IMPACT ON MARKET AREA				
Output	$ 98,025,000	$ 15,955,000	$ 6,966,000	$ 120,946,000
Household Earnings	$ 27,800,000	$ 2,881,000	$ 1,731,000	$ 32,412,000
Indirect Jobs Held by Market Area Residents	550	30	50	630
TOTAL ECONOMIC IMPACT ON MARKET AREA				
Output (Total Economic Activity)				$ 211,206,000
Household Earnings				$ 44,414,000
Direct Jobs at Newton Energy Center (market area residents)				109
Total Direct and Indirect Jobs at Newton Energy Center				739

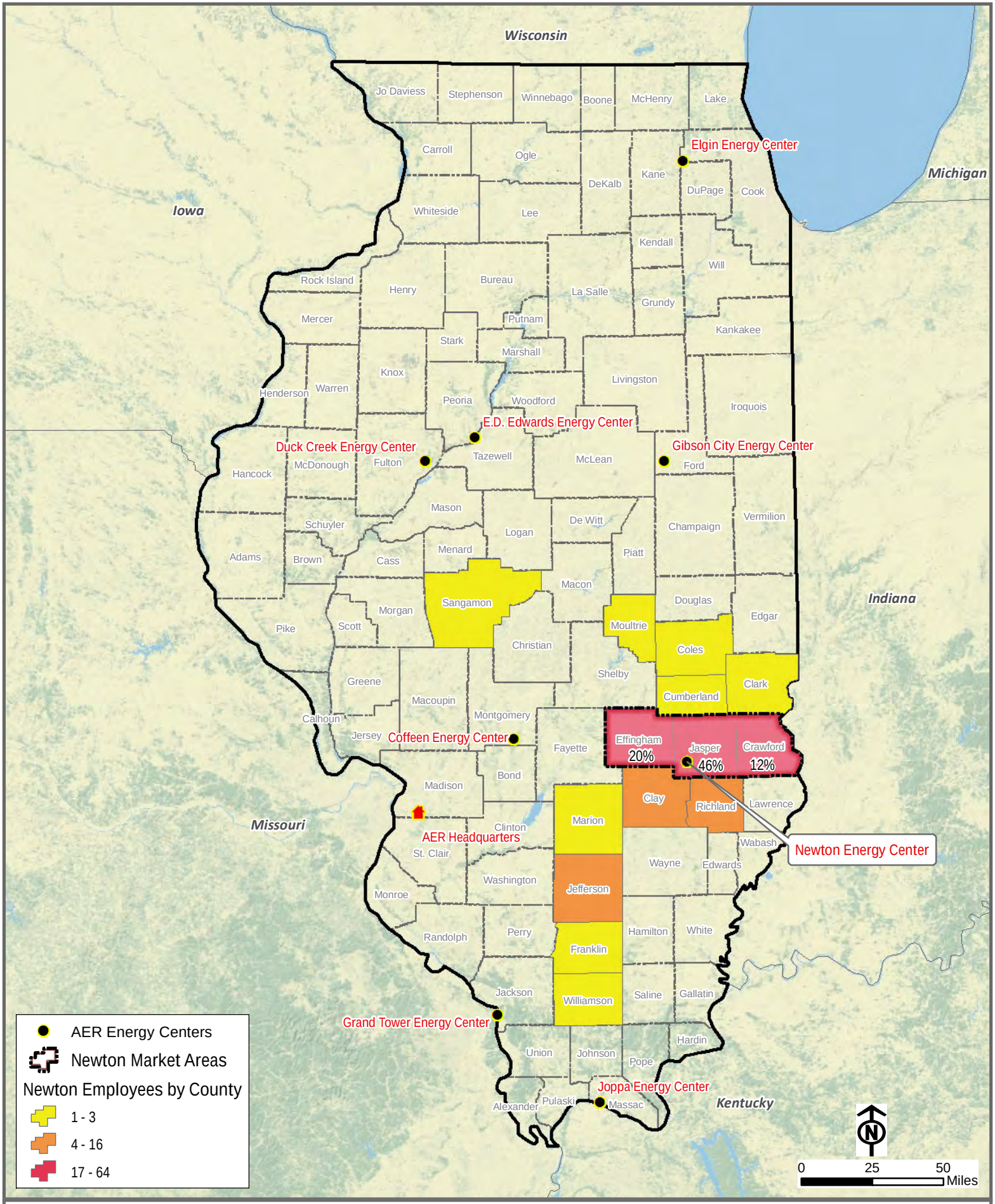
[1] *Actual operating data from 2008 to 2012 adjusted to 2013 dollar amounts using the CPI and averaged.*

[2] *Estimate based on number of employees who reside in labor market area (109 of 143) and overall average labor expenditure per employee.*

[3] *Employment multiplier represents jobs per $1 million in expenditures. Since the original RIMS-II multiplier is based on 2008 economic data, the employment multipliers presented in this table have been adjusted to jobs per $1 million in 2013 dollars using the CPI, or jobs per $1,081,940.*

The top of the table shows that the direct expenditures by AER at the Newton Energy Center in the market area averaged approximately $90.3 million per year from 2008 to 2012 in 2013 dollars. This is less than for the state as a whole because employees outside of the market area are excluded. Employee compensation is an estimate based on the number of Newton employees that live in the labor market area (109 of 143). Additional results are discussed below:

- The $90.3 million spent by AER at Newton Energy Center triggered an additional $120.9 million in value added activity in the market area, of which $32.4 million was household earnings that supported 630 jobs. The multipliers vary for different types of major expenditures shown at the top of the table.
- The estimated total output (economic activity) triggered by Newton Energy Center's direct operations ($90.3 million) and the added multiplier effects ($120.9 million) were $211.2 million for the market area.
- Of that amount, Newton Energy Center's operations triggered nearly $44.4 million in household earnings for other workers in the market area, including $12.0 million in direct compensation for employees and $32.4 million in added earnings from the multiplier effects.
- In total, Newton Energy Center's operations supported an annual average of 739 jobs for residents of the market area, including 109 direct jobs and approximately 630 jobs added through the multiplier effects.



AER: Newton Labor Market Areas

Source: Ameren provided employment counts by work location and county of residence, as of June 26, 2013

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July 2013

EXHIBIT 8

AFFIDAVIT OF DANIEL P. THOMPSON

AFFIDAVIT OF DANIEL P. THOMPSON

I. BACKGROUND AND QUALIFICATIONS

1. My name is Daniel P. Thompson. I am Vice President and General Manager for Dynegy Midwest Generation, LLC ("DMG"), an indirect, wholly owned subsidiary of Dynegy Inc. ("Dynegy"). I also serve as Vice President of Illinois Power Holdings, LLC ("IPH"), which is also an indirect, wholly owned subsidiary of Dynegy. My business address is 604 Pierce Blvd., O'Fallon, Illinois, 62269. I provide this affidavit in support of the Petition for Variance filed by IPH, AmerenEnergy Medina Valley Cogen, L.L.C. ("Medina Valley") and Ameren Energy Resources, LLC ("AER") ("Petition"). I make this affidavit based on personal knowledge or on knowledge I have obtained through inquiry of individuals employed by Dynegy or its affiliates.

2. As Vice President of DMG, I am responsible for the safe and efficient operation of Dynegy's coal-fired electric generating fleet in Illinois. My responsibilities include oversight of environmental compliance at Dynegy's Illinois coal fleet.

3. Prior to my current position with Dynegy, I served as Dynegy's Vice President of Operations, West Region from 2007 to late 2011; Vice President, Northeast Operations (New York) from 2001 to 2007; and Vice President, Engineering for Generation from 1999 to 2001. Prior to that, I had worked for Illinois Power since 1987 in numerous capacities, including the Manager of the Vermilion and Hennepin Stations; Operations Supervisor at Baldwin Station, Plant Manager at Havana Station; Manager of Nuclear Training at Clinton Nuclear Station and Manager of Nuclear Engineering. Prior to joining Illinois Power, I was Maintenance Manager for Pfizer, Inc. at its Minerals and Pigments Division in East St. Louis, Illinois from 1980 to 1982 and the Maintenance Superintendent for the Allis Chalmers Coal Gasification R&D

Facility at East Alton, Illinois from 1982 to 1987. I graduated in 1975 from the United States Naval Academy, subsequently completed Naval Nuclear Power School and then served as a Nuclear Propulsion/Surface Warfare Officer aboard the USS Long Beach (CNG-9) until 1980. I hold an MBA from Southern Illinois University Edwardsville (1984).

4. I am familiar with the contemplated transaction between IPH and Ameren Corporation ("Ameren") and led Dynegy's due diligence efforts on operations-related issues for the transaction. I have read and am familiar with the September 20, 2012 Opinion and Order ("Order") by the Illinois Pollution Control Board ("Board"), Docket PCB 12-126, granting AER variance relief from the sulfur dioxide ("SO_2") annual emission rates in the multi-pollutant standard ("MPS") rules applicable to the Ameren MPS Group.

II. DYNEGY'S PRESENCE AND EXPERIENCE IN ILLINOIS

5. Dynegy is a holding company that conducts substantially all of its business operations through its subsidiaries. Dynegy's primary business is the production and sale of electric energy, capacity and ancillary services on a wholesale basis to Regional Transmission Organizations ("RTOs"), Independent System Operators ("ISOs"), integrated utilities, electric cooperatives, municipalities and other energy companies in the Midwest, Northeast and West Coast regions of the U.S. Dynegy's power generation portfolio consists of twelve operating power plants in six states totaling approximately 9,800 megawatts ("MW") of baseload, intermediate and peaking generation fueled by a mix of coal, fuel oil and natural gas.

6. Through its subsidiaries Dynegy Midwest Generation, LLC ("DMG") and Dynegy Kendall Energy, LLC, Dynegy owns and operates five coal and natural gas-fired power generation facilities in Illinois, with the capacity of producing approximately 4,200 MW of reliable, low cost energy for wholesale customers. Dynegy has had a strong and meaningful presence in the

State of Illinois since its February 2000 acquisition of Illinova Corporation (*i.e.*, the fossil fuel-fired electric generating assets of Illinois Power Company), which formed the basis of DMG's current generating fleet in Illinois. In 2004, Dynegy sold the Illinois Power Company regulated energy delivery business to Ameren Corporation, but retained the generating assets.

7. DMG's generating assets include four operating coal-fired electric generating stations located in southern Illinois: the Baldwin Energy Complex in Randolph County, the Havana Power Station in Mason County, the Hennepin Power Station in Putnam County, and the Wood River Power Station in Madison County. In November 2011, DMG permanently retired a fifth coal-fired power plant, the Vermilion Power Station, located in Vermilion County. Through its subsidiaries operating in Illinois, Dynegy has approximately 600 full-time employees statewide, employing approximately 550 persons at its Illinois power stations and approximately 50 persons at its corporate office located in O'Fallon, Illinois. The economic impact of Dynegy's operations in Illinois and in the affected local Illinois communities is significant. For example, in 2012, through its subsidiaries, Dynegy's direct investments in Illinois (*i.e.*, maintenance, capital, and taxes) totaled approximately $261 million.

8. Dynegy and its subsidiaries have a strong commitment to safe and environmentally responsible operations in Illinois. DMG has invested approximately $1 billion in air pollution controls at its Illinois facilities (including installation of flue gas desulfurization, activated carbon injection systems, and/or baghouses on select generating units) to comply with the Illinois Mercury Rule, including the MPS, and DMG's Consent Decree.[1] Since 1998, DMG's fleet has reduced its aggregate annual emissions by almost 90 percent. Dynegy is very familiar and experienced with the Illinois MPS requirements. DMG's five coal-fired stations

[1] *United States. v. Illinois Power Co.*, No. 99-CV-833-MJR (S.D. Ill.) (Consent Decree entered May 27, 2005) (a copy of the Consent Decree as originally entered is available at: http://www.epa.gov/compliance/resources/decrees/civil/caa/dmgfinal-cd.pdf.

elected into the MPS in 2007 (*i.e.*, the DMG MPS Group) and Dynegy's environmental support group staff was directly involved in the MPS rulemakings. DMG has met its MPS limits. Indeed, DMG met the MPS's mercury emission rate limit at all but one of its MPS generating units three years earlier than the required January 1, 2015 deadline.

9. Dynegy also has been involved in carbon sequestration efforts, with tree-planting projects covering more than 45,000 acres in a portion of the Shawnee National Forest. The Lower Mississippi River Valley reforestation project is registered under the Verified Carbon Standard and was the first U.S. forest carbon offset project to receive this certification. Dynegy has also donated 1,100 acres along the Middle Fork Vermilion River to the Illinois Department of Natural Resources and has sponsored activities preserving 1,200 acres of forests in Illinois. Each year, these trees will sequester increasing levels of carbon dioxide. Dynegy also reuses coal ash produced at its Illinois coal-fired generating facilities through agreements with cement manufacturers that incorporate the material into cement products, helping to reduce carbon dioxide emissions from the cement manufacturing process.

III. TRANSACTION AGREEMENT WITH AMEREN

10. On March 14, 2013, IPH entered a Transaction Agreement with Ameren to acquire the equity interest in Ameren's merchant utilities businesses (collectively, the "Acquired Merchant Utilities"). Upon closing of the transaction, IPH will own the Acquired Merchant Utilities, which own and operate five operating coal-fired electric energy generating centers in central and southern Illinois -- specifically the Duck Creek Energy Center in Fulton County, the Coffeen Energy Center in Montgomery County, the E.D. Edwards Energy Center in Peoria County, the Newton Energy Center in Jasper County, and the Joppa Energy Center in Massac County (the five operating energy centers, collectively, the "Acquired Plants"). Under the

Transaction Agreement, the shuttered Hutsonville and Meredosia power plants will remain with Petitioner Medina Valley, a subsidiary of Ameren, and will not be acquired by IPH. Closing on the Transaction Agreement is expected to occur in the fourth quarter of 2013. Given Dynegy's experience in Illinois, IPH's acquisition of the Acquired Merchant Utilities will position the businesses and the Acquired Plants to move forward with a company committed to Illinois and with a history of providing environmentally sound, safe, affordable, and reliable power in Illinois.

IV. WITHOUT THE REQUESTED VARIANCE RELIEF COMPLIANCE WITH THE MPS WOULD IMPOSE UNREASONABLE HARDSHIP ON IPH

11. IPH has analyzed its options to meet the Ameren MPS Group Multi-Pollutant Standard rule 2015 and 2017 overall SO_2 annual emission rates and concluded that its only compliance alternative not involving shutdown of some combination of the Acquired Plants is to follow through on AER's chosen compliance plan to meet the Ameren MPS Group system-wide SO_2 emission rate limits, namely by installing and operating a flue gas desulfurization ("FGD") system on each unit at the Newton Energy Center.

12. Because IPH will not acquire ownership of the Acquired Plants until late 2013 and because construction activities needed to install the Newton FGDs are expected to take up to 24 months, IPH could not complete construction of the Newton FGDs in time to comply with the MPS 2015 overall SO_2 annual emission rate, even if IPH were financially able to ramp up construction immediately upon acquiring ownership (which, as explained in the Affidavit of Mario E. Alonso, will not be possible). Thus, without the requested variance relief, IPH's only option to comply with the MPS would be to shut down a combination of the Newton, E.D. Edwards and Joppa Energy Centers by January 1, 2015. In IPH's analysis, without the requested variance relief, E.D. Edwards and Joppa would be shut down by January 1, 2015 to meet the

MPS. Moreover, without the requested variance relief, even after shutting down the E.D. Edwards and Joppa Energy Centers by 2015, the remaining three operating energy centers (Coffeen, Duck Creek, and Newton) would not meet the 2017 MPS overall SO_2 annual emission rate without operational curtailments or implementation of other SO_2 emission reduction measures at Newton, as IPH likely would not complete construction of the Newton FGDs given the significant remaining capital expense of doing so. As discussed below, there are no other viable compliance alternatives.

A. Compliance Alternatives

i. Curtailment of Operations

13. Curtailment of operations (*i.e.*, derates, seasonal operations, etc.) to meet the MPS overall SO_2 annual emission rate limits would not be economically feasible because less power would be generated, resulting in less revenues to run the business and cover fixed operating costs. In other words, curtailing operations at the Acquired Plants as a compliance strategy would prevent the plants from generating sufficient funds to sustain their operations and obligations. More specifically, IPH's analysis indicates that in order to meet the 2015 MPS overall SO_2 emissions limit with all five plants remaining in operation would effectively require each of the Newton, E.D. Edwards and Joppa energy centers to limit its respective generation to approximately one-third of its capacity. Given their significant fixed costs, such a limit on generation would eliminate the ability of these energy centers to generate positive cash flows going forward and result in their shutdown. For the same reason, seasonal operation of the Newton, E.D. Edwards and Joppa stations would be infeasible.

ii. Low Sulfur Coal

14. IPH will continue to honor AER's prior commitment to limit the use of higher sulfur coal to the Duck Creek and Coffeen stations (both of which utilize wet FGD systems) and to use low sulfur Powder River Basin ("PRB") coal (*i.e.*, 0.55 lbs sulfur/mmBtu) at the E.D. Edwards, Newton and Joppa stations. In fact, IPH, through the Acquired Merchant Utilities, will inherit the binding 0.55 lb/mmBtu low sulfur coal purchase contracts AER already has in place for 2013-2017. More specifically, IPH understands that AER is already contracted for the majority of its expected coal supply needs in 2013 and 2014, approximately one-half of its expected coal supply needs in 2015 and 2016, and approximately one quarter of its coal supply needs in 2017. Those contracts could not be breached without material penalties.

15. Based on DMG's coal purchasing experience, IPH understands that 0.50 lb/mmBtu sulfur PRB coal is available from one coal supplier. Ongoing dependence for coal from a single supplier may materially increase contracted prices by 10 percent or more above current market prices and would expose IPH to production and performance specific risks. In completing coal purchasing to meet its fuel inventory needs in 2013-2017 (*i.e.*, purchasing coal to supplement the quantities for which AER has already entered binding contracts), 2018 and 2019, IPH anticipates that it may need to purchase certain quantities of coal with a sulfur content lower than 0.55 lb/mmBtu to ensure compliance with the variance's SO_2 mitigation emissions limit. However, IPH does not at this time know the precise quantities of such coal (*i.e.*, sulfur content lower than 0.55 lb/mmBtu) that may be needed for compliance, as that will depend on actual SO_2 emissions performance of the Acquired Plants in future years. Moreover, given the material increased risks associated with relying on a single supplier of such coal and the financial liquidity challenges that the Acquired Plants will face, IPH cannot now commit to purchasing

only coal with sulfur content lower than 0.55 lb/mmBtu for the currently uncontracted coal supply needs of the Newton, E.D. Edwards and Joppa stations during the requested variance period. As stated above, IPH will commit to using low sulfur PRB coal with a sulfur content not to exceed 0.55 lb/mmBtu at the E.D. Edwards, Newton and Joppa stations during the term of the requested variance.

iii. Alternative Control Technologies

16. IPH also has independently reviewed the availability of alternative SO_2 emission control technologies and reaches the same conclusion that AER did, as approved by the Board's prior grant of the AER variance, that these technologies are infeasible because they would cost more than the Newton FGD project. The costs and technological limits prevailing at the time of the Board's Order in September 2012 have not changed in any material way. Thus, there are no other cost-effective control technologies that IPH could used at the Acquired Plants to achieve compliance with the MPS.

17. Specifically with regard to dry sorbent injection ("DSI") technology as a potential compliance alternative, the overall cost of DSI as applied to the Joppa and/or E.D. Edwards energy centers renders DSI infeasible. Based upon IPH's analysis of DSI at other coal-fired plants, IPH estimates that the capital cost of installing DSI would alone be in the range of $60 million at Joppa (all six units) and $30 million at E.D. Edwards (Units 2 and 3). These are order of magnitude estimates based on DMG's experience, as IPH has not performed a site-specific engineering analysis of DSI at either facility. As explained in the Affidavit of Mario E. Alonso, IPH will not have sufficient liquidity to fund any such large-scale capital projects over the next several years. Importantly, however, as AER demonstrated in obtaining its variance, the capital costs of installing DSI at Joppa and/or E.D. Edwards would not be limited only to the DSI

technology. Because of the size of the existing particulate control equipment and the injection of activated carbon to control mercury emissions at E.D. Edwards and Joppa, the additional use of DSI would result in a significant increase in particulate matter ("PM") emissions, necessitating installation of PM control technologies (*e.g.*, baghouses, significant upgrades to the existing ESPs). Thus, the real expected capital cost of installing DSI would be materially higher, approximately $433 million at Joppa and approximately $280 million at E.D. Edwards (Units 2 and 3), as identified in AER's Post-Hearing Brief (p.15) (PCB 12-126) (filed Aug. 15, 2012), which cites to a 2011 URS engineering report and attaches a cost table from the URS report as Post-Hearing Brief, Exhibit 1.

18. The annual operation and maintenance ("O&M") expense of DSI also is itself significant. As AER demonstrated, the estimated annual cost of dry sorbent ranges from $15 million to $44 million depending upon the type of material used and the location of injection (before or after the air heater). See PCB 12-126, Petitioner's Post-Hearing Brief, 20-21 (citing 2010 report completed by the Shaw Group (Post-Hearing Brief, Exhibit 2)). Those estimated O&M costs cited by AER are consistent with DMG's analysis of DSI O&M costs at other coal-fired plants. In addition, use of DSI would result in O&M expenses associated with the disposal of the reacted DSI material. Those costs would not be insignificant. The impact of DSI annual O&M costs is even more pronounced given the liquidity challenges the Acquired Plants will face.

iv. Natural Gas

19. IPH also has considered firing natural gas as a means to comply with the MPS. Natural gas pipelines are not currently interconnected to E.D. Edwards or Newton. The cost of constructing natural gas pipelines to either facility would be cost prohibitive. Based on

preliminary analysis by AER, an order of magnitude estimate of the cost to develop natural gas supply to E.D. Edwards is $100 million and the cost to develop natural gas supply to Newton is $70 million. Further, the additional capital expenditures needed to convert the coal–fired boilers at E.D. Edwards or Newton to natural gas firing are expected to be significant. In the absence of detailed site-specific natural gas conversion engineering studies at E.D. Edwards or Newton, based on reported industry trade literature and case studies involving natural gas conversion of existing coal-fired boilers, the cost of converting each plant would be expected to be tens of millions of dollars, if not more. *See, e.g.,* Babcock & Wilcox, Natural Gas Conversions of Existing Coal-Fired Boilers, White Paper MS-14 (2010) (identifying cost range of $50 to $75/kW). In addition, converting the Newton units to natural gas firing in lieu of completing construction of the Newton FGDs also would waste the several hundred million dollars already spent on the Newton FGDs.

20. Moreover, natural gas firing at Newton or E.D. Edwards would not be a cost-effective compliance alternative because dispatch on natural gas is more expensive than on coal, with the result that natural gas firing would result in significantly lower production by the plant and, thus, generate lower revenues needed for the recovery of fixed operating costs and capital expenditures. Based on current power market conditions in Illinois, production costs related to fuel are roughly $20-$25 per megawatt hour ("$/MWh") on PRB coal and would be roughly $40/MWh on natural gas. Based on MISO published clearing prices in 2012, power prices at, for example, the Newton busbar averaged in excess of $22.00/MWh during 76 percent of the on-peak days while only of two percent of the on-peak day averages exceeded $40.00/MWh. In other words, Newton fired on natural gas during 2012 would have been dispatched approximately only two percent of the time. Thus, IPH concludes that it is infeasible to convert

E.D. Edwards or Newton to natural gas.

21. Further, IPH concludes that, for several reasons, converting Joppa to natural gas would be cost prohibitive and not economically feasible. First, based on preliminary analysis by AER, an order of magnitude cost estimate to convert the relevant Joppa units to natural gas ranges from $25 million (*i.e.*, convert to 50 percent capacity on natural gas) to $38 million (*i.e.*, convert to 100 percent capacity on natural gas), with an additional estimated $4.5 million in capital expenditures needed for gas supply pipeline and equipment improvements. As explained in the Affidavit of Mario E. Alonso, IPH will not have sufficient liquidity to fund any such large-scale capital projects over the next several years. Second, as discussed in the following paragraph, natural gas firing at Joppa would not be a cost-effective compliance alternative because dispatch on natural gas is more expensive than on coal, with the result that natural gas firing would result in lower production at Joppa and, thus, generate lower revenues needed for the recovery of fixed operating costs and capital expenditures. Finally, as determined by the Board in AER's variance proceeding, conversion of Joppa to natural gas firing would reduce the plant's operations to a seasonal basis only, thereby resulting in reduced revenues and, ultimately, a loss of jobs. Thus, IPH concludes that, as the Board determined in the AER variance proceeding, it is infeasible to convert Joppa to natural gas.

22. IPH understands that two units at Joppa (Units 1 and 4) have the physical capability to co-fire natural gas up to approximately 45 percent of heat input at full load. Based on DMG's experience with analyzing natural gas co-firing as an option to reduce SO_2 emissions at its coal-fired plants in Illinois, IPH concludes that natural gas co-firing at these two Joppa units, even at levels less than 45 percent, is not cost effective. Because dispatch on natural gas is more expensive than dispatch on coal, natural gas co-firing would result in lower production and,

thus, generate lower revenues for the recovery of fixed operating costs and capital expenditures. The key factor for sustained use of natural gas co-firing is the price differential between natural gas and coal. As mentioned above, based on current market conditions, production costs related to fuel are roughly $20 - $25/MWh on PRB coal and would be roughly $40/MWh on natural gas. In general, it would only be cost effective to co-fire natural gas if natural gas prices approached $2.50/mmBtu. Thus, even at the historically low natural gas prices in recent times, natural gas co-firing does not make economic sense. Accordingly, IPH concludes that natural gas co-firing at Joppa Units 1 and 4, while technically possible, is not a cost-effective compliance alternative, nor would it achieve compliance with the MPS overall SO_2 emission rate limits.

V. IPH's COMPLIANCE PLAN UNDER THE REQUESTED VARIANCE RELIEF

23. IPH will keep intact the seven-plant Ameren MPS Group, including the shutdown Hutsonville and Meredosia plants, through the requested variance period. Even though IPH will not acquire the shuttered Hutsonville and Meredosia plants, IPH understands that these two shutdown plants must remain in the Ameren MPS Group for MPS compliance determination purposes, including MPS reporting. In addition, as provided in the Petitioners' proposed variance order, IPH will assume responsibility for ensuring that the shuttered electrical generating units at the Hutsonville and Meredosia plants remain shuttered through December 31, 2020. Petitioner Medina Valley, who will acquire the Hutsonville and Meredosia plants, also has independently committed not to operate the electrical generating units at Hutsonville and Meredosia through December 31, 2020. As in AER's existing variance, the requirement to keep the electrical generating units at Meredosia shuttered through December 31, 2020 would exempt the FutureGen project.

24. IPH will meet an overall SO_2 mitigation emission rate of 0.35 lb/mmBtu for each year from 2013 through December 31, 2019, and 0.23 lb/mmBtu annually thereafter (*i.e.*, the same overall SO_2 annual mitigation emission rate and final MPS SO_2 emission rate at the Acquired Plants that AER committed to by accepting the Order). IPH will honor AER's prior commitment to limit the use of higher sulfur coal to the Duck Creek and Coffeen stations and to use low sulfur coal (*i.e.*, 0.55 lbs sulfur/mmBtu) at the E.D. Edwards, Newton and Joppa stations during the variance term. IPH also will honor AER's commitment to maximize operation of the existing FGD systems at the Duck Creek and Coffeen stations at a 98-99 percent SO_2 removal rate during the variance term. Finally, IPH will continue the construction of the Newton FGD project and comply with the Newton FGD project construction milestones and reporting requirements as set forth in the Petitioners' proposed variance order (*i.e.*, the same Newton FGD project construction milestones and reporting requirements that AER committed to by accepting the Order).

25. IPH estimates that total costs of construction for the two FGD units at the Newton energy center are approximately $500 million. Approximately one-half of the total costs have been spent to date. In accordance with the construction milestones in the proposed variance order, IPH has budgeted $18 million in annual expenditures through 2017 to continue construction of the Newton FGDs, with the remainder of the total estimated spend scheduled for 2018 and 2019 to complete the Newton FGDs. In addition, several million dollars in annual O&M expenses will be required to comply with the MPS NO_x and mercury emission limits at the Acquired Plants.

VI. THE PROPOSED VARIANCE ORDER WILL HAVE NO ADVERSE ENVIRONMENTAL IMPACT AND WILL REDUCE OVERALL SO_2 EMISSIONS

26. The proposed variance would reduce overall SO_2 emissions compared to the SO_2 reductions achieved by compliance with the Ameren MPS Group Multi-Pollutant Standard rule. As identified in the Affidavit of Aric D. Diericx, the proposed variance will result in a net reduction of 74,303 tons of SO_2 over the period 2010-2020 and a net reduction of 7,778 tons of SO_2 over the period 2013-2020.

27. IPH anticipates that additional overall net reductions will occur for one or more of several reasons. First, IPH expects that during the term of its requested relief E.D. Edwards Unit 1 will be permanently retired. In December 2012, AmerenEnergy Generating Resources Company ("AERG") filed a request with the Midcontinent Independent System Operator, Inc. ("MISO"), the regional transmission organization, to retire E.D. Edwards Unit 1 effective December 31, 2012. MISO then informed AERG that MISO's reliability analysis indicated the unit was needed for reliability purposes and that continued service of E.D. Edwards Unit 1 as a System Support Resource ("SSR") unit would be required. MISO determined that E.D. Edwards Unit 1 would be needed for reliability purposes until such time as numerous transmission system reinforcements were put into service in order to mitigate thermal and voltage issues. Accordingly, effective January 1, 2013, AERG was required to continue to run E.D. Edwards Unit 1. MISO filed an unexecuted SSR Agreement, pursuant to attachment Y-1 of MISO's tariff, with the Federal Energy Regulatory Commission ("FERC") on July 11, 2013 (the "July 11 SSR Filing"). The maximum term of an SSR Agreement is twelve months and the July 11 SSR Filing covers the 2013 calendar year, however an SSR Agreement can be renewed and continue subject to an annual review of mitigation alternatives. As noted in the July 11 SSR Filing, MISO

expects that E.D. Edwards Unit 1 will continue as an SSR unit until all of the required transmission system reinforcements are implemented in December 2016, though newly available alternatives will be sought in considering the annual review of the SSR Agreement. Therefore, annual renewal of the SSR Agreement seems likely. The ultimate retirement date of E.D. Edwards Unit 1 is subject to MISO approval, which is beyond IPH's control. Thus, IPH cannot commit to retiring E.D. Edwards Unit 1 by a date certain. However, based on information currently available from MISO, IPH does expect that E.D. Edwards Unit 1 will be retired before the end of the requested variance term. With respect to the net reductions identified above, the retirement of E.D. Edwards Unit 1 is expected to reduce SO_2 emissions by approximately 2,000 tons per year beginning in the first full year the unit is retired.

28. Second, as explained above, IPH anticipates that it may at times purchase certain quantities of even lower sulfur coal than included in AER's commitment for Newton, E.D. Edwards and Joppa, depending on SO_2 emissions performance of the Acquired Plants. While IPH cannot commit to purchasing lower than 0.55 lb/mmBtu sulfur coal for the currently uncontracted coal supply needs of Newton, E.D. Edwards and Joppa during the variance period given the material increased risks associated with relying on a single supplier of such coal and the financial liquidity challenges that the energy centers will face, IPH anticipates that any such purchases of lower than 0.55 lb/mmBtu sulfur coal would achieve additional reductions beyond those identified.

29. Third, the net reductions identified above do not reflect the expected reductions in SO_2 emissions that will occur in 2019 due to installation of the two FGDs at Newton. That is, the reductions identified above do not reflect that extended unit outages at Newton that will be required to install the FGDs, during which time the respective unit will not emit SO_2. In

addition, the net reductions identified above do not reflect that the FGDs would, in all likelihood, be installed in series (*i.e.*, after FGD installation is completed on one Newton unit, the second FGD would be installed on the second Newton unit), meaning that at least one of the FGDs would be operating for a portion of calendar year 2019.

30. Finally, IPH will meet the applicable MPS NO_x and mercury emission rate limits at the Acquired Plants. IPH also will comply with the federal Mercury and Air Toxics Standards ("MATS") at the Acquired Plants. Cross-media impacts resulting from the proposed variance will remain a non-issue, as they were for the AER variance.

VII. IPH'S VARIANCE REQUEST IS CONSISTENT WITH ILLINOIS SIP OBLIGATIONS AND FEDERAL LAW

31. Granting the petition with the conditions imposed by the proposed variance order would be within Illinois' current obligations under the Illinois state implementation plan ("SIP") to attain and maintain compliance with the National Ambient Air Quality Standards ("NAAQS") and, therefore, would be consistent with federal law.

32. IPH understands that the requested variance relief would not exempt the Acquired Plants from compliance with federal requirements. Thus, if new requirements are adopted under the federal Clean Air Act in the future, additional controls might need to be implemented at an Acquired Plant(s).

VIII. CONCLUSION

33. I have read the Petition and the facts stated therein with regard to the subject matters of this affidavit are true and correct to the best of my knowledge and belief.

FURTHER, Affiant sayeth not.

DATED: 7/17/2013

Daniel P. Thompson

Subscribed and swore to before me
this 17th day of July, 2013

Notary Public

"OFFICIAL SEAL"
LAUREN R. SCHMIERBACH
NOTARY PUBLIC—STATE OF ILLINOIS
MY COMMISSION EXPIRES MAR 16, 2014

EXHIBIT 9

AFFIDAVIT OF GEORGE W. BILICIC

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I. BACKGROUND AND QUALIFICATIONS

1. My name is George Bilicic. I am employed by Lazard Frères & Co. LLC ("Lazard" or the "Firm") in the Financial Advisory practice. Lazard is an independent financial advisory and asset management firm. With over 160 years of history, Lazard, together with its affiliates, operates in 26 countries and employs approximately 2,500 people. Lazard's Financial Advisory practice provides advice to corporate, institutional, government, sovereign and individual clients on a broad array of strategic and financial matters.

2. I am currently a Managing Director and Vice Chairman of Investment Banking at Lazard, and head the Firm's global efforts in Power, Energy and Infrastructure. I serve as a member of the Firm's Investment Banking Committee and Deputy Chairman Committee. I have worked extensively on a variety of transactional, strategic and financial advisory assignments in the power, utility, alternative energy and infrastructure sectors for over 20 years. I have a B.A. from DeSales University and a J.D. from Georgetown University Law Center.

3. In my testimony, I will refer to the following: Ameren Corporation ("Ameren"); Ameren Energy Resources Company ("AER"); a newly formed limited liability company that is a direct wholly owned subsidiary of AER ("New AER" or the "Company"); each of the (i) Coffeen Plant, (ii) Duck Creek Plant, (iii) E.D. Edwards Plant, (iv) Newton Power Plant, and (v) Joppa Generating Station (collectively, the "Acquired Plants"); each of the (i) Ameren Energy Generating Company ("GENCO"), (ii) AmerenEnergy Resources Generating Company, (iii) Ameren Energy Marketing Company, (iv) Electric Energy, Inc., and (v) Midwest Electric Power, Inc. (collectively, the "Ameren Merchant Utilities"); and each of the (i) Grand Tower Energy Center, (ii) Gibson City Energy Center and (iii) Elgin Energy Center

(collectively, the "Put Assets").

4. The purpose of my testimony is to provide an overview of the financial and market challenges that I believe New AER will likely face following its sale to Dynegy Inc.'s ("Dynegy's") wholly-owned subsidiary Illinois Power Holdings, LLC ("IPH"). The challenges IPH and New AER will likely face are very similar to the challenges cited in the September 20, 2012 Opinion and Order by the Illinois Pollution Control Board granting AER variance relief, Docket PCB 12-126, from the sulfur dioxide emission rate in the multi-pollutant standard ("MPS") rules ("Variance Relief"). My testimony will also describe how, as was the case with AER under Ameren, these challenges are expected to limit New AER's ability to access third-party capital for investment in state- and federally-mandated environmental control equipment (or otherwise) on economic terms supportable by New AER's financial condition, if at all.

II. THE EXPECTED FINANCIAL CONDITION OF NEW AER

5. AER's financial outlook, credit profile and access to third-party capital have weakened further since AER received the Variance Relief, as a result of persistently low power prices and ongoing uncertainty regarding federal environmental regulations. Ameren specifically cited its "analysis of the current and projected future financial condition of [AER], including the need to fund GENCO debt maturities" as one of its chief motivations for exiting the merchant generation business in December 2012.[1] Similarly, as described below, New AER's financial condition outlook is expected to be challenged. Thus, the variance relief requested by IPH will continue to play a critical role in allowing New AER to manage its liquidity and credit quality in the midst of a currently challenged merchant generation

[1] Ameren Form 8-K filing (December 20, 2012).

operating environment.

6. AER continues to face a persistently low power price environment that has impaired its credit profile and its ability to fund capital expenditures and cash flow shortfalls. As a merchant generator, AER's earnings and cash flow exhibit significant volatility and are materially impacted by changes in the relationship between fuel and power prices. The decline and ongoing weakness in power prices has pressured the earnings of AER's primarily coal-fired generation fleet, impairing AER's financial health and access to third-party capital on economic terms supportable by AER's financial condition. Forecasts of future power prices suggest that AER's cash flow are expected to remain under pressure through at least 2016. Moody's Investor Services ("Moody's") recently stated:

> "Energy prices for power continue to trade at depressed levels owing in large part to low natural gas prices. Gas prices, which once lifted the overall price of power, have declined significantly over the past several years. While natural gas prices have recovered somewhat from a low in 2012, they are expected to remain depressed for the foreseeable future due to market fundamentals driven by the glut of shale gas supply. ... Outside of ERCOT, most of the deregulated markets have significant surplus capacity. ... To have shortages, another round of widespread shutdowns would be required, involving many gigawatts of large coal or nuclear plant capacity. This scenario is unlikely to occur unless the price of gas falls further on a sustained basis or there is a marked shift in the economic calculus of power plant owners. Demand growth is also not expected to be helpful in closing the surplus gap any time soon."[2]

While power prices in all markets have been negatively affected by low natural gas prices, certain regions have fared worse on a relative basis. Energy and capacity prices in MISO, for example, have been particularly depressed, given an oversupply of low-marginal-cost

[2] Moody's, "Unregulated Utility & Power Companies: Still No Sign of Recovery" (February 6, 2013).

generation. Moody's, in the same report, stated:

> "The downturn [for merchant generators] is most severe in the MISO and upstate New York regions. MISO and upstate New York have very low capacity prices as well as low energy prices, because these regions are dominated by coal and nuclear generation and, in upstate New York, significant hydropower. Companies most concentrated in these regions include Dynegy and Ameren GENCO."

Specifically, as of July 5, 2013, forward market power prices for the Indiana Hub (located in MISO), the relevant liquid trading hub for the majority of the Acquired Plants, are projected to be $32.76/MWh, $31.64/MWh, $32.62/MWh and $34.59/MWh in 2013, 2014, 2015 and 2016, respectively, which suggests that AER's cash flow are expected to remain under pressure through at least 2016.[3] Similarly, equity analyst Steve Fleishman of Wolfe Trahan suggested that the outlook for power and natural gas prices is unlikely to improve in the near term:

> "We see limited upside potential for power and natural gas prices in the near term since key structural changes in these markets do not come until 2015 or beyond. In power, there will be some shutdowns over this period to implement EPA rules and also some regions, such as Texas, are already tight. For the most part, however, power markets should have ample supply. More importantly, power demand shows little sign of turning and may even contract in certain regions. For natural gas, there will likely be ebbs and flows in pricing due to weather and coal-to-gas switching, but forward prices likely stay range bound in the $3.50 - $4.50 area until the new structural demand forces kick in. Even when demand ultimately drives prices above this trading range, we do not expect natural gas to rise above $5.00 - $6.00 long term, given the vast supply of shale

[3] SNL, prices as of 7/5/2013.

gas in the United States."[4]

7. AER's credit profile has been further challenged by the ongoing uncertainty regarding potential federally-mandated environmental regulations. Incremental expenditures stemming from the potential federal regulation of greenhouse gasses and coal combustion residuals, for example, could further exacerbate AER's currently weak liquidity profile. Unregulated power companies are generally more challenged by increasingly stringent environmental mandates than their regulated utility peers. Environmental regulations increase the operating costs of all fossil generation. However, while regulated power companies are able to recover the costs of environmental regulations through authorized rates, unregulated power companies recover their costs through market driven prices and earnings.

8. As shown in Table 1 below, GENCO, AER's only rated subsidiary, has seen its credit rating cut 7 notches by both Standard & Poor's ("S&P") and Moody's since 2008. The downgrades appear to be attributable to a decline in net income and cash flow during that time period, among other factors. AER's net income declined from $359 million in 2008 to ($396) in 2012. GENCO's credit rating has been cut 4 and 3 notches by S&P and Moody's, respectively, since AER was granted the Variance Relief.

[4] Steve Fleishman (Wolfe Trahan), "Utilities and Power: Income But Little Growth; Patience on Power" (March 13, 2013).

TABLE 1 ($ IN MILLIONS)						
	2008	**2009**	**2010**	**2011**	**2012**	**2013**
S&P Rating /Outlook	BBB-/Stable	BBB-/Stable	BBB- /Negative	BBB- /Negative	B-/Stable	CCC+/ Negative
Moody's Rating /Outlook	Baa2/Stable	Baa3/Stable	Baa3/ Stable	Baa3/Stable	Ba3/Negative	B3/ Negative
Net Income/(Loss)	$359	$238	($415)	$41	($396)	NA

The challenged financial outlook for AER (and, accordingly, New AER) is further evidenced by the trading performance of the GENCO bond prices (Table 2), which were trading relatively close to par at the time AER was granted the Variance Relief. GENCO bond prices traded down significantly following Ameren's announcement on December 20, 2012 that it planned to exit the merchant generation business, and still trade well below par, which I believe reflects the understanding that Dynegy will not provide liquidity support, investor concern regarding the long-term financial health of New AER, and the attendant effect of such concern on the Company's ability to access the capital markets in order to refinance the GENCO debt at maturity, among other factors.

TABLE 2			
	7.00%—Due 4/2018	**6.30%—Due 2/2020**	**7.95%—Due 6/2032**
Price on 9/20/2012	$97.19	$89.69	$91.56
Price on 12/21/2012	$75.44	$75.31	$74.06
Price on 3/13/2013	$55.69	$52.56	$53.19
Price on 3/15/2013	$75.81	$71.19	$71.56
Price on 7/5/2013	$81.81	$75.81	$76.06

9. With Ameren retaining the Put Assets, nearly 100 percent of New AER's energy

production and gross margin will be derived from coal-fired generation facilities. Moody's recently stated:

> "Falling natural gas prices have had the most dramatic impact on the operating cash flow of coal and nuclear generation. As the price of natural gas falls, it drives down the energy price of power. For a natural gas plant, there is a corresponding fall in its fuel cost, which is also based on price of natural gas. But for coal and nuclear plants, there has not been much of a decline for delivered price of coal or processed uranium. To make matters worse, coal and nuclear plants also have a much higher fixed operating cost on a $/kW basis than gas plants. ... Though they are both heavily impacted by low natural gas prices, nuclear plants generally fare better than coal plants because their all-in production cost tends to be lower and they have much less burden in terms of environmental compliance costs."[5]

10. Ameren specifically cited AER's challenged financial condition as one of its chief motivations for exiting the merchant generation business:

> "Ameren's Merchant Generation business segment and GENCO have experienced decreasing earnings and cash flows from operating activities over the past few years, including the current year, as margins have declined principally as a result of weaker power prices. In addition, environmental regulations have resulted in significant investment requirements over the same timeframe. ... Ameren has sought to have its Merchant Generation business segment and GENCO fund their operations internally and not rely on financing from Ameren. In December 2012, Ameren determined that it intends to, and it is probable that it will, exit its Merchant Generation business segment before the end of the previously estimated useful lives of that business segment's long-lived assets. This determination resulted from Ameren's analysis of the current and projected future financial condition of its Merchant Generation business segment, including the need to fund GENCO debt maturities beginning in

[5] Moody's, "Unregulated Utility & Power Companies: Still No Sign of Recovery" (February 6, 2013).

2018."[6]

Prior to its decision to divest its merchant generation business, Ameren had taken several measures to preserve liquidity and manage its credit profile with the goal of weathering the power market downturn. Specifically, Ameren reduced operating and maintenance capital expenditures, divested selected generating plants, and established an internal plant "put" mechanism to provide GENCO with an emergency standby liquidity. Despite these measures, Ameren appears to have ultimately determined that market conditions were not improving quickly enough to allow AER to fund its cash needs and near-term GENCO debt maturities ($300 million in 2018; $250 million in 2020) without parent support.

In fact, given the debt incurrence covenant under the terms of its current bond indenture, and its weakened financial condition and outlook, GENCO is currently contractually prohibited from incurring any additional debt financing. In its 1Q 2013 10-Q, Ameren stated:

> "During the first quarter of 2013, Genco's interest coverage ratio fell to a value less than the specified minimum level required for external borrowings, and we expect the ratio to remain less than this minimum level through at least 2015. As a result, Genco's ability to borrow additional funds from external third-party sources is restricted."

11. Upon closing of the transaction, IPH, New AER and its consolidated subsidiaries will have approximately $220 million in cash, a majority of which will be utilized over the next several years to fund operations, pay interest and provide some working capital and credit support.[7] This suggests that, at closing, IPH would not have the ability to fund the remainder of the approximately $500 million projected by IPH for the installation of the Newton FGD project. Similarly, Dynegy has concluded that both the upfront cash at closing of

[6] Ameren Form 8-K filing (December 20, 2012).
[7] See Affidavit of Mario E. Alonso (paragraph 20).

the transaction and the synergies that Dynegy projects following the transaction are required to provide comfort that the business will have the necessary liquidity over the next several years and adequate liquidity will not exist over the next several years to simultaneously continue operating the Acquired Plants and also spend hundreds of millions on capital investments to accelerate installation of the Newton FGD project.[8]

Likewise, Dynegy has stated that New AER's affiliation with Dynegy will not improve the Company's ability to fund environmental-related expenditures, whether via Dynegy parent equity contributions or enhanced access to third-party capital:

> "IPH and the Acquired Merchant Utilities, as AER under Ameren, must be self-funding and support their own expenses through their own operating revenues."[9]

Dynegy has publicly committed to its investors and bondholders that New AER will need to be self-sufficient. That commitment was made clear by Dynegy CEO Bob Flexon on a March 14, 2013 investor call:

> "The acquisition of AER is being accomplished through a newly created subsidiary of Dynegy, IPH, which will be a ring-fenced non-recourse subsidiary ... that will observe corporate separateness formalities. In structuring the transaction, we established and followed these principles: IPH must stand on its own and be a viable self-sustaining business; Dynegy cannot and will not put its balance sheet at risk; and there is no intent, no plans and no reason to engage in any type of financial restructuring of Genco's public debt."

Feedback received by Dynegy from credit rating agencies suggests that the agencies would likely view any Dynegy provision of financial support to New AER negatively:

> "As part of its diligence process prior to entering the Transaction Agreement, Dynegy contacted the credit rating agencies (Moody's and Standard & Poor's) to

[8] See Affidavit of Mario E. Alonso (paragraph 25).
[9] See Affidavit of Mario E. Alonso (paragraph 13).

> understand the transaction's implications, if any, on Dynegy's credit rating. Both credit rating agencies agreed that, as structured, the transaction was a credit neutral event because of the non-recourse nature of IPH. However, the credit rating agencies made clear that the transaction would have a negative effect on the credit rating of Dynegy if the acquired entities were to be absorbed into the Dynegy capital structure or if Dynegy were to provide financial support to the Acquired Merchant Utilities other than limited amounts of working capital."[10]

Thus, given (a) the inability of IPH to fund the remainder of the approximately $500 million Newton FGD project with cash on the balance sheet of New AER and its consolidated subsidiaries at transaction close; (b) Dynegy's conclusion that both (i) the upfront cash at closing of the transaction and (ii) the synergies that Dynegy projects over the next several years following the transaction are required to provide comfort that the business will have the necessary liquidity over the next several years; (c) Dynegy's conclusion that adequate liquidity will not exist over the next several years to simultaneously continue operating the Acquired Plants and also spend hundreds of millions on capital investments to accelerate installation of the Newton FGD project, it appears that New AER will not be able to meet the MPS requirements without the requested variance relief, or to accelerate installation of the remainder of the approximately $500 million Newton FGD project. In addition, given (a) the public commitments Dynegy has made to its equity investors in respect of not placing its balance sheet at risk by providing capital to New AER; and (b) commentary of credit rating agencies in respect of Dynegy potentially providing capital to New AER, as described below, it appears that for Dynegy to operate New AER absent the requested variance relief and to provide capital to New AER, other than limited amounts of working capital, would adversely affect Dynegy's own access to capital (e.g., a credit rating downgrade could materially

[10] See Affidavit of Mario E. Alonso (paragraph 17).

increase Dynegy's cost of capital).

12. Moreover, even if Dynegy were to provide financial support to New AER, its current credit ratings suggest that it has less financial flexibility than Ameren had at the time the Variance Relief was granted. Dynegy is currently rated B (S&P) and B2 (Moody's), while Ameren benefited from significantly stronger investment-grade credit ratings of BBB- (S&P) and Baa3 (Moody's) at the time the Variance Relief was granted.

III. INVESTOR AND RATING AGENCY ANALYSES OF NEW AER

13. Highlighted below is the current commentary of certain equity analysts that are responsible for providing independent guidance to large institutional and retail investors regarding the power sector. In their commentary, equity analysts highlight New AER's challenged cash flow profile, but note the limited potential downside for Dynegy shareholders, given the non-recourse nature of the transaction.

> "The debt assumed is non-recourse back to Dynegy and does not directly deteriorate Dynegy's preexisting liquidity or capital structure. … Our analysis presumes current forward power prices and a $1/kW-month capacity price. Under these conditions, we believe the [New AER] portfolio will not likely be free cash flow positive on an unhedged basis in 2015, which is a more conservative outlook than Dynegy's guidance." – *Citi,* 3/15/2013

> "[The] acquisition yields little equity value, as we expect restructuring to continue. Consistent with the structuring of NRG and GenOn's transaction, the deal will be done at a non-recourse subsidiary. … We believe the Genco subsidiary (Joppa, Newton, Coffeen) does not have equity value net of its debt, and believe the fact that Ameren would transact its non-encumbered assets (Edwards, Duck Creek) for nothing is suggestive of limited underlying value in those assets, net of liabilities, which includes coal ash ponds (which has recently attracted some attention). … We estimate the portfolio in aggregate continues to

generate cash losses; we anticipate the Company will continue to use its existing liquidity to fund these losses." – *UBS*, 3/14/2013

The equity analyst commentary suggests that the Acquired Plants may have negative equity value, even with the benefit of the requested variance relief. As such, any investment to meet the MPS requirements without the requested variance relief, or to accelerate installation of the remainder of the approximately $500 million Newton FGD project, would likely be viewed as uneconomic and imprudent by investors.

14. The credit rating agencies, whose views are taken into consideration by investors in debt securities and lenders, have taken an increasingly negative view on the credit quality of AER since the time it received the MPS Variance Relief because of ongoing deterioration of power market conditions. Given the expectation that Dynegy will not provide additional funds to New AER, the agencies have also made clear that they have not penalized Dynegy's credit rating. Below are samplings of credit rating agency commentary following the announcement of IPH's agreement to acquire New AER:

Credit Rating Agency Statements Regarding the Outlook for New AER

"The negative outlook reflects our base case scenario that Genco's financial measures and profit margins will meaningfully deteriorate over the next few years because of continued weak power prices. These trends could result in lower ratings during the next 12 months and, absent a reversal of price trends, could lead to a payment default or debt restructuring. ... Genco's 'vulnerable' business risk profile reflects its dependence on the commodity price of electricity, its competitive position in its markets, and its reliance on a meaningful improvement to power prices to fully meet its financial obligations. ... Over the next year, we expect that expiring higher-priced hedges will continue to be replaced by lower market prices. While we expect that management may continue to identify further cost reduction opportunities, the

business risk profile and operating results will continue to be pressured by continued weak electricity prices and the company's Midwest location, which lacks a robust capacity market. ... Genco has 'less than adequate liquidity', reflecting the following qualitative factors and assumptions: the Company lacks a core bank relationship and essentially relies on its ability to generate cash, cash on hand, and its asset put option as its sole sources of liquidity; the Company has a poor standing in the credit markets as demonstrated by the Company's debt, which is trading with a yield to maturity of about 20%; in our view, the Company would not be able to withstand a material low probability event, such as a prolonged plant outage." – *S&P,* 3/28/2013

Credit Rating Agency Statements Regarding Dynegy Support of New AER

"In March, Dynegy secured an agreement to acquire the AER merchant assets and operations from Ameren, with the closing planned by the end of 2013. We have not factored any cash flow from AER into our analysis. Dynegy will hold the acquired assets as a ring-fenced subsidiary, to shield Dynegy from risk associated with them. We do not expect Dynegy to financially support the acquired assets over the next two years, since Ameren is essentially providing deal liquidity to get them through the next few years of likely depressed power prices." – *S&P,* 4/2/2013

IV. CONCLUSION

15. AER's financial outlook and credit profile have weakened further since AER received the Variance Relief—I believe this is a result of persistently low power prices and ongoing uncertainty regarding federal environmental regulations. Accordingly, the prospects of sourcing additional third-party capital on economic terms supportable by New AER's financial condition, if at all, are likely to remain challenged. In fact, Dynegy was unable to obtain a debt facility at New AER on economic terms coincident with the transaction, *"given the low cash flow profile [of the Ameren Merchant Utilities], negligible lien capacity of the*

assets, existing debt and weak credit profile."[11] Importantly, based on Dynegy analysis, both the upfront cash at closing of the AER transaction and the synergies that it projects following the transaction are required to provide comfort that the business will have the necessary liquidity over the next several years, particularly given the volatile nature of the markets. Dynegy has stated, therefore, that it is not feasible over the next several years to simultaneously have adequate liquidity necessary to continue operating the Acquired Plants and also spend hundreds of millions on capital investments to accelerate installation of the Newton FGD project, install air pollution controls or otherwise comply with the MPS without the requested variance relief. Moreover, given the potential adverse reaction of the credit rating agencies, investors and bondholders were Dynegy to provide financial support to IPH or New AER, New AER's affiliation with Dynegy will not improve New AER's financial outlook or its ability to fund environmental-related expenditures on a more accelerated timeframe. In short, I believe that the various challenges faced by New AER are likely the same, if not worse, than those faced by AER when it was granted the Variance Relief. The rationale for IPH's requested variance relief remains the same as for the Variance Relief—it will continue to play a critical role in allowing the Company to manage its liquidity and credit quality in the midst of a currently challenged merchant generation operating environment.

[11] See Affidavit of Mario E. Alonso (paragraph 15).

FURTHER, Affiant sayeth not.

George W. Bilicic

Subscribed and swore to before
me this 19 day of July, 2013

Notary Public

IRENE M. MONTERO
Notary Public, State of New York
No. 01MO6270607
Qualified in Queens County
Commission Expires October 22, 2016

EXHIBIT 10

ENVIRONMENTAL IMPACT: *TABLE 1 & TABLE 2*

Table 1

Ameren MPS Group Variance SO2 Limit Comparison to the Current MPS

Year	Baseline Heat Input MMBtu	MPS SO2 Rate lb/MMBtu	MPS Baseline SO2 Tons	Variance SO2 Rate lb/MMBtu	Variance SO2 Tons	Actual SO2 Emissions	SO2 Reduced Tons (1)	Net Variance SO2 Tons	Cumulative Reductions in SO2 Variance Tons
2010	340,446,252	0.50	85,112	0.50	85,112	70,560	14,552	70,560	14,552
2011	340,446,252	0.50	85,112	0.50	85,112	72,538	12,574	72,538	27,125
2012	340,446,252	0.50	85,112	0.38	64,685	45,712	18,973	45,712	66,525
2013	340,446,252	0.50	85,112	0.35	59,578		8,289	51,289	100,347
2014	340,446,252	0.43	73,196	0.35	59,578		8,289	51,289	122,254
2015	340,446,252	0.25	42,556	0.35	59,578		8,289	51,289	113,521
2016	340,446,252	0.25	42,556	0.35	59,578		8,289	51,289	104,787
2017	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	92,060
2018	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	79,332
2019	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	66,604
2020	340,446,252	0.23	39,151	0.23	39,151		7,699	31,452	74,303
Total			655,359		691,106		110,050	581,056	74,303

Note for the "Cumulative Reductions in SO2 Variance Tons" column, a positive number indicates an emission decrease (benefit).

(1) Tons shown for 2010, 2011 and 2012 are based on actual SO2 emissions. Tons shown for 2013-2020 are based on not operating Hutsonville and Meredosia. Tons shown for 2013-2016 do not include any SO2 emissions for FutureGen 2.0 because FutureGen 2.0 is not scheduled to begin operations until mid-2017. For 2017-2020, reduced tons are less nearly two times (1.8) worst-case potential SO2 emissions from FutureGen 2.0.

Table 2

Ameren MPS Group Variance SO2 Limit Comparison to the Current MPS

Year	Baseline Heat Input MMBtu	MPS SO2 Rate lb/MMBtu	MPS Baseline SO2 Tons	Variance SO2 Rate lb/MMBtu	Variance SO2 Tons	Actual SO2 Emissions	SO2 Reduced Tons (1)	Net Variance SO2 Tons	Cumulative Reductions in SO2 Variance Tons
2013	340,446,252	0.50	85,112	0.35	59,578		8,289	51,289	33,822
2014	340,446,252	0.43	73,196	0.35	59,578		8,289	51,289	55,729
2015	340,446,252	0.25	42,556	0.35	59,578		8,289	51,289	46,996
2016	340,446,252	0.25	42,556	0.35	59,578		8,289	51,289	38,263
2017	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	25,535
2018	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	12,807
2019	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	79
2020	340,446,252	0.23	39,151	0.23	39,151		7,699	31,452	7,778
Total			400,024		456,198		63,952	392,246	7,778

Note for the "Cumulative SO2 Variance Reduced Tons" column, a positive number indicates an emission decrease (benefit).

(1) Reduced tons shown for 2013-2020 are based on not operating Hutsonville and Meredosia. Reduced tons in 2017-2020 are less nearly two times (1.8) worst-case potential SO2 emissions from FutureGen 2.0. Tons shown for 2013-2016 do not include any SO2 emissions for FutureGen 2.0 because FutureGen 2.0 is not scheduled to begin operations until mid-2017.

EXHIBIT 11

AFFIDAVIT OF ARIC D. DIERICX

AFFIDAVIT OF ARIC D. DIERICX

I. Background and Qualifications

1. My name is Aric D. Diericx. I am the Senior Director - Environmental Compliance for Dynegy Operating Company. Dynegy Operating Company, an affiliate of Dynegy Inc. ("Dynegy"), provides business services to Dynegy's operating subsidiaries, including Illinois Power Holdings, LLC ("IPH"), Dynegy Midwest Generation, LLC ("DMG"), and Dynegy Kendall Energy, LLC. My business address is 604 Pierce Blvd., O'Fallon, Illinois, 62269.

2. I have been employed with Dynegy in my current position or similar environmental compliance positions for the past 13 years. Prior to that and beginning in 1979, I was employed by Illinois Power Company and worked in its environmental department. In February 2000, Dynegy acquired Illinova Corporation, the fossil fuel-fired electric generating assets of Illinois Power Company. I received a Bachelor of Science degree in Meteorology from Northern Illinois University in 1979.

3. As Senior Director - Environmental Compliance, my responsibilities include oversight of permitting, regulatory and policy development, and compliance for air, water, waste and other environmental matters at DMG's coal-fired power plants in Illinois, as well as Dynegy's power plants in other states. My duties include supervising environmental staff personnel, representing Dynegy before environmental regulatory agencies and governmental authorities, and developing and implementing environmental compliance strategies. More specifically, I am responsible for DMG's compliance efforts regarding the Illinois multi-pollutant standard ("MPS") rule by the DMG MPS Group, which consists of five coal-fired

power plants (*i.e.*, ten electrical generating units) that elected into the MPS in 2007.[1] I was directly involved in the 2006 and 2009 Illinois rulemaking proceedings concerning development of the MPS rule.

4. I am familiar with the contemplated transaction between IPH and Ameren Corporation ("Ameren"), having led Dynegy's environmental due diligence efforts for the transaction. I provide this affidavit in support of the Petition for Variance filed by IPH, AmerenEnergy Medina Valley Cogen, L.L.C. and Ameren Energy Resources, LLC ("AER") ("Petition for Variance"). I make this affidavit based on personal knowledge or on knowledge I have obtained through inquiry of individuals employed by Dynegy or its affiliates.

II. The Proposed Variance's Compliance Plan Will Reduce Overall SO_2 Emissions

5. The Petition for Variance includes as Exhibit 10 two tables -- Table 1 and Table 2 -- that identify the sulfur dioxide ("SO_2") emissions, in tons, that are expected to occur from the seven-plant AER MPS Group under the current Ameren MPS Group Multi-Pollutant Standard rule (*i.e.,* 35 Ill. Admin Code 225.233(e)(3)) as compared to the projected SO_2 emissions under the compliance plan set forth in the Petition for Variance. The two tables are based on the format and content of the emissions table used by AER in its variance petition proceeding, PCB 12-126, Petitioner's Post-Hearing Brief, Exhibit 4 (referred to as Table 3 in the Post-Hearing Brief) (filed Aug. 15, 2012).

6. Table 1 identifies SO_2 emissions for the seven-plant AER MPS Group for the period 2010 through 2020. Table 1 reflects two updates to the emissions table used by AER in PCB 12-126. First, Table 1 includes the AER MPS Group's actual SO_2 emissions for calendar

[1] In 2011, DMG retired the Vermilion Power Station and its two coal-fired generating units.

year 2012, as reported by AER. The actual tons of SO_2 emitted during 2012 by the AER MPS Group were less than projected in the emissions table used by AER in PCB 12-126. Second, Table 1 does not include SO_2 emissions in years 2013 through 2016 from the FutureGen 2.0 project, which is planned for development at the Meredosia facility, because, based on information provided by Ameren Services Company, the FutureGen 2.0 project is not expected to begin operations until September 2017. With these two updates, as identified in Table 1, the compliance plan set forth in the Petition for Variance will result in a net reduction of 74,303 tons of SO_2 over the period 2010-2020. Furthermore, over the period 2012-2020, Table 1 identifies a 47,178 ton net reduction in SO_2 emissions.

7. Table 2 identifies SO_2 emissions for the seven-plant AER MPS Group for the period 2013 through 2020. As identified in Table 2, the compliance plan set forth in the Petition for Variance will result in a net reduction of 7,778 tons of SO_2 over the period 2013-2020.

8. Accordingly, Tables 1 and 2 each show that the compliance plan in the Petition for Variance would result in a net overall reduction of SO_2 emissions by achieving additional tons of SO_2 emissions reduction as compared to the tons of SO_2 emissions reductions that would result from compliance with the current Ameren MPS Group Multi-Pollutant Standard rule.

9. I have read the Petition for Variance and the facts stated therein concerning the compliance plan, environmental impact, compliance with federal and Illinois law, and DMG's environmental compliance activities are true and correct to the best of my knowledge and belief.

FURTHER, Affiant sayeth not.

DATED: 7/17/13

Aric D. Diericx

Subscribed and sworn to
before me this 17th day
of July, 2013.

Notary Public

"OFFICIAL SEAL"
LAUREN R. SCHMIERBACH
NOTARY PUBLIC—STATE OF ILLINOIS
MY COMMISSION EXPIRES MAR. 16, 2014

EXHIBIT 12

ENVIRONMENTAL IMPACT: *AECOM MEMORANDUM*

AECOM
250 Apollo Drive
Chelmsford, MA 10824

978-905-2100 tel
978-905-2100 fax

Memorandum

To	Illinois Power Holdings AmerenEnergy Medina Valley Cogen Ameren Energy Resources	Page 1
Subject	Health Effects Evaluation of Request for Variance from the Illinois Sulfur Dioxide Multi-Pollutant Standard by Illinois Power Holdings, AmerenEnergy Medina Valley Cogen, and Ameren Energy Resources	
From	Lisa JN Bradley, Ph.D., DABT	
Date	July 18, 2013	

The purpose of this memorandum is to provide a toxicologist's perspective on the joint Petition for Variance sought by Illinois Power Holdings, LLC (IPH) and AmerenEnergy Medina Valley Cogen, LLC (Medina Valley) (collectively, "the Petitioners"), along with Ameren Energy Resources, LLC (AER) as a Co-Petitioner. The information in this memorandum builds upon the variance from the Illinois Sulfur Dioxide (SO2) Multi-Pollutant Standard (MPS) sought by AER and granted by the Illinois Pollution Control Board on September 20, 2012. The commitments made by AER in the original variance proceeding are proposed, in this variance request, to be continued by IPH and Medina Valley. The variance is from the 2015 and 2017 MPS SO2 emission rate provisions applicable to the seven plants that are referred to as the Ameren MPS Group (Duck Creek, Coffeen, E.D. Edwards, Newton, Joppa, Meredosia, and Hutsonville).

In March 2013, IPH and Ameren Corporation announced that they had entered an agreement under which IPH would acquire AER. When the sale is completed, IPH will control the Duck Creek, Coffeen, E.D. Edwards, Newton and Joppa power plants, while Medina Valley will control the Meredosia and Hutsonville power plants, which are shuttered.

The evaluation concludes that there would be no adverse impact as a result of implementing the requested variance and proposed compliance plan, in fact, a net environmental benefit would be realized. In support of this conclusion, this memorandum provides: an overview of the Clean Air Act's National Ambient Air Quality Standards (NAAQS) and a summary of SO2 emissions in the U.S. and Illinois; an analysis of the impact of the requested variance; and a discussion of the health effects information available regarding exposure to SO2. A discussion of the variance request as it may relate to the U.S. Environmental Protection Agency (USEPA) revision in December 2012 of the NAAQS for annual PM2.5 (airborne particulate matter of 2.5 micrometers in diameter and smaller) is also included.

THE CLEAN AIR ACT AND NAAQS

The Clean Air Act (CAA) was originally passed in 1963, and in 1970 was amended to identify pollutants that may reasonably be anticipated to endanger public health and welfare and to issue air quality standards for them. SO2 and PM were included in the original constituents identified as a "criteria pollutant" and USEPA issued NAAQS in 1971 that have been updated periodically since then. The primary NAAQS are to protect public health, and the secondary NAAQS are to protect the public welfare, including animals, crops, visibility, and buildings. The current NAAQS for SO2 and PM are shown in Table 1, below.

Table 1. NAAQS for SO2 and PM

Pollutant [final rule cite]		Primary/ Secondary	Averaging Time	Level	Form
Sulfur Dioxide [75 FR 35520, Jun 22, 2010] [38 FR 25678, Sept 14, 1973]		primary	1-hour	75 ppb (a)	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years
		secondary	3-hour	0.5 ppm	Not to be exceeded more than once per year
Particle Pollution [78 FR 3086, January 15, 2013]	$PM_{2.5}$	primary	Annual	12 µg/m^3	annual mean, averaged over 3 years
		secondary	Annual	15µg/m^3	annual mean, averaged over 3 years
		primary and secondary	24-hour	35 µg/m^3	98th percentile, averaged over 3 years
	PM_{10}	primary and secondary	24-hour	150 µg/m^3	Not to be exceeded more than once per year on average over 3 years

(a) Final rule signed June 2, 2010. The 1971 annual and 24-hour SO2 standards were revoked in that same rulemaking. However, these standards remain in effect until one year after an area is designated for the 2010 standard, except in areas designated nonattainment for the 1971 standards, where the 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standard are approved.

Source: USEPA. 2012. National Ambient Air Quality Standards (NAAQS). Retrieved July, 17, 2013, from: http://www.epa.gov/air/criteria.html.

Title IV, the Acid Rain Program, of the Clean Air Act Amendments was enacted in 1990 and requires reductions in both SO2 and nitrogen oxides (NOx) emissions from the electric power industry. Since 1990, emissions of SO2 (and NOx) from the electric power sector have decreased dramatically, this at a time when the use of coal in the U.S. by the electric power sector has been increasing. Figure 1, below, graphically illustrates these dramatic changes for the U.S. (US EIA, 2012). Figure 2 shows the trend in SO2 emissions in Illinois in recent years, and Figure 3 shows the trends in ambient air concentrations of SO2 for Illinois, including the decrease in SO2 concentrations since 2008 (IEPA, 2012).

Figure 1. Coal Consumption, and SO2 and Nitrogen Oxides Emissions Over Time

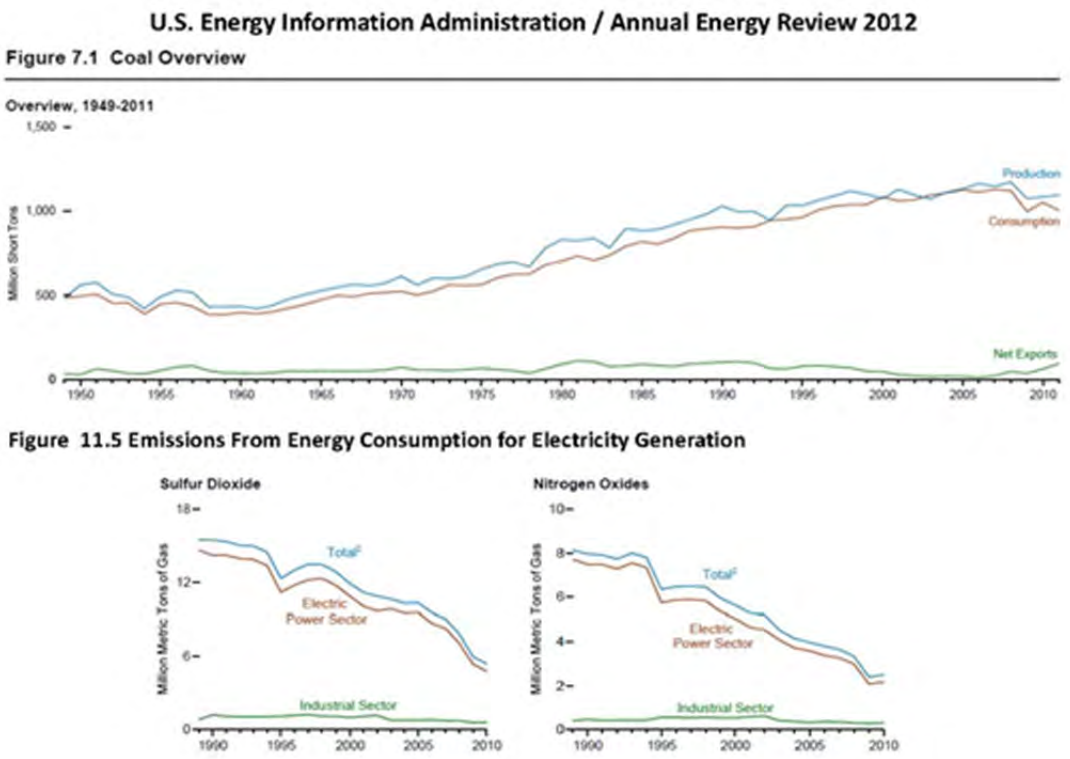


Figure 2. SO2 Emissions Trends (1000s of Tons/Year), Illinois

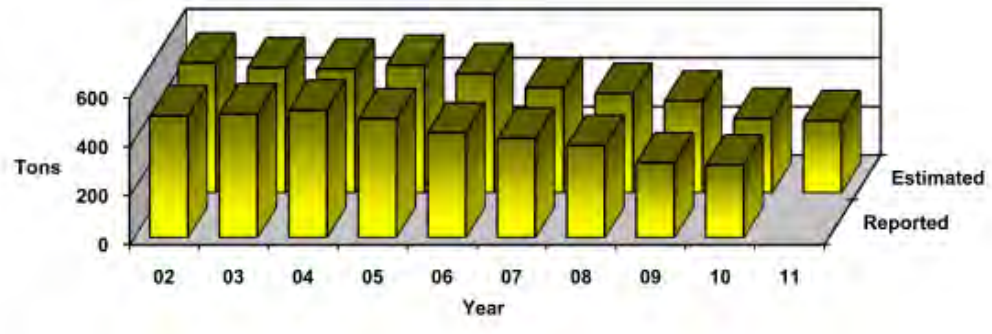
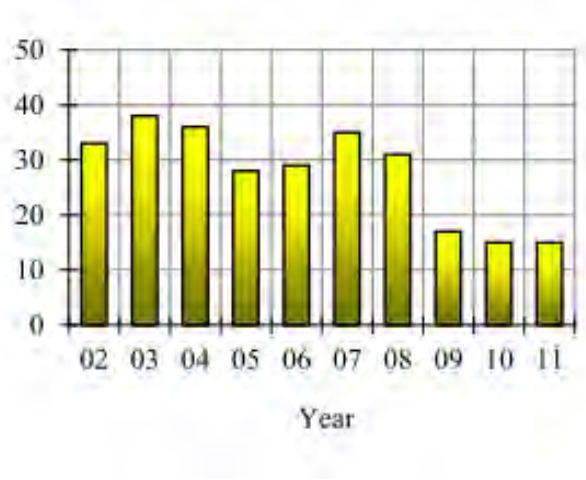


Figure 3. SO2 24-hour Trends (ppb), Illinois



THE MPS AND THE REQUESTED VARIANCE

Specifics of the Requested Variance

The MPS specifies a 0.5 lb/MMBtu SO2 emission rate until 2014 when the required emission rate is decreased to 0.43 lb/MMBtu, followed by a decrease to 0.25 lb/MMBtu in 2015. Under the MPS, the SO2 emission rate is further decreased to 0.23 lb/MMBtu in 2017. The requested variance for the seven power plants in the Ameren MPS Group (as defined above) seeks relief from meeting the 0.25 lb/MMBtu SO2 emission rate required by the provisions of the MPS beginning in 2015 and the 0.23 lb/MMBtu emission rate that is required beginning in 2017. The commitments made by AER in the original variance proceeding are proposed, in this variance request, to be continued by IPH and Medina Valley. Specifically, IPH and Medina Valley are proposing a mitigation emission rate of 0.35 lb/MMBtu for the MPS Group that would take effect in 2013, which means that a more stringent SO2 emissions limitation will be in effect in 2013 and 2014 than would be otherwise in effect under the MPS rule. The MPS Group would comply with the 0.35 lb/MMBtu mitigation emission rate from 2013 through 2019, with the 2017 MPS emission rate of 0.23 lb/MMBtu being met beginning in 2020. Table 2 provides the comparison of MPS Group SO2 emissions under the provisions of the MPS rule and the requested variance, and these are shown graphically in Figure 4.

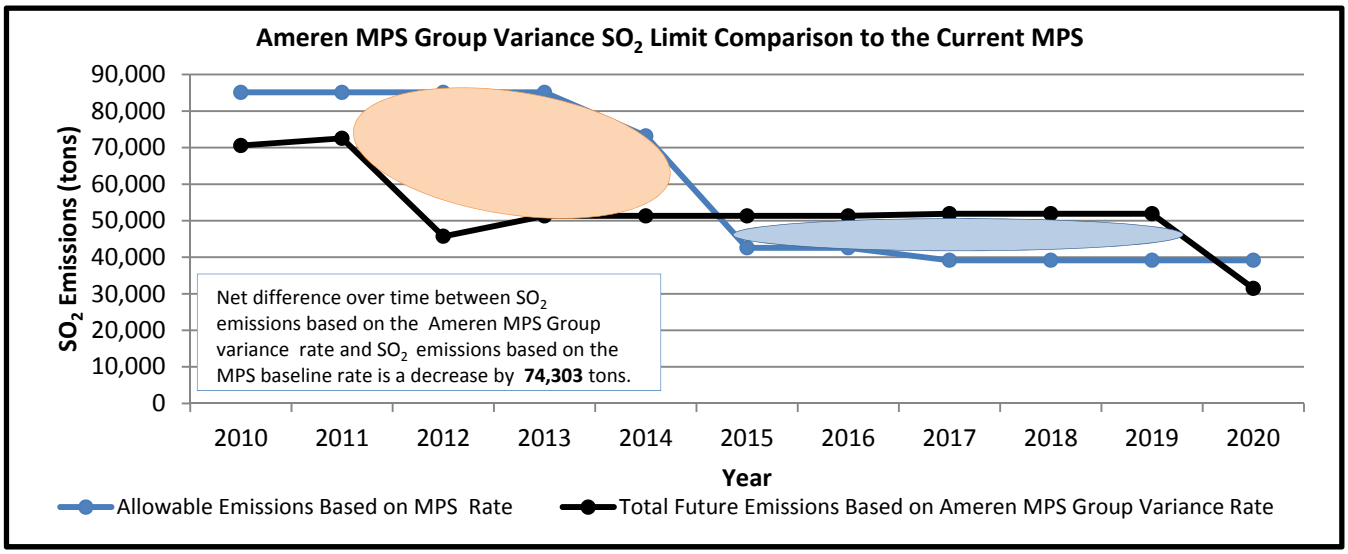
Table 2. The Ameren MPS Group Variance SO2 Limit Comparison to the Current MPS, 2013-2020

Year	Baseline Heat Input MMBtu	MPS SO2 Rate lb/MMBtu	MPS Baseline SO2 Tons	Variance SO2 Rate lb/MMBtu	Variance SO2 Tons	Actual SO2 Emissions	SO2 Reduced Tons (1)	Net Variance SO2 Tons	Cumulative Reductions in SO2 Variance Tons
2013	340,446,252	0.50	85,112	0.35	59,578		8,289	51,289	33,822
2014	340,446,252	0.43	73,196	0.35	59,578		8,289	51,289	55,729
2015	340,446,252	0.25	42,556	0.35	59,578		8,289	51,289	46,996
2016	340,446,252	0.25	42,556	0.35	59,578		8,289	51,289	38,263
2017	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	25,535
2018	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	12,807
2019	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	79
2020	340,446,252	0.23	39,151	0.23	39,151		7,699	31,452	7,778
Total			400,024		456,198		63,952	392,246	7,778

Note for the "Cumulative SO2 Variance Reduced Tons" column, a positive number indicates an emission decrease (benefit).

(1) Reduced tons shown for 2013-2020 are based on not operating Hutsonville and Meredosia. Reduced tons in 2017-2020 are less nearly two times (1.8) worst-case potential SO2 emissions from FutureGen 2.0. Tons shown for 2013-2016 do not include any SO2 emissions for FutureGen 2.0 because FutureGen 2.0 is not scheduled to begin operations until mid-2017.

Figure 4. The Ameren MPS Group Variance SO2 Limit Comparison to the Current MPS, 2013-2020



The blue line in Figure 4 represents the MPS Group's baseline SO2 emissions under the MPS rule and the black line represents projected SO2 emissions under the requested variance and compliance plan. As can be seen in the figure, SO2 emissions under the requested variance are considerably lower than the MPS emissions in 2013 and 2014 and are slightly higher in 2015 through 2019. However, the area representing the difference between the MPS and variance SO2 emissions from 2013 to 2014 is larger than the area between the MPS and variance SO2 emissions

in 2015 through 2019. Therefore, there is an overall net improvement (i.e., decline) in SO2 emissions under the requested variance.

It should be noted that since 2010 these power plants have voluntarily operated at lower SO2 emission rates than allowable under the MPS, demonstrating a commitment to reducing emissions. If the reduced SO2 emissions starting in 2010 are taken into consideration, the positive difference between variance SO2 emissions and those allowable under the MPS is even larger (see Table 3 and Figure 5, below).

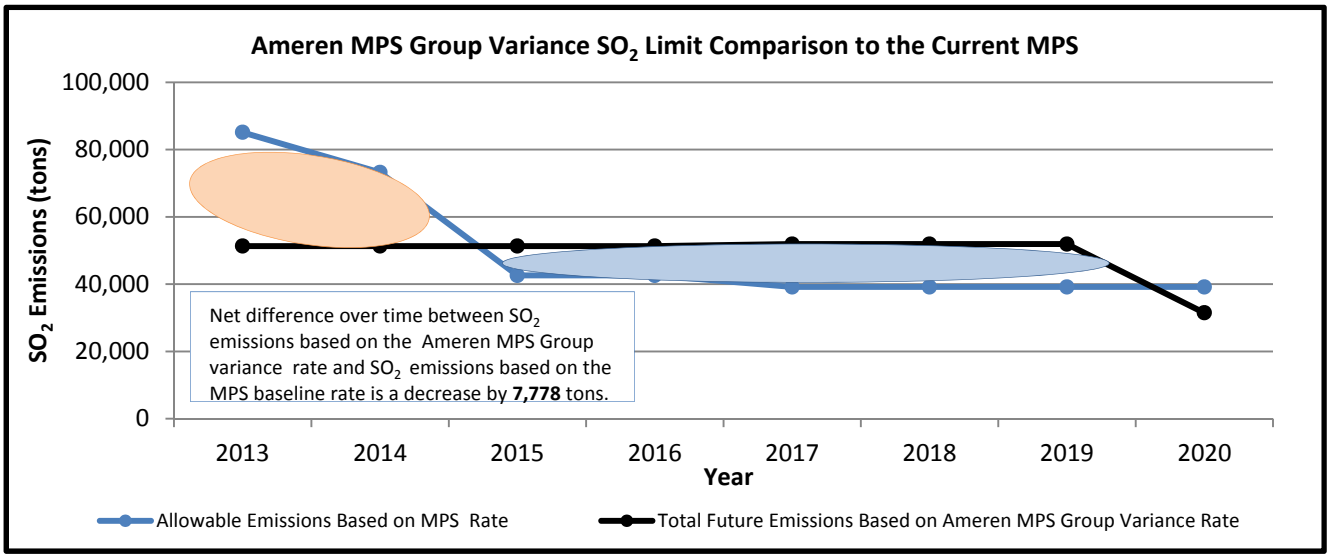
Table 3. The Ameren MPS Group Variance SO2 Limit Comparison to the Current MPS, 2010-2020

Year	Baseline Heat Input MMBtu	MPS SO2 Rate lb/M MBtu	MPS Baseline SO2 Tons	Variance SO2 Rate lb/MMBtu	Variance SO2 Tons	Actual SO2 Emissions	SO2 Reduced Tons (1)	Net Variance SO2 Tons	Cumulative Reductions in SO2 Variance Tons
2010	340,446,252	0.50	85,112	0.50	85,112	70,560	14,552	70,560	14,552
2011	340,446,252	0.50	85,112	0.50	85,112	72,538	12,574	72,538	27,125
2012	340,446,252	0.50	85,112	0.38	64,685	45,712	18,973	45,712	66,525
2013	340,446,252	0.50	85,112	0.35	59,578		8,289	51,289	100,347
2014	340,446,252	0.43	73,196	0.35	59,578		8,289	51,289	122,254
2015	340,446,252	0.25	42,556	0.35	59,578		8,289	51,289	113,521
2016	340,446,252	0.25	42,556	0.35	59,578		8,289	51,289	104,787
2017	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	92,060
2018	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	79,332
2019	340,446,252	0.23	39,151	0.35	59,578		7,699	51,879	66,604
2020	340,446,252	0.23	39,151	0.23	39,151		7,699	31,452	74,303
Total			655,359		691,106		110,050	581,056	74,303

Note for the "Cumulative Reductions in SO2 Variance Tons" column, a positive number indicates an emission decrease (benefit).

(1) Tons shown for 2010, 2011 and 2012 are based on actual SO2 emissions. Tons shown for 2013-2020 are based on not operating Hutsonville and Meredosia. Tons shown for 2013-2016 do not include any SO2 emissions for FutureGen 2.0 because FutureGen 2.0 is not scheduled to begin operations until mid-2017. For 2017-2020, reduced tons are less nearly two times (1.8) worst-case potential SO2 emissions from FutureGen 2.0.

Figure 5. The Ameren MPS Group Variance SO2 Limit Comparison to the Current MPS, 2010-2020



Lack of Adverse Impact of the Variance

Over the course of the entire period 2013-2020, the total tons of SO2 reduced in the atmosphere will be greater if the requested variance is granted than if it is not. The source of reduction in SO2 emissions attributable to granting the variance period is two-fold: 1) the MPS Group will emit less SO2 via a mitigation emissions rate representing a 19% to 30% reduction in the MPS allowable SO2 emissions rate through 2014; and 2) the Hutsonville and Meredosia coal-fired power plants will remain shuttered through 2020, which will result in less coal being burned and less SO2 being emitted.

Based on the emissions mitigation commitments in the requested variance, granting the variance request would not result in an adverse impact and, in fact, would result in an overall net health benefit.

THE POTENTIAL FOR ADVERSE HEALTH EFFECTS FROM SO2

While concerns about potential health effects associated with exposure to SO2 are understandable, there are misconceptions about what the scientific research is telling us. From controlled studies with human subjects, there appears to be a continuous spectrum of sensitivity to SO2, with some people being completely unaffected by concentrations that lead to severe bronchoconstriction in others. Asthmatics are particularly sensitive to the effects of SO2 and the effects are enhanced if sufficient amounts of SO2 reach the lower regions of the lungs, which is more likely to occur during mouth breathing (as opposed to breathing through the nose) and exercise. Maximum effects of SO2 occur within a few minutes and continued exposure does not typically increase the response and the effects are generally short-lived and completely reversible (WHO, 2006).

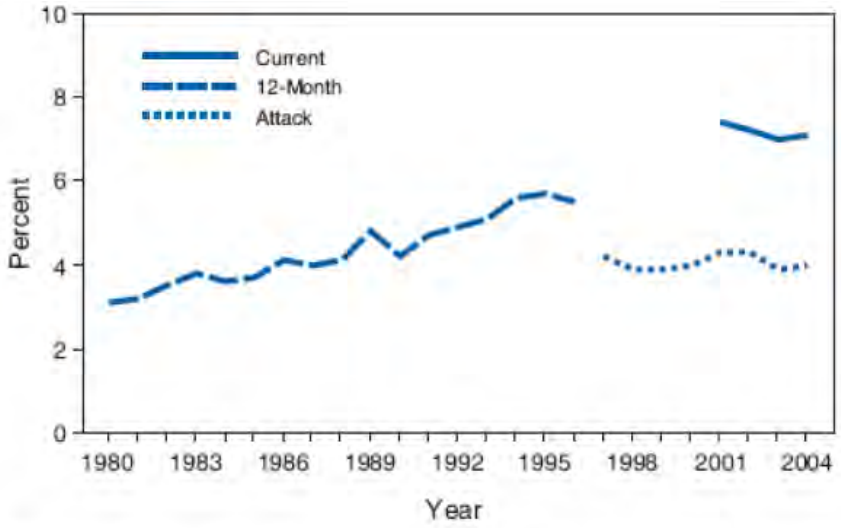
However, more studies than not have failed to find statistically significant associations between long-term and short-term SO2 concentrations and adverse health outcomes on an epidemiological basis, indicating that the apparent associations found in the laboratory may well be due to other factors in an environmental setting. In fact, USEPA has concluded that there is not a causal relationship between long-term SO2 exposure and respiratory effects or mortality (USEPA, 2008). While USEPA has concluded that the results of clinical studies in which humans are exposed to SO2 concentrations much higher than those found in ambient air support a causal relationship between respiratory morbidity and short-term exposure to SO2, nine of the 10 primary epidemiology studies attempting to correlate short-term exposure to asthma-related emergency room visits or hospitalizations relied upon by USEPA found either no association or very small positive associations. USEPA further concludes that the evidence on short-term SO2 exposure is only suggestive of a causal relationship with mortality (USEPA, 2008). Therefore, although there is a public perception of a correlation between SO2 and health effects, when the studies providing the underlying support for such declarations are more closely examined, it becomes clear that the association between SO2 exposure and respiratory health effects and mortality is not a scientific certainty.

Asthma Prevalence in the U.S.

Asthma is the health effect most commonly cited as associated with SO2 exposure, and there is public concern about rise in asthma in the U.S. population. However, there are many theories about the rise in asthma over the past 30 years, and exposure to outdoor pollution is probably the least plausible explanation given that the air quality in Illinois (IEPA, 2012) and the nation as a whole, specifically with respect to SO2 emissions, has improved dramatically during the same time period over which asthma prevalence has increased.

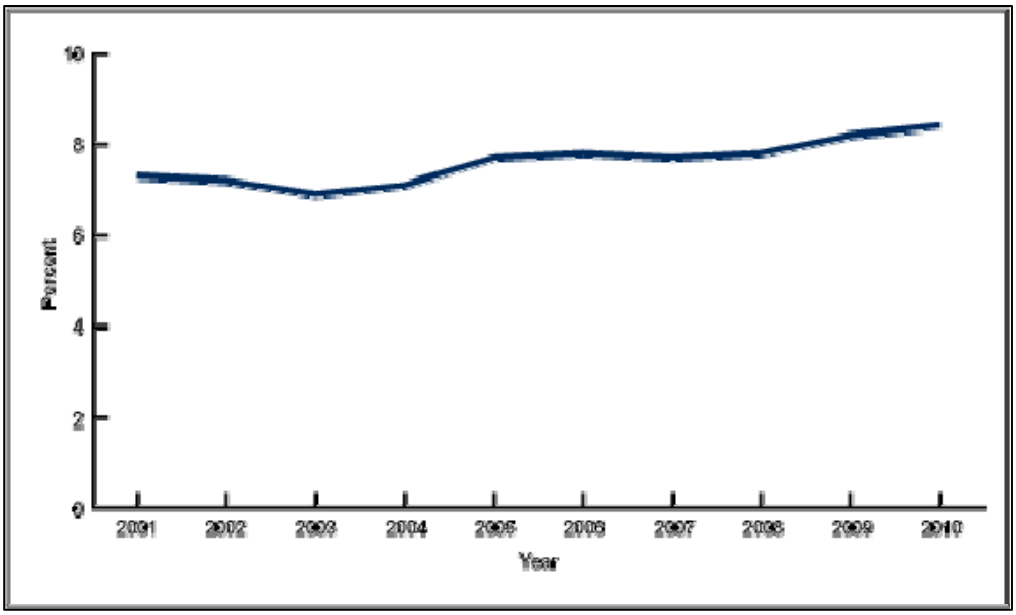
This theory of causality cannot be supported when the dramatic decreases in SO2 emissions in the U.S. by the electric power sector is compared to asthma prevalence data. As shown in Figure 6, below, asthma prevalence increased from 1980 through 1996 (MMWR, 2007). Less dramatic increases have occurred from 2001 through 2010 (CDC, 2012), as shown in Figure 7 below.

Figure 6. Asthma Prevalence 1980 - 1996



Source: National Health Interview Survey; National Center for Health Statistics.

Figure 7. Asthma Prevalence 2001 - 2010



NOTES: Asthma prevalence refers to percentage of people who have ever been diagnosed with asthma and still have asthma. Data are age adjusted to the 2000 U.S. standard population. SOURCE: CDC/NCHS, National Health Interview Survey.

Thus, the perceived connection between the rising prevalence of asthma in the U.S. is not borne out by the dramatic decreases in SO2 emissions over the same time period. The distribution of asthma in other countries also fails to implicate SO2 or other pollutants as an aggravating factor. Some of the highest asthma mortality rates occur in Australia and New Zealand, which have excellent air quality. Asthma is more prevalent in rural areas of the Scottish highlands, which have some of the lowest ozone concentrations in the world, than in more urban and polluted parts of the United Kingdom, according to a recent report (Friebele, 1996).

Changes in the diagnostic coding of asthma and survey questions in self-reporting asthma questionnaires over the last 30 years have likely altered the diagnosis of asthma cases and caused changes in prevalence and incidence statistics. The International Classification of Diseases (ICD) provided by the World Health Organization (WHO) was revised in 1978 (9th revision) and 1990 (10th revision) resulting in a change to the coding of asthma. In the ICD 8, a patient with "asthmatic bronchitis" would have been coded under bronchitis, while in ICD 9 this same person would be coded under asthma (Marcus and Braman, 2010). One study that analyzed asthma patient records found an increase in patients with an asthma classification that had a history of smoking in the 1980s versus the 1970s. The cause of this difference was attributed to the change in classification of asthmatic bronchitis from a bronchitis heading to an asthma heading, resulting in asthmatic bronchitis patients now falling under the umbrella of asthma in the 1980s (Marcus and Braman, 2010). This change in coding may also influence the validity of epidemiology studies that look at hospital emergency room (ER) visits for asthma as potential indicators of an association between ambient pollutant concentrations and respiratory effects over years during which changes in the asthma definition has changed.

A large source of asthma surveillance data is compiled by the National Center for Health Statistics of the Centers for Disease Control and Prevention (CDC) under the National Health Interview Survey (NHIS). The NHIS questions used to evaluate asthma prevalence changed in 1997 and 2001, resulting in three separate types of questions that could impact asthma prevalence estimates from 1980 to 1996, 1997 to 2000, and 2001 to the present (National Heart and Lung Institute; www.nhlbi.nih.gov/health/prof/lung/asthma/surveil.htm). These changes prevent comparisons of reported asthma rates from 1980 to 1997 to the more recent data set from 1997 to 2001 and from 2001 to 2010, and illustrate the potential variability in reported asthma prevalence depending on how asthma questions are phrased, and what sort of asthma information is requested (lifetime incidence versus episodes in the past 12 months, for example). Thus the prevalence graphs above a provided for two time periods.

The increase in asthma cases may also be partially explained by factors relating to changes in healthcare access and physician perceptions. The diagnosis of asthma may have become more likely than a similar diagnosis of bronchitis or chronic obstructive pulmonary disease (COPD) among patients with similar symptoms. One study looked at healthcare data from Manitoba, Canada from 1980-1990 and found a statistically significant increase in asthma diagnosis above background increases found for other diseases with similar symptoms over that time period (Manfreda et al., 1993). The study attributes some of the increase to an increase in the likelihood of asthma diagnoses.

Another factor that may have contributed to the apparent increase in childhood asthma prevalence is that children spend much more time indoors today than they did 30 years ago. In addition to contributing to the development of asthma, exposure to various indoor air irritants can also exacerbate asthma symptoms. Cat, cockroach, and house mite dust allergens have all been causally linked to exacerbation of asthma symptoms in sensitive individuals, and environmental

tobacco smoke exposure has also been causally linked to exacerbation of asthma symptoms in young children (Institute of Medicine, 2000).

Therefore, the suggestion that SO2 emissions are significant contributors to the rise in reported asthma cases (and other diseases) is not supported by evidence in the literature.

Long-term Health Evaluation

Despite the calculations demonstrating an overall reduction in the tonnage of SO2 emissions over the variance period (see Tables 2 and 3 and Figures 4 and 5 above), there is the concern that potential harm could occur during the period of the increase in emissions that would be allowed between the years of 2015 and 2019 under the requested variance.

While looking exclusively at the MPS Group plants there could, theoretically, be additional adverse health outcomes between the years of 2015 and 2019, those theoretical health effects will be offset by fewer theoretical adverse health outcomes in the years of 2013 and 2014. Specifically, because the magnitude of the emission reductions during 2013 and 2014 is greater than the increased SO2 emissions that will occur between 2015 and 2019, there are fewer adverse health effects overall. In addition, because the requested variance and proposed compliance plan include the commitment to keep the Hutsonville and Meredosia power plants shutdown, the requested variance will ensure a reduction in emissions of other pollutants that otherwise would be allowed under the MPS. Therefore, the health benefits of approving the requested variance outweigh the potential for adverse health effects, resulting in an overall health benefit, when the entire period of the requested variance taken into account. Assuming that one accepts that the SO2 emissions pose a health threat, the requested variance represents a tradeoff between greater reductions in health effects in 2013 and 2014 in exchange for smaller reductions in health effects between the years of 2015 and 2019.

It is important to note that the above discussion is predicated on the assumption that the C-R (concentration-response) relationships reported in early epidemiological studies indicate causal relationships between the SO2 exposures and adverse health effects. However, in most studies that have examined the potential for confounding by other co-pollutants (particulates, ozone, nitrogen oxides), the small associations observed between ambient SO2 concentrations and adverse health outcomes usually become null when two-pollutant models are used, indicating that the associations are stronger for the other pollutants or that there is no association with SO2 (USEPA, 2008; USEPA, 2009; Goodman et al., 2010). [See also the discussion below on particulate matter.] As a result, more studies than not have failed to find statistically significant associations between long-term and short-term SO2 concentrations and adverse health outcomes. According to the USEPA's own Integrated Science Assessment (ISA, USEPA, 2008) prepared in support of the most recent SO2 NAAQS review, "Overall, the epidemiologic studies do not provide sufficient evidence to infer a causal relationship between long-term exposure to SO2 and asthma, bronchitis, or respiratory symptoms". The USEPA ISA also concluded that "The available epidemiologic evidence on the effect of long-term exposure to SO2 on mortality is inadequate to infer a causal relationship at this time" (USEPA, 2008).

The USEPA ISA does conclude that "the human clinical, epidemiologic, and animal toxicological data are sufficient to conclude that there is a causal relationship between respiratory morbidity and short-term exposure to SO2" and that "The evidence is suggestive of a causal relationship between short-term exposure to SO2 and mortality". However, of the 10 primary epidemiology studies attempting to correlate short-term (daily) SO2 exposures to adverse health outcomes relied upon by USEPA, nine found either no association or very small positive associations between daily SO2 concentrations and asthma-related emergency room visits or hospitalizations. Among the studies

for which weak positive associations were observed, conclusions were either: 1) based only on results from single-pollutant models (i.e., multiple pollutant models were not used, which are applied to determine confounding by co-pollutants); or 2) based on results from single-pollutant models that were not statistically significant in two-pollutant models.

Statistical significance is key to determining if exposure and effect are causally associated. Determining whether the effect is isolated, independent, or secondary to a known effect of exposure is also important because these types of effects may be the result of other factors not related to the exposure of interest (Goodman et al., 2010). Isolated effects occur in only a few test subjects and independent effects are those which occur in the absence of other effects expected via the same mechanism of action. The fact that these effects occur inconsistently and lack biological plausibility is an indication that they are more likely due to another factor or measurement error rather than exposure related. A test of statistical significance helps determine whether effects are caused by the exposure under study. These tests compare differences between exposed and non-exposed groups of test subjects as opposed to evaluating effects in independent individuals. If the difference between exposed and non-exposed groups is not statistically significant, the exposure is either insufficient to cause the effect under study or the study is not sufficiently powered, most likely due to having too few test subjects.

Only one of the 10 epidemiological studies (NYSDOH, 2006) correlating daily SO2 concentrations to adverse health outcomes relied upon by USEPA in the latest NAAQS review found a marginally statistically significant association with increased SO2 levels in both single-and two-pollutant models. However, the authors of that one study acknowledged that correlations between co-pollutants made these results difficult to interpret.

Short-term Health Evaluation

Concern has been raised previously that the long-term cumulative SO2 reductions do nothing to help communities with short-term pollution impacts and it is those short-term impacts that happen to children and the elderly population across the state. However, it is not correct that cumulative SO2 reductions do nothing to abate short-term pollutant impacts. Long-term concentrations are not completely independent of short-term concentrations of the same pollutant. In fact, USEPA has performed extensive evaluations to determine relationships between short-term and longer-term concentrations of various pollutants and has on occasion set a longer-term standard to limit the relative frequency with which shorter-term exposures will exceed a particular level. In addition, USEPA's screening modeling guidance indicates that for a point source it can be assumed that the maximum daily average concentration is 0.4 of the maximum 1-hour and that the maximum annual concentration is 0.08 of the max 1-hr (http://www.colorado.gov/airquality/permits/screen.pdf). From this we can infer 24-hour to annual ratio of 0.4/0.08 = 5. Thus, it is widely accepted that long-term and short-term concentrations are related to one another. For this reason, the overall net reduction in SO2 provided by the requested variance in comparison to the MPS rule is also expected to have an effect on reducing short-term exposures over the variance time period.

SO2 Levels

Concern has also been expressed previously that high levels of SO2 (and NOx) can exacerbate respiratory systems in at-risk individuals (e.g., children, the elderly), including asthma and COPD attacks. The operative words regarding this concern are "high levels." There are many controlled human studies that have exposed healthy and asthmatic test populations to SO2 and that have measured small lung function decrements in the asthmatic population, particularly at higher than normal exertion levels. However, most fail to show a statistically significant response, and even in asthmatics (a sensitive subpopulation), responses are only seen at high concentrations on the order

of 250 ppb (715 µg/m3) over a 10 minute period (WHO, 2006). Peak exposures in the range of 4,000 ppb (11,440 µg/m3) to 5,000 ppb (14,330 µg/m3) are required for reductions in mean lung function in normal (non-asthmatic) individuals at rest. No significant changes in group mean lung function in healthy individuals have been seen below short-term exposures of 1000 ppb (2860 µg/m3), even with exercise (WHO, 2006).

To put the SO2 concentrations above into context, according to the Illinois EPA 2011 Air Quality Report (IEPA, 2012), the statewide average 24-hour SO2 concentration for 2011 was 39 µg/m3 (15 ppb) and was the same in 2010, and 45 µg/m3 (17 ppb) in 2009. The statewide average 1-hour high in 2011 was 165 µg/m3 (63 ppb), compared with 197 µg/m3 (75 ppb) in 2010, 212 µg/m3 (81 ppb) in 2009 and 335 µg/m3 (128 ppb) in 2008. Therefore, not only have the air concentrations monitored in Illinois been well below levels demonstrated to cause respiratory effects in healthy and asthmatic individuals, there has been an overall downward trend in SO2 concentrations in the state (corresponding to the national data). See Figures 1, 2 and 3 above.

In the original variance proceeding, reference was made to a 2010 study conducted by the National Research Council (NRC) that indicated that annual health related damages from particulate, SO2 and NO2 cost $62 billion in 2005 alone. The concentration-response (C-R) relationship used in the NRC Health Impact Assessment (HIA) to estimate damages associated with SO2-related hospital admissions was from a study conducted by Sheppard et al. (1999). However, this study, like most SO2 epidemiology studies, failed to find an association between ambient SO2 concentrations and asthma-related hospital admissions, as was clearly acknowledged by the authors.

The C-R function is a key component of HIAs because it is this function that allows the effect of interest to be linked in a quantitative way to incremental changes in concentrations by assuming a response continuum. However, C-R relationships are calculated for all pollutants and health endpoints examined in a scientific study by the authors, even for those pollutant-health effect pairings that are determined through statistics not to be associated with the exposure of interest. Therefore, it is up to those conducting the HIA (individuals other than the scientific study authors) to choose appropriate C-R relationships for use in modeling. It is disconcerting that the NRC study would use a C-R function from a study in which the ambient SO2 concentrations and asthma-related hospital admissions were determined not to be correlated and casts doubt on the validity of the entire NRC report. This is a clear example of how findings published in the scientific literature are often misinterpreted and inadvertently or intentionally misused.

Epidemiological Studies

Concerns have been raised previously that research demonstrates that even moderate levels of SO2 are associated with bronchospasm. Indeed, in the original variance proceeding reference was made to the USEPA's ISA (USEPA, 2008) to support the assertion that epidemiologic studies have observed respiratory effects in areas where the SO2 concentration was below the regulatory level in place at the time. However, the evidence of respiratory effects below the 24-hour NAAQS referenced in the ISA comes entirely from epidemiological studies. To put this finding into context, it is important to understand what epidemiological studies can and cannot do.

Observational epidemiological studies attempt to determine which factors are associated with diseases (risk factors) and which factors may protect people or animals against disease (protective factors). However, epidemiological studies cannot prove that a specific risk factor actually causes the disease being studied. This is because epidemiological studies cannot control for, nor can they necessarily identify, all of the factors that may influence a health outcome. Therefore, they are plagued with issues of confounding. For example, if coffee drinkers were more likely to also be cigarette smokers, and a study was conducted to explore potential associations between coffee

drinking and lung cancer, without taking the smoking habits of the coffee drinkers into account, smoking would be a confounder and the results may seem to show that coffee drinking increases the risk of lung cancer.

Epidemiological evidence can only show that a risk factor is or is not associated (correlated) with a higher incidence of disease in the population exposed to that risk factor. The higher the correlation, the more certain the association; but causation cannot be proven in these studies. Therefore, the fact that there may be studies showing that hospital admissions or emergency room visits were increased in an area where short-term SO2 concentrations were below the NAAQS does not necessarily mean that the SO2 concentrations caused the increase in hospital admissions.

Studies that use population level data, such as respiratory hospital admissions or emergency room visits obtained from databases without collecting any data on the individuals involved, are prone to what is known as "ecologic fallacy." This occurs when a correlation observed at the population level is assumed to apply at the individual level. Without information on whether the correlations were statistically significant and whether co-pollutants and other intervening variables were properly controlled for, it is not possible to know what the implications of the findings are or if the statement even accurately characterizes the findings.

Thus, while USEPA's ISA may have noted that epidemiologic studies observed respiratory effects in areas where the SO2 concentration was below the regulatory level in place at the time, the respiratory effects were not necessarily due to SO2 exposure. This is discussed in more detail below.

Particulate Matter

Epidemiological data do indicate that particulate matter is a stronger causal agent for mortality and morbidity (i.e., effects other than mortality) than gaseous SO2, and gaseous SO2 is usually found in association with particulate matter, as SO2 is a precursor for fine sulfate particles. The original scientific health data on particulates, both PM10 (airborne particulate matter of 10 micrometers in diameter and smaller data) and PM2.5 only measured the total amount of PM, and certain adverse health effects are correlated with total PM, whether measured as PM10 or PM2.5.

However, the scientific and regulatory communities understood that PM can have many different sources, and many different compositions. The National Academy of Sciences, National Research Council report (NRC, 2004) states: "The current NAAQS for PM is both size and mass-based and implicitly assumes that all particles of a given size have the same toxicity per unit mass, irrespective of chemical composition. In the committee's judgment, this mass-based NAAQS greatly oversimplifies complex biological phenomena."

Thus, recent studies have focused on speciating the types of PM present in ambient air, and these studies indicate that the sulfate component of PM2.5 is not associated with adverse health effects; instead, indications are that carbonaceous forms of PM2.5 (black carbon, elemental carbon, such as emitted from diesel engines or the combustion of residual oils) are the critical health determinants.

However, recent epidemiological studies have not shown a correlation between adverse health effects and ambient SO2, or its particulate product, sulfate.

- Metzger et al. (2004) demonstrated that 1-hr SO2 and 24-hr PM2.5 from sulfates were <u>not</u> associated with hospital emergency room visits for cardiovascular disease symptoms in a

study of 31 hospitals in the Atlanta area. Associations were shown for NO2, CO, PM2.5, organic carbon, elemental carbon, and oxygenated hydrocarbons.

- Schwartz et al. (2005) demonstrated that there were no associations between heart rate variability (HRV), an indicator of potential cardiovascular complications, and ambient SO2 or NO2 in a group of elderly residents in Boston, nor for secondary PM. Total PM2.5 was correlated with adverse HRV values, but black carbon, a traffic-related component of PM2.5, had the strongest correlation with adverse HRV values. The remaining secondary PM had a weak association with one adverse indicator.

- Jerrett et al. (2005) studied health outcomes in 51 cities originally evaluated by the American Cancer Society (ACS). Relative Risks (RR) for sulfate [PM2.5 component] exhibit a large decline from the 1980s to the 1990s. In contrast, PM2.5 RRs follow the opposite pattern, with larger RRs later in the 1990s. The authors state that "The reduction in sulfate RR may have resulted from air quality improvements that occurred through the 1980s and 1990s in response to the acid rain control program. PM2.5 concentrations also declined in many places, but toxic mobile sources are now the largest contributors to PM in urban areas. This may account for the heightened RR of mortality associated with PM2.5 in the 1990s."

- Reiss et al. (2007) reviewed the "Evidence of Health Impacts of Sulfate- and Nitrate-Containing Particles in Ambient Air." They conclude: "In total, the epidemiologic and toxicologic evidence provide little or no support for a causal association of PM sulfate and health risk at ambient concentrations." There is general consensus that SO2 is unlikely to be causally associated with mortality. Where adverse outcomes are associated with SO2, they indicate that SO2 may be a surrogate for some other exposure.

- Black carbon, an indicator of traffic emissions, is consistently associated with adverse health outcomes in the studies where speciation of the components of PM2.5 is conducted. Interestingly, where PM2.5 and the sulfate component are measured, but black carbon is not measured, the secondary sulfate component of PM2.5 will track with adverse health effects; this is considered to be a phenomenon of "transference" of health associations from a poorly or measured parameter to one that is well measured. However, where SO2 and/or sulfate (the PM2.5 component) are measured, significant adverse health outcome associations are rarely demonstrated (Grahame, 2009).

Attachment 2 provides an evaluation of PM2.5 measurements in the vicinity of the MPS Group power plants. The results indicate that there is no evidence to suggest that the power plants are contributing to elevated PM2.5 concentrations. PM2.5 concentration trends are decreasing at the monitoring locations, and this trend is expected to continue, and there is no reason to conclude that the requested variance will adversely impact these results.

Health-Outcome Predictive Tools

Concerns have also been raised based on reported statistics for deaths associated with emissions from specific power plants, including, statistics from the Power Plant Impact Estimator Software Tool located at http://www.catf.us/resources/publications/view/138 and its accompanying report entitled, "Toll from Coal: An Updated Assessment of Death and Disease from America's Dirtiest Energy Source." This study was commissioned by the Clean Air Task Force (CATF, 2010). The underlying assumptions used in deriving these statistics are not particularly transparent, even upon examination of the technical support document for the estimator tool and Toll from Coal report (Abt, 2010). However, one thing noted is that the C-R relationship for SO2 exposure and asthma-related

hospital admissions used in the tool was from a study (Sheppard et al., 1999) that failed to find an association between ambient SO2 concentrations and asthma-related hospital admissions (a shortcoming noted for the NRC report discussed above). Although these types of evaluations are becoming increasingly more common, use of these C-R relationships are subject to significant uncertainty related to their generalizability and accuracy. One thing is certain, C-R relationships from studies that fail to establish an association between the exposure and effect of concern should not be extrapolated to other situations in the hopes of providing accurate predictions of adverse health outcomes. The other comments made above about C-R relationships and their use apply here as well.

Public Perceptions

The public debate on air pollution coupled with the sensationalized air pollution health stories in the media have created the appearance that harm from air pollution is much greater and more certain than suggested by the underlying scientific evidence. According to Dr. Joel Schwartz (2006), whose work on the relationship between respiratory hospital admissions and ambient air pollutants is amongst some of the most highly cited and who is one of the premier authors of many epidemiological studies that have been relied upon by USEPA in establishing and re-evaluating the NAAQS, “the incentives in air pollution health research encourage risk exaggeration...Through exaggeration, omission of contrary evidence, and lack of context, regulators, activists, and even many health scientists misrepresent the results of air pollution health studies and the overall weight of the evidence from the research literature” (Schwartz, 2006). Dr. Schwartz’ work is cited across multiple fields, including Clinical Medicine, Environment & Ecology, Biology & Biochemistry, and Pharmacology & Toxicology. http://www.esi-topics.com/airpoll/interviews/JoelSchwartz.html

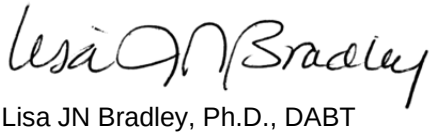
Attached is a copy of “Air Pollution and Health: Do Popular Portrayals Reflect the Scientific Evidence?” by Dr. Joel Schwartz, which provides several case studies aimed at demonstrating that misinformation about air pollution is a pervasive problem. The Schwartz (2006) article demonstrates why it is so important for those involved in evaluating and setting health policy to look deeper than the summaries of studies provided by other governmental agencies, health scientists in press conferences, and activists in hearings.

CONCLUSION

There is no question that very high levels of pollution can kill, as occurred during the “London Fog” of 1952, when soot and SO2 were at levels orders of magnitude higher than those experienced in developed countries today and visibility was less than 20 feet. However, claims that low levels of pollutants cause death is based on observational studies, many of which have not controlled for co-pollutants and lifestyle variables and usually do not contemplate regional disease patterns that have nothing to do with air pollution. It is noteworthy that researchers have been unable to evoke adverse health outcomes in animals with SO2 concentrations anywhere near as low as those found in ambient air today. And the preponderance of the evidence from a variety of epidemiological studies indicates, as noted above, where SO2 and/or sulfate (the PM2.5 component) are measured, significant adverse health outcome associations are rarely demonstrated (Grahame, 2009).

More specifically related to the requested variance that is the direct subject of this Memorandum, this evaluation concludes that there would be no adverse impact as a result of implementing the requested variance and, in fact, a net environmental benefit would be realized.

Sincerely,



Lisa JN Bradley, Ph.D., DABT
Vice President and Senior Toxicologist

Enclosures:

Attachment 1. References
Attachment 2. Regional Evaluation of PM2.5
Attachment 3. Schwartz, J. 2006. Air Pollution and Health: Do Popular Portrayals Reflect the Scientific Evidence? American Enterprises Institute for Public Policy Research. Environmental Policy Outlook, No. 2.
Attachment 4: Resume for Lisa JN Bradley, Ph.D., DABT

Attachment 1: References

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Attachment 2: Regional PM2.5 Evaluation

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Memorandum

To	Lisa Bradley	Page	1
CC	Carlos Szembek, Bob Paine		
Subject	Ambient PM2.5 Concentrations – Ameren Power Plants, Illinois		
From	Brian Stormwind		
Date	July 10, 2013		

Review of $PM_{2.5}$ Monitoring Data in the Vicinity of the Ameren Power Plants to be Purchased by Illinois Power Holdings (IPH)

Figure 1 shows the location of the power plants and closest and most representative $PM_{2.5}$ ambient air quality monitors relative to each plant. The proximity, surrounding land use (e.g., rural or urban) and prevailing wind direction were considered in selecting representative monitors, although monitors in all directions were reviewed for consideration. For facilities with a lack of nearby monitors, distant monitors that were not necessarily representative of the facility locations were included for reference. The monitors with respect to each power plant are reviewed below.

The source of the $PM_{2.5}$ monitoring data is U.S. EPA's AirData website[1]. The AirData site provides annual summaries of measured concentrations from state-run ambient air quality monitors including the design concentrations used to evaluate the monitor results relative to the National Ambient Air Quality Standards (NAAQS).

The $PM_{2.5}$ NAAQS are as follows:

- 24-hour = 35 $\mu g/m^3$; design value is the 3-year average of the 98th percentile daily concentration.
- Annual = 12 $\mu g/m^3$; design value is the 3-year average of the annual mean concentration.

Discussion of Individual Power Plants and Surrounding $PM_{2.5}$ Ambient Air Monitors

E.D. Edwards and Duck Creek

Due to the proximity of the E.D. Edwards and Duck Creek power plants, the monitors for these have been grouped together. No representative monitors for these facilities were found north of the nearest monitor at Peoria (Figure 1). The prevailing wind pattern for both these facilities is shown in Figure 2, with wind primarily from the south.

[1] http://www.epa.gov/airdata/ad_rep_mon.html

The E.D. Edwards power plant is located in Bartonville, IL in Peoria County. The closest $PM_{2.5}$ monitors relative to the E.D. Edwards plant are located in Peoria, IL, 13 km to the northeast; in Normal, IL, 57 km to the east southeast; Springfield, IL, 86 km to the south and Decatur, IL, 103 km to the south-southeast. Further out (and upwind) from E.D. Edwards are the Keokuk, IA monitor, 148 km to the west and the Quincy, IL monitor 148 km to the southwest. The most recent 3 years of data and corresponding design values for these monitor stations are summarized in Table 1. The monitoring data indicate compliance with the NAAQS and a likely decreasing trend as 2012 data were consistently lower than 2011. The trend of decreasing $PM_{2.5}$ concentrations is expected due to consistent reductions in precursor emissions, as noted by EPA in their June 2013 trends update available at http://www.epa.gov/ttnchie1/trends/.

The Duck Creek power plant is located east-southeast of St. David, IL in Fulton County. The closest $PM_{2.5}$ monitors relative to the Duck Creek facility are located in Peoria, IL, 42 km to the northeast; Springfield, IL, 77 km to the south-southeast; Normal, IL, 84 km to the east; Decatur, IL 112 km to the southeast; Keokuk, IA, 121 km to the west; and in Quincy, IL, 132 km to the west-southwest. The most recent 3 years of data and corresponding design values for the monitor stations are summarized in Table 1. The monitoring data indicate compliance with the NAAQS and, similar to the monitors surrounding the E.D. Edwards plant, a likely trend for decreased concentrations as the 2012 data were consistently lower than the previous two years.

Table 1: $PM_{2.5}$ Monitor Concentrations – E.D. Edwards and Duck Creek Power Plants

Monitor	Ave. Period	Ranking	Design Concentrations (µg/m^3)				NAAQS (µg/m^3)
			2010	2011	2012	3-yr Ave	
Peoria, IL	24-hour	98th %	26.0	27.7	20.7	**24.8**	**35**
ID 17-143-0037	Annual	Highest	11.5	11.7	9.8	**11.0**	**12**
Springfield, IL	24-hour	98th %	24.2	27.8	20.0	**24.0**	**35**
ID 17-167-0012	Annual	Highest	11.5	10.7	9.5	**10.6**	**12**
Normal, IL	24-hour	98th %	25.0	25.8	21.3	**24.0**	**35**
ID 17-113-2003	Annual	Highest	10.6	10.7	9.3	**10.2**	**12**
Decatur, IL	24-hour	98th %	22.1	25.5	18.1	**21.9**	**35**
ID 17-115-0013	Annual	Highest	12.2	11.6	10.0	**11.3**	**12**
Keokuk, IA	24-hour	98th %	30.4	23.9	22.7	**25.7**	**35**
ID 19-111-0008	Annual	Highest	11.8	11.3	10.9	**11.3**	**12**
Quincy, IL	24-hour	98th %	22.6	24.6	20.8	**22.7**	**35**
ID 17-001-0007	Annual	Highest	10.5	10.4	9.5	**10.1**	**12**

Coffeen

The Coffeen power plant is located in Coffeen, IL in Montgomery County. The closest $PM_{2.5}$ monitors relative to the Coffeen plant are located in Wood River, IL, 65 km west southwest; Alton, IL 68 km to the southwest; and Granite City, IL, 75 km to the southwest. The most recent 3 years of data and corresponding design values for these monitor stations are summarized in Table 2. The monitoring data for Wood River and Alton indicate a large margin of compliance with the 24-hour NAAQS, while annual concentrations are slightly below the revised annual NAAQS of 12 µg/m^3. The Granite City monitor shows compliance for the 24-hour NAAQS, but exceeds the new annual NAAQS. However, the annual averages at this location are decreasing year by year, and the Granite City monitor is in an urban setting and likely most significantly influenced by local commercial/industry and vehicular emissions. As indicated by climatological data from Springfield, IL (Figure 3), Coffeen is predominately downwind of all three monitors; i.e., winds in the region are predominantly from the southerly and southwesterly sectors. The closest downwind monitors

relative to the Coffeen plant are located in Springfield (~90 km NNW) and Decatur (~100 km NNE). The monitored concentrations for these stations are below the annual NAAQS.

Table 2: $PM_{2.5}$ Monitor Concentrations – Coffeen Power Plant

Monitor	Ave. Period	Ranking	Design Concentrations (µg/m^3)				NAAQS (µg/m^3)
			2010	2011	2012	3-yr Ave	
Wood River, IL	24-hour	98th %	22.1	28.6	23.2	**24.6**	**35**
ID 17-119-3007	Annual	Highest	12.0	12.4	10.6	**11.7**	**12**
Alton, IL	24-hour	98th %	25.0	23.9	23.6	**24.2**	**35**
ID 17-119-2009	Annual	Highest	13.3	11.6	10.6	**11.8**	**12**
Granite City, IL	24-hour	98th %	28.6	30.6	23.7	**27.6**	**35**
ID 17-119-0024	Annual	Highest	14.6	14.3	13.1	**14.0**	**12**
Springfield, IL	24-hour	98th %	24.2	27.8	20.0	**24.0**	**35**
ID 17-167-0012	Annual	Highest	11.5	10.7	9.5	**10.6**	**12**
Decatur, IL	24-hour	98th %	22.1	25.5	18.1	**21.9**	**35**
ID 17-115-0013	Annual	Highest	12.2	11.6	10.0	**11.3**	**12**

Newton

The Newton power plant is located in Newton, IL in Jasper County. The closest $PM_{2.5}$ monitors relative to the Newton plant are located at the Purdue Agricultural Farm near Vincennes, IN, 72 km to the east southeast; co-located monitors in Terre Haute, IN, 96 km to the northeast and Knight Prairie, IL, 99 km to the south-southwest. The most recent 3 years of data and corresponding design values for these monitor stations are summarized in Table 3.

All monitors indicate a large margin of compliance with the 24-hour NAAQS. The Purdue and Terra Haute #1 annual concentrations are just below the annual NAAQS, while Terra Haute #2 exceeds the new annual NAAQS. The Purdue monitored concentrations are likely influenced by local farming activities. The Terre Haute monitors are located in an urban area and the higher concentrations are likely a result of local commercial/industrial activities and vehicular traffic. Note that although regional wind patterns (Figure 3) suggest potential transport of emissions from the Newton power plant toward Terra Haute, the power plant, which is almost 100 km away, is too far to have a significant contribution to the Terre Haute monitored concentrations.

Table 3: $PM_{2.5}$ Monitor Concentrations – Newton Power Plant

Monitor	Ave. Period	Ranking	Design Concentrations (µg/m^3)				NAAQS (µg/m^3)
			2010	2011	2012	3-yr Ave	
Purdue	24-hour	98th %	27.6	26.7	23.1[(1)]	**25.8**	**35**
ID 18-083-0004	Annual	Highest	12.3	11.4	11.4[(1)]	**11.7**	**12**
Terre Haute, IN	24-hour	98th %	29.2	26.5	24.1	**26.6**	**35**
ID 18-167-0018 (POC1)	Annual	Highest	13.0	12.4	10.4	**11.9**	**12**
Terre Haute, IN	24-hour	98th %	31.0	33.6	26.2	**30.3**	**35**
ID 18-167-0018 (POC2)	Annual	Highest	13.4	13.8	11.6	**12.9**	**12**
Knight Prairie	24-hour	98th %	25.3	20.6	15.7	**20.5**	35
ID 17-065-0002	Annual	Highest	11.3	10.1	8.4	**9.9**	12

[(1)] Data listed for 2009. Monitor discontinued after 2011.

Joppa

The Joppa power plant is located in Joppa, IL in Massac County on the border with Kentucky. The regional wind pattern for south-southeastern IL is best represented by the 30-year wind rose from Evansville, IN airport (Figure 4) that shows both strong northwest and southerly flow in the area. The closest $PM_{2.5}$ monitors relative to the Joppa plant are located in Paducah, KY, 25 km to the southeast and in Knight Prairie, IL, 98 km to the north-northeast. No other representative monitors were found within 125 km of the Joppa plant. Given the wind pattern for the region shown in Figure 4, the Joppa plant lines up reasonably well with the Paducah (northwest flow) and the Knight Prairie monitors (southerly flow). The most recent 3 years of data and corresponding design values for both monitor stations are summarized in Table 4. The monitoring data indicate a large margin of compliance with the NAAQS and a likely decreasing trend as the data for each year is lower than the data for previous year.

Table 4: $PM_{2.5}$ Monitor Concentrations – Joppa Power Plant

Monitor	Ave. Period	Ranking	Design Concentrations (µg/m^3)				NAAQS (µg/m^3)
			2010	2011	2012	3-yr Ave	
Paducah, KY	24-hour	98th %	25.0	23.2	19.3	**22.5**	**35**
ID 21-145-1004	Annual	Highest	11.4	10.4	9.9	**10.6**	**12**
Knight Prairie	24-hour	98th %	25.3	20.6	15.7	**20.5**	35
ID 17-065-0002	Annual	Highest	11.3	10.1	8.4	**9.9**	12

Conclusions

Based on a review of available monitoring data in the vicinity of the Ameren power plants, there is no evidence to suggest that the stations are contributing to elevated $PM_{2.5}$ concentrations or, in the case of the Coffeen and Newton facilities, concentrations in excess of the NAAQS. It is important to note that the 2012 24-hour and annual $PM_{2.5}$ concentrations for all the monitors listed (with the sole exception of the Purdue monitor which was discontinued after 2011) are consistently lower than the 2011 year values indicating a potential regional downward trend. This trend is expected due to downward trends in precursor emissions of SO_2 and NOx.

Sincerely yours,

Brian Stormwind
brian.stormwind@aecom.com

Figure 1 Location of Power Plant Facilities and Noted $PM_{2.5}$ Ambient Air Monitors. The power plants are noted with the red markers; the ambient air monitors are noted with the yellow markers.

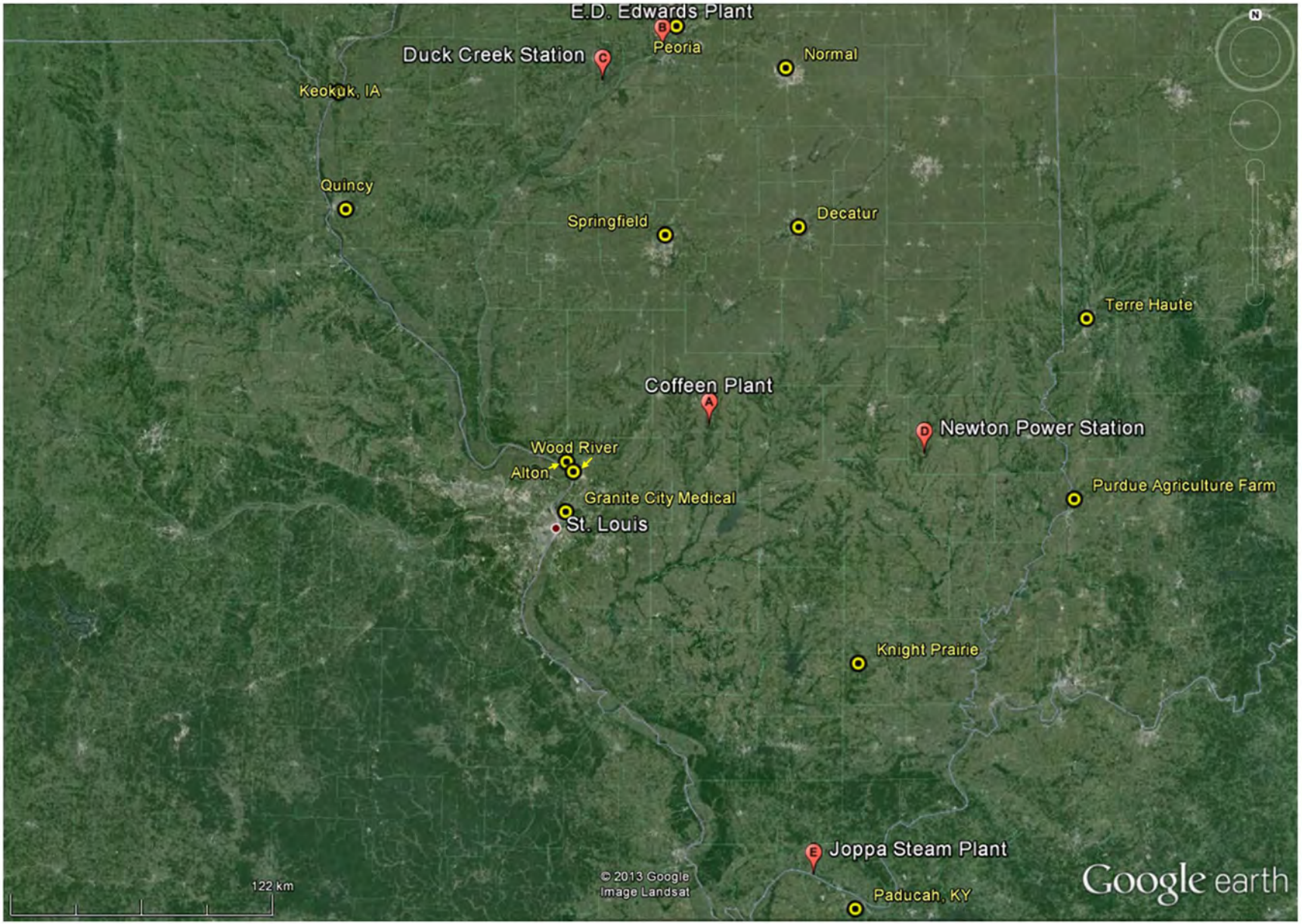
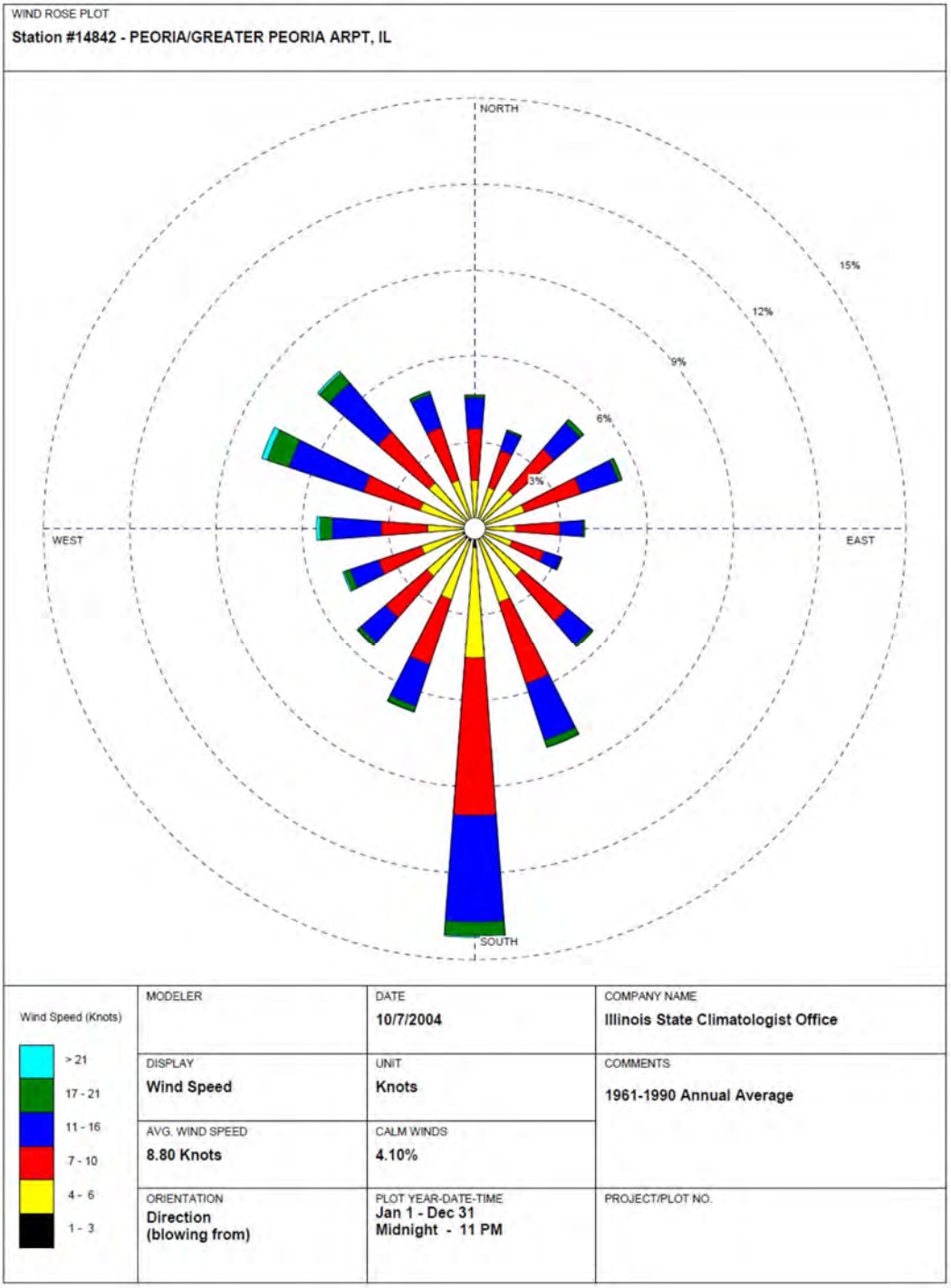
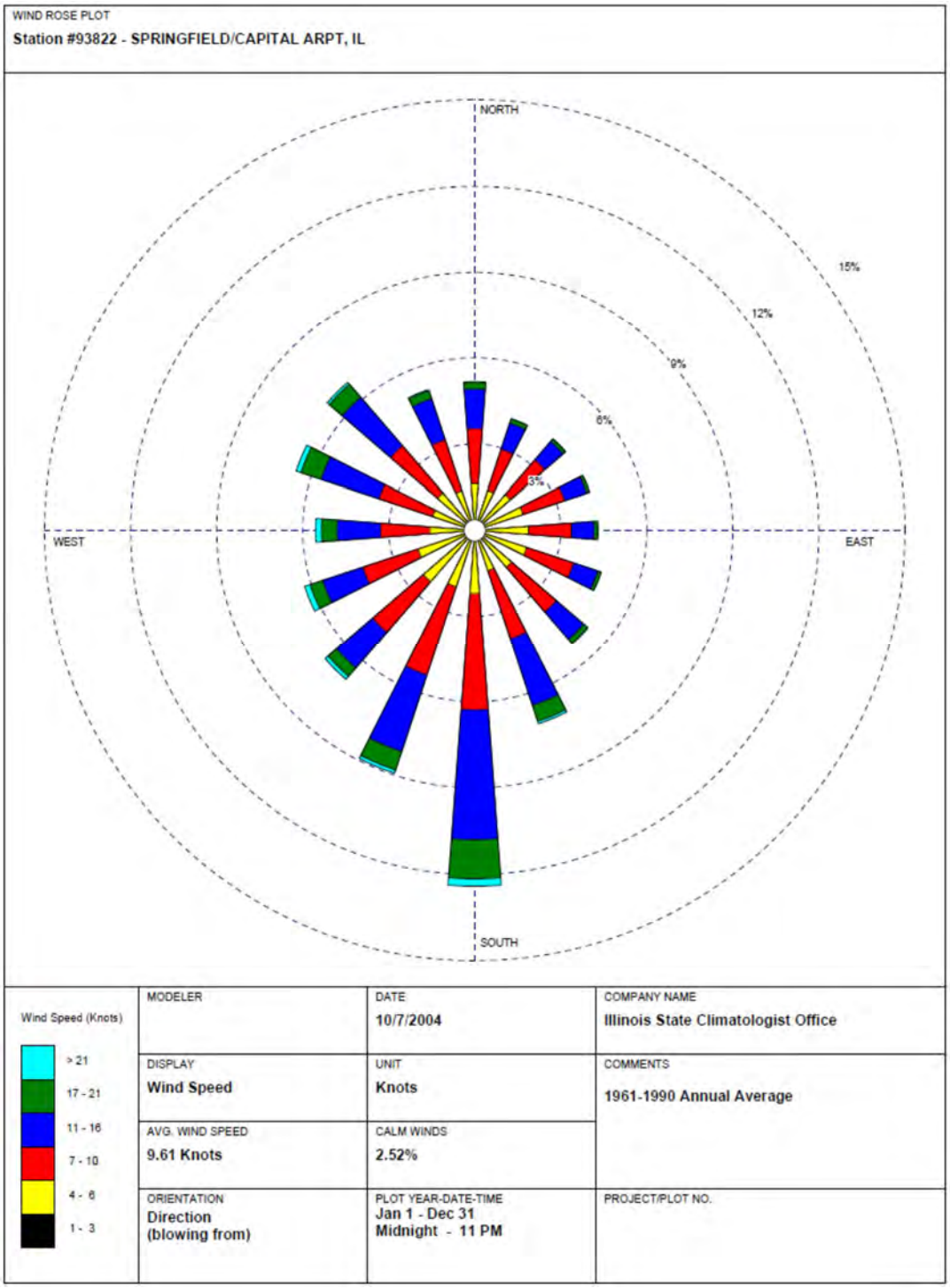


Figure 2 30-year Climatological Wind Rose for Peoria Airport, IL[2]



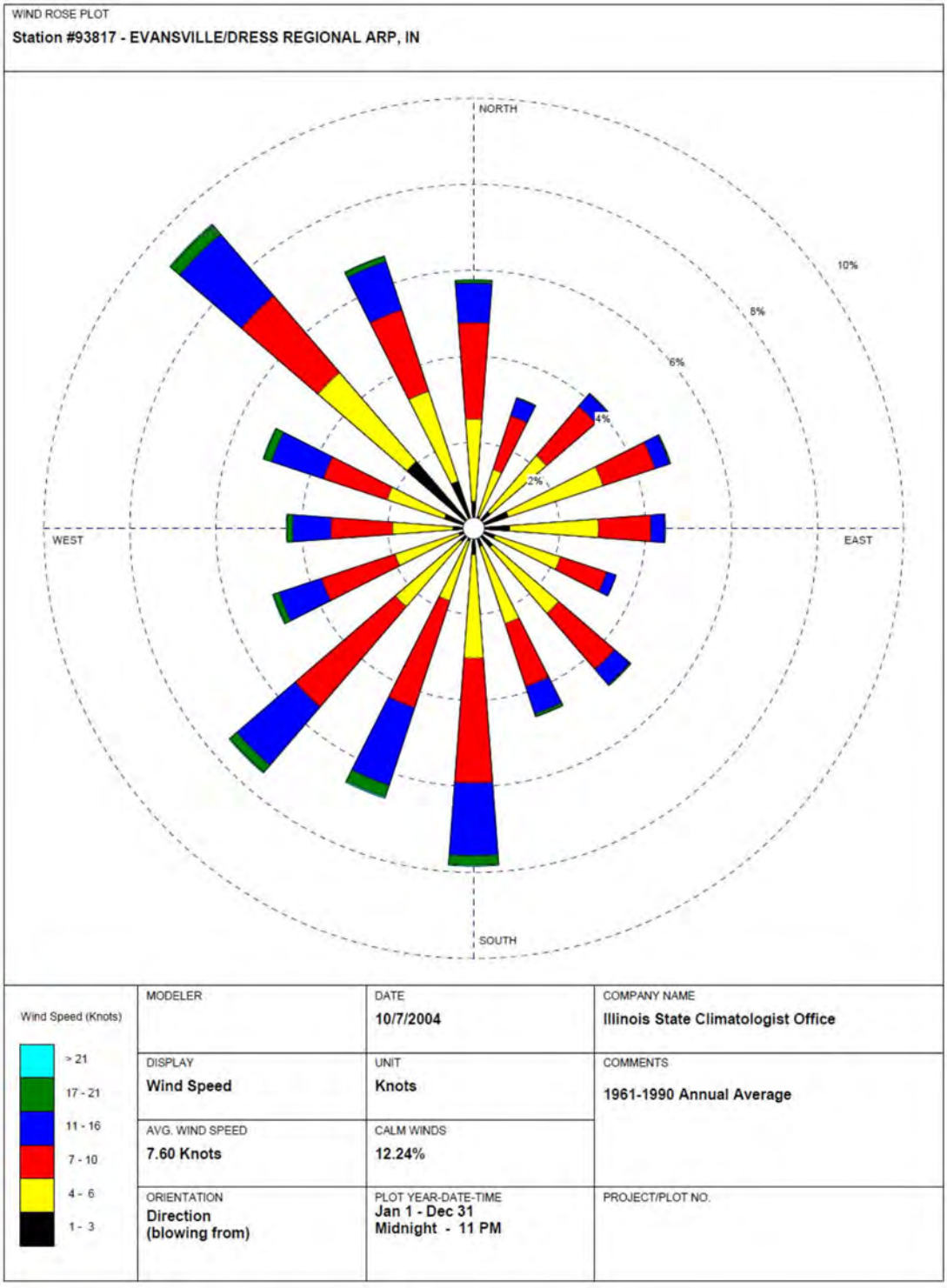
[2] http://www.isws.illinois.edu/atmos/statecli/roses/pia_rose_13.pdf

Figure 3 30-year Climatological Wind Rose, Springfield Airport[3]



[3]Source: http://www.isws.illinois.edu/atmos/statecli/roses/spi_rose_13.pdf

Figure 4 30-year Climatological Wind Rose for Evansville Airport, IN[4]



[4] http://www.isws.illinois.edu/atmos/statecli/roses/eva_rose_13.pdf

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Air Pollution and Health: Do Popular Portrayals Reflect the Scientific Evidence?

By Joel Schwartz

Environmentalists, regulators, health scientists, and journalists are the main purveyors of information on air pollution health risks. Unfortunately, these groups create the appearance that harm from air pollution is much greater and more certain than suggested by the underlying evidence. The incentives in air pollution health research encourage risk exaggeration, because information purveyors depend on public fear to maintain their funding and influence. Investigative reporters are in the best position to assess how the political economy of environmental health research affects the production and portrayal of the evidence. Public debate on air pollution will continue to proceed from false premises until journalists take up this challenge.

In a nationwide survey in 2004, 85 percent of Americans rated air pollution as a "very serious" or "somewhat serious" problem, with similar results for state surveys.[1] In a recent Gallup Poll, 78 percent of Americans said they worry about air pollution "a fair amount" or "a great deal."[2] Public fear of air pollution is understandable, because most popular information about air pollution is indeed alarming.

Activist groups regularly issue reports with scary titles such as *Danger in the Air; Death, Disease and Dirty Power; Highway Health Hazards; Plagued by Pollution; and Children at Risk*.[3] Health researchers often issue alarming summaries of their research as well. Recent press-release headlines from health research institutes include "Smog May Cause Lifelong Lung Deficits," "Link Strengthened between Lung Cancer, Heart Deaths and Tiny Particles of Soot," "USC Study Shows Air Pollution May Trigger Asthma in Young Athletes," and "Traffic Exhaust Poisons Home Air."[4]

Regulators declare "code orange" and "code red" alerts on days when air pollution is predicted to exceed federal health standards. And news stories on air pollution often feature menacing headlines such as "Air Pollution's Threat Proving Worse than Believed," "Don't Breathe Deeply," "Study Finds Smog Raises Death Rate," "State's Air Is among Nation's Most Toxic," and "Asthma Risk for Children Soars with High Ozone Levels."[5]

Headlines like these might be warranted if they accurately reflected the weight of the scientific evidence. But they do not. Through exaggeration, omission of contrary evidence, and lack of context, regulators, activists, and even many health scientists misrepresent the results of air pollution health studies and the overall weight of the evidence from the research literature. They create the appearance that harm from air pollution is much greater and more certain than suggested by the underlying evidence.

Journalists are the final line of defense between the public and the proponents of air pollution health scares. Unfortunately, the majority of media air pollution health stories are sensationalized exaggerations of air pollution's risks.

Through several case studies, this essay shows that misinformation on air pollution and health is a pervasive problem. As a result, public fear of air pollution is out of all proportion to the minor risks posed by current, historically low air pollution levels.

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False Alarm on Asthma and Air Pollution

Beginning in 1993, the California Air Resources Board (CARB) funded the Children's Health Study (CHS). Researchers from the University of Southern California (USC) tracked several thousand California children living in twelve communities with air pollution ranging from near-background to the worst in the nation.

At a joint press conference in 2002, the USC researchers and CARB managers reported that children who played three or more team sports were more than three times as likely to develop asthma if they lived in the six highest-ozone communities in the study, when compared with the six lowest-ozone communities.[6] They also claimed the study's results applied to cities across the United States.

Ironically, the CHS asthma study actually showed just the opposite. While higher ozone was associated with a greater risk of developing asthma for children who played three or more team sports (8 percent of children in the study), higher ozone was associated with a 30 percent *lower* risk of developing asthma in the full sample of children in the study.[7] While this fact was discussed in a journal article on the study, it was not mentioned at the press conference.[8]

Higher levels of other pollutants, including nitrogen dioxide and particulate matter (PM_{10}), were also associated with a lower asthma risk.[9] Also mentioned in the journal article, but not at the press conference, was that when the researchers divided the twelve communities in three groups of four (rather than two groups of six), the association of ozone with increased asthma prevalence in child athletes applied only to the four communities in the highest ozone group and not to the medium-ozone group.

The assertion that the study is relevant for other parts of the country was also false. The four high-ozone areas in the study averaged 89 days per year exceeding the federal eight-hour ozone standard and 59 days per year exceeding the one-hour standard during 1994–1997, the years used to assess pollution exposure in the study.[10] No area of the United States, outside of a few parts of California, has *ever* had ozone levels this high even for a single year, much less for several years running.

In fact, by the time of its release in February 2002, the study no longer applied even in the southern California areas where it was performed. Eight-hour ozone exceedances had declined 55 percent, and one-hour exceedances had declined 78 percent in the interim. By 2002, communities that were "high-ozone" areas during the study had become "medium-ozone" areas, for which ozone had no effect on asthma risk.

At the press conference releasing the CHS asthma results, the chairman of the Air Resources Board claimed: "This study illustrates the need not to retreat but to continue pushing forward in our efforts to strengthen air pollution regulations."[11] But if anything, the CHS asthma study showed that current standards already include a large safety margin. Ozone was not associated with a change in asthma risk in the medium-ozone areas of the study. Yet these areas exceeded federal ozone standards by large margins—an average of 41 eight-hour exceedance days per year and 17 one-hour exceedances.

> Through exaggeration, omission of contrary evidence, and lack of context, regulators, activists, and even many health scientists misrepresent the results of air pollution health studies and the overall weight of the evidence from the research literature.

False information on the CHS asthma results was not limited just to CARB officials or USC scientists. Health experts from around the country misinterpreted the study's results. For example, on the day the study was released, a professor at the State University of New York at Stony Brook, who has since become the American Lung Association's medical director, claimed: "This is not just a Southern California problem. There are communities across the nation that have high ozone."[12] According to the *Houston Chronicle*, Houston asthma specialists said the study showed that "Houston [should] step up its efforts to implement a state plan to reduce ozone."[13] The director of the pediatric asthma program at the University of California at Davis claimed "Sacramento is a very high ozone area, so this [the CHS asthma study] is going to be very relevant to us."[14]

Not only were all of these nominal experts wrong about whether the study is relevant to actual ozone levels in the United States, all of them completely missed the fact that ozone and other air pollutants were associated with an overall lower risk of developing asthma.

In a recent commentary on air pollution and asthma in the *Journal of the American Medical Association*, two prominent air pollution health researchers claimed:

"Some evidence suggests that air pollution may have contributed to the increasing prevalence of asthma."[15] The "evidence" they cite is the CHS asthma study.

Journalists also often act as cheerleaders for air pollution alarmists when reporting on air pollution and health. For example, a recent editorial headline in the *Sacramento Bee* declared "Smog and Asthma: The Link—and Threat—Are Real."[16] The *Bee*'s source for this claim? Once again, the CHS asthma study.

Much Ado about Very Little

The Children's Health Study also suggests that even the highest air pollution levels in the nation are having little or no effect on children's lung development. But once again, the scientists involved in the study obscured that fact.

After following more than 1,700 children from ages ten to eighteen (years 1993 to 2001), CHS scientists reported that there was no association between ozone and lung-function growth.[17] This is despite the fact that the twelve communities in the study ranged from zero to more than 120 eight-hour ozone exceedance days per year, and zero to more than 70 one-hour ozone exceedance days per year during the study period.[18] Once again, no area outside California has ever had anywhere near this frequency of elevated ozone, even for a single year, so we can conclude that ozone is not causing any reduction in children's lung capacity. This has not stopped environmental groups from claiming otherwise. For example, in *Impacts of Ozone on Our Health*, the Carolinas Clean Air Coalition claims: "Children have a 10 percent decrease in lung function growth when they grow up in more polluted air."[19]

The Children's Health Study also suggests that fine particular matter ($PM_{2.5}$) is causing little or no long-term harm to lung growth. Unlike ozone, $PM_{2.5}$ actually was associated with a small effect on lung development. Annual-average $PM_{2.5}$ levels ranged from about 6 to 32 micrograms per cubic meter ($\mu g/m^3$) in the twelve communities in the study.[20] Across this range, $PM_{2.5}$ was associated with about a 2 percent decrease in forced expiratory volume in one second (FEV_1) and a 1.3 percent decrease in force vital capacity (FVC), both measures of lung capacity.

But even this small effect drastically inflates the apparent importance of the results. First, no location outside of the CHS communities has $PM_{2.5}$ levels anywhere near 32 $\mu g/m^3$. In fact, outside California there is not a single area with $PM_{2.5}$ above 21 $\mu g/m^3$. And by the time the study was published in 2004, even the highest $PM_{2.5}$ area in California was at 25 $\mu g/m^3$.

It is also worth noting that the children in the CHS were already ten years old when they entered the study in 1993 and had therefore been breathing the even-higher air pollutant levels extant during the 1980s in southern California. For example, Riverside averaged about 48 $\mu g/m^3$ $PM_{2.5}$ during the 1980s, or about 50 percent greater than the highest $PM_{2.5}$ level measured during the CHS years.[21] If it were really these higher 1980s $PM_{2.5}$ levels that caused the lung-function declines, then the current worst $PM_{2.5}$ in the country would be causing about a 1 percent decrease in FEV_1 and a 0.5 percent decrease in FVC. Thus, taking the CHS results at face value, ozone is having no effect on children's lung development anywhere in the United States. $PM_{2.5}$ is having virtually no effect.

Nevertheless, the USC researchers' press release on the study created an unwarranted appearance of serious harm. Titled "Smog May Cause Lifelong Lung Deficits," the press release asserted: "By age 18, the lungs of many children who grow up in smoggy areas are underdeveloped and will likely never recover."[22] The National Institutes of Health (NIH) also misled the public about the study's findings and relevance. The director of the National Institute of Environmental Health Sciences claimed the study "shows that current levels of air pollution have adverse effects on lung development in children."[23]

Furthermore, although the study is relevant only to a few areas of California with uniquely high air pollution levels, by asserting that it applies to all "smoggy areas" and to "current levels of air pollution," NIH and USC created the false impression that the study applies to much of the United States.

The scientists were able to create these false impressions, because the journal article on the study, which was published in the prestigious *New England Journal of Medicine* (*NEJM*), does not explicitly reveal the magnitude of the percentage change in children's lung capacity. Instead, readers have to be vigilant enough to realize that the percentage change can be calculated by combining information found in three different places in the article.[24] It is odd that a study whose main outcome measure is changes in lung capacity never actually states the percentage change explicitly.

The researchers reported a different outcome measure in their *NEJM* paper: the percent of children in

each community with a lung capacity of less than 80 percent of the "predicted" value for their age.[25] Between the least and most polluted communities, $PM_{2.5}$ was associated with nearly a five-fold increase in this percentage, from about 1.6 percent of children in the lowest-$PM_{2.5}$ community, up to about 7.9 percent in the highest-$PM_{2.5}$ community.

This seems like a large effect, but it is not. What is going on is that the 2 percent average decline in lung function in the highest-$PM_{2.5}$ community relative to the lowest meant a shift of some children who were at, say, 80 or 81 percent of "predicted" lung capacity for their age, down to maybe 78 or 79 percent. Because lung-capacity scores have a bell-curve distribution, and few children have low lung capacity, there are many more children slightly above 80 percent than slightly below 80 percent. A small shift in average lung-capacity scores therefore results in a large change in the fraction of children scoring below a given cutoff level.[26]

Reporting that even the highest air pollution levels in the country were associated with only a 2 percent decrease in lung capacity would not have caused much alarm. This probably explains why that number is nowhere to be found in the *NEJM* report or the press releases on it.

NIH took advantage of this omission in its press release, which begins: "Children who live in polluted communities are five times more likely to have clinically low lung function—less than 80 percent of the lung function expected for their age."[27] Note how this statement creates the appearance of a decline of more than 20 percent in average lung function by leading readers to tacitly make the incorrect assumption that all children would be at 100 percent if there were no air pollution.

This is exactly the mistake environmentalists have made in promoting the study. For example, the American Lung Association's (ALA) *State of the Air 2005* report claims the "average drop in lung function was 20 percent below what was expected for the child's age."[28] The Carolinas Clean Air Coalition made a similar error.[29]

The ALA clearly did not understand the study's results. But NIH and the USC researchers created the confusion. The editors and peer reviewers at the *New England Journal of Medicine* also bear responsibility for not requiring that its article on the study explicitly state the percentage change in lung capacity associated with air pollution.

> Scientists, regulators, and environmentalists have ignored these weaknesses and continue to make believe these spurious statistical correlations are telling us something real about the effects of low-level air pollution.

Monkey Business

A University of California at Davis press release begins "Primate Research Shows Link between Ozone Pollution, Asthma."[30] The press release goes on to claim the ozone exposures in the study "mimic the effect of exposure to occasional ozone smog—for example as it occurs in the Sacramento area."

In fact, the ozone exposures in the study were far higher than the actual ozone levels in American air—including the air in Sacramento. The monkeys were exposed to 0.5 parts per million (ppm) ozone for eight hours a day for five days in a row, followed by nine days of clean air. This cycle was repeated eight times. To give you an idea of the magnitude of these ozone exposures, during the last thirty years only one site in the U.S. has ever exceeded 0.5 ppm ozone for even one hour, and that happened in 1976. Today, the worst site in the United States never reaches even 0.25 ppm for one hour, and the average site never reaches 0.11 ppm.

Despite the real-world irrelevance of this study, environmental activists cite it to support claims that ozone is causing permanent lung damage in people. For example, under the headline "Lung Development of Young Monkeys Drastically Changed when Exposed to Ozone Pollution," the American Lung Association concludes, "This study presents data suggesting that the changes caused by ozone pollution are long-lasting, and maybe even permanent."[31]

Some reporters also failed to compare ozone levels in the study to real-world ozone levels. For example, according to the *Modesto Bee*, "Monkeys were exposed to air contaminated with ozone, mimicking the smog in the [Central] valley."[32] But even more nuanced stories still took an alarmist tack. For example, the *Sacramento Bee* explicitly compared ozone levels in the Sacramento region with the far higher ozone levels used in the study.[33] But you have to go halfway into the 1,100-word story to find this information. The story's headline—"Study Suggests Asthma Culprit; Young

Lungs Exposed to Ozone Seem More Prone to Problems with Development"—leaves no doubt that readers are supposed to conclude that ozone is causing Americans to develop asthma.

Of Mice and Men

By far the most serious health claim about air pollution is that it kills tens of thousands of Americans each year, mainly due to exposure to $PM_{2.5}$. There is no question that high levels of air pollution can kill. About 4,000 Londoners died during the infamous five-day "London Fog" of December 1952, when soot and sulfur dioxide soared to levels tens of times greater than the highest levels experienced in developed countries today, and visibility dropped to less than 20 feet.[34]

However, current fears center on whether today's comparatively low levels of air pollution are also deadly. An embarrassment for proponents of low-level air pollution as a cause of death is that the evidence is almost solely circumstantial, being based on statistical studies reporting small correlations between long- or short-term air pollution levels and risk of dying. These "observational" studies are not based on randomized trials, but on non-random data that inherently suffer from confounding by non-pollution factors with much larger effects on health than the purported effects of air pollution.

Observational studies could be taken more seriously if they were supported by evidence from randomized, controlled studies that eliminate the possibility of confounding by non-pollution factors. Such studies cannot, of course, be done with people, but they can be done with animals. However, researchers have been unable to kill animals with air pollution at levels anywhere near as low as the levels found in ambient air. As a recent review of particulate matter toxicology concluded:

> It remains the case that no form of ambient PM—other than viruses, bacteria, and biochemical antigens—has been shown, experimentally or clinically, to cause disease or death at concentrations remotely close to U.S. ambient levels.[35]

This seemingly changed in December 2005 when the *Journal of the American Medical Association* (*JAMA*) published the results of a study that claimed $PM_{2.5}$ at current ambient levels is increasing Americans' risk of developing heart disease. The study exposed mice to 85 $\mu g/m^3$ of $PM_{2.5}$ concentrated from ambient air for six hours per day for six months, or about one-fourth of a typical mouse life span.[36]

Mice fed a high-fat diet and exposed to $PM_{2.5}$ had more than a 50 percent greater rate of atherosclerosis (as measured by arterial plaque area) and other signs of heart disease, when compared with a control group that was fed a high-fat diet, but not exposed to $PM_{2.5}$. $PM_{2.5}$ was associated with greater atherosclerosis in mice on a low-fat diet as well, but the effect was not statistically significant.

NIH highlighted the study with a press release that begins: "Test results with laboratory mice show a direct cause-and-effect link between exposure to fine particle air pollution and the development of atherosclerosis . . . [The study] may explain why people who live in highly polluted areas have a higher risk of heart disease."[37] The study caused a minor media sensation, with both journalists and health experts claiming the study provides strong evidence that $PM_{2.5}$ is causing serious harm to human beings.[38]

Despite the enthusiastic reception, there is much less here than meets the eye. The mice used in the study were genetically engineered in ways that make them unrepresentative of even real-world mice, much less of humans. The mice were designed to lack the gene for apolipoprotein E (ApoE), a key substance for fat and cholesterol metabolism. As a result, these ApoE "knockout" mice have blood cholesterol levels 5 to 6 times greater than normal mice when fed regular rat chow. ApoE knockout mice have 14 times the cholesterol of normal mice when both are fed a high-fat diet.[39]

These are stupendous cholesterol levels. For comparison, medical authorities define "high cholesterol" as a serum cholesterol level greater than 240 milligrams per deciliter (mg/dl), which is about 20 percent greater than the average cholesterol level in American men.[40] Only one in 50 American men exceeds 1.5 times the U.S. average, and only one in 500 exceeds twice the average.[41]

The very reason for using such grossly unrealistic mice to study $PM_{2.5}$ is that $PM_{2.5}$ does not kill regular mice or other animals at PM concentrations relevant to real-world human exposures. For that matter, $PM_{2.5}$ did not actually kill the high-cholesterol mice in the study either.

NIH downplayed the vast gulf between the genetically engineered mice and normal mice, stating only that they were "genetically programmed to develop atherosclerosis at a higher-than-normal rate." This is a bit

like doing a study on people who weigh 500 pounds and referring to them merely as "overweight."

If you build a house out of cards, you would expect even a gentle breeze to knock it down. But this does not tell you much about the ability of a real house to withstand a gentle breeze. Likewise, if you design an artificial mouse that cannot regulate its fat or cholesterol levels, it is not surprising that even a minor environmental insult can cause it some health problems. But this does not tell you much about the effects of low-level air pollution levels on regular mice or on people.

Unfortunately, news articles on the study failed to provide the context that would show that study has little real-world relevance. A Nexis search turned up ten news reports on the study. Seven did not even mention that the mice had been genetically engineered, leaving the impression that real-world $PM_{2.5}$ levels caused heart disease in normal mice.

Three other news outlets followed NIH's lead, creating the impression that the mice in the study were merely analogous to people with a higher-than-average risk of heart disease. For example, according to the *Los Angeles Times*, the mice were "bred to be susceptible to developing heart disease."[42]

NIH and the study authors also misled reporters about the relevance of the $PM_{2.5}$ doses to real-world $PM_{2.5}$ levels. According to NIH, "The fine particle [$PM_{2.5}$] concentrations used in the study were well within the range of concentrations found in the air around major metropolitan areas." The press release also quotes one of the study's authors saying that "the average exposure over the course of the study was 15 micrograms per cubic meter, which is typical of the particle concentrations that urban area residents would be exposed to, and well below the federal air quality standard of 65 $\mu g/m^3$ over a 24-hour period."[43]

In fact, the $PM_{2.5}$ levels in the study were nothing like real-world $PM_{2.5}$ levels. The mice were exposed to $PM_{2.5}$ at 85 $\mu g/m^3$ for six hours in a row during five days of each week, and filtered air the rest of the time. Over the six-month study period, this does indeed average out to about 15 $\mu g/m^3$, the level of the federal $PM_{2.5}$ annual standard. But in the real world, areas that average 15 $\mu g/m^3$ of $PM_{2.5}$ over a year rarely approach short-term $PM_{2.5}$ levels of 85 $\mu g/m^3$.

For example, in the mouse study, the mice spent the equivalent of 1,560 hours per year breathing 85 $\mu g/m^3$ $PM_{2.5}$ (30 hours per week times 52 weeks per year). In contrast, Modesto California averaged 16 $\mu g/m^3$ of $PM_{2.5}$ over the past year, but spent only 80 hours at 85 $\mu g/m^3$ or above.[44] Furthermore, 40 percent of those high-$PM_{2.5}$ hours occurred between 11 p.m. and 6 a.m., when most people are in bed. There were only 420 hours when Modesto exceeded even 50 $\mu g/m^3$ of $PM_{2.5}$.

Even areas with the highest $PM_{2.5}$ levels in the country have far fewer hours of high $PM_{2.5}$ than were used in the mouse study. For example, Riverside California averaged 27 $\mu g/m^3$ $PM_{2.5}$ over the past year, but had only 135 hours at or above 85 $\mu g/m^3$, and 1,055 hours above 50 $\mu g/m^3$.

Health effects depend not only on the average dose, but on the acute dose. For example, you could take 2 aspirins 4 times per day, or you could take 8 all at once each day. Either way, your average dose is 8 aspirins per day. But you are more likely to suffer ill effects if you take the aspirins all at once. The mice received an analogously unrealistic daily $PM_{2.5}$ exposure. NIH and the scientists involved in the study then created the false appearance that this unrealistic exposure schedule has some relevance to the real world.

There is nothing wrong with the *JAMA* mouse study in principle. It shows that when you take a mouse specially designed to have unrealistically stupendous cholesterol levels, feed it a high-fat diet, and repeatedly expose it to unrealistically high acute levels of $PM_{2.5}$, that $PM_{2.5}$ increases the extent of heart disease. The problem arose when the study's proponents claimed that this has something to do with $PM_{2.5}$ risks faced by human beings.

You can now find a summary of the study on NIH's website. Its title? "Particulate Air Pollution and a High Fat Diet: A Potentially Deadly Combination."[45]

Sins of Omission

At the March meeting of the California Air Resources Board, staff members gave a detailed presentation on Jerrett et al. (2005)—a new epidemiological study of the Los Angeles region that reported a stronger link between $PM_{2.5}$ and mortality than suggested in previous research regulators have used to support tougher $PM_{2.5}$ standards.[46] What CARB's staff did not tell its board is that right around the same time that Jerrett et al. was published, another study of $PM_{2.5}$ risks in California by Enstrom (2005) concluded that $PM_{2.5}$ was having no effect on mortality.[47] Several California papers, including the *Los Angeles Times*, covered the alarming findings

of Jerrett et al. But none covered the benign results reported by Enstrom.

This is a typical pattern. Studies that report harm from air pollution receive a great deal of attention from regulators, environmentalists, and journalists. Studies finding no harm from air pollution are ignored. As a result, claims of harm from air pollution appear more consistent and robust than suggested by the actual weight of the evidence.

The American Lung Association's website includes an area called Medical Journal Watch, which summarizes hundreds of air pollution health studies.[48] But the site omits studies that do not report any harm from air pollution. For example, the site does not include any studies by Fred Lipfert, Suresh Moolgavkar, Richard Smith, Gary Koop, William Keatinge, or James Enstrom—all of whom have provided evidence against a connection between low-level air pollution and risk of death.[49]

The ALA also excludes specific studies and portions of studies that fail to find any harm from air pollution. For example, Medical Journal Watch does not mention Gong et al. (2003) and Holgate et al. (2003), which found little or no adverse health effects in human volunteers who breathed high levels of $PM_{2.5}$ and diesel soot, respectively.[50] The ALA does summarize the CHS findings on children's lung capacity discussed earlier, but does not mention that the study found that even the highest ozone levels in the country had no effect on lung growth.

Three studies have used CHS data to assess whether ozone is associated with increases in school absences. One study reported an increase.[51] Two reported no effect.[52] The ALA mentions only the first study on Medical Journal Watch. CARB likewise cites only the first study in its review of California's ozone standard.[53]

Coal-fired power plants have been one of environmentalists' premier targets during the last several years. In reports such as *Danger in the Air; Death, Disease and Dirty Power; Power to Kill; Children at Risk*; and many more, environmental groups claim that particulate pollution from power plants is killing thousands of Americans each year.[54] The Bush administration, a constant target of environmental groups for supposedly "gutting" power plant pollution requirements, last year adopted the Clean Air Interstate Rule (CAIR).[55] CAIR requires that power plants reduce their sulfur dioxide emissions by more than 70 percent below current levels.[56] Some sulfur dioxide is converted to ammonium sulfate in the atmosphere, and this is the main form of $PM_{2.5}$ from power plants. EPA claims these $PM_{2.5}$ reductions will prevent 17,000 premature deaths each year.[57]

Environmental groups want to increase support for ever more stringent regulations, maintain and enhance their control over other people's lives, and bring in the donations that support their activism. Regulators want to show the success of their efforts to reduce air pollution, but they also want to justify the need to preserve or expand their powers and budgets.

There is just one problem: ammonium sulfate is not toxic, even at levels many times those ever found in ambient air.[58] In fact, ammonium sulfate is used as an inert control—that is, a compound not expected to have any health effects—in studies of the health effects of acidic aerosols.[59] If ammonium sulfate is not toxic, then the campaign against $PM_{2.5}$ from power plants is based on a false premise.

Last year CARB adopted a tougher ozone standard for California.[60] To justify the tougher standard, CARB prepared a detailed report summarizing ozone health effects research. The report analyzes hundreds of health studies in nearly 1,000 pages, but fails to mention a study reporting that *higher* ozone was associated with a *lower* rate of hospital visits in California's Central Valley.[61] CARB was certainly aware of the existence of this study, because CARB funded and published it. EPA also failed to mention the study in its latest review of the federal ozone standard.[62]

EPA based its annual $PM_{2.5}$ standard mainly on the American Cancer Society (ACS) study, which followed more than 500,000 Americans in fifty cities from 1982 to 1989 and looked for correlations between $PM_{2.5}$ levels and risk of death.[63] The most recent ACS report covered the period from 1982 to 1998 and reported that each 10 $\mu g/m^3$ increase in long-term $PM_{2.5}$ levels is associated with a 4 percent increase in risk of death.[64]

The validity of epidemiological studies, such as the ACS study, depends on the assumption that correlations between air pollution and health outcomes represent genuine causal relationships. The implicit assumption is that after researchers have controlled for non-pollution

health factors like income or smoking, any residual correlation between air pollution and health represents a genuine causal linkage. Experience has shown that this assumption is false.

For example, a reanalysis of the ACS data showed that the apparent $PM_{2.5}$-mortality link was spurious. According to sensitivity analyses of the ACS data, $PM_{2.5}$ apparently kills men, but not women; those with no more than a high school degree, but not those with at least some college; and those who said they were moderately active, but not the very active or the sedentary.[65] Results like these are biologically implausible and suggest a failure to adequately control for confounding by non-pollution factors.

When migration rates into and out of various cities over time were added to the statistical model relating $PM_{2.5}$ and risk of death, the apparent effect of $PM_{2.5}$ disappeared.[66] Cities that lost population during the 1980s—Midwest "rust belt" cities—also had higher $PM_{2.5}$ levels. People left these cities, which were in economic decline, in search of work in more economically dynamic parts of the country. But people who work and have the wherewithal to migrate also tend to be healthier than the average person. Hence, what appeared to be an effect of $PM_{2.5}$ was actually the result of differential migration. Migration was just one of several confounding factors that diminished or erased the apparent harm from $PM_{2.5}$, but that were not accounted for by the ACS researchers.

This problem of spurious air pollution risk estimates is not limited to the ACS study, but is endemic to air pollution epidemiology and to epidemiology in general.[67] Nevertheless, scientists, regulators, and environmentalists have ignored these weaknesses and continue to make believe these spurious statistical correlations are telling us something real about the effects of low-level air pollution.

The Politics of Air Pollution Health Science

Most public information on air pollution and health comes from environmental activists, regulators, and health researchers. As these case studies show, their claims of harm from current, historically low air pollution levels are at best exaggerations and at worst fabrications. The result is unwarranted public fear, and continued support for ever more costly regulatory requirements that deliver little or no benefit in exchange for their high costs.

Regulators, environmentalists, and scientists enjoy substantial credibility with the public and the press. But like other interest groups, their goals often do not coincide with the interests of the vast majority of Americans. Environmental groups want to increase support for ever more stringent regulations, maintain and enhance their control over other people's lives, and bring in the donations that support their activism. Regulators want to show the success of their efforts to reduce air pollution, but they also want to justify the need to preserve or expand their powers and budgets. Maintaining a climate of crisis and pessimism meets these institutional goals, but at the expense of encouraging people to exaggerate the risks they face.

While it is not surprising that activists and regulators exaggerate air pollution risks, they would not be taken as seriously without scientific authority to back them up. The credibility of science and scientists flows from the power of scientific methods to uncover truths about the world, and from the perceived objectivity of scientists themselves. As the case studies above show, trust in scientific authority is often misplaced.

Scientific and medical research does have checks and balances that are absent from more explicitly political endeavors. Environmental health research nevertheless suffers from its own set of pressures that militate against evenhanded inquiry and dispassionate analysis and presentation of evidence. Studies that report harm from air pollution are more likely to be published than studies that do not. Regulatory agencies, whose power and budgets depend on the perception that air pollution is a serious health problem, are also major funders of the research intended to demonstrate the severity of the problem. Scientists who believe air pollution is a serious health threat and who report larger health effects are more likely to attract research funding. It is not a big leap to conclude that there is a great deal of selection bias in who does environmental health research, what questions they ask, and how they report their results.

Journalists should be acting as a check on air pollution misinformation, but they are not. Media outlets face their own pressures to sensationalize stories. Good news does not sell newspapers or attract viewers. As a result, journalists and editors are more likely to cover studies claiming harm from air pollution, and to pass along these claims with little or no critical review.

True, few journalists have the expertise to evaluate the technical merits of specific studies. But continuing

to rely on scientific authority will only perpetuate the problem of risk exaggeration. Among the major providers of public information on environmental risks, investigative reporters are in the best position to assess how the political economy of environmental health research affects the production and portrayal of scientific evidence. It would be a breath of fresh air if journalists and editors took up this challenge.

AEI editor Scott R. Palmer worked with Mr. Schwartz to edit and produce this Environmental Policy Outlook.

Notes

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7. The risk of developing asthma was 30 percent lower based on one-hour ozone levels and was statistically significant. Asthma risk was 20 percent lower based on eight-hour ozone levels and was just a hair short of statistical significance. (The top of the 95 percent confidence interval for relative risk was 1.0. Anything less than that would have been statistically significant.)

8. The journal article is R. McConnell, K. T. Berhane, F. Gilliland et al., "Asthma in Exercising Children Exposed to Ozone: A Cohort Study," *Lancet* 359 (2002): 386–91.

9. Once again the risk was 20 percent lower and was just barely short of statistical significance.

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11. California Air Resources Board, "Study Links Air Pollution and Asthma," news release, January 31, 2002, available at www.arb.ca.gov/newsrel/nr013102.htm.

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14. In fact, even the worst areas of Sacramento never average more than a few days per year exceeding the one-hour ozone standard and 20 or so days per year exceeding the eight-hour standard—ozone levels typical of the "medium-ozone" CHS communities, in which there was no relationship between air pollution and asthma risk. Dr. Jesse Joad, quoted in C. Bowman, "Asthma's Toll: A New Study Links Children's Sports Activities in Smoggy Areas to the Illness," *Sacramento Bee*, February 1, 2002.

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18. The CHS study set up special-purpose monitors to measure pollution levels in the communities where the study was performed. CARB staff provided data from these monitors.

19. *Impacts of Ozone on Our Health* (Charlotte, NC: Carolinas Clean Air Coalition, undated), available at http://003af56.netsolhost.com/air_basics_ozone_impact.htm.

20. Based on research by CARB staff, these values have been adjusted upward by 13.6 percent to make them comparable with $PM_{2.5}$ levels determined by the Federal Reference Method, which has been used nationwide since 1999 for determining compliance with federal $PM_{2.5}$ standards. See N. Motallebi, J. Taylor, A. Clinton, B. E. Croes et al., "Particulate Matter in California: Part 1—Intercomparison of Several $PM_{2.5}$, $PM_{10\text{-}2.5}$, and PM_{10} Monitoring Networks," *Journal of the Air & Waste Management Association* 53 (2003): 1509–16.

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22. Di Rado, "Smog May Cause Lifelong Lung Deficits."

23. Dr. Kenneth Olden, quoted in NIH, "New Research Shows Air Pollution Can Reduce Children's Lung Function," news release, September 9, 2004, www.nih.gov/news/pr/sep2004/niehs-08a.htm.

24. Here's how: First, note from table 3 of the *NEJM* article that $PM_{2.5}$ was associated with a 79.7 milliliter (ml) reduction in FEV_1 between the least and most polluted community. Then from table 2, note that at eighteen years of age average FEV_1 was 3,332 ml for girls and 4,464 ml for boys. Given that there were 876 girls and 883 boys in the study (p. 1,059, column 1), the weighted average FEV_1 for the study population was 3,900 ml. The percentage decline is then 79.7/3,900 = 0.02 or 2 percent. A similar calculation can be done to show that the average decline in FVC was 1.3 percent. Gauderman, Avol, Gilliland et al., "The Effect of Air Pollution on Lung Development from 10 to 18 Years of Age."

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Attachment 4: Resume for Lisa JN Bradley, Ph.D., DABT

Lisa J. N. Bradley, Ph.D., DABT
Vice President and Senior Toxicologist

Professional History

AECOM (formerly ENSR)
Massachusetts Institute of Technology
University of Idaho

Education

PhD (Toxicology) Massachusetts Institute of Technology, 1991
BS (Zoology) University of Idaho, 1983
BS (Chemistry) University of Idaho, 1983

Years of Experience 25

Technical Specialties

Toxicology
Risk Assessment
Environmental Communication
Regulatory Negotiation
Site Strategy Development

Professional Affiliations

Diplomate, American Board of Toxicology, 1994
Society of Toxicology
Phi Beta Kappa

Dr. Lisa Bradley is a Senior Toxicologist/Risk Assessor and Vice President with AECOM. She has a Ph.D. in toxicology from the Massachusetts Institute of Technology. She has 25 years of experience in risk assessment and toxicology, and is certified by the American Board of Toxicology. She has managed risk assessments for hazardous waste sites in many EPA Regions, and under many state programs. Dr. Bradley has also served as an advisor on strategic risk assessment issues for clients in the natural gas, utility, and railroad industries. She has developed the risk assessment approach for a large multi-site program for a railroad client, for a national steel client, and developed and managed the risk evaluation component of a large multi-site, multi-state federal program for a natural gas client. Dr. Bradley is experienced in public speaking and environmental communications, and she has published articles in peer reviewed scientific journals based on both her laboratory and risk assessment work. Dr. Bradley is the global risk practice technical lead for AECOM. She is the manager and technical lead for AECOM's coal combustion product (CCP) initiative and was recently elected to the Executive Committee of the American Coal Ash Association.

Experience

A. Representative Superfund Experience

Pines Area of Investigation, Indiana, USEPA Region 5. Serving as project manager for a multi-disciplinary team conducting the Remedial Investigation/Feasibility Study for the Respondents of an Administrative Order on Consent (AOC) being administered under the Superfund Alternative program in USEPA Region 5. The AOC addresses the placement of coal combustion by-products (CCBs) within a local permitted landfill and allegedly used as fill in other locations within the Area of investigation. Activities to date include agency negotiations on the AOC and scope of work; submission of a Site Management Strategy document, and subsequent approval by the

Agency; submittal of the RI/FS Work Plan (including a Field Sampling Plan, Human Health and Ecological Risk Assessment Work Plans, HASP, QAPP, and a Quality Management Plan), and subsequent approval by the agency; submission of additional Sampling and Analysis Plans; and communications activities (including a website – www.pinesupdate.com - and regular mailings of information updates to the community). Regular communications with the agency is also a cornerstone of the project. As the site covers not a facility, but a town and surrounding area, executing access agreements with the land owners for sampling and well installation was a critical task. Four rounds of sampling and analysis have been successfully completed. The Final RI Report has been approved, and the Human Health Risk Assessment Report and the Ecological Risk Assessment Report have been approved and the Draft Feasibility Study has been submitted to the agency. Approved project documents to date are available on USEPA's website: http://www.epa.gov/region5/sites/pines/index.htm.

Aurora Energy, Fairbanks, AK. Providing consulting services for an EPA HRS scoring investigation of the coal-fired power plant. Activities have included fact sheet preparation, frequently asked questions and answers, document review, strategy development, and risk-based evaluation of detailed coal and coal ash data sets for the facility.

Delaware Sand & Gravel Remedial Trust, Delaware, USEPA Region 3. A human health risk assessment (HHRA) focusing on evaluation of the vapor intrusion exposure pathway was performed for the PRPs at a former drum disposal area to evaluate the effectiveness of a Bioremediation System installed as a result of an EPA Superfund Record of Decision Amendment. A tiered vapor intrusion assessment was performed consistent with USEPA guidance using groundwater and then soil gas data. It was successfully concluded, with acceptance from EPA Region 3, that no unacceptable risk to human health was posed to occupants of on-site buildings via the vapor intrusion inhalation pathway.

Solutia, Inc., Human Health Risk Assessment, Sauget Area 1, Illinois, USEPA Region 5. Prepared a human health risk assessment work plan to follow Superfund guidelines for several abandoned landfill areas and areas downgradient of the landfills. The work plan was accepted by U.S. EPA Region V. A comprehensive human health risk assessment was prepared that evaluated the former land fill areas as well as local residential areas, a creek, and a borrow pit lake. A total of 64 receptor and area scenarios were quantitatively evaluated. Supporting risk modeling included indoor and outdoor air from subsurface soil and groundwater. Activities included site visits, meetings with personnel from USEPA Region 5 and their contractors, and preparations of responses to comments and document revisions. The human health risk assessment has been accepted by the agency, and the results have been used to guide the feasibility study and remedy selection. Constituents of interest included PCBs in ditch sediments. The final report is available on EPA's website:
http://www.epa.gov/region5/cleanup/saugetarea1/pdfs/sauget1_deadcreek_final_remedy_200604.pdf

Sauget Area 2 Sites Group, Human Health Risk Assessment, Illinois, USEPA Region 5. Serving as the senior human health risk assessment manager for a multi-party PRP group. Prepared a human health risk assessment work plan to follow Superfund guidelines for a set of sites that include abandoned landfill areas. Conducted the multi-receptor, multi-pathway human health risk assessment, including vapor intrusion modeling for both indoor and outdoor air for the multiple multi-acre sites within the project area. Activities included a site visit, meetings and negotiations with USEPA Region 5 and their contractors, and preparation of responses to comments.

Columbia Gas Transmission, Strategic Risk Assessment Advisor, West Virginia, USEPA Region 3. Served as strategic risk assessment advisor to a multi-site, ten-state AOC with U.S. EPA Region III to assess environmental conditions along their pipeline system in the Mid-Atlantic States. Provided strategic risk assessment advice and technical support on the design and implementation of the program, and developed a programmatic approach to the evaluation of risk across the program. Was responsible for: review of other contractor reports, development of a common strategy for TPH and mercury to be used across the program, review and summary of risk assessment regulations and guidance for each of the states (Ohio, Pennsylvania, West Virginia, Virginia, Kentucky, North Carolina, Delaware, New Jersey, Maryland, New York, and Louisiana), conducted risk assessments, provided critical review of individual site characterization reports prepared by other contractors, and provided support in negotiations and meetings with regulators. Additional constituents of interest include PCBs, arsenic, and PAHs.

Tippecanoe Landfill, Human Health Risk Assessment, Indiana, USEPA Region 5. Conducted agency negotiations (U.S. EPA Region V) concerning the human health risk assessment for a Superfund site. Because arsenic concentrations in groundwater were of concern to the agency, researched and reviewed the toxicological information available for arsenic, and prepared a literature review and evaluation of the dose-response values developed by the U.S. EPA for arsenic.

Industri-Plex CERCLA Site, Risk Assessment Review and Strategy for PRP Group, Massachusetts, USEPA Region 1. Provided risk assessment review and strategy for PRP group, and developed risk assessment work plan to address surface water and groundwater exposure pathways.

Tennessee Valley Authority, Human Health Risk Assessment, Tennessee, USEPA Region 4. Prepared human health risk assessment and developed target cleanup levels for an abandoned battery manufacturing site. Primary constituent was lead and both child and adult lead models were used in the evaluation.

Confidential Client, Human Health Risk Assessment, New Jersey, USEPA Region 5. Conducted a human health risk assessment for a school district's baseball fields located adjacent to a potential Superfund site. Report

was prepared for community distribution, and results presented at a public meeting.

Motco Superfund Site, Review of AIC for Volatile Organics, Texas, USEPA Region 6. Reviewed U.S. EPA-developed acute inhalation criteria (AIC) for volatile organics. Developed a consistent and scientifically-defensible methodology for AIC development, and applied this methodology to provide alternative AICs for use at the site.

Brio Site Task Force, Texas, USEPA Region 6. Developed acute inhalation criteria for use in a remedial program for benzene, 1,1-dichloroethane, 1,2-dichloroethane, ethyl benzene, methylene chloride, styrene, toluene, 1,1,1-trichloroethane, 1,1,2-trichloroethane, and vinyl chloride.

B. Representative RCRA Experience

Solutia, Inc., Human Health Risk Assessment Oversight for the J.F. Queeny Facility, St. Louis, Missouri. Provided oversight for the human health risk assessment prepared for the facility under an order with USEPA Region 6. The risk assessment is designed to meet the requirements of both USEPA and the State of Missouri Risk-Based Corrective Action Program.

Solutia, Inc., Human Health Risk Assessment for the W.G. Krummrich Facility, Sauget, Illinois, USEPA Region 5. Developed the human health risk assessment workplan and report for the RCRA Sampling Plan for Solutia's W.G. Krummrich Facility. The workplan was designed to permit evaluation of the "Human Exposures Environmental Indicator" as well as human health risk. Used risk assessment and data visualization to identify extent of areas for remediation such that total site risk would not exceed target risk levels once remediation is complete. Also used the risk assessment to identify remedial treatment objectives for soils and groundwater. Target chemicals included PCBs and chlorinated compounds.

U.S. Steel, Human Health Risk Assessment, Gary, Indiana, USEPA Region 5. Developed the RCRA RFI Human Health Risk Assessment Workplan for the U.S. Steel Gary Works. Activities included response to regulatory comments on previous reports, site visits, review of reports generated both by USS and by local groups about the facility and its environs, development of the risk-related portions of the facility-wide RCRA RFI workplan, in addition to the HHRA workplan, and agency negotiation. Participated in strategy development for and preparation of the human health sections of the Sampling and Analysis Plans for each of the Solid Waste Management Areas being addressed at Gary Works under RCRA (13 in total). Managed and prepared the human health risk evaluation of perimeter groundwater data. Work included conducting a two tiered well-by-well screening (55 wells total). The first tier comparison was to generic and readily available standards, and the second tier took into account background and dilution into receiving water bodies, and evaluated construction worker and indoor air scenarios.

U.S. Steel, Human Health Risk Assessment, Fairless Hills, Pennsylvania, USEPA Region 3. Prepared the human health risk evaluation under RCRA Corrective Action for a parcel of property to be leased by U.S. Steel at Fairless Works. The work was conducted to satisfy Pennsylvania Department of Environmental Protection (PADEP) requirements under the Pennsylvania Act 2 program, as well as USEPA Region 3 requirements. Activities included site visit, meetings and presentations to both agencies, as well as preparation of memoranda and reports. Included in the evaluation was a sensitivity analysis of the parameters used to evaluate a construction worker scenario; site-specific parameters, parameters from the scientific literature, and parameters provided by the agency were evaluated.

U.S. Steel, Human Health Risk Assessment, Fairfield, Alabama, USEPA Region 4. Developed the RCRA RFI Human Health Risk Assessment Workplan for the U.S. Steel Fairfield Works under USEPA Region 4 and Alabama Department of Environmental Management (ADEM) requirements. Activities included site visits, preparation of strategy, review of the full RFI workplan to ensure consistency with risk objectives, and preparation of responses to agency comments. Work included a detailed evaluation of USEPA's current and proposed adult soil ingestion rates.

Hartford Working Group, Hartford Hydrocarbon Plume Site, Hartford, Illinois, USEPA Region 5. Provided toxicology and risk assessment services to the PRP group for the Hartford Hydrocarbon Plume site in Hartford, IL. Provided review of indoor air screening levels developed by the Agencies for benzene, butane, isopentane, trimethylbenzene and other petroleum-related constituents used in vapor intrusion evaluations.

C. Representative Risk Assessment Experience Under Other Programs

NiSource, Risk Assessment Issues, Columbus, Ohio. Serving as the human health risk assessment expert for NiSource's environmental programs. Have addressed issues related to PCBs (including conducting employee informational meetings), MGP-related constituents (benzene, PAHs), radon, and mercury.

Confidential Utility. Have provided PCB expert support for issues related to PCBs in natural gas pipeline systems and potential residential and commercial exposures.

Bureau of Land Management, Environmental Impact Statement, Western States. Developed human health risk assessment to evaluate five pesticides proposed for use in BLM vegetation treatment programs. Risk assessment uses standard USEPA Office of Pesticide Policy risk assessment methods and includes use of the AgDRIFT model to evaluate off-site spray drift and deposition, and transport models to evaluate surface water impacts. Worker, public and Native American subsistence receptors were evaluated. Work has included interagency scoping meetings. Report

available at: http://www.blm.gov/wo/st/en/prog/more/veg_eis.html. 2007.

Bureau of Land Management, Environmental Impact Statement, Western States. Conducting human health risk assessment for additional pesticides for the BLM vegetation treatment programs following the protocol developed for the 2007 BLM Vegetation EIS.

Confidential Client, Indiana. Evaluated groundwater and soil gas data for vapor intrusive to indoor air using the USEPA version of the Johnson and Ettinger model. Used the Johnson (2002) sensitivity analysis method to ensure that critical model parameters were within acceptable/realistic ranges. Provided deposition testimony and testimony in a court hearing on both the vapor intrusion pathway risk assessment and the toxicology of benzene.

U.S. Steel, Development of a Standardized Risk Evaluation Guidance Manual, Pennsylvania. Worked in conjunction with another firm and USS personnel to develop a standardized Risk Evaluation Guidance Manual for USS. The manual addresses important issues in human health and ecological risk assessment, provides background for the issues, USS strategy to address the issues, and examples of standard language and references to be used in future USS reports. The manual will allow for more cost-effective and consistent risk evaluations to be conducted for USS facilities and sites.

U.S. Steel, Review and Comment on Indiana's RISC Program, Indiana. Reviewed several draft versions of Indiana's "Risk Integrated System for Closure" guidance, and submitted comments to the agency. Detailed comments were provided on the following topics: construction worker soil ingestion rate, soil saturation limit, arbitrary caps for metals concentrations in soil. Have also prepared comments on Indiana's draft groundwater policy and The User's Guide that details how the RISC program will be applied to RCRA sites under state authority.

U.S. Steel, Human Health Risk Assessment, Fairfield, Alabama. Conducted a human health risk evaluation for a parcel of property to be leased by U.S. Steel at Fairfield Works. Activities included evaluation of a construction worker scenario, and use of the Johnson & Ettinger and ASTM models to evaluate indoor and outdoor air.

West Virginia Manufacturer's Association, West Virginia. Worked with the WVMA on a committee to review and provide language to the West Virginia Department of Environmental Protection in development of their tiered site closure guidance.

Indiana Department of Environmental Management, Indiana. Served on an IDEM committee to review and provide language in the development of revisions to the "Risk Integrated System for Closure" guidance.

D. Representative Toxicology Experience

Utility Solid Waste Activities Group (USWAG), Washington, DC. Reviewed and developed comments on the risk assessment aspects of

USEPA's June 2010 proposed rulemaking for the disposal of coal combustion residuals (CCRs). Comments focused on a critique of the USEPA's updated human health and ecological risk assessment, a critique of the USEPA's fugitive dust model report, and a critique of USEPA's proposed listing of CCRs as a hazardous waste under RCRA Subtitle C.

Utility Solid Waste Activities Group (USWAG), Washington, DC. Reviewed and developed comments on the USEPA's risk assessment for coal combustion wastes. The risk assessment was released in 2007, and comments were submitted under USWAG cover in January 2008. AECOM addressed all aspects of the risk assessment including human health, ecological risk and fate and transport. Provided oral comments during a national teleconference.

Utility Solid Waste Activities Group (USWAG), Washington, DC. Developed information sheet on "What is Coal Ash" for use by the USWAG membership for community relations.

Electric Power Research Institute, Palo Alto, CA. Developed the report "Comparison of Risks for Leachate from Coal Combustion Product Landfills and Impoundments with Risks for Leachate from Municipal Solid Waste Landfill Facilities," EPRI Report Number 1020555, available at www.epri.com.

Prairie State Energy Campus, Washington County, IL. Provided presentation to county board on coal ash composition and health risk issues.

We Energies, Milwaukee, WI. Reviewed the basis of the state and USEPA screening levels and toxicity values for molybdenum, and demonstrated the over-conservatism used in their derivation. Provided the review to the state agency, and developed a fact sheet on molybdenum in groundwater for communications with a local community.

We Energies, Milwaukee, WI. Reviewed the basis of the state screening levels and toxicity values for aluminum as part of review of the Wisconsin Department of Natural Resources proposed groundwater standards under NR 140. Provided testimony for a board hearing, and met with the state regulators, and demonstrated the over-conservatism used in their derivation.

Ameren UE, St. Louis, MO. Developed a human health and ecological risk assessment to support the regulatory closure under the state agency of a former ash impoundment located along a major river at the Hutsonville, IL Power Station. Boron and molybdenum were constituents of interest. Pathways evaluated in the risk assessment included use of groundwater for irrigation purposes and the migration of groundwater to the river and potential impact on the benthic community. Work included negotiation meeting with the local agency.

Ameren UE, St. Louis, MO. Serving as an expert for a landfill siting project in Missouri, for issues related to exposure, toxicity and risk assessment. Provided public testimony at a county board meeting as well as written comments that have been submitted into the record.

Ameren UE, St. Louis, MO. Providing toxicology and risk assessment support for various coal ash related projects in Illinois and Missouri.

AES, New York. Provided expert testimony on the lack of human health effects of ammonia in groundwater associated with coal ash landfills. Developed expert opinion, reviewed and critiqued opposing opinions, and testified at hearing.

AES, Puerto Rico. Provided review and synthesis of data associated with a beneficial use product, AGREMAX™ manufactured by AES Puerto Rico using bottom ash and fly ash from the coal-fired power plant. Specifically, evaluation of data on metals content, leaching of metals, and radionuclides were shown not to pose a human health or environmental risk based on the beneficial uses of AGREMAX™. Testified on AES behalf at a Puerto Rican Senate subcommittee hearing on coal ash issues.

South Carolina Electric & Gas, Columbia, SC. Provided presentation materials for use in a landfill siting and zoning process. Materials addressed the comparison of arsenic and other metals and radionuclides in coal ash and in our natural environment, and background levels of arsenic in foods and background levels of exposure to radioactivity in our natural environment.

Utility Solid Waste Activities Group (USWAG), Washington, DC. Provided oversight of comments developed on the proposed listing of naphthalene as a carcinogen by the National Toxicology Program, and on the USEPA's childhood cancer document.

Electric Power Research Institute, California. Worked with another ENSR toxicologist to develop a critique of the benzo(a)pyrene toxicity value developed by the United Kingdom for their Contaminated Lands program.

Confidential Natural Gas Client, Toxicity Assessment, Ohio. Provided toxicity assessment of cleaning compounds proposed for use in the decommissioning of a natural gas pipeline laid on the bed of a reservoir that serves as the primary drinking water source for a community. Demonstrated that even should a catastrophic release of cleaning fluid and/or PCBs occur, human and ecological health would not be adversely affected and that concentrations at the drinking water intake would be much lower than health-based values or detection limits.

Confidential Client, Toxicology Review, Indiana. Provided a review of the toxicology and potential carcinogenicity of two structurally similar proprietary industrial chemicals. Used recent data on the nongenotoxic/cytotoxic mechanism of action of a class of potential carcinogens to demonstrate that a safe level for worker exposure exists.

U.S. Environmental Protection Agency, Literature Review. Developed a strategy for evaluating absorption data in the literature and applied it to the development of absorption adjustment factors for oral and dermal exposures to soil and water for 5 metals of concern at hazardous waste sites (arsenic, cadmium, chromium III, chromium VI, inorganic mercury, organic mercury,

and nickel) based on a thorough review of the literature.

Georgia Pacific, Literature Review, Georgia. Reviewed literature and summarized the current scientific knowledge of the endogenous synthesis of halogenated compounds in humans.

E. Representative MGP Experience

Natural Gas Company, Risk Assessment Advisor, Ohio. Serving as strategic risk assessment advisor to the manager of MGP sites. Work includes conducting risk assessments for MGP sites under various state programs, evaluation of program-wide vapor intrusion data, regulatory negotiations, environmental communications, and employee meetings.

Natural Gas Company, Former MGP Site Advisor, Wisconsin. Have reviewed remediation plans and fenceline monitoring plans, gave presentation at public meetings discussing the air monitoring plan, and have reviewed fenceline monitoring data for a remediation project.

Energy Company, Former MGP Site Review, Rhode Island. Provided senior review of an air monitoring program and identified where flexibility can be used in the development of fenceline air monitoring standards.

Village of Oak Park, Former MGP Site Advisor, Illinois. Provided senior review of remediation plans, and fenceline monitoring plans, and provided air monitoring data evaluation. Was involved in regulatory meetings, negotiations, and presentations to the Village council, including public meetings concerning air monitoring aspects of the project.

Committees

Leader of AECOM's Risk Assessment Technical Practice Group including practitioners internationally within AECOM with specialties in human health and ecological risk assessment and other supporting disciplines.

Leader of AECOM's Coal Combustion Product (CCP) Initiative; responsible for following regulatory developments, and keeping AECOM staff and clients updated on the issues.

Elected member of the American Coal Ash Association (ACAA) Executive Committee, and member of the Government Relations Committee, and the Women's Leadership Forum.

Publications and Presentations

"Coal Ash Material Safety: A Health Risk-Based Evaluation of USGS Coal Ash Data from Five US Power Plants." LJN Bradley. Poster presented at the Society of Toxicology Annual meeting, March 2013, San Antonio, TX. Abstract 2211, The Toxicologist, Volume 132, Issue 1. Available at: www.toxci.osfordjournals.org.

"Key Decisions in Establishing National Ambient Air Quality Standards." L Fraiser and LJN Bradley. Poster presented at the Society of Toxicology Annual meeting, March 2013, San Antonio, TX. Abstract 1567, The Toxicologist, Volume 132, Issue 1. Available at: www.toxci.osfordjournals.org.

"Coal Ash Material Safety: A Health Risk-Based Evaluation." LJN Bradley. American Coal, Issue 2, 2012. Available at: www.americancoalonlime.com.

"Coal Ash Material Safety: A Health Risk-Based Evaluation of USGS Coal Ash Data from Five US Power Plants." LJN Bradley. Ash at Work, Issue 1, 2012. Available at: www.acaa-usa.org.

"Health Hazards and Risk Issues: Sorting Fact from Fear." Invited presentation at the Coal Combustion Products Utilization & Management: A Practical Workshop. Lexington, KY. October 9-10, 2012.

"Is this Risk for Real? Putting Risk Results into Context." Invited presentation at the Midwest Energy Association meeting, Minneapolis, MN. September 2012.

"Coal Ash Material Safety: A Health Risk-Based Evaluation of USGS Coal Ash Data from Five US Power Plants." American Coal Ash Association Summer Meeting, Portsmouth, VA. June 2012.

"Coal Ash Material Safety: A Health Risk-Based Evaluation of USGS Coal Ash Data from Five US Power Plants." June 2012. Report prepared for the American Coal Ash Association. Available at: www.acaa-usa.org.

"Coal Ash Material Safety: A Health Risk-Based Evaluation of USGS Coal Ash Data from Five US Power Plants." Press Conference, National Press Club, Washington, DC. June 6, 2012.

"Health Risk of CCPs: Is Coal Ash Toxic?" Presentation at the South Carolina SWANA Meeting. Myrtle Beach, SC, May 2012.

"Health Risk of CCPs: Is Coal Ash Toxic?" Presentation at Electric Power 2012. Baltimore, MD, May 2012.

"Hexavalent Chromium in Perspective" Presentation and invited Chair – Human Health Risk Panel, MGP 2012, Chicago, IL, March 29, 2012.

"Health Risk of CCPs." Invited presentation at the Coal Ash Consortium, Scottsdale, AZ, March 28, 2012.

"Health Risk of CCPs." Presented at the EUCI conference on CCR Management: Impacts of Regulations and Technological Advances. , Nashville, TN, February 28-29, 2012.

"Coal Ash in Context: Separating Science from Sound Bites As Regulatory

and News Media Debates Continue." LJN Bradley and J Ward. Ash at Work, Issue 1, 2011. Available at www.acaa-usa.org.

"Management of Coal Ash Disposal and Household Trash – Do They Need to be Different?" LJN Bradley. Energeia, Volume 22, No. 4, 2011. Available at: http://www.caer.uky.edu/energeia/enerhome.shtml.

Bradley, L.J.N., "Comparison of Risks for Leachate from Coal Combustion Product Landfills and Impoundments with Risks for Leachate from Municipal Solid Waste Landfill Facilities." EPRI Report Number 1020555, available at www.epri.com.

"Risk Assessment: How the EPA Looks at Coal Combustion Products." Presented at the ACAA Fall meeting, Indianapolis, IN, September 27, 2011.

"Risk assessment: An overview of how the U.S. Environmental Protection Agency looks at coal combustion residuals." Presented at the American Chemical Society meeting in Denver, CO, August 28, 2011.

"Is Coal Ash Toxic?" Keynote Presentation at the World of Coal Ash May 10-12, 2011, and invited presentation at The Coal Institute/NCCI meeting July 11, 2011.

"Potential Effect of Proposed Coal Combustion Residuals Regulation and Alternative Leach Testing on Beneficial Reuse." World of Coal Ash May 10-12, 2011.

"Comparison of Risks for Leachate from Coal Combustion Product Landfills and Impoundments with Risks for Leachate from Municipal Solid Waste Landfill Facilities." World of Coal Ash May 10-12, 2011, and poster at Society of Toxicology March 6-10, 2011.

"Overview of Coal Ash Regulatory Issues." NCASI Northern Regional Meeting May 18-19, 2011.

"Perspectives on Health Risks Associated with Beneficial Re-Use of Byproducts of Coal Combustion." McIlvaine Hot Topic Hour. April 28, 2011.

"Risk Assessment: How the EPA Looks at Coal Combustion Products." EUCI March 13-14, 2011.

"Risk Assessment: How the EPA Looks at Coal Combustion Products." Presented at the EUCI conference on Future of Coal Combustion Products (CCPs): Regulatory, Legal, Technical, and New Markets, March 2011, Denver, CO.

"Development of a Realistic Risk Assessment Conceptual Site Model for an Urban River Sediment Site." B. Ruffle, L. Bradley, K. Durocher, and L. Fraiser. Battelle Sediment Conference February 7-10, 2011.

Press Conference with ACAA (American Coal Ash Association) , October 27,

2010, Knoxville, TN.

“USEPA’s Proposed rule for Coal Combustion Residual (CCRs): Beneficial Use Aspects.” Keynote address given at the June 2010 meeting of the American Coal Ash Association, Baltimore, MD. Bradley, L.J.N, and A. Ellis.

“Overview of a CCP Site Investigation Conducted Under the Superfund Alternative Program.” Presented at the ACAA spring meeting, March 2010, Nashville, TN.

“Coal Ash Business Planning and Management: Addressing Risks and Liabilities in a Changing Regulatory Environment.” Workshop presented at the EUCI Conference on the Future of Coal Combustion Products, March 2010, Houston, TX. L.J.N. Bradley, J. Trast, J. Matus,, and A. Kier.

“PAHs and Dioxins Not Present in Fly Ash at Levels of Concern.” World of Coal Ash, May 2009 and Society of Toxicology, March 2009.

Bradley, L.J.N., G.M. Fent, and S.W. Casteel. “In Vivo Bioavailability of Arsenic in Coal Combustion By-Products.” Poster presented at the Society of Toxicology 2008 annual meeting in Seattle, WA.

Bradley, L.J.N., K. Sullivan, and M. Garcia. “Background Levels of Benzene in Indoor and Outdoor Air.” Paper presented at the Gas Technology Institute’s Natural Gas Technologies II Conference, Phoenix, Arizona. February, 2004

Bradley, L.J.N., and K.A. Sullivan. "Risk-Based Action Levels for Remediation Project Fence-Line Air Monitoring Programs." The Toxicologist. 72(S-1): 395. March, 2003

Bradley, L.J.N., and M. Gerath. "Generic Risk and Fate Analysis for Mercury at Natural Gas Meters." Paper presented at the December 1998 Society for Risk Analysis Annual Meeting, Phoenix, AZ.

Bradley, L.J.N., K.B. Lemieux, M.C. Garcia, A.H. Parsons, and D.E. Rabbe. "Comparison of Concentrations of Selected Metals and Organics in Fish Tissue and Sediment in the Grand River, Ohio, and the Southern Lake Erie Drainage Basin." Human and Ecological Risk Assessment 4(1):57-74 (1998).

Bradley, L.J.N. "TPH Analyses Provide Means of Direct Assessment of Diesel Releases." Paper presented at the October, 1997, Contaminated Soils Conference, Amherst, MA.

Bradley, L.J.N. "Risk Assessment of Hazardous Air Pollutants in Arizona." Paper presented at the December, 1996 Society for Risk Analysis Annual Meeting, New Orleans, LA.

Bradley, L.J.N. "Cost-Effective Use of Tiered Approaches in Risk Assessment." Paper presented at the October, 1996 Annual Conference on

Contaminated Soils, Amherst, MA.

Bradley, L.J.N. "Role of Risk Assessment in Environmental Management." Invited paper presented at the West Virginia Manufacturers Association Environmental Compliance Conference, May, 1996, Charleston, WV.

Bradley, L.J.N. "New Toxicology Data for Chloroform: Implications for the Pulp and Paper Industry." Proceedings of the 1996 Environmental Conference of the Technical Association of the Pulp and Paper Industry. Vol 1, pp. 13-16 (1996).

Bradley, L.J.N. "Ingested Arsenic - Are the Taiwanese Data Appropriate for Risk Assessment in the U.S." Paper presented at the December, 1994, Society of Risk Analysis Conference, Baltimore, MD.

Magee, B.H., and L.J.N. Bradley. "Absorption Adjustment Factors for Use in Risk Assessment." Proceedings of the International Congress on the Health Effects of Hazardous Waste. (1994).

Bradley, L.J.N., B.H. Magee, and S.L. Allen. "Background Levels of Polycyclic Aromatic Hydrocarbons and Selected Metals in New England Urban Soils." J. Soil Contam. 3(4):349-361. (1994).

Magee, B.H., L.J.N. Bradley, E.L. Butler, A. Dasinger, J. Grabowski. "Risk-Based Target Clean-Up Levels for TPH in Soils." In: Hydrocarbon Contaminated Soils. Vol. 3. pp. 303-319. Edited by P.T. Kostecki and E.J. Calabrese. 1993.

Bradley, L.J.N. "Human Health Risk Assessment Workshop." Presented at the September, 1992, Hydrocarbon Contaminated Soils Conference, Amherst, MA.

EXHIBIT 13

AFFIDAVIT OF STEVEN C. WHITWORTH

AFFIDAVIT OF STEVEN C. WHITWORTH

I. BACKGROUND AND QUALIFICATIONS

1. My name is Steven C. Whitworth, and I am employed by Ameren Services Company as the Director of Environmental Services. Ameren Services Company provides business services to Ameren Corporation's operating companies including Ameren Energy Resources ("AER") and its subsidiary companies, Ameren Energy Generating Company ("GENCO") and AmerenEnergy Resources Company. I have been employed with Ameren Services Company since 1998 following the merger of Central Illinois Public Services Company and Union Electric Company. During the course of my career I have worked in the environmental air quality and permitting arena since 1989. I have been in my current position since 2007. In addition to supervising staff personnel, I am responsible for implementing policies and procedures relating to environmental compliance. In this capacity, I am responsible for representing the Ameren Companies before regulatory and administrative bodies with respect to state and federal permitting conditions and regulatory requirements.

II. MERCURY EMISSIONS REDUCTIONS

2. In 2006, the State of Illinois adopted regulations pertaining to mercury emissions. Thereafter in 2007, the Ameren MPS Group elected to comply with the state's mercury regulation by opting into an alternative compliance mechanism called the Multi Pollution Standard ("MPS"). By enrolling in the MPS, sources agreed to specified reductions in NOx and SO_2 emissions in exchange for deferring until 2015 compliance with mandatory emission standards. The Ameren MPS Group opted all of its twenty-one coal-fired steam generating units located at seven power stations throughout the state into the MPS. On a system-wide basis those units are required to meet enumerated declining emission rates for NOx and SO_2.

3. AER sought to delay the implementation dates for two of the SO_2 annual emission rates of the MPS. Specifically, AER sought a variance from the Illinois Pollution Control Board ("Board") to defer compliance with the MPS 2015 SO_2 annual emission rate of 0.25 pounds per million British thermal units ("lbs/mmBtu"), and the 2017 SO_2 annual emission rate of 0.23 lbs/mmBtu. 35 Ill. Adm. Code 225.233(e)(3)(C)(iii) and (iv). It is important to note that AER did not seek a change to either the NOx limits or the mercury requirements.

4. The Board granted AER a variance on September 20, 2012. The Board-issued variance also did not grant any changes to the MPS NOx emission limits or mercury requirements. AER has taken additional steps since the date of the Board opinion and order to reduce mercury emissions from the fleet beyond what is required by the MPS. AER early elected five EGUs to meet the 0.008 lb/GWh mercury emission limit in 2013. Those EGUs include: Coffeen Units 1 and 2 beginning February 1, 2013, Newton Units 1 and 2 beginning April 1, 2013, and E.D. Edwards Unit 3, beginning July 1, 2013. Moreover, Duck Creek and Joppa Units 1 through 6 have qualified as "Low Mass Emitting" units by demonstrating that potential mercury emissions are de minimis (<29 lbs/year).

5. AER's voluntary early mercury reductions resulted in compliance with the MPS requirements (35 Ill. Adm. Code 225.233(d)(1)) a year to a year and a half earlier than the January 1, 2015 date required under the rule.

Further affiant sayeth not.

Steven C. Whitworth

Subscribed and sworn to before me
this 16th day of July, 2013.

Debby Anzalone - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #10435722
My Commission Expires 5/23/2014

EXHIBIT 14

NEWTON FGD CONSTRUCTION PERMIT

File AQ-3.2.10.4

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

1021 NORTH GRAND AVENUE EAST, P.O. BOX 19506, SPRINGFIELD, ILLINOIS 62794-9506 – (217) 782-2113

PAT QUINN, GOVERNOR DOUGLAS P. SCOTT, DIRECTOR

217/782-2113

CONSTRUCTION PERMIT
NSPS AND NESHAP SOURCE

PERMITTEE

Ameren Energy Generating Company
Attn: Michael L. Menne, Vice President
1901 Chouteau Avenue
St. Louis, Missouri 63103

Application No.: 10070051 I.D. No.: 079808AAA
Applicant's Designation: NEWTONFGD Date Received: July 23, 2010
Subject: Addition of Flue Gas Desulfurization Systems
Date Issued: December 20, 2010
Location: 6725 North 500th Street, Newton, Jasper County

Permit is hereby granted to the above-designated Permittee to CONSTRUCT emission source(s) and/or air pollution control equipment consisting of the addition of two flue gas desulfurization (FGD) systems, one each for the existing Newton steam generating units, Units NB-1 and NB-2, and one diesel-fired engine-generator, as described in the above-referenced application. This permit is subject to standard conditions attached hereto and the following special conditions:

Conditions for the Project and Newton Units NB-1 and NB-2

1.1 Introduction

a. This permit authorizes the addition of two FGD systems, one each for Units NB-1 and NB-2. The FGD systems are being installed in order to comply with future environmental requirements.

b. This permit also authorizes construction of the following equipment and facilities as part of this project:

- Two new induced draft fans for each unit (four total).
- A single new chimney with separate flues for each unit.
- A limestone handling facility for the pulverized limestone for the FGD systems.
- A gypsum handling facility for the gypsum material from the FGD systems.
- A diesel engine-generator to provide emergency electrical power for the FGD systems.

1.2 Non-Applicability Provisions

a. This permit is issued based on this project being an emission control project that will reduce emissions of sulfur dioxide (SO_2) and sulfuric acid mist from Units NB-1 and NB-2 and will not increase emissions of other pollutants from these Units.

b. This permit is issued based on the new support equipment and facilities associated with the FGD systems, as constrained by the limitations and requirements in this permit, not being a major modification for purposes of the federal PSD rules. This is because the increases in emissions of individual PSD pollutants from these units are less than the significant emission rates set in the PSD rules.

1.3 Other Applicable Requirements

a. This permit does not relax or revise applicable requirements for Units NB-1 and NB-2 and associated control equipment, including requirements in existing permits for the source, including provisions for startup, malfunction and breakdown, recordkeeping, and reporting.

b. This permit does not relieve the Permittee of the responsibility to comply with all Local, State and Federal Regulations that are part of the applicable Illinois State Implementation Plan, as well as all other applicable Federal, State and Local requirements. In particular, this permit does not excuse the Permittee from the obligation to undertake further actions at or for the source as may be needed to ensure that it would not cause or contribute to violations of National Ambient Air Quality Standards, including accepting additional limits on the emissions of Units NB-1 and NB-2 and other emission units at the source, enhancing the operation of the new FGD systems for the Units, their existing control equipment, or the control equipment or control measures for other emission units at the source to assure compliance with such limits, and/or enhancing dispersion of emissions from the Units and other emission units at the source.

1.4. Control Practices

a. Each FGD system shall be equipped with a high efficiency mist eliminator to minimize entrained scrubbant carryover.

b. At all times, the Permittee shall, to the extent practicable, maintain and operate Units NB-1 and NB-2 with new FGD systems in a manner consistent with good air pollution control practice for minimizing emissions.

1.5 Emissions Testing Requirements

a. Within one year (365 days) after the initial startup of Unit NB-1 and NB-2 with an FGD system, the emissions of particulate matter, both filterable and condensable, from the unit shall be measured by an approved testing service while the unit is operating in the maximum load range and other representative operating conditions.

b. The following methods and procedures shall be used for testing of emissions, unless another method is approved by the Agency:

Refer to 40 CFR 60, Appendix A, and 40 CFR Part 51, Appendix M, for USEPA test methods.

Location of Sample Points	USEPA Method 1
Gas Flow & Velocity	USEPA Method 2
Particulate Matter	USEPA Method 5
Condensable Particulate Matter	USEPA Method 202

c. Prior to carrying out these tests, the Illinois EPA's Regional Office and Source Emission Test Specialist shall be notified a minimum of 30 days prior to the expected date of these tests and further notified a minimum of 5 working days prior to the tests of the exact date, time and place of these tests, to enable the Agency to witness these tests.

d. Three copies of the Final Report(s) for these tests shall be submitted to the Illinois EPA within 14 days after the test results are compiled and finalized. The following information shall be submitted with the results:

i. The gross power generation and the steam generation rate for the unit during the test.

ii. Significant operating parameters of the FGD system, such as absorber pH levels, scrubber slurry density, scrubbant circulation rate, limestone slurry makeup rate and slurry bleed rate, as measured during the tests.

iii. SO_2 emission data during the periods of testing based on emission monitoring, and the calculated SO_2 control efficiency on a daily basis.

iv. Opacity data collected by the continuous opacity monitoring systems during each test run and if conditions are suitable for such observation, observations of opacity at the stack (two 6-minute averages) for each test run.

1.6 Recordkeeping Requirements

All records required by this permit shall be retained at a readily accessible location at the source for at least three years from the date of entry and shall be made available for inspection and copying by the Illinois EPA upon request. Any records retained in an electronic format (e.g., computer) shall be capable of being retrieved and printed on paper during normal source office hours so as to be able to respond to an Illinois EPA request for records during the course of a source inspection.

1.7 Notifications

The Permittee shall notify the Illinois EPA in writing within 30 days of the initial startup of each FGD system.

1.8 Reporting Requirements

If there is a deviation from the requirements of this permit, the Permittee shall promptly report the deviation to the Illinois EPA. Unless otherwise specified, this report shall be submitted within 30 days of the deviation. The report shall describe the deviation, the probable cause of the deviation, corrective actions that were taken and any actions to prevent future occurrences.

1.9 Report/Notifications Submittals

Two copies of all reports and notifications required by this permit shall be sent to:

Illinois Environmental Protection Agency
Division of Air Pollution Control
Compliance Section (#40)
P.O. Box 19276
Springfield, Illinois 62794-9276

Telephone: 217/782-5811 Fax: 217/782-6348

and one copy shall be sent to the Illinois EPA's regional office at the following address unless otherwise indicated:

Illinois Environmental Protection Agency
Division of Air Pollution Control
2009 Mall Street
Collinsville, Illinois 62234

Telephone: 618/346-5120 Fax: 618/346-5155

1.10 Authorization for Operation

a. i. Units NB-1 and NB-2 with FGD systems each may operate for up to one year under this permit during which period shakedown and emissions testing shall be completed.

ii. This period of time may be extended by the Illinois EPA for up to an additional 365 days upon written request by the Permittee as needed to reasonably accommodate difficulties that are encountered in the shakedown and emissions testing of the unit(s) with the new FGD systems.

b. Following completion of required emissions testing, the Permittee is allowed to operate Units NB-1 and NB-2 with FGD systems under this permit until the operation of the FGD systems is addressed by a CAAPP permit.

c. These conditions supersede Standard Condition 6.

Unit-specific Conditions for the New Material Handling Facilities

2.0 Introduction

The affected facilities for the purpose of these Unit-Specific Conditions are the new facility for handling limestone for the new FGD systems and the new facility for handling the "gypsum" (sludge or spent material) from these FGD systems.

2.1 Applicable Emission Standards

a. The Permittee shall not cause or allow the emission of fugitive particulate matter (PM) from an affected facility that is visible by an observer looking generally toward the zenith (that is looking at the sky directly overhead) from a point beyond the property line of the source pursuant to 35 IAC 212.301.

b. The Permittee shall not cause or allow the emission of smoke or other PM, with an opacity greater than 30 percent into the atmosphere from an affected facility, pursuant to 35 IAC 212.123(a).

c. The process emission units in the affected facilities shall comply with 35 IAC 212.321(a), which provides that no person shall cause or allow PM emissions into the atmosphere in any one hour period from any new process emission unit which, either alone or in combination with the PM emission from all other new similar process emission units at a source or premises, exceeds the allowable emission rates specified in 35 IAC 212.321(c).

2.2 Non-Applicability Provisions

a. This permit is issued based on the affected limestone handling facility not being subject to the federal New Source Performance Standards (NSPS) for Nonmetallic Mineral Processing Plants, 40 CFR 60 Subpart OOO, because the facility does not crush or grind limestone so that it does not constitute a nonmetallic mineral processing plant, as defined by 40 CFR 60.671, for limestone.

b. This permit is issued based on the affected gypsum handling facility not being subject to the NSPS, 40 CFR 60 Subpart OOO because it does not crush or grind gypsum, so that it does not constitute a nonmetallic mineral processing plant for gypsum.

2.3 Operational Limitations

a. The amount of limestone received by the affected limestone handling facility shall not exceed 150,000 tons per year. Compliance with this limit and other annual limits set by this permit shall be determined from a running total of 12 months of data, i.e., from the sum of the data for the current month and the data for the preceding 11 months.

2.4 a. i. A. There shall be no visible PM emissions from the affected limestone handling facility.

B. The filters for affected limestone handling facility shall have a design outlet loading for PM of no more than 0.02 grains/scf, as shown by the manufacturer's performance specifications for the device or representative emission test data for similar filter devices.

ii. A. The total stack emissions of PM and PM10 from the limestone silos (bin vent filters) shall both not exceed 0.85 tons per year. This limit for PM10 emissions, and other limits for PM10 emissions set in this permit, shall only apply to filterable emissions of PM10, as would be measured in accordance with 35 IAC 212.108(a).

B. Other than stack emissions from the limestone silos, as addressed above, this permit is issued based upon negligible emissions of particulate from the affected limestone handling facility. For this purpose, emissions of PM and PM10 from the affected facility, other than from the limestone silos, shall each not exceed 0.44 tons per year.

b. i. Gypsum material shall only be mechanically de-watered, i.e., this permit does not authorize thermal drying of the material.

ii. The particulate emissions from the affected gypsum handling facility, including both stack and fugitive emissions, shall not exceed 7.4 and 2.6 tons per year of PM and PM10, respectively. These limits are based on the information in the application, including the projected maximum throughput of de-watered material per year, a nominal 15 percent moisture content for de-watered material, and appropriate USEPA AP-42 emission factors for handling wet material.

c. At all times, the Permittee shall maintain and operate the affected limestone and gypsum handling facilities, including associated air pollution control measures, in a manner consistent with good air pollution control practices for minimizing emissions.

d. i. A. The transport of limestone on roads at the source shall be on paved roads that are maintained in good condition to control PM emissions.

B. The transport of the gypsum on roads at the source shall either be on paved roads that are maintained in

good condition to control PM emissions or on roads that are treated with wet suppression to achieve at least a nominal 85 percent control for PM emissions.

ii. A. The PM and PM_{10} emissions from transport of gypsum on roads at the source shall not exceed 10.0 and 2.5 tons/year, respectively.

B. This permit is issued based upon negligible emissions of particulate from transport of limestone on roads at the source. For this purpose, emissions of PM and PM10 shall each not exceed 0.44 tons per year.

2.5 Inspection and Maintenance Requirements

a. Inspections of the affected limestone and gypsum handling facilities including emission control measures shall be conducted at least once per month when a facility is in operation to confirm compliance with the requirements of this permit.

b. Maintenance and repair of enclosures, filters, and other control measures shall be performed to assure that such measures function properly when material is being handled.

c. The Permittee shall maintain records of the above inspections and maintenance/repair activity in an operating and maintenance log or other records. These records shall contain, at a minimum, the date, time and description of the inspections or maintenance/repair activities.

2.6 Opacity Measurements

Upon written request by the Illinois EPA, the Permittee shall conduct opacity observations for operation(s) or unit(s) at the affected facilities, as specified in the request. These observations shall be conducted within 45 calendar days of the date of the request or by the date agreed upon by the Illinois EPA, whichever is later.

2.7 Recordkeeping Requirements

a. For each filter in the affected limestone handling facility, the Permittee shall maintain a file containing documentation for guaranteed PM emission rate, in gr/dscf, as provided by the supplier of the device.

b. The Permittee shall maintain operating records for the following items for the affected facilities:

i. Amount of limestone received, tons/month and tons/year.

ii. Amount of limestone transferred to the FGD systems, tons/month and tons/year.

iii. Amount of gypsum handled, tons/month and tons/year.

c. The Permittee shall keep records for the implementation of fugitive dust control measures on roadways used by trucks that handle limestone and gypsum.

d. The Permittee shall keep the following records related to PM and PM10 emissions (tons/month and tons/year), with supporting calculations:

i. Records of stack emissions from the silos at the affected limestone handling facility.

ii. Records of emissions from the gypsum handling facility.

iii. Records of emissions from roadways at the source from transport of gypsum.

2.8 The limestone and gypsum handling facilities may be operated pursuant to this construction permit until an operating permit becomes effective that addresses operation of these facilities. This condition supersedes Standard Condition 6.

Unit-Specific Conditions for the Emergency Engine Generator

3.1 Introduction

One new diesel-fired reciprocating internal combustion engine-generator (the affected engine) will be installed at the source to provide electricity to the FGD systems on a temporary basis during interruptions or outages of the normal power supply. The affected engine would also be operated for maintenance and readiness checks.

3.2 Applicable Emission Standards

a. i. The affected engine is subject to the NSPS for Stationary Compression Ignition Internal Combustion Engines, 40 CFR 60, Subpart IIII. The Permittee must comply with applicable requirements of the NSPS, 40 CFR 60 Subpart IIII, and related requirements of 40 CFR 60, Subpart A, General Provisions, for the affected engine.

ii. This permit is issued based on the affected engine being subject to the NSPS requirement for 2010/11 model year and later emergency engines with a displacement of less than 30 liters per cylinder so that the engine is subject to and shall comply with the applicable emission standards in 40 CFR 89.112 and 89.113, pursuant to 40 CFR 60.4205(b).

iii. The Permittee shall operate and maintain the affected engine according to the manufacturer's written instructions

or procedures developed by the Permittee that are approved by the engine manufacturer, pursuant to 40 CFR 60.4211(a). The Permittee shall also meet any applicable requirements of 40 CFR Parts 89, 94 and/or 1068 for the affected engine.

iv. The Permittee shall use diesel fuel in the affected engine that meets the requirements of 40 CFR 80.510, pursuant to 40 CFR 60.4207.

v. The Permittee shall demonstrate compliance with the NSPS emission standards for the affected engine in accordance with 40 CFR 60.4211(c), by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b). The affected engine must be installed and configured according to the manufacturer's specifications.

vi. The Permittee shall install, operate and maintain a non-resettable hour meter on the affected engine, as required by 40 CFR 60.4209(a).

vii. This permit is issued based on the affected engine not being equipped with a diesel particulate filter, so that the monitoring requirements of the NSPS, 40 CFR 60.4209(b), for such devices do not apply.

b. i. The affected engine is subject to the federal National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Compression Ignition Internal Combustion Engines. The Permittee must comply with applicable requirements of this NESHAP, 40 CFR 63 Subpart ZZZZ, and related requirements of 40 CFR 63, Subpart A, General Provisions, for the affected engine.

ii. This permit is issued based on the affected engine being subject to limited requirements of the NESHAP for emergency engines, which consist of the initial notification requirements as described in 40 CFR 63.6645(f), because the affected engine is a new emergency engine pursuant to 40 CFR 63.6590(b)(1)(i).

c. i. The emission of smoke or other particulate matter from the affected engine shall not exceed an opacity greater than 30 percent, pursuant to 35 IAC 212.123(a), except as provided by 35 IAC 212.124(a) and Conditions 3.2(c)(ii) below.

ii. Subject to the following terms and conditions, the Permittee is authorized to continue operation of the affected engine in violation of the applicable opacity standard in 35 IAC 212.123(a) in the event of a malfunction or breakdown of the engine. This authorization is provided pursuant to 35 IAC 201.149, 201.161 and 201.262, as the Permittee has applied for such authorization in its

application, generally explaining why such continued operation would be required to prevent severe damage to equipment, and describing the measures that will be taken to minimize emissions from any malfunctions and breakdowns.

A. This authorization only allows such continued operation as necessary to provide essential service or to prevent injury to personnel or severe damage to equipment and does not extend to continued operation solely for the economic benefit of the Permittee.

B. Upon occurrence of excess emissions due to malfunction or breakdown, the Permittee shall as soon as practicable restore normal power to the FGD systems or complete the shutdown of Units NB-1 and NB-2 or undertake other action so that excess emissions cease.

C. The Permittee shall fulfill applicable recordkeeping and reporting requirements of Conditions 3.8(c) and 3.9.

D. If the Permittee continues to operate the affected engine with excess emissions during malfunction or breakdown for purposes that are not related to providing emergency power to the FGD systems, the Permittee shall immediately notify the Illinois EPA's Regional Office, by telephone, facsimile or e-mail for each incident in which the opacity from engine exceeds or may have exceeded 30 percent for more than one hour (ten 6-minute periods) unless the Permittee has begun the shutdown of the engine by such time.

Following this notification to the Illinois EPA of a malfunction or breakdown with excess emissions, the Permittee shall comply with all reasonable directives of the Illinois EPA with respect to such incident, pursuant to 35 IAC 201.263. (Otherwise, if opacity during an incident only exceeds or may have exceeded 30 percent for less than one hour, the Permittee need only report the incident in the periodic compliance report for Units NB-1 and NB-2.)

E. This authorization does not relieve the Permittee from the continuing obligation to minimize excess emissions during malfunction or breakdown

d. Pursuant to 35 IAC 214.301, emissions of sulfur dioxide into the atmosphere from the affected engine shall not exceed 2,000 ppm.

3.3 Non-Applicability Provisions

a. This permit is issued based on the affected engine not being subject to the requirements of the federal Acid Rain Program because it is not a utility unit. (Refer to 40 CFR 72.2 and 72.6.) Accordingly, electricity generated by the affected engine may not be sold to the power grid on a commercial basis.

b. This permit is issued based on the affected engine not being subject to the requirements of 35 IAC Part 212, Subpart L, because a process weight rate cannot be set, due to the nature of such unit, so that these rules cannot reasonably be applied, pursuant to 35 IAC 212.323.

3.4 Operational Limitations

a. The rated output of the affected engine shall not exceed 1250 KW.

b. The affected engine shall not be operated for any purpose other than emergency operation and maintenance and operational testing, pursuant to 40 CFR 60.4211(e).

c. i. Operation of the affected engine shall not exceed 500 engine-hours per calendar year, provided, however, that the Illinois EPA may authorize temporary operation of the engine in excess of 500 hours per year to address extraordinary circumstances that require operation of this device, by issuance of a separate State construction permit addressing such circumstances.

ii. The operation of the affected engine for maintenance and readiness checks shall be limited to 100 hours per calendar year so that the engine qualifies as an emergency engine for purposes of the NSPS.

3.5 Emission Limitations

a. Emissions from the affected engine shall not exceed the following limitations. Compliance with these annual limitations shall be determined from a running total of 12 months of data.

Pollutant	Lbs/Hour[1]	Tons/Year[2]
NO_x	18.6	4.7
CO	2.8	0.7

[1] The hourly limitations for NO_x and CO are based on emission data from the manufacturer of the engine calculated using nameplate capacity of the engine (1,677 HP), which was provided in the application. The SO_2 emission limitation is based on fuel sulfur specifications, pursuant to 40 CFR 80.510(a)(2).

[2] The annual limitations are based on operation of the affected engine for 500 hours per year at the hourly emission rate limit.

b. This permit is issued based on negligible emissions of SO_2, PM/PM_{10} and VOM from the affected engine. For this purpose, emissions of SO_2 and PM/PM_{10} shall not each exceed 0.1 tons/year. Emissions of VOM shall not exceed 0.2 tons/year.

3.6 Opacity Measurements

a. Upon written request by the Illinois EPA, the Permittee shall have the opacity of the exhaust from the affected engine during representative operating conditions determined by a qualified observer in accordance with USEPA Method 9, as further specified below. These observations shall be conducted within 45 calendar days of the date of the request, or on the date the affected engine next operates, or by the date agreed upon by the Illinois EPA, whichever is latest.

b. i. The Permittee shall notify the Illinois EPA at least 7 days in advance of the date and time of testing, in order to allow the Illinois EPA to witness testing. This notification shall include the name and employer of the observer(s) and identify any concerns for successful completion of observations, i.e., lack of suitable point for proper observation or inability to conduct observations under specified operating conditions.

ii. The Permittee shall promptly notify the Illinois EPA of any changes in the date or time of testing.

c. The Permittee shall provide a copy of its observer's readings to the Illinois EPA at the time of testing, if Illinois EPA personnel are present.

d. The Permittee shall submit a written report for these observations within 15 days of the date of observation. This report shall include:

i. Date and time of testing.

ii. Name and employer of qualified observer.

iii. Copy of current certification.

iv. Description of observation conditions.

v. Description of engine operating conditions.

vi. Raw data.

vii. Opacity determinations.

viii. Conclusions.

3.7 Emission Testing Requirements

Within 180 days of a written request from the Illinois EPA, or the date agreed upon by the Illinois EPA, whichever is later, the Permittee shall have tests conducted for the affected engine for emissions of NO_x, CO, PM, and NMHC by an approved independent testing service. These tests must be conducted in accordance with the requirements in 40 CFR 60.4212.

3.8 Recordkeeping Requirements

a. The Permittee shall fulfill applicable recordkeeping requirements of the NSPS for the affected engine.

b. The Permittee shall maintain records of the following items for the affected engine:

i. A. A file containing manufacturer's specifications for the affected engine's model year, maximum engine capacity, manufacturer's certification of compliance with 40 CFR Part 89 or Part 1039, and associated emission factors.

B. Data for the maximum hourly emission rates (lb/hour) from the affected engine, with supporting calculations.

ii. An operating log or other operating records, which shall include the following information:

A. Information for each time the engine is operated, with date, time, duration, and purpose (i.e., exercise or emergency need), in accordance with 40 CFR 60.4214(b).

B. Information for any incident in which the operation of the engine continued during malfunction or breakdown, including: date, time, and duration; a description of the incident; whether emissions exceeded or may have exceeded any applicable standard; a description of the corrective actions taken to reduce emissions and the duration of the incident; and a description of the preventative actions taken.

iii. A maintenance and repair log or other records, listing each activity performed with date.

iv. The following operating records:

A. Type of fuel used in the affected engine, including maximum sulfur content.

B. Operating hours of the affected engine (hours/month and hours/year).

v. Records of NO_x and CO emissions (tons/month and tons/year), with supporting calculations.

vi. Records for opacity observations made in accordance with USEPA Method 9 for the affected engine that it conducts or that are conducted on its behest by individuals who are qualified to make such observations. For each occasion on which such observations are made, these records shall include the identity of the observer, a description of the various observations that were made, the observed opacity, and copies of the raw data sheets for the observations.

c. Pursuant to 35 IAC 201.263, the Permittee shall maintain the following records related to malfunction and breakdown of the affected engine:

i. Maintenance and repair log(s) for the affected engine that, at a minimum, address aspects or components of the engine for which malfunction or breakdown has resulted in excess emissions, which shall list the activities performed on such aspects or components, with date and description.

ii. Records for each incident when operation of the affected engine continued with excess opacity, including malfunction or breakdown as addressed by Condition 3.2(c)(ii), that, at a minimum, include the following information:

A. Date, time, duration and description of the incident, including actions taken to reduce the duration of the incident.

B. If opacity exceeded the applicable standard for more than 60 minutes during the incident:

1. A detailed explanation why continued operation of the affected engine was necessary.

2. The preventative measures that have been or will be taken to prevent similar incidents, including any repairs to the affected engine and associated equipment and any changes to operating and maintenance procedures.

3.9 Reporting Requirements

a. The Permittee shall fulfill applicable notification and reporting requirements of the NSPS and the NESHAP for the affected engine.

b. If there is a deviation from the requirements of this permit for the affected engine, the Permittee shall report the deviation with the periodic compliance report for Units NB-1 and NB-2. (See also Condition 1.8.)

3.10 Authorization for Operation

The affected engine may be operated pursuant to this construction permit until an operating permit becomes effective that addresses this engine. This condition supersedes Standard Condition 6.

If you have any questions on this permit, please contact Shashi Shah at 217/782-2113.

Edwin C. Bakowski

Edwin C. Bakowski, P.E.
Manager, Permit Section
Division of Air Pollution Control

Date Signed: December 20, 2010

ECB:SRS:jws

cc: Illinois EPA, Region 3

STATE OF ILLINOIS
ENVIRONMENTAL PROTECTION AGENCY
DIVISION OF AIR POLLUTION CONTROL
P. O. BOX 19506
SPRINGFIELD, ILLINOIS 62794-9506

STANDARD CONDITIONS FOR CONSTRUCTION/DEVELOPMENT PERMITS ISSUED BY THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY

July 1, 1985

The Illinois Environmental Protection Act (Illinois Revised Statutes, Chapter 111-1/2, Section 1039) authorizes the Environmental Protection Agency to impose conditions on permits which it issues.

The following conditions are applicable unless susperseded by special condition(s).

1. Unless this permit has been extended or it has been voided by a newly issued permit, this permit will expire one year from the date of issuance, unless a continuous program of construction or development on this project has started by such time.

2. The construction or development covered by this permit shall be done in compliance with applicable provisions of the Illinois Environmental Protection Act and Regulations adopted by the Illinois Pollution Control Board.

3. There shall be no deviations from the approved plans and specifications unless a written request for modification, along with plans and specifications as required, shall have been submitted to the Agency and a supplemental written permit issued.

4. The permittee shall allow any duly authorized agent of the Agency upon the presentation of credentials, at reasonable times:

   a. to enter the permittee's property where actual or potential effluent, emission or noise sources are located or where any activity is to be conducted pursuant to this permit,

   b. to have access to and to copy any records required to be kept under the terms and conditions of this permit,

   c. to inspect, including during any hours of operation of equipment constructed or operated under this permit, such equipment and any equipment required to be kept, used, operated, calibrated and maintained under this permit,

   d. to obtain and remove samples of any discharge or emissions of pollutants, and

   e. to enter and utilize any photographic, recording, testing, monitoring or other equipment for the purpose of preserving, testing, monitoring, or recording any activity, discharge, or emission authorized by this permit.

5. The issuance of this permit:

   a. shall not be considered as in any manner affecting the title of the premises upon which the permitted facilities are to be located,

   b. does not release the permittee from any liability for damage to person or property caused by or resulting from the construction, maintenance, or operation of the proposed facilities,

   c. does not release the permittee from compliance with other applicable statutes and regulations of the United States, of the State of Illinois, or with applicable local laws, ordinances and regulations,

   d. does not take into consideration or attest to the structural stability of any units or parts of the project, and

e. in no manner implies or suggests that the Agency (or its officers, agents or employees) assumes any liability, directly or indirectly, for any loss due to damage, installation, maintenance, or operation of the proposed equipment or facility.

6. a. Unless a joint construction/operation permit has been issued, a permit for operation shall be obtained from the Agency before the equipment covered by this permit is placed into operation.

   b. For purposes of shakedown and testing, unless otherwise specified by a special permit condition, the equipment covered under this permit may be operated for a period not to exceed thirty (30) days.

7. The Agency may file a complaint with the Board for modification, suspension or revocation of a permit:

   a. upon discovery that the permit application contained misrepresentations, misinformation or false statements or that all relevant facts were not disclosed, or

   b. upon finding that any standard or special conditions have been violated, or

   c. upon any violations of the Environmental Protection Act or any regulation effective thereunder as a result of the construction or development authorized by this permit.

BUREAU OF AIR

For assistance in preparing a permit application contact the Permit Section.

Illinois Environmental Protection Agency
Division of Air Pollution Control
Permit Section
1021 N. Grand Ave E.
P.O.Box 19506
Springfield, Illinois 62794-9506

or a regional office of the Field Operations Section. The regional offices and their areas of responsibility are shown on the map. The addresses and telephone numbers of the regional offices are as follows:

Illinois EPA
Region 1
Bureau of air, FOS
9511 West Harrison
Des. Plaines, Illinois 60016
847/294-4000

Illinois EPA
Region 2
5415 North University
Peoria, Illinois 61614
309/693-5463

Illinois EPA
Region 3
2009 Mall Street
Collinsville, Illinois 62234
618/346-5120