Exhibit 1

Map Depicting Ameren's Power Stations and Agency Air Quality Monitoring Stations

Illinois Environmental Protection Agency, *Illinois Annual Air Quality Report 2010*, including map depicting Agency air quality monitoring stations with the locations of the Ameren MPS Group superimposed.

State of Illinois
Illinois Environmental Protection Agency

4  th

Annual Air Quality Report

Illinois • 2010

December 2011

ILLINOIS ANNUAL
AIR QUALITY REPORT
2010

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

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2010 EXECUTIVE SUMMARY

This report presents a summary of air quality data collected throughout the State of Illinois during the calendar year - 2010. 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 over 80 different site locations collecting data from more than 200 instruments.

In terms of the Air Quality Index (AQI) air quality during 2010 was either good or moderate 91 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 one Unhealthy day in 2009. There were 32 days (22 for 8-hour ozone, 9 for $PM_{2.5}$ and 1 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 13 Unhealthy for Sensitive Groups days reported in 2009. 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 2001 – 2010 are as follows: Particulate Matter (PM_{10}) 25 percent decrease, Particulate Matter ($PM_{2.5}$) 24 percent decrease, Sulfur Dioxide 43 percent decrease, Nitrogen Dioxide 25 percent decrease, Carbon Monoxide 52 percent decrease, Lead 33 percent decrease, and Ozone 19 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, 2010. Emission estimates are for the calendar year 2010 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 2009. In general there has been a trend toward decreasing emissions over this time period.

SECTION 2: STATEWIDE SUMMARY OF AIR QUALITY FOR 2010

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 33 sites.

No sites recorded hourly concentrations above the 0.12 parts per million (ppm) 1-hour standard. The highest 1-hour concentration in the Chicago area 0.100 ppm at Zion and Lemont compared with a high 1-hour value of 0.118 ppm at Zion in 2009. The highest value in the St. Louis Metro East area was 0.115 ppm recorded at East St. Louis compared with a high in 2009 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 two sites in Illinois that had a fourth high value above 0.075 ppm in 2010 compared with zero sites in 2009. The highest fourth high value was 0.080 ppm at Alton. The highest level in the Chicago area was 0.078 ppm at Zion. For the three year period 2008 – 2010, no 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 2001-2010. The graph shows some year-to-year fluctuation and a general decreasing 10-year trend since 2002 with high years in 2002 and 2005 and low years in 2004, 2008 and 2009. The Statewide average for 2010 was 0.087 ppm compared with 0.082 ppm in 2009 and 0.082 ppm in 2008.

Statewide, the total number of 1-hour excursion days in 2010 was zero compared with zero in 2009 and zero in 2008.

Figure 1
Average 1-Hour Ozone Maximum (ppm)

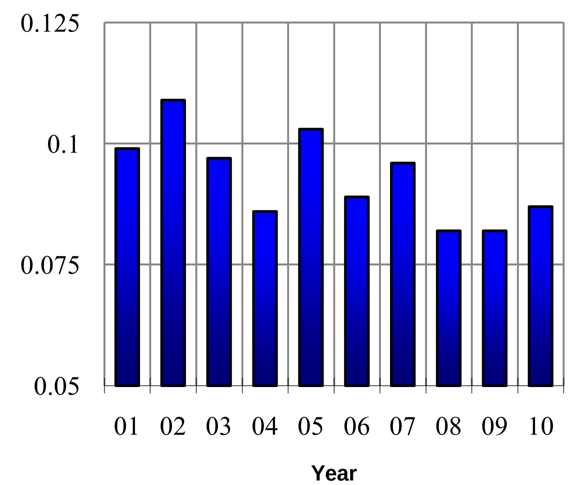


Figure 2
Average 8-Hour Ozone 4th High (ppm)

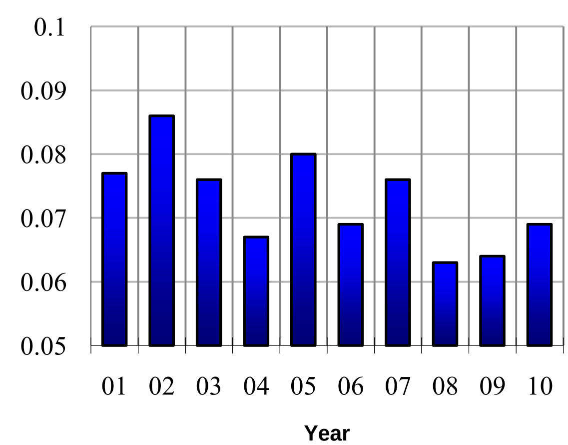


Figure 2 shows for each year the statewide average of the 4th highest 8-hour ozone value for the same period 2001-2010. This trend is generally decreasing since 2002 as well.

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

August 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 above average numbers.

PARTICULATE MATTER

Monitoring was conducted at 38 sites for $PM_{2.5}$. Valid annual averages were obtained for 34 of the 38 sites. No sites recorded an average above 15.0 ug/m^3, the level of the annual standard, compared with no sites in 2009 and one site in 2008. The Statewide average of the annual averages was 11.6 ug/m^3 in 2010 compared with 10.6 ug/m^3 in 2009 and 11.6 ug/m^3 in 2008. **Figure 3** shows the trend of the Statewide annual averages for $PM_{2.5}$ for the period 2001-2010. There were 31 exceedances of the revised 24-hour standard of 35 ug/m^3 in 2010 compared with 16 exceedances in 2009. The Statewide peak of 48.1 ug/m^3 was recorded at Chicago Mayfair Pump Station. The Statewide average of the 98th percentile of 24-hour averages was 26.9 ug/m^3 in 2010 compared with 24.3 ug/m^3 in 2009 and 27.4 ug/m^3 in 2008.

In 2010 there were 17 sites monitoring PM_{10}. The Statewide annual average was 23 ug/m^3 compared with 20 ug/m^3 in 2009 and 22 ug/m^3 in 2008.

For PM_{10}, the Statewide average of the maximum 24-hour averages in 2010 was 62 ug/m^3 compared with 56 ug/m^3 in 2009 and 62 ug/m^3 in 2008. **Figure 4** depicts this trend for the period 2001-2010.

No sites exceeded the former primary annual standard of 50 ug/m^3. The highest annual average was 32 ug/m^3 in Granite City. The lowest annual was 17 ug/m^3 in Northbrook and Nilwood. There were no exceedances of the 24-hour primary standard of 150 ug/m^3. The highest 24-hour average was recorded in Granite City with a value of 106 ug/m^3 compared with a high 24-hour value of 115 ug/m^3 in Granite City in 2009.

Figure 3
Particulate Matter (PM2.5) Annual Trends (ug/m3)

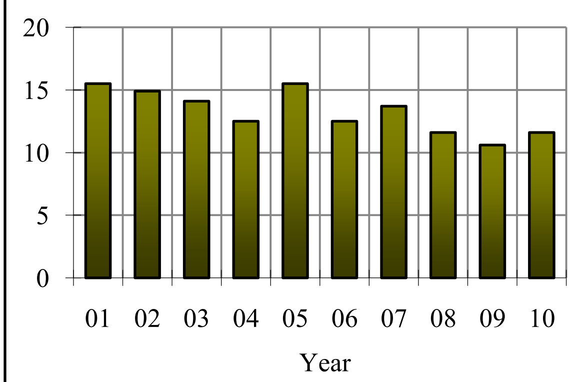
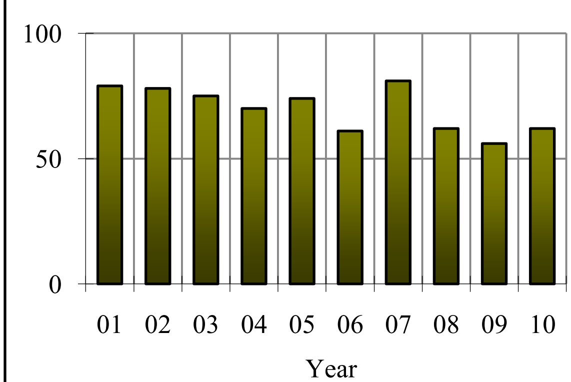


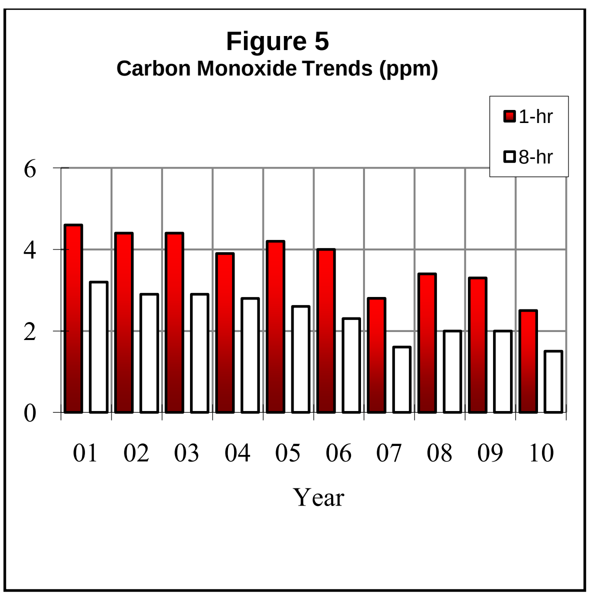
Figure 4
Particulate Matter (PM10) 24-Hour Trends (ug/m3)



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 2010. The highest 1-hour average was 4.3 ppm recorded at Chicago Transit Authority. The highest 8-hour average was 2.0 ppm recorded in Maywood.

Figure 5 shows the trend for the period 2001-2010 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 2.5 ppm in 2010 compared with 3.3 ppm in 2009. The statewide average for the 8-hour high was 1.5 ppm in 2010 compared with 2.0 ppm in 2009.



SULFUR DIOXIDE

There were 50 exceedances of the new 1-hour primary standard of 75 ppb in 2010 compared with 68 exceedances in 2009. There were no exceedances of the 3-hour secondary standard of 500 ppb in 2010. The annual and 24-hour primary standards were revoked by USEPA in 2010. The highest 1-hour average was 331 ppb recorded in Pekin compared with 352 ppb in Pekin in 2009. The statewide average of the 1-hour high in 2010 was 75 ppb. This compares with 81 ppb in 2009 and 128 ppb in 2008. The highest 3-hour average of 223 ppb was recorded in Pekin in 2010 compared with 265 ppb in Pekin in 2009. There were four sites over the primary 1-hr standard of 75 ppb for the 2008-2010 period compared to six sites for the 2007-2009 period (Table B17).

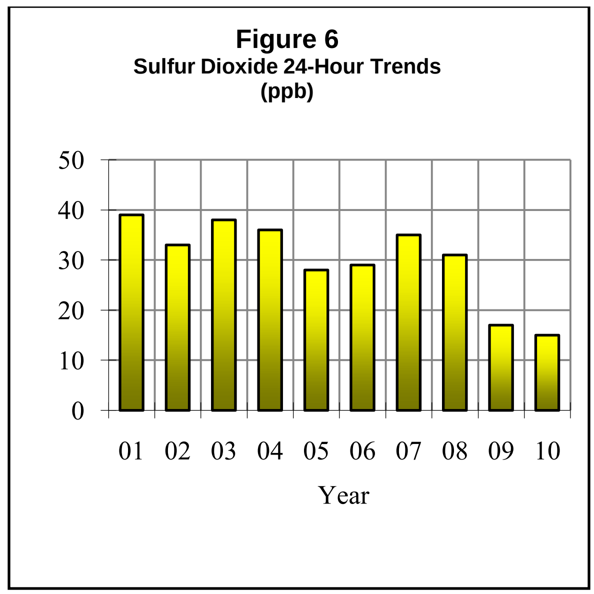


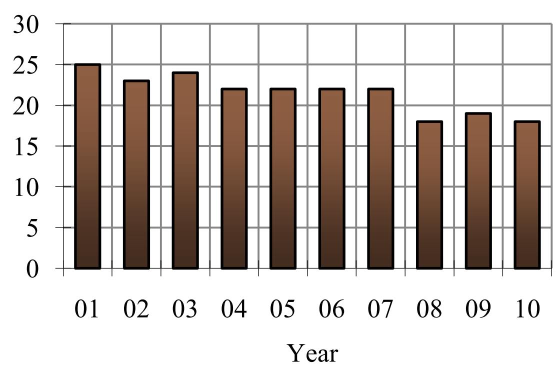
Figure 6 shows the statewide trend for the maximum 24-hour averages for the period 2001-2010. The 24-hour average trend has been overall downward; however a greater degree of year-to-year fluctuations have occurred. The statewide average for 2010 was 15 ppb compared with the 2009 average of 17 ppb. Statewide 1-hour average maximums have also declined. The 2010 average was 75 ppb compared to 81 ppb in 2009.

NITROGEN DIOXIDE

There were no violations of the annual primary standard of 53 ppb recorded in Illinois during 2010. The highest annual average of 25 ppb was recorded at Chicago - CTA. The Statewide average for 2010 was 18 ppb compared with 19 ppb in 2009 and 18 ppb in 2008. There were no violations of the new 1-hour primary standard in 2010 as well. This compares to 15 violations in 2009. There were no sites over the 1-hour primary standard of 100 ppb for the 2008-2010 period compared to one site for the 2007-2009 period (Table B20).

One site operated only during part of the ozone season as PAMS. **Figure 7** depicts the trend of statewide averages from 2001-2010. The trend has been generally stable for the period ranging from 17 ppb to 25 ppb. There have been no violations of the annual standard since 1980.

Figure 7
Nitrogen Dioxide Annual Trend (ppm)



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/m3 to a rolling 3-month maximum mean of 0.15 ug/m3.

There were no violations of the former quarterly lead standard of 1.5 ug/m3. There were two violations of the new rolling 3-month maximum mean standard for the 2008 to 2010 period recorded at Granite City - 15th & Madison with a value of 0.42 ug/m3 and Chicago Perez with a value of 0.24 ug/m3. This compares with a statewide high of 0.28 ug/m3 for 2007 to 2009 at Granite City 15th & Madison.

Figure 8
Lead Maximum 3-Month Trend (ug/m3)

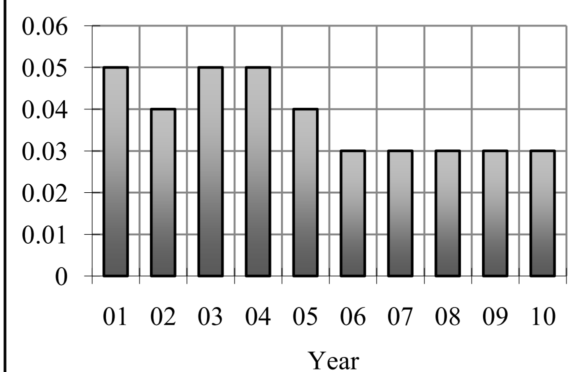


Figure 8 shows the trend of the statewide non-source maximum monthly averages from 2001-2010. The chart shows a general flat trend of ambient lead levels over the last several years. In 2010, several source oriented monitors were installed and one non-source monitor was discontinued. Currently, not enough data exists for the source oriented sites to establish a trend.

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 0.136 ug/m^3 measured in Granite City. The highest annual average of 0.007 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 0.031 ug/m^3. The highest annual average of 0.004 ug/m^3 was also recorded at Chicago Perez. The highest 24-hour chromium average was 0.066 ug/m^3 recorded at Chicago – Washington. Maywood had the highest annual average at 0.020 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 Granite City with a value of 0.184 ug/m^3. The highest annual average was in Maywood with an average of 0.010 ug/m^3. For nitrates, the highest 24-hour average was 33.9 ug/m^3 recorded at Summit. The highest annual average was 5.6 ug/m^3 recorded at Alsip. For sulfates, the highest 24-hour average was 18.2 ug/m^3 recorded at Maywood. The highest annual average was 7.2 ug/m^3 at Chicago - Washington. In general, metals, nitrate and sulfate values were slightly higher in 2010 than in 2009.

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, 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	AIRS CODE
0	Alsip Village Garage	439028.14	4613506.98	170310001
1	Aurora Health Department	389528.14	4626729.16	170890007
2	Blue Island Eisenhower H.S.	442015.58	4612496.03	170312001
3	Braidwood Comm ED Maintenance	400173.37	4564033.85	171971011
4	Cary Grove H.S.	397480.49	4675110.16	171110001
5	Cicero IEPA Trailer	437539.20	4633977.22	170314002
6	Cicero Liberty School	437852.27	4634984.05	170316005
7	Des Plaines Regional Office Building	428543.56	4656797.86	170314007
8	Elgin Larsen Junior H.S.	394651.06	4656017.29	170890005
9	Elgin McKinley School	394074.74	4656164.53	170890003
10	Evanston Water Pumping Station	444223.82	4656857.88	170317002
11	Joliet Pershing Elementary School	406854.40	4597853.20	171971002
12	Joliet Water Plant West	401280.73	4590491.30	171970013
13	Lemont IEPA Trailer	417538.46	4613403.03	170311601
14	Lisle Morton Arboretum	410890.26	4629582.92	170436001
15	Lyons Township Village Hall	430877.97	4628036.70	170311016
16	Maywood 1500 Maybrook Drive Platform	431442.48	4635917.35	170316003
17	Maywood Comm ED Maintenance	431199.07	4635910.07	170316004
18	Maywood 4th District Court Building	431466.96	4635994.08	170316006
19	Midlothian Bremen H.S.	440382.95	4607283.07	170311901
20	Naperville City Hall	404209.07	4625007.66	170434002
21	Northbrook Water Plant	433953.24	4665668.78	170314201
22	Schiller Park IEPA Trailer	427390.48	4646283.31	170313103
23	Summit Graves Elementary School	433134.91	4626002.30	170313301
24	Waukegan North Fire Station	430740.20	4693056.11	170971002
25	Zion Camp Logan	433408.66	4702013.37	170971007
26	Chicago Carver H.S.	450923.96	4611812.47	170310060
27	Chicago Cermak Pump Station	446450.82	4635956.70	170310026
28	Chicago Comm ED	440680.96	4622421.39	170310075
29	Chicago Jardine Water Plant	449590.78	4638386.72	170310072
30	Chicago Willis Tower	447259.34	4636533.43	170310042
31	Chicago CTA Building	447307.81	4636384.48	170310063
32	Chicago South Water Filtration Plant	454702.37	4622802.04	170310032
33	Chicago Southeast Police Station	452696.62	4617465.15	170310050
34	Chicago Spring eld Pump Station	440063.88	4640354.22	170310057
35	Chicago Taft H.S.	434390.00	4648367.48	170311003
36	Chicago University of Chicago	450011.00	4626726.33	170310064
37	Chicago Washington H.S.	455116.70	4615183.98	170310022
38	Chicago Mayfair Pump Station	437859.32	4646216.44	170310052
39	Bondville SWS Climate Station	382927.63	4434458.00	170191001
40	Carbondale Maintenance Building	305288.88	4177389.00	170770004
41	Champaign Booker T. Washington Elementary School	395236.97	4442222.50	170190004
42	Decatur IEPA Trailer	335319.94	4414769.00	171150013
43	Effingham Central Junior H.S.	366000.19	4325369.00	170491001
44	Houston Baldwin Site 2 - IEPA Trailer	255745.52	4229049.50	171570001
45	Knight Prairie Township	357489.72	4216177.00	170650002
46	Maryville Southwest Cable TV	242682.59	4290595.00	171191009
47	Mount Carmel Division Street	432441.06	4250177.00	171850001
48	Rural Wabash County South of State Route 1	427103.06	4247142.00	171851001
49	Nilwood IEPA Trailer	258043.88	4364498.50	171170002
50	Normal ISU Physical Plant	330837.53	4487250.50	171132003
51	Oglesby IEPA Trailer	328401.31	4573311.00	170990007
52	Peoria City Office Building	281616.22	4508336.50	171430037
53	Pekin Fire Station 3	275274.31	4492892.00	171790004
54	Peoria Commercial Building	279203.50	4508748.50	171430036
55	Peoria Fire Station 8	279707.38	4507329.50	171430024
56	Peoria Heights H.S.	281679.94	4513723.50	171431001
57	Loves Park Maple Elementary School	332121.41	4688981.00	172012003
58	Rockford City Hall	327811.72	4681606.50	172010011
59	Rockford Winnebago County Health Department	327392.16	4681107.00	172010013
60	Spring eld Sewage Treatment Plant	278158.03	4408840.50	171670006
61	Spring eld Public Health Warehouse	277126.53	4413724.50	171670010
62	Spring eld Illinois Agriculture Building	273728.00	4412449.00	171670012
63	Spring eld Federal Building	273312.59	4408832.50	171670008
64	Swansea Village Maintenance Building	239082.08	4268828.00	171634001
65	Bartonville Pump Station	276515.00	4503674.00	171430110
66	Decatur Mueller	333988.00	4414303.00	171150110
67	Mapleton Catepillar Plant	267429.00	4493834.00	171430210
68	Perez Elementary School	445348.00	4633988.00	170310110
69	Rockford J. Rubin and Company	327440.00	4678637.00	172010110
70	Sterling Sauk Medical Clinic	275084.00	4629822.00	171950110
71	Alton SIU Dental Clinic	747734.94	4309900.00	171192009
72	Alton Clara Barton Elementary School	747358.56	4308458.00	171190008
73	East St. Louis RAPS Trailer	747238.69	4277551.00	171630010
74	Edwardsville RAPS Trailer	757101.44	4298007.00	171192007
75	Granite City Fire Station 1	748727.63	4287873.00	171191007
76	Granite City Air Products	747522.88	4286713.50	171190010
77	Rock Island Arsenal	707169.75	4598886.00	171613002
78	South Roxana Grade School	755353.88	4301836.50	171191010
79	Wood River Water Treatment Plant	751122.13	4305295.00	171193007
80	Jerseyville Illini Junior H.S.	731349.00	4332451.50	170831001
81	Quincy John Wood Community College	642227.44	4419695.50	170010007
82	Granite City Gateway Medical	748300.44	4287426.50	171190024
83	Spring eld Blandco Building	277036.77	4413835.99	171670013

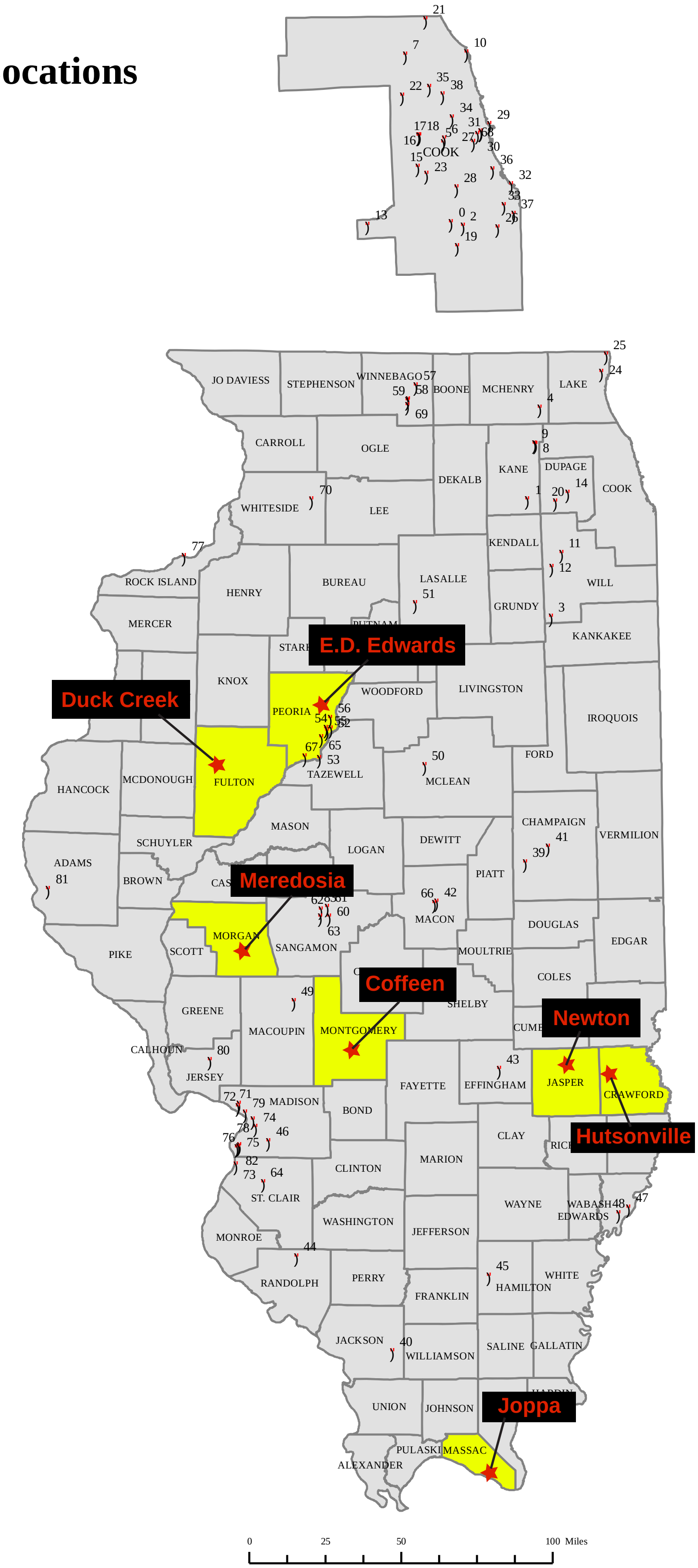


Exhibit 2

Table 1: Ameren MPS Group Information

Information provided by Ameren Energy Resources, April 2012, including location, permits, pollution control equipment, etc.

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address **Number of Employees**	**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 Power Station (I.D. No. 135803AAA)					
134 CIPS Lane Coffeen, Illinois Montgomery County 156 employees	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]	2011 SO_2 emission rate = 0.003 lb/MMBtu 2011 SO_2 mass emissions = 82.5 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

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Coffeen Power Station (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 App. No. 12020019 Temporary Mercury Re-Emission Reduction System

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Power Stations and Units Comprising the MPS Group
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Address Number of Employees	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 Power Station (I.D. No. 135803AAA)					
					<u>CAAPP Permit</u>: September 29, 2005 App. No. 95090009 Appealed November 3, 2005 (PCB 06-064) Stayed February 16, 2006

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 (I.D. No. 057801AAA)				
17751 North CILCO Road Canton, Illinois Fulton County 72 employees	Unit 1 Nominal 3,713 mmBtu/hr (1976)	LNB[7] SCR ESP FGD[8]	2011 SO_2 emission rate = 0.014 lb/MMBtu 2011 SO_2 mass emissions = 167 tons	<u>State Operating Permit</u>: November 13, 1995 App. No. 78020006 <u>Construction Permits</u>: Nov. 22, 2006; revised May 23, 2008 App. No. 06070049 New WFGD[9] system February 16, 2007 App. No. 06070048 Boiler project; New ESP

[7] low NOx burner

[8] flue gas desulfurization (scrubber)

[9] wet FGD

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Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 (I.D. No. 057801AAA)				
				May 7, 2007; revised. January 31, 2008 App. No. 07030025 Pilot Air Quality Control System Aug 15, 2011 App. No. 11080047 Canton Fuels Company Reduced Emission Fuel (REF) Production Facility CAAPP Permit: September 29, 2005 App. No. 95070025 Appealed November 3, 2005 (PCB 06-066) Stayed February 16, 2006

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 Power Station (I.D. No. 143805AAG)						
7800 South CILCO Lane Bartonville, Illinois Peoria County 108 employees	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 New LNB and OFA on Unit 3	2011 SO_2 emission rate = 0.45 lb/MMBtu 2011 SO_2 mass emissions = 12,596 tons	State Operating Permit: July 1, 2004 App. No. 73010724 Construction Permits: March 9, 2007 App. No. 07030026 LNB and OFA for Unit 3 August 24, 2008 App. No. 08080029 LNB and OFA for Unit 2 Sorbent Injection System Units 1, 2, 3 App. No. 08100002 September 9, 2009 March 30, 2011 App. No. 11030003 Pilot System for HBr injection (Hg Control) for Unit 3

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address **Number of Employees**	**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 Power Station (I.D. No. 143805AAG)						
						<u>CAAPP Permit</u>: September 29, 2005 App. No. 95070026 Appealed November 3, 2005 (PCB 06-067) Stayed February 16, 2006

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Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address **Number of Employees**	**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 Power Station (I.D. No. 033801AAA)					
15142 East 1900th Ave. Hutsonville, Illinois Crawford County 7 employees	Unit 5 nominal 695 mmBtu/hr (1952)	Unit 6 nominal 695 mmBtu/hr (1953)	ESP	2011 SO_2 emission rate = 2.26 lb/MMBtu 2011 SO_2 mass emissions = 9,894 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

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 Power Station (I.D. No. 033801AAA)					
					August 18, 2008 App. No. 08080015 Pilot OFA Evaluation for Units 5 and 6 <u>CAAPP Permit</u>: September 29, 2005 App. No. 95080105 Appealed November 3, 2005 (PCB 06-070) Stayed February 16, 2006

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 (I.D. No. 127855AAC)				
2100 Portland Road Joppa, Illinois Massac County 233 employees	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, 5 and 6	2011 SO_2 emission rate = 0.62 lb/MMBtu 2011 SO_2 mass emissions = 26,180 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 October 31, 2008 App. No. 08100052

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 (I.D. No. 127855AAC)				
				OFA system for Unit 4 March 31, 2006 App. No. 06020085 Pilot for Mercury Control December 5, 2006, revised Oct. 30, 2007 and Aug. 27, 2008 App. No. 06110002 Pilot for Mercury Control July 18, 2008, revised Dec. 1, 2009 App. No. 08020070 Sorbent Injection System Oct. 20, 2008, revised April 21, 2009 App. No. 08090057 Pilot for SNCR for NOx Control for Unit 3 April 28, 2010 App. No. 11060053 Pilot for Injection System for SO_2 Control June 30, 2011, revised Feb. 24, 2012

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 (I.D. No. 127855AAC)				
				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

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 Power Station (I.D. No. 137805AAA)						
800 South Washington Street Meredosia, Illinois Morgan County 10 employees	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 and FGC on Unit 5	2011 SO_2 emission rate = 0.55 lb/MMBtu 2011 SO_2 mass emissions = 2,747 tons	State Operating Permits: 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

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 Power Station (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 CAAPP Permit: September 29, 2005 App. No. 95090010 Appealed November 3, 2005

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address **Number of Employees**	**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 Power Station (I.D. No. 137805AAA)						
						(PCB 06-069) Stayed February 16, 2006

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 Power Station (I.D. No. 079808AAA)					
6725 North 500th Street Newton, Illinois Jasper County 155 employees	Unit 1 nominal 5,500 mmBtu/hr (1972)	Unit 2 nominal 5,500 mmBtu/hr (1975)	LNB OFA ESP with FGC Primary Air Duct Burners on Unit 2	2011 SO_2 emission rate = 0.55 lb/MMBtu 2011 SO_2 mass emissions = 20,871 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 December 20, 2010 App. No. 10070051 Flue Gas Desulfurization (FGD)

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 Power Station (I.D. No. 079808AAA)					
					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 CAAPP Permit: September 29, 2005

Table 1
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	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 Power Station (I.D. No. 079808AAA)					
					App. No. 95090066 Appealed November 3, 2005 (PCB 06-068) Stayed February 16, 2006

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Exhibit 3

Newton Energy Center FGD Project Construction Permit

Illinois Environmental Protection Agency, Issued to Ameren Energy Generating Company (Dec. 20, 2010).

File A9-3.2.10.4

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.

2.1 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.

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

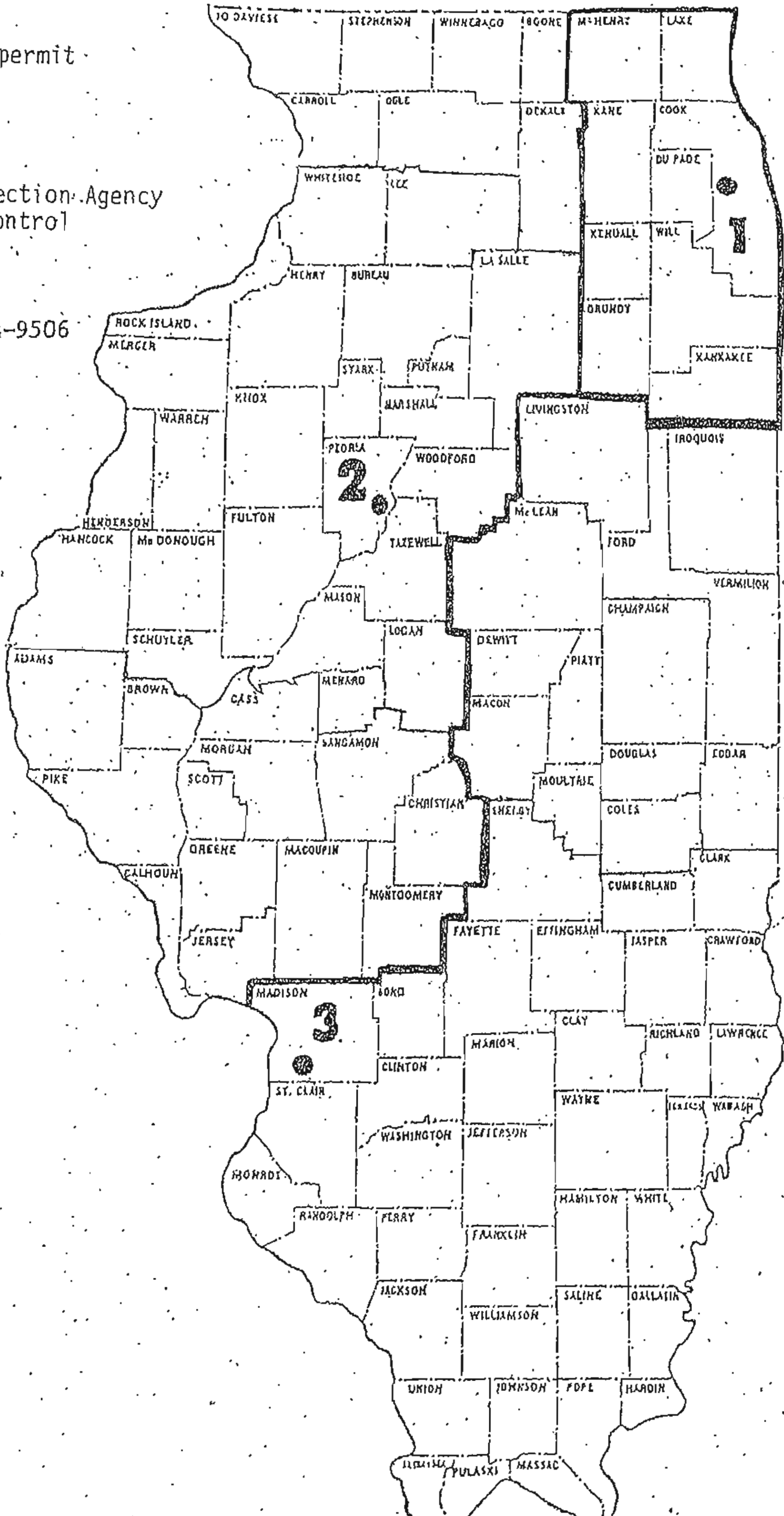


Exhibit 4

Ameren's MPS Opt-In Letter

Ameren, Letter to Jim Ross, Manager, Division of Air Pollution Control, Illinois Environmental Protection Agency (December 27, 2007).

Ameren Energy Resources

R. Alan Kelley
President & Chief Executive Officer

One Ameren Plaza
1901 Chouteau Avenue
PO Box 66149, MC 10
St. Louis, MO 63166-6149
314.554.2849
314.554.3066 fax
rakelley@ameren.com

December 27, 2007

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 - Notice of Intent

Ameren

Dear Mr. Ross:

In accordance with 35 Illinois Administrative Code Part 225 Subpart B Section 225.233 (b), Ameren Energy Resources, as authorized agent for Ameren Energy Generating Company, AmerenEnergy Resources Generating Company and Electric Energy Inc., submits this notice of intent that the owners of the following eligible electric generating units elect to demonstrate compliance with the multi-pollutant emission limitation as an alternative to the emission standards of Section 225.230. This notice of intent is submitted for the following emission units that are eligible electric generating units (EGUs):

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

AmerenEnergy 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

The electric generating units (EGUs) identified above are eligible to participate as an Multi-Pollutant Standard Group for the purpose of demonstrating compliance with the requirements of 35 Illinois Administrative Code Part 225 Subpart B Section 225.233. This notice of intent includes the following components as attachments to this submittal: the base emission rates for the EGUs and supporting data; a summary of current pollution control equipment installed; and a summary of additional pollution control equipment that will likely be installed to comply with the MPS.

The EGUs identified in this notice of intent have commenced commercial operation on or before December 31, 2004 and constitute all affected EGUs that were owned by the listed affiliates as of July 1, 2006.

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 Steven Whitworth at (314) 554 - 4908 if you have any questions concerning this submittal or if additional information is required.

Sincerely,

R. Alan Kelley
President, Ameren Energy Generating Company
President, AmerenEnergy Resources Generating Company
Director and Chairman, Electric Energy, Inc.

SCW/AEGAERGEEI_MPSnotice

Attachments

Ameren Energy Resources Company
Multi-Pollutant Standard Notice of Intent
Attachment A
Summary of Existing Pollution Control Equipment

Ameren Energy Generating Company

Facility	Facility I. D.	Emission Unit	Particulate Control	NOx Control	SO2 Control
Coffeen	135803AAA	01	ESP	OFA/SCR	
Coffeen	135803AAA	02	ESP	OFA/SCR	
Hutsonville	033801AAA	05	ESP		
Hutsonville	033801AAA	06	ESP		
Meredosia	137805AAA	01	ESP		
Meredosia	137805AAA	02	ESP		
Meredosia	137805AAA	03	ESP		
Meredosia	137805AAA	04	ESP		
Meredosia	137805AAA	05	ESP	LNB	
Newton	079808AAA	1	ESP	OFA/LNB	
Newton	079808AAA	2	ESP	OFA/LNB	

AmerenEnergy Resources Generating Company

Facility	Facility I. D.	Emission Unit	Particulate Control	NOx Control	SO2 Control
Duck Creek	057801AAA	1	ESP	LNB/SCR	FGD
E. D. Edwards	143805AAG	1	ESP	LNB	
E. D. Edwards	143805AAG	2	ESP	LNB	
E. D. Edwards	143805AAG	3	ESP	OFA/LNB/SCR	

Electric Energy, Inc.

Facility	Facility I. D.	Emission Unit	Particulate Control	NOx Control	SO2 Control
Joppa	127855AAC	1	ESP	LNB	
Joppa	127855AAC	2	ESP	LNB	
Joppa	127855AAC	3	ESP	LNB	
Joppa	127855AAC	4	ESP	LNB	
Joppa	127855AAC	5	ESP	OFA/LNB	
Joppa	127855AAC	6	ESP	OFA/LNB	

Ameren Energy Resources Company
Multi-Pollutant Standard Notice of Intent
Attachment B
Base Emission Rate Determination

Ameren MPS Base Annual Emission Rate Determination

2003 Company	Heat Input (mmBtu)	NOx Rate (#/mmBtu)	NOx (tons)	SO2 Rate (#/mmBtu)	SO2 (tons)
AEGC	158,452,698	0.259	20,527	1.14	90,117
AERGC	63,611,097	0.368	11,690	2.06	65,440
EEI	89,504,514	0.129	5,771	0.54	24,026
AER Illinois	311,568,309	0.244	37,988	1.15	179,583

2004 Company	Heat Input (mmBtu)	NOx Rate (#/mmBtu)	NOx (tons)	SO2 Rate (#/mmBtu)	SO2 (tons)
AEGC	171,427,867	0.249	20,710	1.06	90,532
AERGC	70,737,248	0.309	10,897	1.47	52,058
EEI	92,482,478	0.127	5,860	0.61	28,048
AER Illinois	334,647,593	0.224	37,467	1.02	170,638

2005 Company	Heat Input (mmBtu)	NOx Rate (#/mmBtu)	NOx (tons)	SO2 Rate (#/mmBtu)	SO2 (tons)
AEGC	160,864,003	0.253	18,494	1.04	83,905
AERGC	65,569,490	0.267	8,619	1.22	39,999
EEI	86,505,712	0.128	5,524	0.60	25,963
AER Illinois	312,939,205	0.235	32,637	1.01	149,867

Annual Average Company	Heat Input (mmBtu)	NOx Rate (#/mmBtu)	NOx (tons)	SO2 Rate (#/mmBtu)	SO2 (tons)
AEGC	163,581,523	0.243	19,910	1.08	88,185
AERGC	66,639,278	0.312	10,402	1.58	52,499
EEI	89,497,568	0.128	5,718	0.58	26,012
AER Illinois	319,718,369	0.225	36,031	1.04	166,696

MPS Rates	% of base rate	% of base rate
NOx at 0.11 or 52% of base rate in 2012	0.117	
SO2 at 0.33 or 44% of base rate in 2013		0.46
SO2 at 0.25 or 35% of base rate in 2015		0.36

Ameren MPS Base Seasonal NOx Emission Rate Determination

2003 Company	Heat Input (mmBtu)	NOx Rate (#/mmBtu)	NOx (tons)
AEGC	71,819,229	0.159	5,706
AERGC	26,917,427	0.255	3,427
EEI	37,416,091	0.126	2,359
AER Illinois	136,152,747	0.169	11,492

2004 Company	Heat Input (mmBtu)	NOx Rate (#/mmBtu)	NOx (tons)
AEGC	72,205,935	0.153	5,508
AERGC	30,512,335	0.180	2,750
EEI	30,951,063	0.126	1,956
AER Illinois	133,669,333	0.153	10,214

2005 Company	Heat Input (mmBtu)	NOx Rate (#/mmBtu)	NOx (tons)
AEGC	77,068,042	0.146	5,614
AERGC	28,277,603	0.170	2,397
EEI	37,004,541	0.126	2,328
AER Illinois	142,350,186	0.147	10,339

Seasonal Average Company	Heat Input (mmBtu)	NOx Rate (#/mmBtu)	NOx (tons)
AEGC	73,697,735	0.152	5,609
AERGC	28,569,121	0.200	2,858
EEI	35,123,898	0.126	2,214
AER Illinois	137,390,755	0.155	10,682

MPS Rates	% of base rate
NOx at 0.11 or 80% of base rate in 2012	0.124

Ameren Energy Resources Company
Multi-Pollutant Standard Notice of Intent
Attachment C
Summary of Likely Future Pollution Control Equipment

Ameren Energy Generating Company

Facility	Facility I. D.	Emission Unit	Mercury Control	NOx Control	SO2 Control
Coffeen	135803AAA	01	SCR/FGD	OFA/SCR	FGD
Coffeen	135803AAA	02	SCR/FGD	OFA/SCR	FGD
Hutsonville	033801AAA	05	ACI (2013)	OFA/LNB	
Hutsonville	033801AAA	06	ACI (2013)	OFA/LNB	
Meredosia	137805AAA	01	ACI (2013)		
Meredosia	137805AAA	02	ACI (2013)		
Meredosia	137805AAA	03	ACI (2013)		
Meredosia	137805AAA	04	ACI (2013)		
Meredosia	137805AAA	05	ACI (2009)	OFA/LNB	
Newton	079808AAA	1	ACI (2009)	OFA/LNB/SCR	FGD
Newton	079808AAA	2	ACI (2009)	OFA/LNB/SCR	FGD

AmerenEnergy Resources Generating Company

Facility	Facility I. D.	Emission Unit	Mercury Control	NOx Control	SO2 Control
Duck Creek	057801AAA	1	SCR/FGD	LNB/SCR	FGD
E. D. Edwards	143805AAG	1	ACI (2009)	OFA/LNB	
E. D. Edwards	143805AAG	2	ACI (2009)	OFA/LNB	
E. D. Edwards	143805AAG	3	ACI (2009)	OFA/LNB/SCR	FGD

Electric Energy, Inc.

Facility	Facility I. D.	Emission Unit	Mercury Control	NOx Control	SO2 Control
Joppa	127855AAC	1	ACI (2009)	OFA/LNB	FGD
Joppa	127855AAC	2	ACI (2009)	OFA/LNB	FGD
Joppa	127855AAC	3	ACI (2009)	OFA/LNB	
Joppa	127855AAC	4	ACI (2009)	OFA/LNB	
Joppa	127855AAC	5	ACI (2009)	OFA/LNB	FGD
Joppa	127855AAC	6	ACI (2009)	OFA/LNB	FGD

Exhibit 5

Affidavit of Gary M. Rygh

AFFIDAVIT OF GARY M. RYGH

I. BACKGROUND AND QUALIFICATIONS

1. My name is Gary M. Rygh. I am employed by Barclays Bank PLC (Barclays) in the investment banking division. With over 300 years of history and expertise in banking, Barclays operates in over 50 countries and employs over 140,000 people. Barclays provides large corporate, government and institutional clients with a full spectrum of solutions to their strategic advisory, financing and risk management needs. Barclays is one of the largest financial services providers in the world, and is also engaged in retail banking, credit cards, corporate banking, and wealth and investment management.

2. I am currently a Managing Director in the Global Power and Utility Group. Our group is responsible for the corporate finance analysis of, and strategic and capital markets transactions related to the utility and power sectors. I have been in the utility, power and energy investment banking business for approximately 17 years. I have worked extensively on strategic merger and acquisition assignments, debt and equity capital markets transactions, and other corporate finance related assignments in the electric, water and gas utility sectors. I have a Bachelors of Science degree in Commerce, with a concentration in Finance from the University of Virginia.

3. The purpose of my testimony is to provide a comprehensive overview of the significant challenges faced by the unregulated merchant generation subsidiaries of Ameren Corporation (Ameren) and how these challenges have severely limited the ability of those subsidiaries to access third party capital for the purposes of continued investment in state and federally mandated environmental control equipment. Ameren's unregulated merchant generation subsidiaries consist of the subsidiaries of Ameren Energy Resources (AER), including

Ameren Energy Generating Company (GENCO), AmerenEnergy Resources Generating Company, and Electric Energy, Inc.

II. THE CURRENT FINANCIAL CONDITION OF AMEREN ENERGY RESOURCES AND ITS SUBSIDIARIES

4. The deteriorating financial condition of AER coupled with the continued bearish commodity price outlook and uncertain regulatory landscape combine to prevent AER from being able to access any meaningful amount of additional third-party capital. Compounding this distress is the uncertainty regarding federal environmental regulations as well as the stringent state environmental mandates in Illinois that AER must comply with. The lack of flexibility and accelerated timeline required by the state of Illinois for the purchase and installation of environmental control equipment provides Ameren and AER with little flexibility in managing the credit quality, cash flows and the financial health of AER and its subsidiaries. Through cost reductions and continued investment by Ameren, AER has been able to complete the majority of capital expenditures required to comply with both state and likely federal mandates, however the excess stringency of the Illinois standards and shorter timeframe required for state compliance has hastened the deterioration of the financial health of AER. Further, the deterioration in the financial health of subsidiaries such as AER and a dire outlook for financial prospects, could very well inhibit the motivation of parent companies such as Ameren Corporation to continue investing in merchant generation businesses.

5. AER continues to face significant headwinds that have caused a substantial deterioration in credit quality, value to Ameren shareholders and ultimately the ability of AER to independently finance capital expenditures and cash flow shortfalls. AER is a merchant power generator with significant exposure to market prices, swings in load demand and commodity price volatility. AER's gross margin is subject to fluctuations in highly volatile wholesale

energy prices, correlations between power and fuel, and broad macroeconomic supply / demand dynamics. Given this market exposure to continued weak natural gas and power prices, shrinking margins and increasing environmental obligations, AER's financial health and access to capital have both been severely degraded. While the last several years have been difficult for AER, the current outlook is no better. Moody's in its report entitled "Low Natural Gas Prices Herald Long-Term Changes in US Energy Infrastructure" stated: *"Low natural gas prices will keep margins and cash flow under pressure for most unregulated power producers—particularly for those that generate electricity using coal, nuclear power or hydropower. Historically, power producers have used natural gas to meet peak electric demand, which typically determines the price at which these companies sell electricity. Low natural gas prices have encouraged gas-fired power production in North America, adding to the pressure on coal-fired plants, which face increasing environmental restrictions. We expect meaningful increases in fuel switching throughout North America, with natural gas plants favored over coal. Most unregulated power producers continue to hold a "hunker-down" strategy, conserving capital and liquidity in the hope of higher prices for electric power and natural gas. But even though most issuers have good cash reserves and undrawn credit facilities, current market conditions might outlast liquidity." – April 2012*

6. As shown in the Table 1 below, GENCO (AEG), AER's only rated subsidiary, has seen its credit rating cut 3 notches by Standard & Poor's (S&P) and 4 notches by Moody's Investor Services (Moody's) since 2008. The downgrades have been attributable, in large part, to a precipitous decline in net income and cash flow during that time period. AER's net income declined by 85% between 2008 and 2011, and a further decline in net income of up to 100% from 2008 is expected for 2012.

Table 1 ($ in millions)					
	2008	**2009**	**2010**	**2011**	**Current Forecast**
S&P Rating / Outlook	BBB- / Stable	BBB- / Stable	BBB- / Stable	BBB- / Stable	BB- / Negative
Moody's Rating / Outlook	Baa2 / Stable	Baa3 / Stable	Baa3 / Stable	Baa3 / Stable	Ba3 / Negative
Net Income	$352	$247	-$409	$45	$0

The 2010 net loss includes a $522 million after-tax asset impairment charge. The charge was recorded because management concluded that the carrying values of certain merchant generation segment assets, including goodwill, intangible assets, and fixed assets, likely would not be recoverable. The decline in the estimated value of these assets that led to recognition of the impairment charge was driven primarily by a sustained decline in market prices for electricity. Excluding the asset impairment charge, 2010 net income would have been $113 million.

7. AER and its subsidiaries have been some of the worst performing companies in their sector due to high reliance on coal fired generation and lack of fuel and market diversification. While the total capacity of AER when measured in megawatts is approximately 70% coal-fired the actual energy production and related gross margin are well over 90% derived from its coal fired plants. Moody's also said recently "*The ongoing shift in natural gas prices reflects a permanent change across the US energy sector, and will make it more difficult for coal to compete with natural gas as a power source in the future. A rise in gas-fired power generation will not be strong enough to raise natural gas prices on a sustained basis.*" – *April 2012*

8. Taking market share from coal has represented the marginal demand in the gas market for the past four years and will likely play a strong role in setting prices in the next few years. We receive many calls from clients who, when looking at spot coal and gas prices, wonder why gas is not displacing substantially more coal. After all, it would appear that gas-fired units run at substantially lower utilization rates than their coal counterparts, implying that underutilized gas-fired capacity can knock more coal out of the market. Gas prices have been falling relative to coal spot prices, especially after considering rail charges for coal, which are compounded by distance and strong diesel prices. If one were simply to compare the costs of producing a megawatt-hour (Mwh) of power from a coal plant using delivered spot coal prices in January 2012 with the cost of producing that same MWh from a gas-fired unit using delivered spot Henry Hub prices for the same month, the result would suggest that gas should be idling almost all coal. In reality, it is not the most efficient gas-fired unit standing ready to displace the least efficient coal-burning plant. The least efficient coal plant seldom operates, whereas the more efficient gas-fired units are likely running already. During light load periods (i.e., spring and fall) many coal units are idle, requiring gas prices to fall further to displace the cheaper-to-operate coal plants. Likewise, during peak demand periods (i.e., summer and winter), power demand may be high enough to require the near-full utilization of gas-burning units, leaving little spare capacity with which to displace coal plants. There is a high degree of load dependency and, therefore, seasonality to coal displacement. In the market, it is a continuum of gas and coal unit efficiencies vying for the marginal MWh.

9. The biggest driver of coal displacement and, therefore, the inability to source capital for investment in coal-fired generation is the cost of coal itself. There is quite a range of delivered coal prices in the US, owing to differing contract terms, transportation rates that

generally vary by distance, and a host of other factors. Transportation costs add considerably to the delivered cost of coal. For Powder River Basin (PRB) coal, transportation costs are often more than the cost of the coal itself, on a dollar per ton basis. With distance comes more cost, as transport is often miles-dependent. Complicating matters is the fact that the bulk of the coal in the US is sold under term contracts. PRB coal competes with natural gas at prices of $4.00/MMBtu and higher. But at prices below $3.00/MMBtu, natural gas begins to displace PRB coal at utilities in the US Midwest, south-central and eastern regions, due to transportation costs and available natural gas capacity. AER burns predominately Powder River Basin coal not Illinois Basin coal because environmental compliance requires it.

10. Unregulated power companies are more challenged by steadily increasing environmental mandates than their regulated utility peers. These regulations increase the operating costs of fossil fueled generation. Unlike regulated utilities, which can recover the costs of environmental regulations through authorized rates, unregulated power companies can only recover their costs through market driven prices and margins. Among the unregulated power companies, firms with coal-fired generating assets are at a significant financial disadvantage relative to companies with less carbon-intensive portfolios. Table 2 below demonstrates the disadvantage AER as well as coal-based companies like AER are facing. When comparing the cost to borrow additional debt capital, represented by the current yields on intermediate term bonds, AER and its peers face considerably higher costs even if the capital was available. As can been seen in Table 2, merchant generators that are less carbon intensive, including Calpine and Exelon Generating, enjoy a significant capital cost advantage.

Table 2					
	AER	**Edison Mission**	**Dynegy**	**Calpine**	**Exelon Generating**
Yield	10.0%	17.1%	16.9%	6.5%	3.4%
Credit Rating	Ba3/BB-	Caa1/B-	NR/D	B1/BB-	Baa1/BBB

III. INVESTOR AND RATING AGENCY ANALYSES OF AER

11. The increasingly negative view of AER by credit rating agencies, Ameren shareholders, current bondholders and equity research analysts not only severely limits AER from accessing additional third-party capital but also inhibit Ameren from further investing in AER without the risk of severe negative investor reaction that could adversely impact cost and access to capital. The credit rating agencies have been very clear that the financial distress being experienced by AER and its subsidiaries will have limited repercussions for Ameren and its regulated operations as long as Ameren does not support AER and its subsidiaries through capital injections. In effect, the credit rating agencies assume the financial health and value of AER and its subsidiaries has been so greatly weakened that Ameren has limited incentive to invest additional capital in AER, therefore the credit ratings of the unregulated, regulated and parent entities are allowed to diverge significantly.

12. In addition to credit rating agency prohibitions on Ameren's continued financial support of AER and its subsidiaries, shareholders have been very disappointed by the returns from the capital already employed in AER and its subsidiaries. There is zero or negative value attributable in the current Ameren share price from AER and its subsidiaries despite the significant environmental and other investments already made which is a clear indication that equity investors have no desire to see Ameren deploy any additional financial resources to its

unregulated businesses. To illustrate the decline in investor confidence and support for AER it is useful to examine the recent trading performance of historically issued GENCO bonds. Table 3 below highlights the trading prices for the outstanding bonds of GENCO at the beginning of 2012 versus the current prices.

Table 3

GENCO Bond	7.00%-Due 4/2018	6.30%-Due 2/2020	7.95%-Due 6/2032
Price on 1/2/2012	$104.50	$102.25	$99.50
Price on 5/1/2012	$86.63	$82.50	$81.50
Change Since 1/2/2012	*-$17.88*	*-$19.75*	*-$18.00*

13. The business conditions for the US unregulated power sector are poor with little expectation for near-term improvement. Unlike their regulated utility peers, unregulated power companies do not enjoy the benefits of recovery assurance for prudently incurred costs and investments. Instead, unregulated power companies can only turn to the markets to generate margins. Moreover, many of the factors that influence margin creation and sustained cash flow, such as gas commodity prices are beyond the control of Ameren or AER management. Operating costs are rising, along with capital expenditures. The costs of complying with increasingly restrictive environmental mandates are likely to introduce a shift in some generators strategic plans, as the differences in operating characteristics, volatility, liquidity requirements and capital structure formation among industry players becomes more evident. Additionally, unregulated power markets remain subject to political intervention, which appears to be a growing risk. These factors are primary drivers of the negative sentiment and outlook debt and equity investors have for AER.

14. Highlighted below in Table 4 and Table 5 below is the current commentary and summary conclusions by leading equity analysts that are responsible for providing independent guidance to large institutional and retail investors with regards to the power sector.

Table 4

"why would Ameren invest in Genco?"

"we do not assign any value to the merchant segment"

"we expect merchant margins to continue to decline meaningfully over the next few years."

"we estimate the merchant segment does not add nominal value"

"our primary concern about the company remains Ameren's merchant generation exposure."

"While the stock still trades at a slight discount to the group, we believe some discount is warranted due to the continuing drag on earnings resulting from the company's merchant energy exposure."

"We are encouraged by Amerens's growing regulated infrastructure investment opportunities and mitigation efforts at Merchant (cost controls, lower CapEx). However, we believe shares adequately reflect the EPS outlook. Our valuation range of $32-33/share reflects $35/share for the regulated operations and a negative $2-3/share for Merchant."

"We are also encouraged by updated CapEx disclosures (higher transmission and lower Merchant)."

Table 5 ($ in millions)		
Research Firm	*Equity Value of AER*	*2013 AER Est. Net Income*
Bank of America Merrill Lynch	$0	-$30
Goldman Sachs	-$950	NA
UBS	-$750	-$163
Wells Fargo	-$600	-$145

15. The credit rating agencies, whose views are critical to providers of debt capital, not only have a negative view on the credit quality of AER but have also made it abundantly clear that further support from the parent Ameren will have negative consequences on the credit quality of Ameren and its other subsidiaries. Below are some recent examples that reflect the substance of their views.

Credit Rating Agency Views Regarding Financial Condition, Liquidity, Asset Value and Outlook

"GenCo's margins have steadily declined due to lower demand because of the recession and by an increased supply of natural gas from shale gas that have contributed to lower natural gas prices. While GenCo continues to manage those areas that it can directly influence, such as reducing capital spending, maintaining its hedging program, and reducing its operation and maintenance (O&M) costs, sustained weak power prices will pressure its cash flow over the intermediate term. Furthermore, the prolonged weakness of the power markets, particularly the flattening of the forward curve, reduces the value of GenCo's hedging strategy to protect it from weak power prices. While GenCo's three-year hedging strategy provides a degree of price insulation over the short term, sustained depressed power prices would eventually undermine this credit enhancement". (S&P March 2012)

"We view Ameren's recent decision to significantly reduce its environmental capital spending at GenCo as prudent from Ameren Corp.'s perspective but believe the reduction adds considerable credit risk to GenCo. This decision will provide Ameren management with additional time to reevaluate its options and to assess its ability to meet federal and state environmental regulations even in the possible absence of a scrubber at Newton. However, the reduction of environmental capital spending also suggests management's lack of confidence in the longer-term economic sustainability of GenCo's business model. This reinforces our view that Ameren's support for GenCo is limited and that it expects GenCo to cover its cash needs as a stand-alone business even over the short term". (S&P March 2012)

"The downgrade of Ameren Genco's ratings reflects the worsening financial prospects for this predominantly coal-fired generating company as low power prices, higher fuel and transportation expenses, and EPA mandated environmental compliance requirements negatively affect the company's margins and cash flow generating ability", said Michael G. Haggarty, Senior Vice President. Moody's expects cash flow coverage metrics to continue to exhibit declining trends for at least the next two years, with any improvement in subsequent years highly dependent on a recovery in power prices, which may not occur. Last week, Ameren Genco announced drastic cutbacks in its environmental compliance expenditure program, specifically related to deceleration and possible cancellation of scrubber installation at its Newton plant, which could hamper the ability of the company to fully dispatch its merchant generation fleet as early as 2015, when Illinois multi-pollutant standards tighten. Although Ameren Genco does not have any long-term debt due until 2018, it may need to finance negative free cash flow in the interim with additional borrowings, the extent of which will depend on whether it decides to again move forward with the Newton scrubber project. The company maintains adequate liquidity predominantly as a result of a $500 million joint credit facility with the parent company that matures in September 2013. Moody's notes that Ameren may not be able to refinance the Ameren Genco bank credit facility on an unsecured basis without a parent company guarantee when it comes up for renewal next year. Moody's would expect the credit facility renewal to be addressed well before the September 2013 maturity date. The negative outlook on the ratings of Ameren

Genco reflects the low power price environment, the likelihood of further deterioration in financial metrics, anticipated weak cash flow generation for the next several years, the lack of a viable capacity market in MISO, the high degree of uncertainty regarding the status of the Newton scrubber project, and the possibility that the company's generating capability could be constrained beginning in 2015." (Moody's March 2012)

"Without the liquidity provided by the Ameren guaranteed Put Option Agreement and the power sales and marketing support provided by Ameren Energy Marketing Company, Ameren Genco would exhibit much less financial flexibility in the face of continued low power prices, deteriorating financial metrics, environmental capital expenditures, as well as the lack of capacity payments in the market in which it operates. The execution of the Put Option Agreement provides Ameren Genco critical time for current power market conditions to improve before it decides on whether to resume the installation of scrubbers at its Newton power plant, which it recently postponed." (Moody's April 2012)

Credit Rating Agency Statements Regarding the Impact to Ameren of any Addition Support of AER or its subsidiaries

"the reduction of environmental capital spending also suggests management's lack of confidence in the longer-term economic sustainability of GenCo's business model. This reinforces our view that Ameren's support for GenCo is limited and that it expects GenCo to cover its cash needs as a stand-alone business even over the short term." (S&P March 2012)

"The downgrade also reflects Moody's view that the Ameren parent company has limited flexibility to support its merchant generating business" (Moody's March 2012)

"Standard & Poor's Ratings Services' ratings on GenCo reflects its stand-alone credit profile with limited support from parent Ameren Corp." (S&P April 2012)

"The negative outlook on GenCo reflects our view that management's support for the merchant business is limited. Although Ameren could theoretically support GenCo during a period of financial stress, we believe that it would not do so to the detriment of the regulated utilities. As such, we view Ameren's support of GenCo as very limited and as a basis to separate the ratings." (S&P April 2012)

"The affirmation also reflects Moody's view that the parent company has thus far been unwilling to provide additional direct financial support to Ameren Genco. Other than sharing a joint bank credit facility and providing parent company counterparty guarantees on behalf of Ameren Energy Marketing Company, Ameren has thus far not provided direct financial support to Ameren Genco. This was most recently demonstrated by the significant cutbacks in the Genco's environmental compliance expenditures announced last week. To the extent that Ameren does provide more material direct financial support or other guarantees to Ameren Genco, the parent's rating or rating outlook could be adversely affected." (Moody's March 2012)

"The reduction from positive to stable rating outlook on Ameren takes into account the continued weakness at GenCo and Ameren's willingness to provide cash to shore up GenCo's liquidity." (S&P April 2012 after the Put Option Agreement was disclosed)

"The affirmation of the parent company also considers the relatively small contribution of Ameren Genco to Ameren's overall cash flow and risk profile compared to its regulated utility subsidiaries; and the parent's thus far limited and measured support for Ameren Genco and our expectation that it will not provide any material capital contributions or other direct financial support to this subsidiary" (Moody's March 2012)

IV. CONCLUSION

16. The value destruction experienced by historically invested capital providers prohibits the ability to source new capital for AER. Ameren has invested in AER approximately $1.0 billion for capital expenditures to comply with environmental regulations. . However, over the same time period the value of AER to Ameren shareholders has diminished from what was a substantial portion of Ameren's share price to what most analysts estimated as less than zero currently. The current GENCO (AEG) bondholders have also experienced multiple credit rating downgrades in addition to the value of their bonds declining rapidly in recent months. Given the experience of previous investors, the prospects of sourcing additional third-party capital are bleak.

17. Despite the persistent negative outlook and the current inability to source necessary third-party capital to complete the installation of environmental control equipment it should not be forgotten that while the financial health of AER and its subsidiaries is commodity sensitive it is also cyclical. Ameren and its shareholders have invested a significant amount of capital in AER over the last several years as the downturn in market conditions worsened. This capital could have been invested elsewhere or been used to raise the dividend to shareholders, yet the management of Ameren chose to weather increasing market headwinds in the face of shrinking support for AER while at the same time making the difficult decisions needed to reduce cost. It should not be lost upon those considering this variance that Ameren has invested considerable amount of capital to comply with state and federal environmental goals and has done so at the expense of short-term shareholder value. When the market begins its inevitable recovery, the capital already spent to comply with state and federal environmental mandates will

allow AER and its facilities to be amongst the best positioned generating assets in the region.

FURTHER, Affiant sayeth not.

Gary M. Rygh

Gary M. Rygh

Subscribed and sworn to before me
this 3 day of May 2012.

Margherita DeLouisa

MARGHERITA DeLOUISA
Registration # 01DE4842124
New York County, State of New York
License Expires 5/10/2015

Exhibit 6

Affidvit of Ryan J. Martin

AFFIDAVIT OF RYAN J. MARTIN

I. BACKGROUND AND QUALIFICATIONS

1. My name is Ryan Martin. I am employed by Ameren Services Company as an Assistant Treasurer and Manager of Corporate Finance. My business address is One Ameren Plaza; 1901 Chouteau Avenue, St. Louis, Missouri, 63103. Ameren Services Company provides business and corporate services such as financing to Ameren Corporation and its subsidiary companies.

2. I am responsible for managing Ameren Corporation and its subsidiary companies' short-term and long-term financing activities, including debt and equity issuances and credit facility arrangements, monitoring the company's liquidity position and key credit metrics, monitoring compliance with our debt agreements, managing relationships with credit rating agencies and banks, and monitoring capital markets for key developments, emerging risks, and opportunities, among other corporate-finance related activities. I received my Bachelor of Business Administration degree, with a concentration in Accountancy, in 1995 from the University of Notre Dame. I received my Master of Business Administration degree, with concentrations in finance, marketing, and strategy, in 2004 from Northwestern University's Kellogg School of Management.

3. I have over 16 years of experience in various audit, accounting, financial reporting, and finance roles. I began my career in 1995 at Arthur Andersen LLP and worked in the firm's Audit and Business Advisory practice for six years. I left Arthur Andersen in 2000 to join Career Education Corporation, a Chicago-based public company that owns and operates for-profit, post-secondary schools. At Career Education Corporation, I managed the company's

accounting and financial reporting functions and at various times was also responsible for accounts payable, payroll, and insurance. In 2007, I joined Ameren Services Company as Assistant Controller. In that role, I managed the Company's general accounting function and plant accounting function and was also responsible for accounting research and policy. In March of 2010, I transitioned to the Finance department and into my current position.

II. AMEREN CORPORATE ORGANIZATION AND FINANCING STRUCTURE

4. Ameren Corporation is a public utility holding company whose primary assets are the common stock of its subsidiaries including Ameren Missouri, Ameren Illinois, and Ameren Energy Resources. Appended to my affidavit as Attachment 1 is an organizational chart for Ameren Corporation and its principal operating companies. Ameren's subsidiaries are separate, independent legal entities with separate businesses, assets, and liabilities. AER consists of merchant generating operations including Ameren Energy Generating Company (GENCO), AER's only publicly registered and rated company, and Ameren Energy Resources Generating Company (AERG). The power generation business is capital intensive, and investments in pollution control equipment such as scrubbers for emission control typically cost hundreds of millions of dollars. Funding for capital projects can come from a variety of sources, including, among others, equity in the form of capital contributions or retained earnings and long or short term debt. For state rate-regulated companies such as Ameren Missouri, the costs of capital investments are ultimately expected to be recovered from rate payers through rates. In contrast, merchant generators such as AER are not assured receipt of state rate-regulated revenue streams from a captive customer base. While fixed-price power supply contracts may provide a limited degree of financial stability for AER, the revenues and profit margins of AER and most other merchant generators are based primarily on dynamic and competitive market-driven commodity

prices for, among other things, power and fuel, which can be highly volatile. Lenders consider the relative stability and predictability of revenue streams and cash flows in evaluating a company's creditworthiness and establishing borrowing and lending terms that are typically specified within a company's bond indentures or credit agreements. Third-party lenders, including bondholders and banks, and credit rating agencies, such as Standard & Poor's and Moody's, typically consider, among other things, a projection of future power prices in assessing the creditworthiness of a merchant generator borrower as well as investment risk. As set forth in more detail in paragraph 12, market prices for power have decreased dramatically over the last three years, which has impacted adversely AER's operating cash flows, its key credit metrics and ability to access, through AEG, external short-term and long-term capital markets.

5. GENCO is a registered company with the Securities and Exchange Commission (SEC), and its financials are publicly reported. GENCO's predicament mirrors the financial predicament facing all of Ameren's merchant generation segment. As reported in Ameren's SEC filings and as noted in the chart below, combined net income for Ameren's merchant generation segment (including AERG, GENCO, AER) has dropped precipitously.

2008	2009	2010	2011
$ 352	$ 247	$ (409)*	$ 45

***The 2010 net loss includes a $522 million after-tax asset impairment charge. The charge was recorded because management concluded that the carrying values of certain merchant generation segment assets, including goodwill, intangible assets, and fixed assets, likely would not be recoverable. The decline in the estimated value of these assets that led to recognition of the impairment charge was driven primarily by a sustained decline in market prices for electricity. Excluding the asset impairment charge, 2010 net income would have been $133 million.**

AER net income is expected to decline significantly once again during 2012, from $45 million in 2011 to between $0 and $25 million in 2012. Clearly, the depressed levels of AER earnings and cash flows, driven primarily by recent and continuing low power prices, are insufficient to fund large-scale capital projects such as the installation of scrubbers.

6. AER has taken a variety of steps during this recent and ongoing period of low power prices to conserve its cash and minimize its capital expenditures. In December 2011, Meredosia and Hutsonville ceased operations in lieu of the installation of pollution control equipment at facilities that are increasingly uneconomical. In addition, actual and forecasted cash outlays for GENCO's Newton scrubber project have been reduced dramatically. The pace of the Newton scrubber project has been significantly decelerated, and AER's ability to ultimately complete the project by 2015 is questionable given chronic unfavorable economic conditions. AER has expended considerable sums on pollution control-related projects. In fact, AER has spent in excess of one billion dollars on such capital investments, including the installation of expensive pollution control equipment at its Duck Creek, Edwards, Coffeen, and Newton energy centers. Such equipment includes scrubbers, SCRs and precipitators. AER has also constructed landfills and cooling basins and towers at its energy centers for purposes of pollution control and compliance with applicable environmental standards. The long-term funding for these investments originated from two primary sources: a $425M unsecured inter-company loan to AER from Ameren Corporation and $825M in unsecured debt publicly issued by GENCO and held by bondholders. The maturity dates for these financing instruments range from 2014 to 2032, including two public debt issuances coming due in 2018 and 2020. As part of the bondholders' efforts to secure their investment and as a condition to financing, restrictive covenants within GENCO's bond indenture impact the ability to secure additional debt financing from external sources. Those restrictions are described below.

III. DEBT COVENANTS IMPACT GENCO'S BORROWING CAPABILITY

7. Certain covenants within GENCO's bond indenture restrict GENCO's ability to incur addition indebtedness from external sources. Specifically, GENCO is prohibited by its

bond indenture covenants from borrowing additional funds from external, third-party sources if its interest coverage ratio is less than a specified minimum (2.5) or its leverage ratio is greater than a specified maximum (60%). GENCO's earnings and operating cash flows have been adversely affected by changes in the market price for power, which have significantly decreased over the last few years. In fact, based on management's projections of future earnings and cash flows, which are driven largely by current forward power price assumptions, it is expected that by the end of 2012, GENCO's interest coverage ratio will fall below the minimum level required for GENCO to incur additional external debt. Therefore, unless power price market conditions improve dramatically in the near term, GENCO will not be able to borrow additional funds from third-party lenders to finance, among other capital projects, the installation of scrubbers at Newton. Note that AER and AERG are not publicly registered companies, nor are they rated by credit rating agencies. Consequently, they have no direct access to public financial markets.

8. AER, GENCO, and AERG are participants in Ameren's non-state regulated utility money pool. In the past, this money pool, under which short-term intercompany loans may be available, has served as a source of short-term debt capital for companies within Ameren's merchant generation segment. While money pool borrowings are not restricted under the terms of GENCO's bond indenture, money pool borrowings are subject to Ameren control, and the availability of money pool funds is based on Ameren review of facts and circumstances existing at the time of any borrowing request. As addressed in further detail in Mr. Gary Rygh's affidavit, given the poor recent financial performance of Ameren's merchant generation segment and the bleak financial prospects for the business in light of, among other things, the current outlook for future power prices, Ameren has virtually no financial motivation to provide additional capital to AER. In fact, any additional investment or other direct financial support

provided by Ameren for its merchant generation segment would likely weaken the perceived creditworthiness and credit ratings of Ameren. . For these reasons, among others, Ameren management expects AER to fund its own operations without additional financial support from Ameren and, given the current outlook for the merchant generation business, Ameren is unlikely to provide additional debt or equity capital to AER.

IV. GENCO BOND MATURITIES

9. As noted above, GENCO has approximately $825 million in long-term public bonds outstanding. Approximately $300 million of this debt matures in 2018, and approximately $250 million of this debt matures in 2020. Generally, GENCO would plan to refinance these bonds in the public market and extend the maturity of the debt. However, if GENCO interest coverage ratios do not improve materially by 2018, indenture borrowing restrictions will prohibit GENCO from refinancing the 2018 maturity, and the $300 million will have to be repaid to bondholders. An inability to repay the bonds when due would constitute an event of default under the GENCO bond indenture, which would likely lead to a GENCO bankruptcy. The same is true for the 2020 maturity. An inability to refinance or repay the 2020 maturity would likely result in a GENCO bankruptcy. Given these pending maturities, a weak financial forecast, and covenant provisions that are expected to restrict GENCO's access to deb capital market, it is vitally important that GENCO preserve cash until market prices recover, operating results and cash flows improve, and borrowing capacity is restored. Failure to do so could threaten the long-term viability of the business and result substantial losses for all AER stakeholders, including both investors and those in the communities in which AER plants operate.

V. CREDIT RANKING IMPACTS GENCO'S BORROWING COST AND CAPABILITY

10. Long-term financing of environmental expenditures for Ameren's Illinois-based merchant generation business segment is dependent in large part on the financial performance, financial outlook, and overall creditworthiness of GENCO. Note that since February 28, 2012 and as described in Mr. Gary Rygh's Affidavit, both Moody's and Standard and Poor's have downgraded GENCO's senior unsecured credit rating three notches, from Baa3/BBB- to Ba3/BB-, largely due to the decline in power prices and the resulting adverse impact on recent and expected future interest coverage metrics. Each report outlines, among other things, key challenges GENCO is facing and the significant adverse impact of those challenges on GENCO's credit profile. The summary below shows the relative placement of current GENCO senior unsecured credit ratings on the credit rating scales used by Standard & Poor's and Moody's.

GENCO's Credit Ratings (Standard and Poor's and Moody's)

Standard and Poor's Senior Unsecured Credit Ratings	Moody's Senior Unsecured Credit Ratings	
AAA	Aaa	Investment Grade
AA+	Aa1	
AA	Aa2	
AA-	Aa3	
A+	A1	
A	A2	
A-	A3	
BBB+	Baa1	
BBB	Baa2	
BBB-	Baa3	
BB+	Ba1	Junk Bond

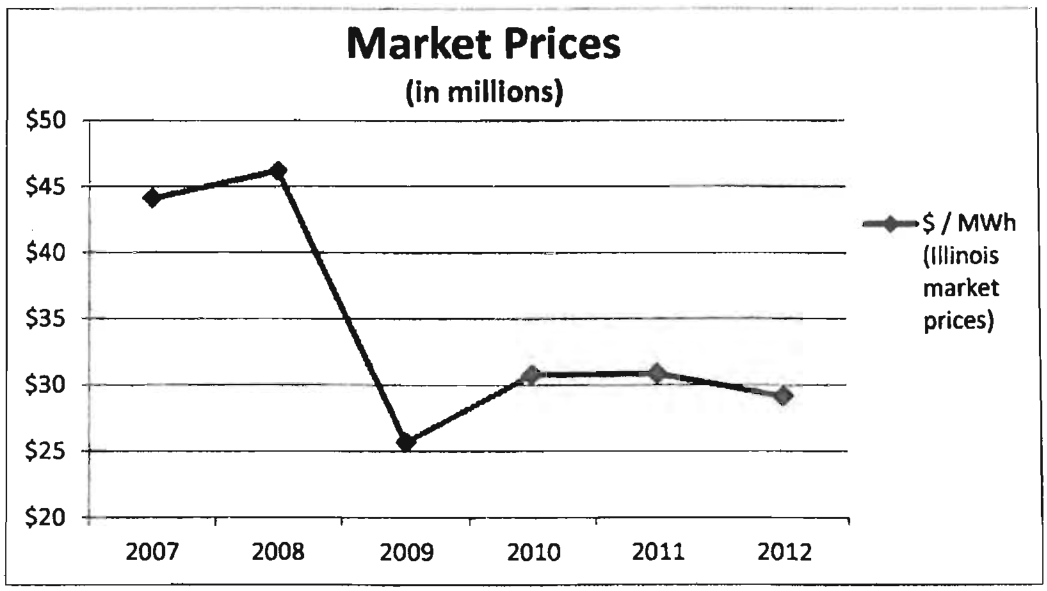
BB	
BB- GENCO	Ba3 GENCO
B	
C	

11. GENCO's recent rating downgrades have relegated GENCO's credit rating to non-investment grade "junk" status, which adversely impacts financing costs and capital market access. The following except from a recent Standard and Poor's credit report (appended hereto as Attachment. 2) summarizes the market pressures facing the AER's merchant generation business.

> *"GenCo's fair business risk profile reflects its ultimate dependence on the market price of electricity, which has recently sharply declined. GenCo's margins have steadily declined due to lower demand because of the recession and by an increased supply of natural gas from shale gas that have contributed to lower natural gas prices. While GenCo continues to manage those areas that it can directly influence, such as reducing capital spending, maintaining its hedging program, and reducing its operation and maintenance (O&M) costs, sustained weak power prices will pressure its cash flow over the intermediate term. Furthermore, the prolonged weakness of the power markets, particularly the flattening of the forward curve, reduces the value of GenCo's hedging strategy to protect it from weak power prices. While GenCo's three-year hedging strategy provides a degree of price insulation over the short term, sustained depressed power prices would eventually undermine this credit enhancement. This could lead Standard & Poor's to revise GenCo's business risk profile to "weak," almost certainly resulting in a ratings downgrade.*
>
> *We view Ameren's recent decision to significantly reduce its environmental capital spending at GenCo as prudent from Ameren Corp.'s perspective but believe the reduction adds considerable credit risk to GenCo. This decision will provide Ameren management with additional time to reevaluate its options and to assess its ability to meet federal and state environmental regulations even in the possible absence of a scrubber at Newton. However, the reduction of environmental capital spending also suggests management's lack of confidence in the longer-term economic sustainability of GenCo's business model. This reinforces our view that Ameren's support for GenCo is limited and that it expects GenCo to cover its cash needs as a stand-alone business even over the short term."*

VI. POWER PRICES CONTINUE TO DECLINE

12. Power prices are the most significant driver of AER revenues and, along with fuel prices, the most significant driver of AER operating margins and cash flows. Power prices began a precipitous drop in July 2008, have continued to fall, and are not expected to improve in the near to immediate term This drop in power prices, along with an increase in fuel costs, has resulted in a sharp decline in AER operating margins and cash flows available to cover operating costs and capital investment.



Given AER's inability to source financing from external sources and the lack of motivation for Ameren to provide additional financial support, AER operating margins and cash flows represent AER's only mechanism for funding both operating activities and capital investment. As noted above, AER's operating margins and cash flows are driven primarily by market prices for power. If power market prices remain depressed, as expected, internally-generated earnings and cash flows will be insufficient to fund major capital projects, including those required for environmental compliance. Ameren Corporation, which must balance the credit and lending needs of all of its operating companies and deploy capital in an efficient manner, will not t take on additional unsecured debt in the absence of a secure revenue stream to support such an obligation, nor will it provide to its merchant generation segment additional equity or debt capital in the absence of financial prospects that support such an investment. As a result, if the power market does not improve, and AER does not receive the variance relief requested, there are no viable financing mechanisms to fund the installation of the Newton scrubber, and AER would need to resort to extreme operational curtailments to comply with existing standards, likely including, but not limited to, the mothballing of units at the Joppa, Edwards, and/or Newton energy centers.

FURTHER, Affiant sayeth not.

DATED: 5/2/12

Ryan J. Martin

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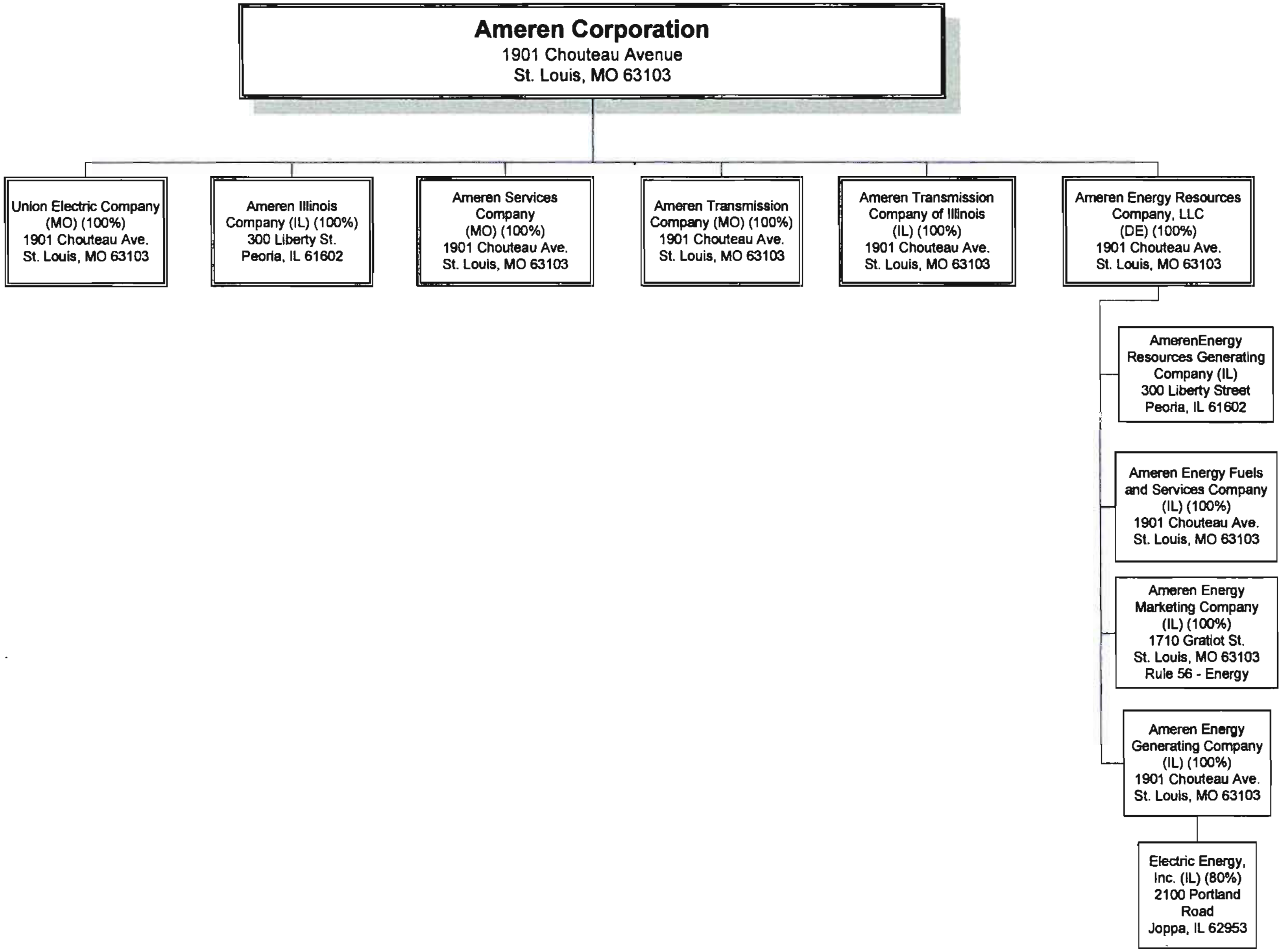
CH2\11152182.1\04.04.12

Stephanie Anne Gifford - Notary Public
Notary Seal, State of
Missouri - St. Charles County
Commission #11479771
My Commission Expires 1/30/2016

Stephanie Anne Gifford
5/2/2012

Attachment 1


Ameren Corporation
1901 Chouteau Avenue
St. Louis, MO 63103
Union Electric Company (MO) (100%) 1901 Chouteau Ave. St. Louis, MO 63103
Ameren Illinois Company (IL) (100%) 300 Liberty St. Peoria, IL 61602
Ameren Services Company (MO) (100%) 1901 Chouteau Ave. St. Louis, MO 63103
Ameren Transmission Company (MO) (100%) 1901 Chouteau Ave. St. Louis, MO 63103
Ameren Transmission Company of Illinois (IL) (100%) 1901 Chouteau Ave. St. Louis, MO 63103
Ameren Energy Resources Company, LLC (DE) (100%) 1901 Chouteau Ave. St. Louis, MO 63103
AmerenEnergy Resources Generating Company (IL) 300 Liberty Street Peoria, IL 61602
Ameren Energy Fuels and Services Company (IL) (100%) 1901 Chouteau Ave. St. Louis, MO 63103
Ameren Energy Marketing Company (IL) (100%) 1710 Gratiot St. St. Louis, MO 63103 Rule 56 - Energy
Ameren Energy Generating Company (IL) (100%) 1901 Chouteau Ave. St. Louis, MO 63103
Electric Energy, Inc. (IL) (80%) 2100 Portland Road Joppa, IL 62953

Attachment 2

STANDARD
&POOR'S

Global Credit Portal®
RatingsDirect®

March 5, 2012

Research Update:

AmerenEnergy Generating Co. Ratings Lowered And Placed On CreditWatch Negative

Primary Credit Analyst:
Gabe Grosberg, New York (1) 212-438-6043;gabe_grosberg@standardandpoors.com

Secondary Contact:
Gerrit Jepsen, CFA, New York (1) 212-438-2529;gerrit_jepsen@standardandpoors.com

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Research Update:

AmerenEnergy Generating Co. Ratings Lowered And Placed On CreditWatch Negative

Overview

- U.S. energy company AmerenEnergy Generating Co. recently disclosed that it expects its ability to borrow additional funds from external third parties as of March 31, 2013, will be limited.
- We are lowering our corporate credit and senior unsecured debt ratings on AmerenEnergy Generating to 'BB-' from 'BB'.
- We have placed the ratings on CreditWatch with negative implications.
- The CreditWatch negative placement reflects the 1 in 2 probability that we will lower our ratings on the company in the very near term.

Rating Action

On March 5, 2012, Standard & Poor's Ratings Services lowered its corporate credit and senior unsecured debt ratings on AmerenEnergy Generating Co. (GenCo) to 'BB-' from 'BB' and placed the ratings on CreditWatch with negative implications. The '3' recovery rating on GenCo's senior unsecured debt, indicating expectations of meaningful (50%-70%) recovery in the event of payment default, is unchanged.

Rationale

We view AmerenEnergy Generating Co.'s (GenCo) recently disclosed projected inability to borrow additional funds from third parties as of April 2013 as a material ratings constraint. Absent GenCo's ability to borrow from third parties, GenCo would most probably not be able to absorb high-impact, low-probability events without parental support. Unless management presents a very credible plan to avert this scenario, we would revise our assessment of GenCo's liquidity to "less than adequate" from "adequate" (as our criteria define the terms), which would lead to a further downgrade.

Our 'BB-' corporate credit rating on GenCo is based on its "fair" and "aggressive" (as our criteria define the terms) business risk and financial risk profiles. Additionally, our 'BB-' corporate credit rating on the company continues to assume a very limited degree of support from parent Ameren Corp. Furthermore, low power prices suggest that Ameren's economic incentive to support GenCo is diminishing and thus we may decide to rate GenCo based on its stand-alone credit quality. In such a scenario, we would likely lower our corporate credit rating on GenCo further.

GenCo's fair business risk profile reflects its ultimate dependence on the market price of electricity, which has recently sharply declined. GenCo's margins have steadily declined due to lower demand because of the recession and by an increased supply of natural gas from shale gas that have contributed to lower natural gas prices. While GenCo continues to manage those areas that it can directly influence, such as reducing capital spending, maintaining its hedging program, and reducing its operation and maintenance (O&M) costs, sustained weak power prices will pressure its cash flow over the intermediate term. Furthermore, the prolonged weakness of the power markets, particularly the flattening of the forward curve, reduces the value of GenCo's hedging strategy to protect it from weak power prices. While GenCo's three-year hedging strategy provides a degree of price insulation over the short term, sustained depressed power prices would eventually undermine this credit enhancement. This could lead Standard & Poor's to revise GenCo's business risk profile to "weak," almost certainly resulting in a ratings downgrade.

We view Ameren's recent decision to significantly reduce its environmental capital spending at GenCo as prudent from Ameren Corp.'s perspective but believe the reduction adds considerable credit risk to GenCo. This decision will provide Ameren management with additional time to reevaluate its options and to assess its ability to meet federal and state environmental regulations even in the possible absence of a scrubber at Newton. However, the reduction of environmental capital spending also suggests management's lack of confidence in the longer-term economic sustainability of GenCo's business model. This reinforces our view that Ameren's support for GenCo is limited and that it expects GenCo to cover its cash needs as a stand-alone business even over the short term.

GenCo's financial risk profile is aggressive and reflects its stand-alone financial risk profile. The aggressive financial risk profile also reflects Standard & Poor's base-case scenario of adjusted funds from operations (FFO) to total debt at about 15% and adjusted total debt to total capital at about 50% over the next 12 months. For the 12 months ending Dec. 31, 2011, adjusted FFO to debt was 24.2% or higher than the 22.7% at year-end 2010, adjusted debt to EBITDA was 3.0x or slightly better from 3.1x at year-end 2010, and adjusted debt to total capital was 48.5% or improved from the 51.4% at year-end 2010. Should power prices continue to remain weak, our stress-case scenario indicates that FFO to debt would decline to below 12% and we would revise GenCo's financial risk profile to highly leveraged and likely further lower our credit rating on GenCo.

Even with the planned reduction in capital spending, we expect that GenCo's discretionary cash flow will turn negative and that it will meet its near-term cash needs through its availability under its existing credit facility.

Liquidity

While GenCo's liquidity is currently adequate based on our assessment for the next 12 months, absent management detailing a credible plan that enhances its liquidity position for the period after March 31, 2013, we will revise our liquidity assessment to "less than adequate."

We base our liquidity assessment on the following factors and assumptions:

- We expect the company's liquidity sources (including cash, FFO, and credit facility availability) over the next 12 months to exceed its uses by more than 3x.
- GenCo does not have long-term debt maturities until 2018.
- Even if FFO declines by 100%, we believe net sources would still be more than 1.2x of cash requirements mostly due to the availability on its credit facility.

In our analysis, we assumed liquidity of about $650 million over the next 12 months, primarily consisting of cash, FFO, and availability under its credit facility. GenCo's $500 million credit facility expires in September 2013. We estimate the company will use about $200 million over the same period for capital spending and working capital needs.

GenCo's bond indenture includes financial covenants that must be met for GenCo to incur additional indebtedness. These financial covenants include a debt to capital ratio of no greater than 60% and a minimum interest coverage ratio of 2.5x. As of Dec. 31, 2011, the debt to capital ratio was 43% and the interest coverage ratio was 4.3x. While we expect that the debt to capital ratio will be maintained at below 50% over the intermediate term, we expect that the interest coverage ratio will drop to about 2.3x in 2013, reflecting weaker operating cash flows as a direct result of weak market power prices.

Recovery analysis

GenCo's unsecured notes are rated 'BB-' and are on CreditWatch with negative implications. The '3' recovery rating indicates our expectations of meaningful (50%-70%) recovery. We will publish a full recovery report on RatingsDirect following the release of this report.

CreditWatch

The CreditWatch with negative implications is based on the 50% probability that we will lower our ratings on GenCo in the very near term. We would lower the ratings if we determine that GenCo's liquidity is less than adequate under our criteria, if we view management's liquidity strategy for the period after March 31, 2013, to be insufficient, or if we determine that we should base our credit rating on GenCo solely on its stand-alone credit quality, without any support from parent Ameren Corp.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Criteria Guidelines For Recovery Ratings On Global Industrials Issuers' Speculative-Grade Debt, Aug. 10, 2009
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009

- Analytical Methodology, April 15, 2008
- Standard & Poor's Extends Recovery Ratings To Unsecured Speculative-Grade Corporate Issues, March 21, 2008

Ratings List

Downgraded; CreditWatch Action; Recovery Rating Unchanged

	To	From
AmerenEnergy Generating Co.		
Corporate Credit Rating	BB-/Watch Neg/--	BB/Negative/--
Senior Unsecured	BB-/Watch Neg	BB
Recovery Rating	3	3

Complete ratings information is available to subscribers of RatingsDirect on the Global Credit Portal at www.globalcreditportal.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

Exhibit 7

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 Manager 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 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 with Ameren 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.

2. In 2006, the State of Illinois adopted regulations pertaining to mercury emissions. Thereafter in 2007, the AmerenMPS 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 NO_x and SO_x 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 NO_x and SO_2. As set forth more fully in the Petition for Variance and the affidavits of Ryan Martin and Gary Rygh, depressed power market

conditions and the uncertain regulatory climate created by the federal courts rejection and/or suspension of federal air quality regulations has combined to make compliance with the SO_2 emission limits of 0.25 and 0.23 pounds per million British thermal units ("lbs/MMBtu") in calendar years 2015 and 2017, respectively, under section 225.233(e)(2)(C) of the MPS a significant economic hardship. Therefore, on behalf of AER, we are seeking a delay in the implementation dates for those rates from 2015 and 2017 to 2020 and 2021, respectively. It is important to note that we are **not** seeking a change to either the NO_x limits or the mercury requirements. In consideration of this limited time extension and to mitigate the environmental impact of the requested variance relief, AER proposes as part of its mitigation plan to immediately comply with a more stringent SO_2 limit than contained in the current rule.

3. The compliance plan will result in a net environmental benefit as compared to the level of reductions required by current MPS requirements should the variance relief not be granted. This is because the proposed compliance plan emission rate is set at a level at which uncontrolled units at the Meredosia and Hutsonville energy centers will not be able to resume operations without additional control technology being installed within the generating system. There are no plans to install additional controls at either the Hutsonville or Meredosia energy centers and, as a result, an emission reduction from the current level of emissions will be realized for the duration of the variance by not operating the units. The current SO_2 limits required in the MPS along with the proposed SO_2 emission limit that AER proposes as part of its compliance plan is set forth below:

Current Rule SO_2 System Average		**Proposed Compliance Plan SO_2 System Average**	
2010 – 2013:	0.50 lb/MMBtu	2010 – 2011:	0.50 lb/MMBtu
2014:	0.43 lb/MMBtu	**2012 – 2019:**	**0.38 lb/MMBtu**
2015 – 2016:	0.25 lb/MMBtu	2020:	0.25 lb/MMBtu
2017+:	0.23 lb/MMBtu	2021:	0.23 lb/MMBtu

4. Appended to my testimony as Attachment 1 are calculations that depict the level of SO_2 emissions expected to occur under the current MPS as compared to projected emissions calculated under the compliance plan. In order to equalize the comparison, AER used the same average heat input projections as were used to support the 2009 rule revisions to the MPS. Based upon those calculations, by implementing a more stringent emission rate in 2012, there is a net reduction of SO_2 tons as compared to projected emissions under the existing rule resulting in an overall environmental benefit.

Current Rule SO_2 Projected Emissions 2010 through 2021 = 694,510 tons

Compliance Plan SO_2 Limits Projected Emissions 2010 through 2021 = 665,294 tons

Overall SO_2 Reduction 2010 through 2021 = 29,217 tons

5. I participated in the preparation of the Petition for Variance to the extent it discusses Ameren Services Company and AER.

6. I have read the Petition for Variance and the facts stated therein with regard to AER Illinois fleet information, the detailed compliance plan, environmental impact, and compliance with federal law are true and correct to the best of my knowledge and belief.

FURTHER, Affiant sayeth not.

Steven C. Whitworth

Subscribed and sworn to before me
this 1st day of May 1, 2012.

Notary Public

Danielle R. Mos- -p - -ary Public
Notary Seal, State of
Missouri - Jefferson County
Co - 027
My Co sion es 7/21/2013

Ameren Energy Resources Alternative SO2 Limit Comparison to the Current MPS

Year	Baseline Heat Input lb/MMBtu	MPS Baseline SO2 Tons	Variance SO2 Tons	Cumulative SO2 Variance Reduced Tons
2010	340,446,252	85,112	70,560	14,552
2011	340,446,252	85,112	72,539	27,125
2012	340,446,252	85,112	56,986	55,251
2013	340,446,252	85,112	56,986	83,377
2014	340,446,252	73,196	56,986	99,587
2015	340,446,252	42,556	56,986	85,157
2016	340,446,252	42,556	56,986	70,727
2017	340,446,252	39,151	56,986	52,892
2018	340,446,252	39,151	56,986	35,058
2019	340,446,252	39,151	56,986	17,223
2020	340,446,252	39,151	34,857	21,518
2021	340,446,252	39,151	31,452	29,217
Total		694,510	665,294	29,217

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

Exhibit 8

EPA gives oil companies more time to capture emissions from wells

Juliet Eilperin and Steven Mufson, Washington Post, Apr. 18, 2012.

The Washington Post

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EPA gives oil companies more time to capture emissions from wells

By Juliet Eilperin and Steven Mufson, Published: April 18

The Environmental Protection Agency said Wednesday that it will delay requirements for capturing air emissions from oil and gas wells until 2015, though in the interim the agency will impose other requirements, including gas flaring, that it said would reduce the release of smog-forming and toxic chemicals by 90 percent.

The move represents a victory for firms that use hydraulic fracturing to tap natural gas resources trapped in shale rock. The American Petroleum Institute, which has been harshly critical of the Obama administration's policies, said EPA's final rules made "constructive changes" from rules the agency proposed earlier.

Half a dozen environmental groups also praised the new regulations, which they said would "result in major reductions" of volatile organic compounds (VOCs), toxic benzene and natural gas, or methane, a potent contributor to climate change.

The issue of whether to regulate drilling emissions has become a political football in an election year and amid the boom in shale gas drilling over the past three years.

President Obama has talked about the need to tap shale gas in an environmentally responsible way. The oil and gas industry has pressed him to open up federal lands for even more drilling and to keep EPA out of fracking regulation. Environmental groups have urged EPA to step in to prevent water pollution and natural gas leaks from pipelines or during drilling that could undermine the climate benefits that gas has over coal.

Under the Clean Air Act, the EPA has the authority to regulate emissions from the drilling activity. But the oil and gas industry has argued that the task should be left in the hands of state regulators.

Assistant EPA administrator Gina McCarthy said Wednesday that "this is a reasonable step for national regulation to try to address." She estimated that there have been 12,000 gas wells drilled using hydraulic fracturing.

McCarthy said the agency delayed requirements for gas capture because of concerns about the availability and cost of equipment needed and the worker training needed on that equipment. But she said that the gas capture method known as "green completion" is already used for about half the wells drilled and that ultimately companies would save money by capturing compounds that can be sold as fuel and chemical feedstocks.

In the meantime, she said, while flaring is wasteful, it would eliminate 90 percent of volatile organic compounds. Moreover, flaring natural gas, or methane, breaks down the methane into water and carbon dioxide. As a greenhouse gas, methane is more than 20 times more potent than carbon dioxide.

Howard Feldman, director of regulatory and scientific affairs for the American Petroleum Institute, said the changes will "push back" requirements to capture air pollutants at well sites until 2015 but will call for "a whole host of" other requirements, including new valves. The agency will phase in over one year a requirement to put captured gas in storage tanks at well sites, for example.

“On the whole, we believe EPA has made constructive changes in the rule, which will reduce emissions while allowing our member companies to keep producing the oil and gas the country needs,” Feldman said in an interview.

The industry had sought to exempt wells with low emissions from having to capture the volatile organic compounds released during hydraulic fracturing, Feldman said, but EPA refused to do so.

About a month ago, senior oil and gas company executives on the board of API met with Obama senior adviser Valerie Jarrett about the hydraulic fracturing proposal and other energy issues. Feldman would not speculate on whether the meeting helped shape the new requirements, but he said the industry made “cogent and technically-supported arguments for our position” in the course of conversations with White House and EPA officials.

“I hope every place we made those arguments they resonated,” he said.

Exhibit 9

Public Notice of Winning Bidders and Average Prices

Public Notice of Winning Bidders and Average Prices

Ameren Illinois Company February 10, 2012 Procurement of Standard Energy Products

February 16, 2012

On February 10, 2012, Levitan & Associates, as one of the Illinois Power Agency's procurement administrators, received bids for the sale of electricity to Ameren Illinois Company, in a request for proposals held pursuant to Section 16-111.5(k-5) of the Public Utilities Act. This public notice reveals the names of the successful bidders and the load weighted average of the winning bid prices.

The names of the successful bidders for the above-described procurement event are as follows:

Ameren Energy Marketing

BP Energy Company

Exelon Generation Company

Iberdrola Renewables

There were five energy products involved in this procurement, identical except for their delivery periods. Each product is a constant around-the-clock (24x7) supply of electric energy for each hour of the delivery period. The constant quantity sought under this procurement was 650 Megawatts (MWs), in 50 MW increments, in all five delivery periods. The total quantities of the bids selected and the average prices of those bids are shown in the following table:

Average Winning Prices and Quantities.

Period	Jun2013-May2014	Jun2014-May2015	Jun2015-May2016	Jun2016-May2017	Jun2017-Dec2017
MW	650	650	200	-	-
Hours	8,760	8,760	8,784	8,760	5,137
MWHs	5,694,000	5,694,000	1,756,800	-	-
Average Price	$29.51	$31.44	$33.62	n/a	n/a

Public Notice of Winning Bidders and Average Prices
ComEd February 10, 2012 Procurement of Standard Energy Products

February 16, 2012

On February 10, 2012, NERA Economic Consulting, as one of the Illinois Power Agency's procurement administrators, received bids for the sale of electricity to Commonwealth Edison Company ("ComEd"), in a request for proposals held pursuant to Section 16-111.5(k-5) of the Public Utilities Act. This public notice reveals the names of the successful bidders and the load weighted average of the winning bid prices.

The names of the successful bidders for the above-described procurement event are as follows:

J.P. Morgan Ventures Energy Corporation

Morgan Stanley Capital Group Inc.

Shell Energy North America (US), L.P.

The only contract sought through this procurement was a constant around-the-clock (24x7) supply of electric energy for each hour of the four-year, seven-month period from June 1, 2013 through December 31, 2017. The constant quantity sought under this procurement was 450 Megawatts (MWs), in 50 MW increments. The lowest nine bids (adding up to 450 MW) were selected. The average winning bid price was $32.57 per Megawatt-hour (MWH). However, the contract calls for an automatic price increase of 2.5% each June 1. As a result, the effective average price will vary as shown below:

Effective Average Winning Prices and Quantities.

Period	Jun2013-May2014	Jun2014-May2015	Jun2015-May2016	Jun2016-May2017	Jun2017-Dec2017
MW	450	450	450	450	450
Hours	8,760	8,760	8,784	8,760	5,137
MWHs	3,942,000	3,942,000	3,952,800	3,942,000	2,311,650
Average Price	$32.57	$33.39	$34.22	$35.07	$35.95

Exhibit 10

Development Strategies Memorandum

***Economic impacts of E.D. Edwards and Joppa Energy Centers of Illinois and surrounding market areas*, Memorandum to Mike Kearney, Manager, Economic Development, Ameren Services from Development Strategies (Apr. 19, 2012)**

Memorandum

To: Mike Kearney, Manager, Economic Development, Ameren Services

From: Robert M. Lewis, Brian Licari, and Yash Yedavalli

Date: April 19, 2012

Re: Economic Impacts of E.D. Edwards and Joppa Energy Centers of Illinois and surrounding market areas

In April, 2012, Development Strategies (DS) was commissioned to conduct an independent analysis of the economic impact that the operations of Ameren Energy Resources (AER) Corporation's E.D. Edwards Energy Center (Peoria County, Illinois) and Joppa Energy Center (Massac County, Illinois) have on the Illinois economy and on their respective economic multi-county regions. Development Strategies is pleased to submit this analysis of the direct and indirect economic impacts for each facility.

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

The number of jobs at the E.D. Edwards Energy Center is 110 and there are 235 at the Joppa Energy Center. We determined which counties in the "region" of each plant are home to a large majority of employees and have calculated economic impacts within those regions. Four Illinois counties make up the primary economic impact region in the case of Edwards, which is home to 97 of its 110 employees. Three counties make up the primary economic impact region in the case of Joppa, which is home to 134 of its 235 employees; additionally, Joppa has 71 of its 235 employees residing in the neighboring state of Kentucky. Because those employees spend the bulk of their incomes not in Illinois, they are excluded from the impact analysis within Illinois. See map "AER: Edwards and Joppa Energy Center Labor Markets" for the local market area boundaries.

Indirect economic impacts measure the "ripple effect" of wages and expenditures associated with AER's direct spending. For instance, plant 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 an Ameren facility 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 each plant 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 economy because some wages and expenditures will be spent outside of the regions in which they are located and possibly even outside the state of Illinois. For this reason, multiplier coefficients are finite and, therefore, measureable.

METHODOLOGY

The analysis of the direct and indirect economic impacts of each AER facility relied on spending and workforce information provided by Ameren, 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 regions around each 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 AER analysis focuses on the multi-county regions noted above and on the state as a whole. That is, each facility has two economic impact tables associated with it: the state and its own 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 each 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 each energy center's direct spending.

- **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 AER facilities.

Multipliers are provided for various economic sectors. The direct, non-labor, operational spending by each plant falls within the Utilities sector; the employee earnings paid by AER fall within the Households sector; 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 regions are applied to the *capital expenditure* figures of the respective plants,

- The *utilities* multiplier coefficients for the state and regions are applied to the *operational expenditures* of the respective plants, and

- The *households* multiplier coefficients for the state and regions are applied to the *employee compensation* figures of the respective plants. 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: We chose not to include the annual fuel expenditures for each energy center in our analysis. From 2008 to 2011, Edwards had an average annual fuel expenditure of $4,660,900 in 2012 dollars and Joppa had an average annual fuel expenditure of $8,331,000 in 2012 dollars. Though a small portion these expenditures likely occur within Illinois, the vast majority of these expenditures occur outside of Illinois (out of state coal and transportation costs); 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 each AER Energy Center has the following economic impact on the Illinois economy on the following pages. Each table summarizes Ameren's direct spending at each energy center (top line in the table), the multipliers for Illinois or the market area, the multiplier effects resulting from Ameren's operational spending, and the total direct and indirect economic impacts generated.

IMPACTS ON THE STATE OF ILLINOIS

Table 1: Annual Economic Impact of Ameren's Edwards Energy Center Operations on the State of Illinois

	Annual Average in 2012 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*	*Total*
Direct Spending	$ 16,620,000	$ 15,384,000	$ 12,387,000	$ 44,391,000
MULTIPLIERS				
Output	2.329	1.502	1.442	0.557
Earnings	0.715	0.286	0.397	0.477
Employment	15.589	4.601	10.422	10.359
ADDED ECONOMIC IMPACT ON ILLINOIS				
Output	$ 38,710,000	$ 23,110,000	$ 17,860,000	$ 79,680,000
Earnings	$ 11,870,000	$ 4,390,000	$ 4,910,000	$ 21,170,000
Indirect Jobs Held by Illinois Residents	260	71	129	460
TOTAL ECONOMIC IMPACT ON ILLINOIS				
Output (Total Economic Activity)				$ 124,071,000
Earnings				$ 33,557,000
Direct Jobs at Edwards Energy Center				110
Total Direct and Indirect Jobs at Edwards Energy Center				570

[1] *Actual operating data from 2008-2011 adjusted to 2012 dollar amounts and averaged*

The top of the table shows the direct expenditures by Ameren at the Edwards Energy Center totaling approximately $44.4 million in 2012. Since all of the employees at this energy center live in Illinois, the employee compensation expenditure represents the total labor expenditure at the Edwards Energy Center. Additional results are discussed below:

- The $44.4 million spent by Ameren at Edwards Energy Center triggered an additional $79.7 million in value added activity in Illinois, of which $21.2 million was household earnings that supported 460 jobs. The multipliers vary for different types of major expenditures shown at the top of the table.
- The estimated output (economic activity) triggered by Edwards Energy Center's direct operations ($44.4 million) and the added multiplier effects ($79.7 million) were $124.1 million for Illinois.
- Of that amount, Edwards Energy Center's operations triggered nearly $33.6 million in household earnings for workers in Illinois, including $12.4 million in direct compensation for employees and $21.2 million in added earnings from the multiplier effects.
- In total, Edwards Energy Center's operations supported 570 jobs in Illinois, including 110 direct jobs and approximately 460 jobs added through the multiplier effects.

Table 2: Annual Economic Impact of Ameren's Joppa Energy Center Operations on the State of Illinois

	Annual Average in 2012 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 28,205,000	$ 33,551,000	$ 14,895,000	$ 76,651,000
MULTIPLIERS				
Output	2.329	1.502	1.442	0.557
Earnings	0.715	0.286	0.397	0.465
Employment	15.589	4.601	10.422	9.775
ADDED ECONOMIC IMPACT ON ILLINOIS				
Output	$ 65,700,000	$ 50,400,000	$ 21,470,000	$ 137,570,000
Earnings	$ 20,150,000	$ 9,580,000	$ 5,910,000	$ 35,640,000
Indirect Jobs Held by Illinois Residents	440	154	155	749
TOTAL ECONOMIC IMPACT ON ILLINOIS				
Output (Total Economic Activity)				$ 214,221,000
Earnings				$ 50,535,000
Direct Jobs at Joppa Energy Center				164
Total Direct and Indirect Jobs at Joppa Energy Center				913

[1]*Actual operating data from 2008-2011 adjusted to 2012 dollar amounts and averaged*

[2]*Estimate based on number of employees who reside in Illinois (164 of 235) and overall average labor expenditure per employee*

The top of the table shows the direct expenditures by Ameren at the Joppa Energy Center totaling approximately $76.7 million in 2012. Employee compensation is an estimate based on the number of Joppa employees that live in Illinois (164 of 235). Additional results are discussed below:

- The $76.7 million spent by Ameren at Joppa Energy Center triggered an additional $137.6 million in value added activity in Illinois, of which $35.6 million was household earnings that supported 749 jobs. The multipliers vary for different types of major expenditures shown at the top of the table.
- The estimated output (economic activity) triggered by Joppa Energy Center's direct operations ($76.7 million) and the added multiplier effects ($137.6 million) were $214.2 million for Illinois.
- Of that amount, Joppa Energy Center's operations triggered nearly $50.5 million in household earnings for workers in Illinois, including $14.9 million in direct compensation for employees and $35.6 million in added earnings from the multiplier effects.
- In total, Joppa Energy Center's operations supported 913 jobs in Illinois, including 164 direct jobs and approximately 749 jobs added through the multiplier effects.

IMPACTS ON THE RESPECTIVE MULTI-COUNTY REGIONS

Table 3: Annual Economic Impact of Ameren's Edwards Energy Center Operations on Market Area

	Annual Average in 2012 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 16,620,000	$ 15,384,000	$ 10,920,000	$ 42,924,000
MULTIPLIERS				
Output	1.613	1.220	0.805	0.790
Earnings	0.499	0.205	0.218	0.322
Employment	10.886	2.923	6.193	6.838
ADDED ECONOMIC IMPACT ON MARKET AREA				
Output	$ 26,800,000	$ 18,770,000	$ 8,790,000	$ 54,360,000
Earnings	$ 8,290,000	$ 3,160,000	$ 2,380,000	$ 13,830,000
Indirect Jobs Held by Area Residents	181	45	68	294
TOTAL ECONOMIC IMPACT ON MARKET AREA				
Output (Total Economic Activity)				$ 97,284,000
Earnings				$ 24,750,000
Direct Jobs at Edwards Energy Center				97
Total Direct and Indirect Jobs at Edwards Energy Center				391

[1]*Actual operating data from 2008-2011 adjusted to 2012 dollar amounts and averaged*

[2]*Estimate based on number of employees who reside in market area (97 of 110) and overall average labor expenditure per employee*

The top of the table shows the direct expenditures by Ameren at the Edwards Energy Center in the market area totaling approximately $42.9 million in 2012. Employee compensation is an estimate based on the number of Edwards employees that live in in the market area (97 of 110). Additional results are discussed below:

- The $42.9 million spent by Ameren at Edwards Energy Center triggered an additional $54.4 million in value added activity in the market area, of which $13.8 million was household earnings that supported 294 jobs. The multipliers vary for different types of major expenditures shown at the top of the table.
- The estimated output (economic activity) triggered by Edwards Energy Center's direct operations ($42.9 million) and the added multiplier effects ($54.4 million) were $97.3 million for the market area.
- Of that amount, Edwards Energy Center's operations triggered nearly $24.8 million in household earnings for workers in the market area, including $10.9 million in direct compensation for employees and $13.8 million in added earnings from the multiplier effects.
- In total, Edwards Energy Center's operations supported 391 jobs in the market area, including 97 direct jobs and approximately 294 jobs added through the multiplier effects.

Table 4: Annual Economic Impact of Ameren's Joppa Energy Center Operations on Market Area

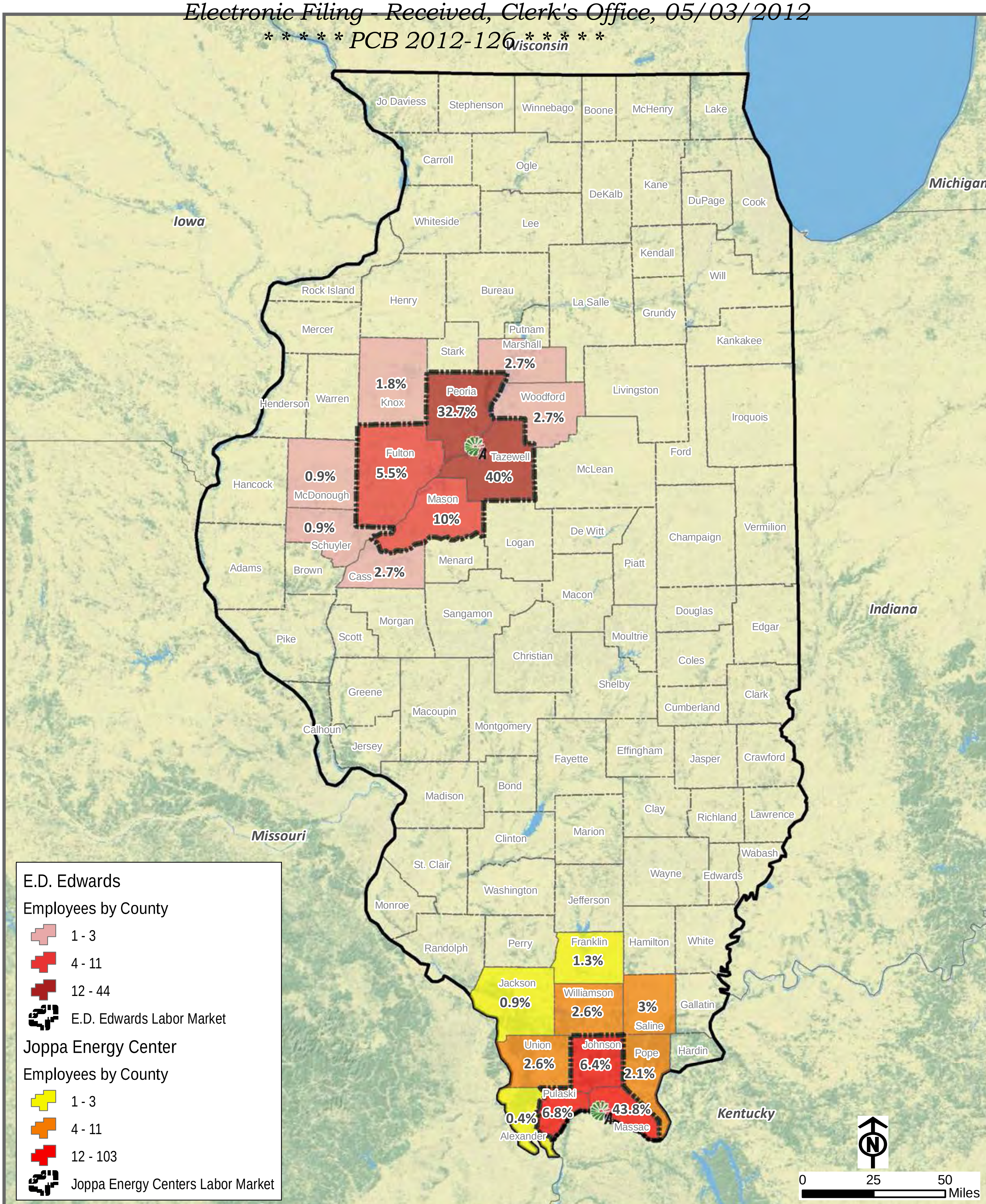
	Annual Average in 2012 Dollars[1]			
	Capital Expenditures	*Operating Expenditures*	*Employee Compensation*[2]	*Total*
Direct Spending	$ 28,205,000	$ 33,551,000	$ 12,171,000	$ 73,927,000
MULTIPLIERS				
Output	1.284	1.111	0.381	0.946
Earnings	0.330	0.161	0.087	0.213
Employment	6.881	1.931	2.751	3.955
ADDED ECONOMIC IMPACT ON MARKET AREA				
Output	$ 36,220,000	$ 37,280,000	$ 4,640,000	$ 78,140,000
Earnings	$ 9,290,000	$ 5,390,000	$ 1,060,000	$ 15,740,000
Indirect Jobs Held by Area Residents	194	65	33	292
TOTAL ECONOMIC IMPACT ON MARKET AREA				
Output (Total Economic Activity)				$ 152,067,000
Earnings				$ 27,911,000
Direct Jobs at Joppa Energy Center				134
Total Direct and Indirect Jobs at Joppa Energy Center				426

[1]*Actual operating data from 2008-2011 adjusted to 2012 dollar amounts and averaged*

[2]*Estimate based on number of employees who reside in market area (134 of 235) and overall average labor expenditure per employee*

The top of the table shows the direct expenditures by Ameren at the Joppa Energy Center in the market area totaling approximately $73.9 million in 2012. Employee compensation is an estimate based on the number of Joppa employees that live in in the market area (134 of 235). Additional results are discussed below:

- The $73.9 million spent by Ameren at Joppa Energy Center triggered an additional $78.1 million in value added activity in the market area, of which $15.7 million was household earnings that supported 292 jobs. The multipliers vary for different types of major expenditures shown at the top of the table.
- The estimated output (economic activity) triggered by Joppa Energy Center's direct operations ($73.9 million) and the added multiplier effects ($78.1 million) were $152.1 million for the market area.
- Of that amount, Joppa Energy Center's operations triggered nearly $27.9 million in household earnings for workers the market area, including $12.2 million in direct compensation for employees and $15.7 million in added earnings from the multiplier effects.
- In total, Joppa Energy Center's operations supported 426 jobs in the market area, including 134 direct jobs and approximately 292 jobs added through the multiplier effects.



AER: E.D. Edwards & Joppa Energy Centers Labor Markets

Source: Ameren provided employment counts by work location and county of residence, as of March 1, 2012

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April 2012

Exhibit 11

Affidavit of Shawn E. Shukar

AFFIDAVIT OF SHAWN E. SCHUKAR

I. BACKGROUND AND QUALIFICATIONS

1. My name is Shawn E. Schukar and I am employed by Ameren Energy Marketing as Senior Vice President-Trading & Marketing. Ameren Energy Marketing (AEM) is the marketing arm of Ameren Energy Resources and is responsible for all aspects of the selling and marketing of power from AER's generating facilities.

2. I received a Bachelor's degree in Mechanical Engineering from the University of Illinois in 1984 and a Master's of Business degree from the University of Illinois in 2001. I joined Illinois Power Company ("Illinois Power") in 1984 as a power plant engineer. I subsequently held several power plant positions from 1986 through 1996, including positions in plant performance management, plant operations management, and plant engineering management. In 1996, I became responsible for the generation control function, which included the dispatch and short-term energy sales associated with the Illinois Power control area. I was responsible for general control, energy trading and energy marketing from 1997 through 1999. I then managed the retail pricing and risk management portions of the business from 1999 through 2000, and transmission operations from 2000 through 2001. I was responsible for the transmission, generation dispatch and gas control functions at Illinois Power from 2001 through 2004. In 2004, I became responsible for the Illinois Power field operations and continued with that responsibility after Ameren Companies acquisition of Illinois Power Company. Over the last several years I have worked for Ameren in a variety of capacities and assumed my current role with AEM in November of 2011.

II. DESCRIPTION OF POWER MARKET

3. AER participates in and sells power into a regional transmission organization known as the Midwest Independent Transmission System (MISO). Participants in the MISO market include both regulated and unregulated generators. Appended to my Affidavit is a chart that depicts average heat rates generating units within the MISO region and including AER's energy facilities. For generation units, efficiency is measured in heat rates where a lower heat rate indicates more efficient units. As depicted in the chart, the Newton, Joppa, and Edwards units are some of the more efficient units in MISO footprint.

4. In Illinois, a customer's electricity costs include both regulated and deregulated components. The generation portion of the customer's electricity costs is based on competitive market prices while the transmission and distribution or delivery service portion is based upon rate-regulated factors. As a deregulated state, Illinois customers have a choice on who supplies generation related service. These supplies can originate from any source that can be delivered to Illinois. This can includes sources that are in bordering states like Indiana and Missouri of from sources that are several states away from Illinois including states like Ohio.

5. The generation costs typically include energy, capacity, and ancillary services costs. In competitive markets these costs are generally determined by supply and demand. Since Illinois companies are part of either the PJM or MISO organized electricity markets, energy and ancillary service costs are determined based on the offers from available generation sources. (Capacity costs are determined by the supply of available generation and the load demands.) The marginal costs of the generators are used by marketers such as AEM in determining a unit's offer price into the marketplace.

6. If AER were to mothball generating units, and assuming all other pricing variables stay the same or are neutral, removal of such low-cost and efficient units from MISO would result in a greater utilization of generating units that are less efficient and have higher marginal costs. Mothballing several of AER's units will cause generation related costs to increase, increasing electric costs above what the costs would have been without the mothballing. If the units are mothballed the market will need to replace the energy from these units with energy from other units that costs more – driving up the costs of energy and ancillary services for Illinois customers. In fact, the generation associated with the Newton, Edwards and Joppa units in 2011 totaled nearly 20,000,000 megawatt hours (MWh) that will need to be replaced by higher cost generation.

7. In addition the mothball of these units will also decrease the supply of available generation which, absent any reductions in load, would tighten the supply demand balance and have upward pressure on capacity costs. Thus the mothballing of any of these higher efficiency, low cost units from the market will drive up costs for energy, ancillary services, and capacity costs which ultimately impacts the cost to consumers in Illinois's deregulated markets.

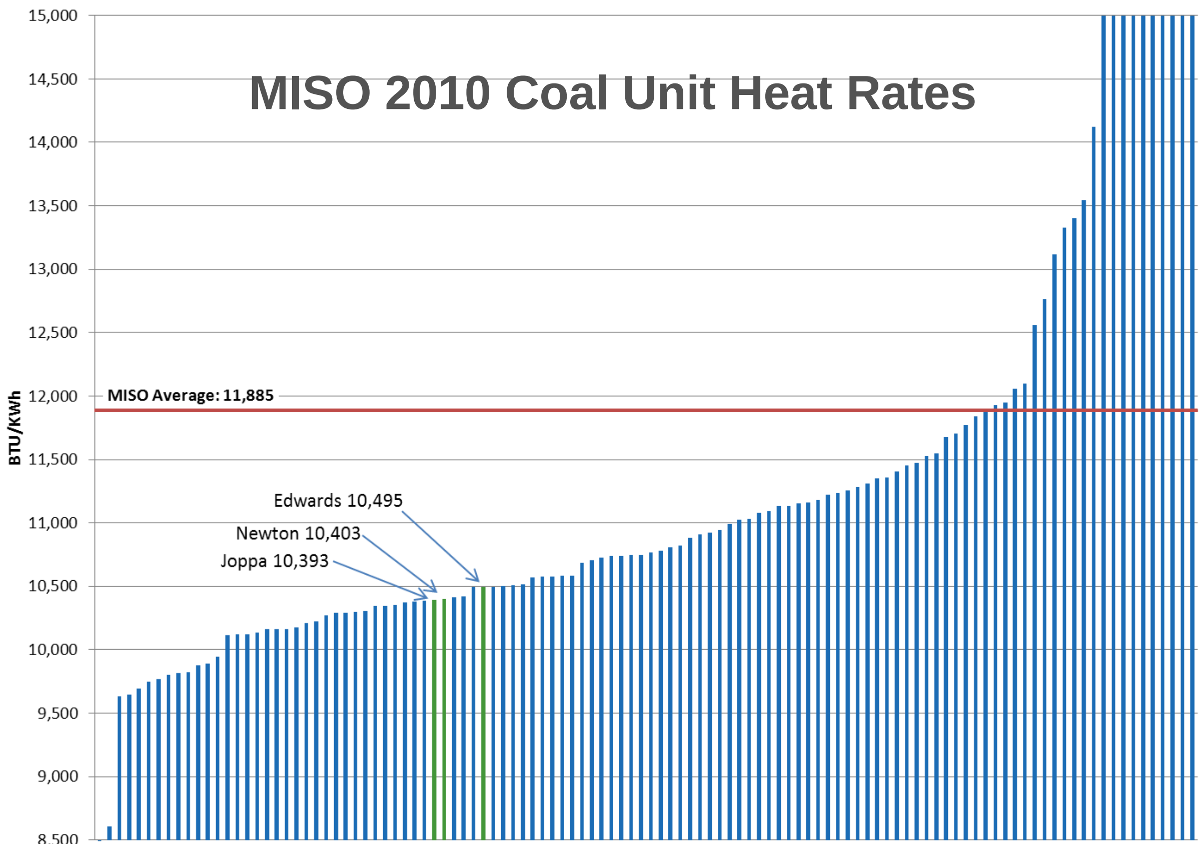
FURTHER, Affiant sayeth not.

DATED: May 3, 2012

Shawn E. Schukar

Notary: Danielle R. Moskop

Danielle R. Moskop - Notary Public
Notary Seal, State of
Missouri - Jefferson County
Commission #09745027
My Commission Expires 7/21/2013



Source: FERC Form 1 data for coal-fired plants, Ameren plants per company data.

Ameren

Exhibit 12

Selected Pages of the *Technical Support Document for Best Available Retrofit Technology Under the Regional Haze*

Cover page and Appendix C of the Illinois Environmental Protection Agency Technical Support Document containing the MPS, AQPSTR 09-06, April 29, 2011.

TECHNICAL SUPPORT DOCUMENT
FOR
BEST AVAILABLE RETROFIT TECHNOLOGY
UNDER THE REGIONAL HAZE RULE

AQPSTR 09-06

April 29, 2011

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
1021 NORTH GRAND AVENUE EAST
P.O. BOX 19276
SPRINGFIELD, ILLINOIS 62794-9276

Appendix C

Illinois Mercury Rule

The Illinois EPA is seeking approval from the United States Environmental Protection Agency of the following ***bolded*** *provisions of the Illinois Mercury Rule, 35 Ill. Adm. Code Part 225, Subpart B: Control of Mercury Emissions from Coal-Fired Electric Generating Units, under this submission. Please note that the non-bolded provisions are included for context.*

Section 225.233 Multi-Pollutant Standards (MPS)

a) **General.**

1) **As an alternative to compliance with the emissions standards of Section 225.230(a), the owner of eligible EGUs may elect for those EGUs to demonstrate compliance pursuant to this Section, which establishes control requirements and standards for emissions of NO_x and SO_2, as well as for emissions of mercury.**

2) **For the purpose of this Section, the following requirements apply:**

A) **An eligible EGU is an EGU that is located in Illinois and which commenced commercial operation on or before December 31, 2004; and**

B) **Ownership of an eligible EGU is determined based on direct ownership, by the holding of a majority interest in a company that owns the EGU or EGUs, or by the common ownership of the company that owns the EGU, whether through a parent-subsidiary relationship, as a sister corporation, or as an affiliated corporation with the same parent corporation, provided that the owner has the right or authority to submit a CAAPP application on behalf of the EGU.**

3) **The owner of one or more EGUs electing to demonstrate compliance with this Subpart B pursuant to this Section must submit an application for a CAAPP permit modification to the Agency, as provided in Section 225.220, that includes the information specified in subsection (b) of this Section and which clearly states the owner's election to demonstrate compliance pursuant to this Section 225.233.**

A) **If the owner of one or more EGUs elects to demonstrate compliance with this Subpart pursuant to this Section, then all EGUs it owns in Illinois as of July 1, 2006, as defined in subsection (a)(2)(B) of this Section, must be thereafter subject to the standards and control**

requirements of this Section, except as provided in subsection (a)(3)(B). Such EGUs must be referred to as a Multi-Pollutant Standard (MPS) Group.

B) Notwithstanding the foregoing, the owner may exclude from an MPS Group any EGU scheduled for permanent shutdown that the owner so designates in its CAAPP application required to be submitted pursuant to subsection (a)(3) of this Section, with compliance for such units to be achieved by means of Section 225.235.

4) When an EGU is subject to the requirements of this Section, the requirements apply to all owners or operators of the EGU.

b) Notice of Intent.

The owner of one or more EGUs that intends to comply with this Subpart B by means of this Section must notify the Agency of its intention by December 31, 2007. The following information must accompany the notification:

1) The identification of each EGU that will be complying with this Subpart B by means of the multi-pollutant standards contained in this Section, with evidence that the owner has identified all EGUs that it owned in Illinois as of July 1, 2006 and which commenced commercial operation on or before December 31, 2004;

2) If an EGU identified in subsection (b)(1) of this Section is also owned or operated by a person different than the owner submitting the notice of intent, a demonstration that the submitter has the right to commit the EGU or authorization from the responsible official for the EGU accepting the application;

3) The Base Emission Rates for the EGUs, with copies of supporting data and calculations;

4) A summary of the current control devices installed and operating on each EGU and identification of the additional control devices that will likely be needed for the each EGU to comply with emission control requirements of this Section, including identification of each EGU in the MPS group that will be addressed by subsection (c)(1)(B) of this Section, with information showing that the eligibility criteria for this subsection (b) are satisfied; and

5) Identification of each EGU that is scheduled for permanent shut down, as provided by Section 225.235, which will not be part of the MPS Group and which will not be demonstrating compliance with this Subpart B pursuant to this Section.

c) Control Technology Requirements for Emissions of Mercury.

1) Requirements for EGUs in an MPS Group.

A) For each EGU in an MPS Group other than an EGU that is addressed by subsection (c)(1)(B) of this Section for the period beginning July 1, 2009 (or December 31, 2009 for an EGU for which an SO_2 scrubber or fabric filter is being installed to be in operation by December 31, 2009), and ending on December 31, 2014 (or such earlier date that the EGU is subject to the mercury emission standard in subsection (d)(1) of this Section), the owner or operator of the EGU must install, to the extent not already installed, and properly operate and maintain one of the following emission control devices:

i) A Halogenated Activated Carbon Injection System, complying with the sorbent injection requirements of subsection (c)(2) of this Section, except as may be otherwise provided by subsection (c)(4) of this Section, and followed by a Cold-Side Electrostatic Precipitator or Fabric Filter; or

ii) If the boiler fires bituminous coal, a Selective Catalytic Reduction (SCR) System and an SO_2 Scrubber.

B) An owner of an EGU in an MPS Group has two options under this subsection (c). For an MPS Group that contains EGUs smaller than 90 gross MW in capacity, the owner may designate any such EGUs to be not subject to subsection (c)(1)(A) of this Section. Or, for an MPS Group that contains EGUs with gross MW capacity of less than 115 MW, the owner may designate any such EGUs to be not subject to subsection (c)(1)(A) of this Section, provided that the aggregate gross MW capacity of the designated EGUs does not exceed 4% of the total gross MW capacity of the MPS Group. For any EGU subject to one of these two options, unless the EGU is subject to the emission standards in subsection (d)(2) of this Section, beginning on January 1, 2013, and continuing until such date that the owner or operator of the EGU commits to comply with the mercury emission standard in subsection (d)(2) of this Section, the owner or operator of the EGU must install and properly operate and maintain a Halogenated Activated Carbon Injection System that complies with the sorbent injection requirements of subsection (c)(2) of this Section, except as may be otherwise provided by subsection (c)(4) of this Section, and followed by either a Cold-Side Electrostatic Precipitator or Fabric Filter. The use of a properly installed, operated, and maintained Halogenated Activated Carbon Injection System that meets the sorbent injection requirements of subsection (c)(2) of this Section is defined as the "principal control technique."

2) For each EGU for which injection of halogenated activated carbon is required by subsection (c)(1) of this Section, the owner or operator of the EGU must inject halogenated activated carbon in an optimum manner, which, except as provided in subsection (c)(4) of this Section, is defined as all of the following:

A) The use of an injection system designed for effective absorption of mercury, considering the configuration of the EGU and its ductwork;

B) The injection of halogenated activated carbon manufactured by Alstom, Norit, or Sorbent Technologies, Calgon Carbon's FLUEPAC CF Plus, or Calgon Carbon's FLUEPAC MC Plus, or the injection of any other halogenated activated carbon or sorbent that the owner or operator of the EGU has demonstrated to have similar or better effectiveness for control of mercury emissions; and

C) The injection of sorbent at the following minimum rates, as applicable:

i) For an EGU firing subbituminous coal, 5.0 lbs per million actual cubic feet or, for any cyclone-fired EGU that will install a scrubber and baghouse by December 31, 2012, and which already meets an emission rate of 0.020 lbs mercury/GWh gross electrical output or at least 75 percent reduction of input mercury, 2.5 lbs per million actual cubic feet;

ii) For an EGU firing bituminous coal, 10.0 lbs per million actual cubic feet for any cyclone-fired EGU that will install a scrubber and baghouse by December 31, 2012, and which already meets an emission rate of 0.020 lb mercury/GWh gross electrical output or at least 75 percent reduction of input mercury, 5.0 lbs per million actual cubic feet;

iii) For an EGU firing a blend of subbituminous and bituminous coal, a rate that is the weighted average of the above rates, based on the blend of coal being fired; or

iv) A rate or rates set lower by the Agency, in writing, than the rate specified in any of subsections (c)(2)(C)(i), (c)(2)(C)(ii), or (c)(2)(C)(iii) of this Section on a unit-specific basis, provided that the owner or operator of the EGU has demonstrated that such rate or rates are needed so that carbon injection will not increase particulate matter emissions or opacity so as to threaten noncompliance with applicable requirements for particulate matter or opacity.

D) For the purposes of subsection (c)(2)(C) of this Section, the flue gas flow shall be the gas flow rate in the stack for all units except for those equipped with activated carbon injection prior to a hot-side electrostatic precipitator; for units equipped with activated carbon injection prior to a hot-side electrostatic precipitator, the flue gas flow rate shall be the gas flow rate at the inlet to the hot-side electrostatic precipitator, which shall be determined as the stack flow rate adjusted through the use of Charles' Law for the differences in gas temperatures in the stack and at the inlet to the electrostatic precipitator ($V_{esp} = V_{stack} \times T_{esp}/T_{stack}$, where V = gas flow rate in acf and T = gas temperature in Kelvin or Rankine

3) The owner or operator of an EGU that seeks to operate an EGU with an activated carbon injection rate or rates that are set on a unit-specific basis pursuant to subsection (c)(2)(C)(iv) of this Section must submit an application to the Agency proposing such rate or rates, and must meet the requirements of subsections (c)(3)(A) and (c)(3)(B) of this Section, subject to the limitations of subsections (c)(3)(C) and (c)(3)(D) of this Section:

A) The application must be submitted as an application for a new or revised federally enforceable operating permit for the EGU, and it must include a summary of relevant mercury emission data for the EGU, the unit-specific injection rate or rates that are proposed, and detailed information to support the proposed injection rate or rates; and

B) This application must be submitted no later than the date that activated carbon must first be injected. For example, the owner or operator of an EGU that must inject activated carbon pursuant to subsection (c)(1)(A) of this subsection must apply for unit-specific injection rate or rates by July 1, 2009. Thereafter, the owner or operator of the EGU may supplement its application; and

C) Any decision of the Agency denying a permit or granting a permit with conditi that set a lower injection rate or rates may be appealed to the Board pursuant tc Section 39 of the Act; and

D) The owner or operator of an EGU may operate at the injection rate or rates proposed in its application until a final decision is made on the application, including a final decision on any appeal to the Board.

4) During any evaluation of the effectiveness of a listed sorbent, an alternative sorbent, or other technique to control mercury emissions, the owner or operator of an EGU need not comply with the requirements of subsection (c)(2) of this Section for any system needed to carry out the evaluation, as further provided as follows:

A) The owner or operator of the EGU must conduct the evaluation in accordance with a formal evaluation program submitted to the Agency at least 30 days prior to commencement of the evaluation;

B) The duration and scope of the evaluation may not exceed the duration and scope reasonably needed to complete the desired evaluation of the alternative control technique, as initially addressed by the owner or operator in a support document submitted with the evaluation program;

C) The owner or operator of the EGU must submit a report to the Agency no later than 30 days after the conclusion of the evaluation that describes the evaluation conducted and which provides the results of the evaluation; and

D) If the evaluation of the alternative control technique shows less effective control of mercury emissions from the EGU than was achieved with the principal control technique, the owner or operator of the EGU must resume use of the principal control technique. If the evaluation of the alternative control technique shows comparable effectiveness to the principal control technique, the owner or operator of the EGU may either continue to use the alternative control technique in a manner that is at least as effective as the principal control technique, or it may resume use of the principal control technique. If the evaluation of the alternative control technique shows more effective control of mercury emissions than the control technique, the owner or operator of the EGU must continue to use the alternative control technique in a manner that is more effective than the principal control technique, so long as it continues to be subject to this subsection (c).

5) In addition to complying with the applicable recordkeeping and monitoring requirements in Sections 225.240 through 225.290, the owner or operator of an EGU that elects to comply with this Subpart B by means of this Section must also comply with the following additional requirements:

A) For the first 36 months that injection of sorbent is required, it must maintain records of the usage of sorbent, the fluegas flow rate from the EGU (and, if the unit is equipped with activated carbon injection prior to a hot-side electrostatic precipitator, flue gas temperature at the inlet of the hot-side electrostatic precipitator and in the stack), and the sorbent feed rate, in pounds per million actual cubic feet of flue, on a weekly average;

B) After the first 36 months that injection of sorbent is required, it must monitor activated sorbent feed rate to the EGU, gas flow rate in the stack, and, if the unit is equipped with activated carbon injection prior to a hot-side electrostatic precipitator, flue gas temperature at the inlet of the hot-side electrostatic precipitator and in the stack. It must automatically record this data and the sorbent carbon feed rate, in pounds per million actual cubic feet of flue gas, on an hourly average; and

C) If a blend of bituminous and subbituminous coal is fired in the EGU, it must keep records of the amount of each type of coal burned and the required injection rate for injection of activated carbon, on a weekly basis.

6) Until June 30, 2012, as an alternative to the CEMS or excepted monitoring system (sorbent trap system) monitoring, recordkeeping, and reporting requirements in Sections 225.240 through 225.290, the owner or operator of an EGU may elect to comply with the emissions testing, monitoring, recordkeeping, and reporting requirements in Section 225.239(c), (d), (e), (f)(1) and (2), (h)(2), (i)(3) and (4), and (j)(1).

7) In addition to complying with the applicable reporting requirements in Sections 225.240 through 225.290, the owner or operator of an EGU that elects to comply with this Subpart B by means of this Section must also submit quarterly reports for the recordkeeping and monitoring conducted pursuant to subsection (c)(5) of this Section.

d) Emission Standards for Mercury.

1) For each EGU in an MPS Group that is not addressed by subsection (c)(1)(B) of this Section, beginning January 1, 2015 (or such earlier date when the owner or operator of the EGU notifies the Agency that it will comply with these standards) and continuing thereafter, the owner or operator of the EGU must comply with one of the following standards on a rolling 12-month basis:

A) An emission standard of 0.0080 lb mercury/GWh gross electrical output; or

B) A minimum 90-percent reduction of input mercury.

2) For each EGU in an MPS Group that has been addressed under subsection (c)(1)(B) of this Section, beginning on the date when the owner or operator of the EGU notifies the Agency that it will comply with these standards and continuing thereafter, the owner or operator of the EGU must comply with one of the following standards on a rolling 12-month basis:

A) An emission standard of 0.0080 lb mercury/GWh gross electrical output; or

B) A minimum 90-percent reduction of input mercury.

3) Compliance with the mercury emission standard or reduction requirement of this subsection (d) must be calculated in accordance with Section 225.230(a) or (d), or Section 225.232 until December 31, 2013.

4) Until June 30, 2012, as an alternative to demonstrating compliance with the emissions standards in this subsection (d), the owner or operator of an EGU may elect to comply with the emissions testing requirements in Section 225.239(a)(4), (b), (c), (d), (e), (f), (g), (h), (i), and (j) of this Subpart.

e) **Emission Standards for NO_x and SO_2.**

1) **NO_x Emission Standards.**

A) **Beginning in calendar year 2012 and continuing in each calendar thereafter, for the EGUs in each MPS Group, the owner and operator of the EGUs must comply with an overall NOx annual emission rate of no more than 0.11 lb/million Btu or an emission rate equivalent to 52 percent of the Base Annual Rate of NO_x emissions, whichever is more stringent.**

B) **Beginning in the 2012 ozone season and continuing in each ozone season thereafter, for the EGUs in each MPS Group, the owner and operator of the EGUs must comply with an overall NO_x seasonal emission rate of no more than 0.11 lb/million Btu or an emission rate equivalent to 80 percent of the Base Seasonal Rate of NO_x emissions, whichever is more stringent.**

2) **SO_2 Emission Standards.**

A) **Beginning in calendar year 2013 and continuing in calendar year 2014, for the EGUs in each MPS Group, the owner and operator of the EGUs must comply with an overall SO_2 annual emission rate of 0.33 lb/million Btu or a rate equivalent to 44 percent of the Base Rate of SO_2 emissions, whichever is more stringent.**

B) **Beginning in calendar year 2015 and continuing in each calendar year thereafter, for the EGUs in each MPS Grouping, the owner and operator of the EGUs must comply with an overall annual emission rate for SO_2 of 0.25 lbs/million Btu or a rate equivalent to 35 percent of the Base Rate of SO_2 emissions, whichever is more stringent.**

3) **Ameren MPS Group Multi-Pollutant Standard**

A) **Notwithstanding the provisions of subsections (e)(1) and (2) of this Section, this subsection (e)(3) applies to the Ameren MPS Group as described in the notice of intent submitted by Ameren Energy Resources in accordance with subsection (b) of this Section.**

B) **NO_x Emission Standards~~.~~**

i) Beginning in the 2010 ozone season and continuing in each ozone season thereafter, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall NO_x seasonal emission rate of no more than 0.11 lb/million Btu.

ii) Beginning in calendar year 2010 and continuing in calendar year 2011, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall NO_x annual emission rate of no more than 0.14 lb/million Btu.

iii) Beginning in calendar year 2012 and continuing in each calendar year thereafter, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall NO_x annual emission rate of no more than 0.11 lb/million Btu.

C) SO_2 Emission Standards

i) Beginning in calendar year 2010 and continuing in each calendar year through 2013, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall SO_2 annual emission rate of 0.50 lb/million Btu.

ii) In calendar year 2014, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall SO_2 annual emission rate of 0.43 lb/million Btu.

iii) Beginning in calendar year 2015 and continuing in calendar year 2016, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall SO_2 annual emission rate of 0.25 lb/million Btu.

iv) Beginning in calendar year 2017 and continuing in each calendar year thereafter, for the EGUs in the Ameren MPS Group, the owner and operator of the EGUs must comply with an overall SO_2 annual emission rate of 0.23 lb /million Btu.

4) Compliance with the NO_x and SO_2 emission standards must be demonstrated in accordance with Sections 225.310, 225.410, and 225.510. The owner or operator of EGUs must complete the demonstration of compliance before March 1 of the following year for annual standards and before November 1 for seasonal standards, by which date a compliance report must be submitted to the Agency.

f) Requirements for NO_x and SO_2 Allowances.

1) The owner or operator of EGUs in an MPS Group must not sell or trade to any person or otherwise exchange with or give to any person NO_x allowances allocated to the EGUs in the MPS Group for vintage years 2012 and beyond that would otherwise be available for sale, trade, or exchange as a result of actions taken to comply with the standards in subsection (e) of this Section. Such allowances that are not retired for compliance must be surrendered to the Agency on an annual basis, beginning in calendar year 2013. This provision does not apply to the use, sale, exchange, gift, or trade of allowances among the EGUs in an MPS Group.

2) The owners or operators of EGUs in an MPS Group must not sell or trade to any person or otherwise exchange with or give to any person SO_2 allowances allocated to the EGUs in the MPS Group for vintage years 2013 and beyond that would otherwise be available for sale or trade as a result of actions taken to comply with the standards in subsection (e) of this Section. Such allowances that are not retired for compliance, or otherwise surrendered pursuant to a consent decree to which the State of Illinois is a party, must be surrendered to the Agency on an annual basis, beginning in calendar year 2014. This provision does not apply to the use, sale, exchange, gift, or trade of allowances among the EGUs in an MPS Group.

3) The provisions of this subsection (f) do not restrict or inhibit the sale or trading of allowances that become available from one or more EGUs in a MPS Group as a result of holding allowances that represent over-compliance with the NO_x or SO_2 standard in subsection (e) of this Section, once such a standard becomes effective, whether such over-compliance results from control equipment, fuel changes, changes in the method of operation, unit shut downs, or other reasons.

4) For purposes of this subsection (f), NO_x and SO_2 allowances mean allowances necessary for compliance with Sections 225.310, 225.410, or 225.510, 40 CFR 72, or Subparts AA and AAAA of 40 CFR 96, or any future federal NO_x or SO_2 emissions trading programs that modify or replace these programs. This Section does not prohibit the owner or operator of EGUs in an MPS Group from purchasing or otherwise obtaining allowances from other sources as allowed by law for purposes of complying with federal or state requirements, except as specifically set forth in this Section.

5) By March 1, 2010, and continuing each year thereafter, the owner or operator of EGUs in an MPS Group must submit a report to the Agency that demonstrates compliance with the requirements of this subsection (f) for the previous calendar year, and which includes identification of any allowances that have been surrendered to the USEPA or to the Agency and any allowances that were sold, gifted, used, exchanged, or traded because they became available due to over-compliance. All allowances that are required to be surrendered must be surrendered by August 31, unless USEPA has not yet deducted the allowances

from the previous year. A final report must be submitted to the Agency by August 31 of each year, verifying that the actions described in the initial report have taken place or, if such actions have not taken place, an explanation of all changes that have occurred and the reasons for such changes. If USEPA has not deducted the allowances from the previous year by August 31, the final report will be due, and all allowances required to be surrendered must be surrendered, within 30 days after such deduction occurs.

g) **Notwithstanding 35 Ill. Adm. Code 201.146(hhh), until an EGU has complied with the applicable emission standards of subsections (d) and (e) of this Section for 12 months, the owner or operator of the EGU must obtain a construction permit for any new or modified air pollution control equipment that it proposes to construct for control of emissions of** mercury, **NO_x, or SO_2.**

(Source: Amended at 33 Ill. Reg. 10427, effective June 26, 2009)

Section 225.291 Combined Pollutant Standard: Purpose

The purpose of Sections 225.291 through 225.299 (hereinafter referred to as the Combined Pollutant Standard ("CPS")) is to allow an alternate means of compliance with the emissions standards for mercury in Section 225.230(a) for specified EGUs through permanent shut-down, installation of ACI, and the application of pollution control technology for NO_x, PM, and SO_2 emissions that also reduce mercury emissions as a co-benefit and to establish permanent emissions standards for those specified EGUs. Unless otherwise provided for in the CPS, owners and operators of those specified EGUs are not excused from compliance with other applicable requirements of Subparts B, C, D, and E.

(Source: Added at 33 Ill. Reg. 10427, effective June 26, 2009)

Section 225.292 Applicability of the Combined Pollutant Standard

a) **As an alternative to compliance with the emissions standards of Section 225.230(a), the owner or operator of specified EGUs in the CPS located at Fisk, Crawford, Joliet, Powerton, Waukegan, and Will County power plants may elect for all of those EGUs as a group to demonstrate compliance pursuant to the CPS, which establishes control requirements and emissions standards for NO_x, PM, SO_2, and mercury. For this purpose, ownership of a specified EGU is determined based on direct ownership, by holding a majority interest in a company that owns the EGU or EGUs, or by the common ownership of the company that owns the EGU, whether through a parent-subsidiary relationship, as a sister corporation, or as an affiliated corporation with the same parent corporation, provided that the owner or operator has the right or authority to submit a CAAPP application on behalf of the EGU.**

b) **A specified EGU is a coal-fired EGU listed in Appendix A, irrespective of any subsequent changes in ownership of the EGU or power plant, the operator, unit designation, or name of unit.**

c) **The owner or operator of each of the specified EGUs electing to demonstrate compliance with Section 225.230(a) pursuant to the CPS must submit an application for a CAAPP permit modification to the Agency, as provided for in Section 225.220, that includes the information specified in Section 225.293 that clearly states the owner's or operator's election to demonstrate compliance with Section 225.230(a) pursuant to the CPS.**

d) **If an owner or operator of one or more specified EGUs elects to demonstrate compliance with Section 225.230(a) pursuant to the CPS, then all specified EGUs owned or operated in Illinois by the owner or operator as of December 31, 2006, as defined in subsection (a) of this Section, are thereafter subject to the standards and control requirements of the CPS. Such EGUs are referred to as a Combined Pollutant Standard (CPS) group.**

e) **If an EGU is subject to the requirements of this Section~~,~~ then the requirements apply to all owners and operators of the EGU.**

(Source: Added at 33 Ill. Reg. 10427, effective June 26, 2009)

Section 225.293 Combined Pollutant Standard: Notice of Intent

The owner or operator of one or more specified EGUs that intends to comply with Section 225.230(a) by means of the CPS must notify the Agency of its intention on or before December 31, 2007. The following information must accompany the notification:

a) **The identification of each EGU that will be complying with Section 225.230(a) pursuant to the CPS, with evidence that the owner or operator has identified all specified EGUs that it owned or operated in Illinois as of December 31, 2006, and which commenced commercial operation on or before December 31, 2004;**

b) **If an EGU identified in subsection (a) of this Section is also owned or operated by a person different than the owner or operator submitting the notice of intent, a demonstration that the submitter has the right to commit the EGU or authorization from the responsible official for the EGU submitting the application; and**

c) **A summary of the current control devices installed and operating on each EGU and identification of the additional control devices that will likely be needed for each EGU to comply with emission control requirements of the CPS.**

(Source: Added at 33 Ill. Reg. 10427, effective June 26, 2009)

Section 225.295 Combined Pollutant Standard: Emissions Standards for NO_x and SO_2

a) **Emissions Standards for NO_x and Reporting Requirements.**

1) **Beginning with calendar year 2012 and continuing in each calendar year thereafter, the CPS group, which includes all specified EGUs that have not been permanently shut down by December 31 before the applicable calendar year, must comply with a CPS group average annual NO_x emissions rate of no more than 0.11 lbs/mmBtu.**

2) **Beginning with ozone season control period 2012 and continuing in each ozone season control period (May 1 through September 30) thereafter, the CPS group, which includes all specified EGUs that have not been permanently shut down by December 31 before the applicable ozone season, must comply with a CPS group average ozone season NO_x emissions rate of no more than 0.11 lbs/mmBtu.**

3) **The owner or operator of the specified EGUs in the CPS group must file, not later than one year after startup of any selective SNCR on such EGU, a report with the Agency describing the NO_x emissions reductions that the SNCR has been able to achieve.**

b) **Emissions Standards for SO_2. Beginning in calendar year 2013 and continuing in each calendar year thereafter, the CPS group must comply with the applicable CPS group average annual SO_2 emissions rate listed as follows:**

year	**lbs/mmBtu**
2013	**0.44**
2014	**0.41**
2015	**0.28**
2016	**0.195**
2017	**0.15**
2018	**0.13**
2019	**0.11**

c) **Compliance with the NO_x and SO_2 emissions standards must be demonstrated in accordance with Sections 225.310, 225.410, and 225.510. The owner or operator of the specified EGUs must complete the demonstration of compliance pursuant to Section 225.298(c) before March 1 of the following year for annual standards and before November 30 of the particular year for ozone season control periods (May 1 through September 30) standards, by which date a compliance report must be submitted to the Agency.** [NOTE: This subsection is relying on the compliance requirements of the Clean Air Interstate Rule Trading Program under Subparts C, D, and E of Part 225 and will need to be amended accordingly when the Transport Rule is promulgated.]

d) **The CPS group average annual SO_2 emission rate, annual NO_x emission rate and ozone season NO_x emission rates shall be determined as follows:**

$$ER_{avg} = \sum_{i=1}^{n} (SO_{2i} \text{ or } NO_{xi} \text{ tons}) / \sum_{i=1}^{n} (HI_i)$$

Where:

ER_{avg} = **average annual or ozone season emission rate in lbs/mmBbtu of all EGUs in the CPS group.**
HI_i , = **heat input for the annual or ozone control period of each EGU, in mmBtu.**
SO_{2i} = **actual annual SO_2 tons of each EGU in the CPS group.**
NO_{xi} = **actual annual or ozone season NO_x tons of each EGU in the CPS group.**
N = **number of EGUs that are in the CPS group.**
I = **each EGU in the CPS group.**

(Source: Amended at 33 Ill. Reg. 10427, effective June 26, 2009)

Section 225.296 Combined Pollutant Standard: Control Technology Requirements for NO_x, SO_2, and PM Emissions

a) **Control Technology Requirements for NO_x and SO_2.**

1) **On or before December 31, 2013, the owner or operator must either permanently shut down or install and have operational FGD equipment on Waukegan 7;**

2) **On or before December 31, 2014, the owner or operator must either permanently shut down or install and have operational FGD equipment on Waukegan 8;**

3) **On or before December 31, 2015, the owner or operator must either permanently shut down or install and have operational FGD equipment on Fisk 19;**

4) **If Crawford 7 will be operated after December 31, 2018, and not permanently shut down by this date, the owner or operator must:**

A) **On or before December 31, 2015, install and have operational SNCR or equipment capable of delivering essentially equivalent NO_x reductions on Crawford 7; and**

B) On or before December 31, 2018, install and have operational FGD equipment on Crawford 7;

5) If Crawford 8 will be operated after December 31, 2017 and not permanently shut down by this date, the owner or operator must:

A) On or before December 31, 2015, install and have operational SNCR or equipment capable of delivering essentially equivalent NO_x emissions reductions on Crawford 8; and

B) On or before December 31, 2017, install and have operational FGD equipment on Crawford 8.

b) Other Control Technology Requirements for SO_2. Owners or operators of specified EGUs must either permanently shut down or install FGD equipment on each specified EGU (except Joliet 5), on or before December 31, 2018, unless an earlier date is specified in subsection (a) of this Section.

c) Control Technology Requirements for PM. The owner or operator of the two specified EGUs listed in this subsection that are equipped with a hot-side ESP must replace the hot-side ESP with a cold-side ESP, install an appropriately designed fabric filter, or permanently shut down the EGU by the dates specified. Hot-side ESP means an ESP on a coal-fired boiler that is installed before the boiler's air-preheater where the operating temperature is typically at least 550° F, as distinguished from a cold-side ESP that is installed after the air pre-heater where the operating temperature is typically no more than 350° F.

1) Waukegan 7 on or before December 31, 2013; and

2) Will County 3 on or before December 31, 2015.

d) Beginning on December 31, 2008, and annually thereafter up to and including December 31, 2015, the owner or operator of the Fisk power plant must submit in writing to the Agency a report on any technology or equipment designed to affect air quality that has been considered or explored for the Fisk power plant in the preceding 12 months. This report will not obligate the owner or operator to install any equipment described in the report.

e) Notwithstanding 35 Ill. Adm. Code 201.146(hhh), until an EGU has complied with the applicable requirements of subsections 225.296(a), (b), and (c), the owner or operator of the EGU must obtain a construction permit for any new or modified air pollution control equipment that it proposes to construct for control of emissions of mercury, **NO_x, PM, or SO_2.**

(Source: Added at 33 Ill. Reg. 10427, effective June 26, 2009)

225.APPENDIX A Specified EGUs for Purposes of the CPS (Midwest Generation's Coal-Fired Boilers as of July 1, 2006)

Plant	Permit Number	Boiler	Permit designation	CPS Designation
Crawford	031600AIN	7	Unit 7 Boiler BLR1	Crawford 7
		8	Unit 8 Boiler BLR2	Crawford 8
Fisk	031600AMI	19	Unit 19 Boiler BLR19	Fisk 19
Joliet	197809AAO	71	Unit 7 Boiler BLR71	Joliet 7
		72	Unit 7 Boiler BLR72	Joliet 7
		81	Unit 8 Boiler BLR81	Joliet 8
		82	Unit 8 Boiler BLR82	Joliet 8
		5	Unit 6 Boiler BLR5	Joliet 6
Powerton	179801AAA	51	Unit 5 Boiler BLR 51	Powerton 5
		52	Unit 5 Boiler BLR 52	Powerton 5
		61	Unit 6 Boiler BLR 61	Powerton 6
		62	Unit 6 Boiler BLR 62	Powerton 6
Waukegan	097190AAC	17	Unit 6 Boiler BLR17	Waukegan 6
		7	Unit 7 Boiler BLR7	Waukegan 7
		8	Unit 8 Boiler BLR8	Waukegan 8
Will County	197810AAK	1	Unit 1 Boiler BLR1	Will County 1
		2	Unit 2 Boiler BLR2	Will County 2
		3	Unit 3 Boiler BLR3	Will County 3
		4	Unit 4 Boiler BLR4	Will County 4

(Source: Amended at 33 Ill. Reg. 10427, effective June 26, 2009)

Exhibit 13

Proposed Revisions to Illinois SIP for Regional Haze

***Approval and Promulgation of Air Quality Implementation Plans; Illinois; Regional Haze*; 77 Fed. Reg. 3999 (Jan. 26, 2012).**

[Federal Register Volume 77, Number 17 (Thursday, January 26, 2012)]
[Proposed Rules]
[Pages 3966-3975]
From the Federal Register Online via the Government Printing Office [www.gpo.gov]
[FR Doc No: 2012-1606]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA-R05-OAR-2011-0598; FRL-9622-6]

Approval and Promulgation of Air Quality Implementation Plans; Illinois; Regional Haze

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve revisions to the Illinois State Implementation Plan (SIP) addressing regional haze for the first implementation period. Illinois submitted its regional haze plan on June 24, 2011. The Illinois regional haze plan addresses Clean Air Act (CAA) section 169B and Regional Haze Rule requirements for states to remedy any existing and prevent future anthropogenic impairment of visibility at mandatory Class I areas. EPA is also proposing to approve two state rules and incorporating two permits into the SIP.

DATES: Comments must be received on or before February 27, 2012.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA-R05-OAR-2011-0598, by one of the following methods:

1. www.regulations.gov: Follow the on-line instructions for submitting comments.
2. Email: blakley.pamela@epa.gov.
3. Fax: (312) 692-2450.
4. Mail: Pamela Blakley, Chief, Control Strategies Section, Air Programs Branch (AR-18J), U.S. Environmental Protection Agency, 77 West Jackson Boulevard, Chicago, Illinois 60604.
5. Hand Delivery: Pamela Blakley, Chief, Control Strategies Section, Air Programs Branch (AR-18J), U.S. Environmental Protection

Agency, 77 West Jackson Boulevard, Chicago, Illinois 60604. Such deliveries are only accepted during the Regional Office normal hours of operation, and special arrangements should be made for deliveries of boxed information. The Regional Office official hours of business are Monday through Friday, 8:30 a.m. to 4:30 p.m., excluding Federal holidays.

Instructions: Direct your comments to Docket ID No. EPA-R05-OAR-2011-0598. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at www.regulations.gov, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through www.regulations.gov or email. The www.regulations.gov Web site is an ``anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA without going through www.regulations.gov your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional instructions on submitting comments, go to Section I of this document.

Docket: All documents in the docket are listed in the www.regulations.gov index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in www.regulations.gov or in hard copy at the Environmental Protection Agency, Region 5, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. This facility is open from 8:30 a.m. to 4:30 p.m., Monday through

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Friday, excluding Federal holidays. We recommend that you telephone Matt Rau, Environmental Engineer, at (312) 886-6524 before visiting the Region 5 office.

FOR FURTHER INFORMATION CONTACT: Matt Rau, Environmental Engineer, Control Strategies Section, Air Programs Branch (AR-18J), Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 886-6524, rau.matthew@epa.gov.

SUPPLEMENTARY INFORMATION: Throughout this document whenever ``we,'' ``us,'' or ``our'' is used, we mean EPA.

Table of Contents

I. What should I consider as I prepare my comments for EPA?

When submitting comments, remember to:

1. Identify the rulemaking by docket number and other identifying information (subject heading, Federal Register date and page number).

2. Follow directions--EPA may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

3. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

4. Describe any assumptions and provide any technical information and/or data that you used.

5. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

6. Provide specific examples to illustrate your concerns, and suggest alternatives.

7. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

8. Make sure to submit your comments by the comment period deadline identified.

II. What is the background for EPA's proposed action?

A. The Regional Haze Problem

Regional haze is visibility impairment that is produced by a multitude of sources and activities located across a broad geographic area that emit fine particles (PM2.5) (e.g., sulfates, nitrates, organic carbon, elemental carbon, and soil dust) and its precursors--sulfur dioxide (SO2), nitrogen oxides (NOX), and in some cases ammonia (NH3) and volatile organic compound (VOCs). Fine particle precursors react in the atmosphere to form fine particulate matter. Aerosol PM2.5 impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity and distance one can see. PM2.5 can also cause serious health effects and mortality in humans and contributes to detrimental environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the ``Interagency Monitoring of Protected Visual Environments'' (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all of the time at most national park and wilderness areas. The average visual range, the distance at which an object is barely discernable, in many Class I areas \1\ in the western United States is 100-150 kilometers. That is about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In the eastern and midwestern Class I areas of the United States, the average visual range is generally less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions. 64 FR 35715 (July 1, 1999).

\1\ Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6000 acres, wilderness areas, and national memorial parks exceeding 5000 acres and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ``mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ``Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ``Class I area,'' we mean ``mandatory Class I Federal area.''

B. Requirements of the Clean Air Act and EPA's Regional Haze Rule

In section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the ``prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution.'' On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is ``reasonably attributable'' to a single source or small group of sources known as, ``reasonably attributable visibility impairment'' (RAVI). 45 FR 80084. These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling, and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues. EPA promulgated the Regional Haze Rule (RHR) on July 1, 1999 (64 FR 35713). The RHR revised the existing visibility regulations to integrate into the regulations provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in EPA's visibility protection regulations at 40 CFR 51.300-309. Some of the main elements of the regional haze requirements are summarized in section III. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands.\2\

\2\ Albuquerque/Bernalillo County, New Mexico must also submit a regional haze SIP to satisfy the section 110(a)(2)(D) requirements of the CAA for the entire state under the New Mexico Air Quality Control Act (section 74-2-4).

C. Roles of Agencies in Addressing Regional Haze

Successful implementation of the regional haze program will require long-term regional coordination among states, tribal governments, and Federal agencies. Pollution affecting the air quality in Class I areas can be transported over long distances, even hundreds of kilometers. Therefore, effectively addressing the problem of visibility impairment in Class I areas means that states need to develop coordinated strategies that take into account the effect of emissions from one jurisdiction on the air quality of another state.

EPA has encouraged the states and tribes to address visibility impairment from a regional perspective because the pollutants that lead to regional haze can originate from sources located across broad geographic areas. Five regional planning organizations (RPOs) were developed to address regional haze and

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related issues. The RPOs first evaluated technical information to better understand how their states and tribes impact Class I areas across the country and then pursued the development of regional strategies to reduce PM2.5 emissions and other pollutants leading to regional haze.

The Midwest RPO (MRPO) is a collaborative effort of state governments and various Federal agencies established to initiate and coordinate activities associated with the management of regional haze, visibility, and other air quality issues in the Midwest. The member states are Illinois, Indiana, Michigan, Ohio, and Wisconsin.

III. What are the requirements for regional haze SIPs?

Regional haze SIPs must assure reasonable progress toward the national goal of achieving natural visibility conditions in Class I areas. Section 169A of the CAA and EPA's implementing regulations require states to establish long-term strategies for making reasonable progress toward meeting this goal. Plans must also give specific attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962, and must require those sources to install emission controls reducing visibility impairment if appropriate. The specific regional haze SIP requirements are discussed in further detail below.

A. Determination of Baseline, Natural, and Current Visibility Conditions

The RHR establishes the deciview \3\ (dv) as the principal metric or unit for expressing visibility impairment. This visibility metric expresses uniform proportional changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions. Visibility expressed in deciviews is determined by using air quality measurements to estimate light extinction and then transforming the value of light extinction using a logarithm function. The deciview is a more useful measure for tracking progress in improving visibility than light extinction itself because each deciview change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility at one deciview.

\3\ The preamble to the RHR provides additional details about the deciview. 64 FR 35714, 35725 (July 1, 1999).

The deciview is used in expressing RPGs, defining baseline, current, and natural conditions, and tracking changes in visibility. The regional haze SIPs must contain measures that ensure ``reasonable progress'' toward the national goal of preventing and remedying visibility impairment in Class I areas caused by anthropogenic air pollution. The national goal is a return to natural conditions such that anthropogenic sources of air pollution would no longer impair visibility in Class I areas.

To track changes in visibility over time at each of the 156 Class I areas covered by the visibility program (40 CFR 81.401-437) and as part of the process for determining reasonable progress, states must calculate the degree of existing visibility impairment at each Class I area at the time of each regional haze SIP submission and at the progress review every five years, midway through each 10-year implementation period. The RHR requires states with Class I areas (Class I states) to determine the degree of impairment in deciviews for the average of the 20 percent least impaired (best) and 20 percent most impaired (worst) visibility days over a specified time period at each of its Class I areas. Each state must also develop an estimate of natural visibility conditions for the purpose of comparing progress toward the national goal. Natural visibility is determined by estimating the natural concentrations of pollutants that cause visibility impairment and then calculating total light extinction based on those estimates. EPA has provided guidance to states regarding how to calculate baseline, natural, and current visibility conditions in documents titled, EPA's Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, September 2003, (EPA-454/B-03-005 located at http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf) (hereinafter referred to as ``EPA's 2003 Natural Visibility Guidance'') and Guidance for Tracking Progress Under the Regional Haze Rule (EPA-454/B-03-004 September 2003 located at http://www.epa.gov/ttncaaa1/t1/memoranda/rh_tpurhr_gd.pdf) (EPA's 2003 Tracking Progress Guidance).

For the first regional haze SIP, the ``baseline visibility conditions'' are the starting points for assessing ``current'' visibility impairment. Baseline visibility conditions represent the degree of visibility impairment for the 20 percent best days and 20 percent worst days for each calendar year from 2000 to 2004. Using monitoring data for 2000 through 2004, states calculate the average degree of visibility impairment for each Class I area, based on the average of annual values over the five-year period. The comparison of initial baseline visibility conditions to natural visibility conditions indicates the amount of improvement necessary to attain natural visibility, while the future comparison of baseline conditions to the then current conditions will indicate the amount of progress made. In general, the 2000 to 2004 baseline period is considered the time from which improvement in visibility is measured.

B. Determination of Reasonable Progress Goals (RPGs)

The vehicle for ensuring continuing progress towards achieving the natural visibility goal is the submission of a series of regional haze SIPs from the states that establish two distinct RPGs, one for the best days and one for the worst days for every Class I area for each approximately 10-year implementation period. The RHR does not mandate specific milestones or rates of progress, but instead calls for states to establish goals that provide for ``reasonable progress'' toward achieving natural visibility conditions. In setting RPGs, Class I states must provide for an improvement in visibility for the worst days over the approximately 10-year period of the SIP and ensure no degradation in visibility for the best days.

Class I states have significant discretion in establishing RPGs, but are required to consider the following factors established in section 169A of the CAA and in EPA's RHR at 40 CFR 51.308(d)(1)(i)(A): (1) The costs of compliance; (2) the time necessary for compliance; (3)

the energy and non-air quality environmental impacts of compliance; and, (4) the remaining useful life of any potentially affected sources. The state must demonstrate in its SIP how these factors are considered when selecting the RPGs for the best and worst days for each applicable Class I area. States have considerable flexibility in how they take these factors into consideration, as noted in EPA's Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, (``EPA's Reasonable Progress Guidance''), July 1, 2007, memorandum from William L. Wehrum, Acting Assistant Administrator for Air and Radiation, to EPA Regional Administrators, EPA Regions 1-10 (pp. 4-2, 5-1). In setting the RPGs, states must also consider the rate of progress needed to reach natural visibility conditions by 2064 (``uniform rate of progress'' or ``glide path'') and the emissions reduction needed to achieve that rate of progress over the approximately 10-year period of the SIP.

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In setting RPGs, each Class I state must also consult with potentially contributing states, i.e. those states that may affect visibility impairment at the Class I state's areas. 40 CFR 51.308(d)(1)(iv).

C. Best Available Retrofit Technology (BART)

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain older large stationary sources to address visibility impacts from these sources. Specifically, CAA section 169A(b)(2)(A) requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress towards the natural visibility goal including a requirement that certain categories of existing major stationary sources built between 1962 and 1977 procure, install, and operate BART as determined by the state. The set of ``major stationary sources'' potentially subject to BART is listed in CAA section 169A(g)(7). The state can require source-specific BART controls, but it also has the flexibility to adopt an alternative such as a trading program as long as the alternative provides greater progress towards improving visibility than BART.

On July 6, 2005, EPA published the Guidelines for BART Determinations Under the Regional Haze Rule at Appendix Y to 40 CFR Part 51 (BART Guidelines) to assist states in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each applicable source. A state must use the approach in the BART Guidelines in making a BART determination for fossil fuel-fired electric generating units (EGUs) with total generating capacity in excess of 750 megawatts. States are encouraged, but not required, to follow the BART Guidelines in making BART determinations for other sources.

States must address all visibility-impairing pollutants emitted by a source in the BART determination process. The most significant visibility impairing pollutants are SO2, NOX, and

PM. EPA has stated that states should use their best judgment in determining whether VOC or NH3 compounds impair visibility in Class I areas.

States may select an exemption threshold value for their BART modeling under the BART Guidelines, below which a BART-eligible source would not be expected to cause or contribute to visibility impairment in any Class I area. The state must document this exemption threshold value in the SIP and must state the basis for its selection of that value. The exemption threshold set by the state should not be higher than 0.5 dv. Any source with emissions that model above the threshold value would be subject to a BART determination review. The BART Guidelines acknowledge varying circumstances affecting different Class I areas. States should consider the number of emission sources affecting the Class I areas at issue and the magnitude of the individual source's impact.

The state must identify potential BART sources in its SIP, described as ``BART-eligible sources'' in the RHR, and document its BART control determination analyses. In making BART determinations, section 169A(g)(2) of the CAA requires the state to consider the following factors: (1) The costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and, (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. A regional haze SIP must include source-specific BART emission limits and compliance schedules for each source subject to BART. The BART controls must be installed and in operation as expeditiously as practicable, but no later than five years after the date of EPA's approval of the state's regional haze SIP. CAA section 169(g)(4); 40 CFR 51.308(e)(1)(iv). In addition to what is required by the RHR, general SIP requirements mandate that the SIP must also include all regulatory requirements related to monitoring, recordkeeping, and reporting for the BART controls on the source.

D. Long-Term Strategy

Consistent with the requirement in section 169A(b) of the CAA that states include in their regional haze SIP a 10 to 15 year strategy for making reasonable progress, section 51.308(d)(3) of the RHR requires that states include a long-term strategy (LTS) in their regional haze SIPs. The LTS is the compilation of all control measures a state will use during the implementation period of the specific SIP submittal to meet applicable RPGs. The LTS must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the RPGs for all Class I areas within or affected by emissions from the state. 40 CFR 51.308(d)(3).

When a state's emissions are reasonably anticipated to cause or contribute to visibility impairment in a Class I area located in another state, the RHR requires the impacted state to coordinate with the contributing states in order to develop coordinated emissions management strategies. 40 CFR 51.308(d)(3)(i). In such cases, the contributing state must demonstrate that it has included in its SIP all measures necessary to obtain its share of the emission reductions needed to meet the RPGs for the Class I area. The RPOs have provided forums for significant interstate consultation, but additional consultations between states may be required to address interstate visibility issues sufficiently.

States should consider all types of anthropogenic sources of visibility impairment in developing their LTS, including stationary, minor, mobile, and area sources. At a minimum, states must describe how each of the following seven factors are taken into account in developing their LTS: (1) Emission reductions due to ongoing air pollution control programs, including measures to address RAVI; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the RPG; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes; (6) enforceability of emissions limitations and control measures; and, (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS. 40 CFR 51.308(d)(3)(v).

E. Coordinating Regional Haze and Reasonably Attributable Visibility Impairment Long-Term Strategy

EPA revised 40 CFR 51.306(c) as part of the RHR regarding the LTS for RAVI to require that the RAVI plan must provide for a periodic review and SIP revision not less frequently than every three years until the date of submission of the state's first plan addressing regional haze visibility impairment in accordance with 40 CFR 51.308(b) and (c). The state must revise its plan to provide for review and revision of a coordinated LTS for addressing RAVI and regional haze on or before this date. It must also submit the first such coordinated LTS with its first regional haze SIP. Future coordinated LTSs, and periodic progress reports evaluating progress towards RPGs, must be submitted consistent with the schedule for SIP submission and periodic progress reports set forth in 40 CFR 51.308(f) and 51.308(g), respectively.

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The periodic review of a state's LTS must report on both regional haze and RAVI impairment and be submitted to EPA as a SIP revision.

F. Monitoring Strategy and Other Implementation Plan Requirements

Section 51.308(d)(4) of the RHR includes the requirement for a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the state. The strategy must be coordinated with the monitoring strategy required in section 51.305 for RAVI. Compliance with this requirement may be met through participation in the IMPROVE network, meaning that the state reviews and uses monitoring data from the network. The monitoring strategy must also provide for additional monitoring sites if the IMPROVE network is not sufficient to determine whether RPGs will be met. The monitoring strategy is due with the first regional haze SIP and must be reviewed every five years.

The SIP must also provide for the following:

Procedures for using monitoring data and other information in a state with mandatory Class I areas to determine the contribution of emissions from within the state to regional haze visibility impairment at Class I areas both within and outside of the state;

Procedures for using monitoring data and other information in a state with no mandatory Class I areas to determine the contribution of emissions from within the state to regional haze visibility impairment at Class I areas in other states.

Reporting of all visibility monitoring data to the Administrator at least annually for each Class I area in the state, and where possible in electronic format;

A statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The inventory must include emissions for a baseline year, emissions for the most recent year with available data, and future projected emissions. A state must also make a commitment to update the inventory periodically; and

Other elements including reporting, recordkeeping, and other measures necessary to assess and report on visibility;

The RHR requires control strategies to cover an initial implementation period extending to the year 2018 with a comprehensive reassessment and revision of those strategies, as appropriate, every 10 years thereafter. Periodic SIP revisions must meet the core requirements of section 51.308(d) with the exception of BART. The requirement to evaluate sources for BART applies only to the first regional haze SIP. Facilities subject to BART must continue to comply with the BART provisions of section 51.308(e), as noted above. Periodic SIP revisions will assure that the statutory requirement of reasonable progress will continue to be met.

G. Consultation With States and Federal Land Managers

The RHR requires that states consult with Federal Land Managers (FLMs) before adopting and submitting their SIPs. 40 CFR 51.308(i). States must provide FLMs an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the SIP. This consultation must include the opportunity for the FLMs to discuss their assessment of impairment of visibility in any Class I area and to offer recommendations on the development of the RPGs and on the development and implementation of strategies to address visibility impairment.

Further, a state must include in its SIP a description of how it addressed any comments provided by the FLMs. Finally, a SIP must provide procedures for continuing consultation between the state and FLMs regarding the state's visibility protection program, including development and review of SIP revisions, five-year progress reports, and the implementation of other programs having the potential to contribute to impairment of visibility in Class I areas.

IV. What is EPA's analysis of Illinois' regional haze plan?

Illinois submitted its regional haze plan on June 24, 2011, which included revisions to the Illinois SIP to address regional haze.

A. Class I Areas

States are required to address regional haze affecting Class I areas within a state and in Class I areas outside the state that may be affected by the state's emissions. 40 CFR 51.308(d). Illinois does not have any Class I areas within the state. Illinois reviewed technical analyses conducted by MRPO to determine what Class I areas outside the state are affected by Illinois emission sources. MRPO conducted both a back trajectory analysis and modeling to determine the affects of its states' emissions. The conclusion from the technical analysis is that emissions from Illinois sources affect 19 Class I areas. The affected Class I areas are: Sipsey Wilderness Area in Alabama; Caney Creek and Upper Buffalo Wilderness Areas in Arkansas; Mammoth Cave in Kentucky; Acadia National Park and Moosehorn Wilderness Area in Maine; Isle Royale National Park and Seney Wilderness Area in Michigan; Boundary Waters Canoe Wilderness Area in Minnesota; Hercules-Glades and Mingo Wilderness Areas in Missouri; Great Gulf Wilderness Area in New Hampshire; Brigantine Wilderness Area in New Jersey; Great Smoky Mountains National Park in North Carolina and Tennessee; Lye Brook Wilderness Area in Vermont; James River Face Wilderness Area and Shenandoah National Park in Virginia; and, Dolly Sods/Otter Creek Wilderness Area in West Virginia.

B. Baseline, Current, and Natural Conditions

The RHR requires states with Class I areas to calculate the baseline and natural conditions for their Class I areas. Because Illinois does not have any Class I areas, it was not required to address the requirements for calculating baseline and natural conditions.

C. Reasonable Progress Goals

Class I states must set RPGs that achieve reasonable progress toward achieving natural visibility conditions. Because Illinois does not have any Class I areas, it is not required to establish RPGs. Illinois consulted with affected Class I states to ensure that it achieves its share of the overall emission reductions necessary to achieve the RPGs of Class I areas that it impacts. Illinois's coordination with affected Class I states is discussed under Illinois Long Term Strategy, in Section IV. E.

Illinois included the MRPO technical support document (TSD) in its submission. In Section 5 of the TSD, MRPO assessed the reasonable progress for regional haze. It first assessed potential control measures using the four factors required to be considered by Class I states when selecting the RPGs: the cost of compliance, time needed, energy and non-air impacts, and remaining useful life of any potentially affected sources. The cost of compliance factor includes calculating the average cost effectiveness and can include costs to health and industry vitality as well as considering the different visibility effects of different pollutants. The time necessary for compliance factor considers whether control measures can be implemented by 2018. The third factor, energy and non-air quality impacts, considers additional energy consumed by or because of the control measure as well as effects due to waste

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generated or water consumption. The final factor, remaining useful life, allows states to consider planned source retirements in calculating costs.

MRPO also assessed the visibility benefits of existing programs. MRPO considered existing on-highway mobile source, off-highway mobile source, area source, power plant, and other point source programs. MRPO also included reductions from the Clean Air Interstate Rule (CAIR) in its analysis, as well from rules adopted by Illinois and included in its regional haze SIP requiring the control of emissions from EGUs.

Illinois has a distinctive situation regarding CAIR, insofar as it has adopted state rules that require EGUs to control NOX and SO2 emissions beyond the control expected from CAIR, even in the absence of CAIR, particularly by 2018 and beyond. Further discussion of these Illinois rules is provided below. The RPGs that pertinent Class I states have adopted are predicated on other contributing states achieving the EGU emission reductions anticipated under CAIR. Since Illinois is mandating a greater degree of control than is expected from other states, EPA concludes that Illinois's regional haze plan is expected to provide emission reductions representing an appropriate contribution toward meeting the RPGs for the affected Class I areas, irrespective of the status of CAIR and irrespective of the associated issues regarding the adequacy of other state's plans. For similar reasons, EPA believes that the approvability of the Illinois plan is also not affected by the status of the Transport Rule, which was promulgated on August 8, 2011 at 76 FR 48208 and stayed on December 30, 2011.

D. Best Available Retrofit Technology

States are required to submit an implementation plan containing emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment in a Class I area, unless the State demonstrates that an emissions trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions. 40 CFR 51.308(e).

Using the criteria in the BART Guidance at 40 CFR 51.308(e) and Appendix Y, Illinois first identified all of the BART-eligible sources and assessed whether the BART-eligible sources were subject to BART. Illinois initially identified 26 potential BART facilities--11 EGUs, four petroleum refineries, three chemical process plants, two Portland cement plants, two glass fiber processing plants, one lime plant, and one iron and steel plant. The state further analyzed these facilities to identify those sources subject to BART. Illinois relied on modeling conducted by MRPO using a modeling protocol MRPO developed. MRPO conferred with its states, EPA, and the FLMs in developing its BART modeling protocol. EPA guidance says that, ``any threshold that you use for determining whether a source `contributes' to visibility impairment should not be higher than 0.5 dv.'' The Guidelines affirm that states are free to use a lower threshold if the location of a large number of BART-eligible sources in proximity of a Class I area justifies this approach. Illinois used a contribution threshold of 0.5 dv for determining which sources warrant being subject to BART. Illinois concluded that the threshold of 0.5 dv was appropriate since its BART-eligible sources are located state-wide and no Class I areas are nearby causing Illinois to correctly conclude that a stricter contribution threshold is not justified. The modeled impact of these facilities indicated that 11 sources have at least 0.5 dv impact (98th percentile) and thus are subject to BART. The 11 sources determined to be subject to BART are nine EGUs and two petroleum refineries. The other 15 potential BART sources were determined not to be subject to BART because the analysis showed impacts well below the 0.5 dv contribution threshold.

The EGUs subject to BART are:

Dynegy Midwest Generating--Baldwin Boilers 1, 2, and 3.
Dominion Kincaid Generation--Boilers 1 and 2.
Ameren Energy Generating--Coffeen Boilers CB-1 and CB-2.
Ameren Energy Generating--E.D. Edwards Boilers 2 and 3.
Ameren Energy Generating--Duck Creek Boiler 1.
Midwest Generation--Powerton Boilers 51, 52, 61, and 62.
Midwest Generation--Joliet Boilers 71, 72, 81, and 82.
Midwest Generation--Will County Boiler 4.
City Water, Light, and Power--Dallman Boiler 1 and 2.
City Water, Light, and Power--Lakeside Boiler 8.

To address mercury emissions from EGUs, Illinois adopted Part 225 of Illinois's air pollution regulations, entitled ``Control of Emissions from Large Combustion Sources.'' In this rule, Illinois offered affected utilities two options, one of which imposes stringent limits on mercury emissions alone and the other of which mandates implementation of specific mercury control technology in conjunction with satisfaction of stringent emission limits for SO2 and NOX. Part 225 includes section 225.233, entitled ``Multi-Pollutant Standards,'' addressing emissions from facilities owned by Ameren and Dynegy, and sections 225.293 to 225.299, collectively referred to as the Combined Pollutant Standards (CPS), addressing emissions from facilities owned by Midwest Generation. In all cases, the utilities have selected the option including mercury control technology and applicability of the SO2 and NOX limits. The emission limits are in the earlier noted sections of the state rules, so these SO2 and NOX limits are now fully enforceable by the state.

The SO2 and NOX emission limits in Part 225 rules reflect substantial averaging across units and across facilities. For example, the collective set of facilities in Illinois owned by Midwest Generation (as listed in the Part 225 rules) are subject to NOX and SO2 limits based on annual average emissions across all facilities. The limit for NOX emissions is 0.11 pounds per million British Thermal Units (lb/MMBTU) starting in 2012 and the limits for SO2 are 0.15 lb/MMBTU in 2017 and 0.11 lb/MMBTU starting in 2019. The collective set of Ameren facilities in Illinois, under the Multi-Pollutant Standards (MPS), must meet an annual average emission limit for NOX of 0.11 lb/MMBTU starting in 2012 and for SO2 of 0.23 lb/MMBTU starting in 2017. Similar limits under the MPS apply to the Dynegy facilities in Illinois.

EPA believes this degree of averaging is acceptable in this context. The limits that Illinois has imposed are sufficiently stringent that the companies have only limited latitude to over control at some facilities in trade for having elevated emissions at other facilities. The facilities owned by each company are sufficiently close to each other, relative to their distances from the nearest Class I areas, that modest shifts in emissions from one facility to another should have minimal impact on the combined impact on regional haze at the Class I areas. Furthermore, regional haze is evaluated across a considerable number of days, e.g., the 20 percent of days with the worst visibility. Therefore, a limit that allows elevated emissions on individual days, so long as other days have lower emissions, should suffice to address the pertinent measures of regional haze. Illinois's limits should also be adequately enforceable since the sources at issue are required to conduct continuous emission monitoring of both SO2 and NOX.

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Dynegy has five facilities with 10 units covered by MPS, including the three Dynegy Baldwin units that are subject to BART. Emission reductions required for seven other Dynegy units not subject to BART will allow it meet the MPS reduction requirements. MPS will reduce emissions from all Dynegy facilities by 23,831 tons per year (TPY) of NOX and 47,347 TPY of SO2, as compared to emissions in the 2002 base year.

Ameren has seven facilities with 21 units covered by MPS. This includes the subject to BART units: Coffeen units 1 and 2, Duck Creek unit 1, and Edwards units 2 and 3. Ameren has installed selective catalytic reduction (SCR) for NOX control and wet scrubbers to limit SO2 emissions from both Coffeen units. Duck Creek unit 1 is controlled by low NOX burners, SCR, and wet scrubbers. Edwards unit 2 will receive an upgraded low NOX burner and overfire air (OFA) to reduce NOX emissions. Edwards unit 3 is already controlled for NOX with low NOX burners, OFA, and SCR. Ameren plans to install a new scrubber and fabric filter at Edwards unit 3. Company-wide reductions from Ameren EGUs are projected to be 27,896 TPY NOX and 131,367 TPY SO2 by 2015 and 134,464 TPY of SO2 by 2017.

Midwest Generating operates six facilities with 19 total units that must comply with CPS, including the Midwest Generation units subject to BART: Powerton units 51, 52, 61, and 62; Joliet units 71, 72, 81, and 82; and Will County unit 4. The four Powerton units currently have low NOX burners and OFA. Midwest Generation plans to add selective non-catalytic reduction (SNCR) in 2012 to reduce NOX emissions and flue gas desulfurization (FGD) in 2013 to cut SO2 emissions. Both control improvements will be added to all four units. Midwest Generating's Joliet facility currently has low NOX burners and OFA on its four BART units. SNCR is expected to be added in 2012 to all four BART units. Midwest Generating is also planning to add FGD on units 71, 72, 81, and 82 by 2019. Will County unit 4 is currently controlled with low NOX burners and OFA. Midwest Generating plans to upgrade the NOX control to SNCR in 2012 and to add FGD control by 2019. CPS will reduce NOX emissions from all Midwest Generating facilities by 38,155 TPY, while SO2 emissions will decrease by 35,465 TPY in 2015, increasing to a 61,194 TPY reduction in 2019.

A state may opt to implement an alternate measure rather than requiring each subject to BART unit to install, operate, and maintain BART if it demonstrates that the alternate measure will achieve greater reasonable progress. The criteria for the assessment if an alternative measure demonstrates greater reasonable progress are provided in 40 CFR 51.308(e)(2). MPS will reduce emissions from both subject to BART and non-BART units at the Ameren and Dynegy facilities. Similarly, CPS will require emission reductions from Midwest Generation's subject to BART and non-BART units. Illinois elected to use MPS and CPS participation as alternative to requiring BART control on each of the Ameren, Dynegy, and Midwest Generation units subject to BART. Illinois stated that implementation of the MPS and CPS emission limits will provide much deeper NOX and SO2 reductions than implementing BART on the subject to BART units and thus the alternate will provide greater reasonable progress. However, Illinois did not provide an analysis comparing BART for each subject unit to the alternative. Illinois compared the emission reductions from MPS and CPS to the presumptive BART emission levels suggested in EPA's guidance. EPA generally requires states to compare the alternative strategy to a fully analyzed set of BART limits for the BART-subject units. However, in this case, the results of such a comparison are clear even without Illinois conducting a full BART analysis for these units. The total NOX emission reductions due to MPS on Dynegy EGUs are greater than the base year NOX emissions from Dynegy's subject to BART units. Therefore, the emission reductions from MPS are greater than the maximum possible reductions from the BART units. The same is true for SO2 emissions for the Dynegy EGUs, the NOX emissions from the Ameren EGUs, and the SO2 emissions from the Ameren EGUs. Similarly, the total NOX emission reductions from all Midwest Generating are greater than the NOX emissions from the BART units and the same for its SO2 emissions. Therefore, even without a full analysis of the precise emission levels that would constitute BART for the BART-subject units, EPA finds that the Illinois rules, MPS and CPS, are an acceptable BART alternative because the emission reductions are greater than the reductions that could possibly be obtained by only requiring BART at the BART-subject units.

Three other EGUs, owned by two other utilities Dominion Energy and the City of Springfield's City Water, Light, and Power (CWLP), are not covered by MPS and CPS but have units subject to BART. CWLP is a smaller utility with a total generating capacity of less than 750 MW and Dominion Energy has only one electric generating facility in Illinois such that these utilities do not have the opportunities for multi-plant averaging of emission limits that the larger utilities have. Rather than adopting an alternative program to address the BART requirements for these two utilities, Illinois is requiring these utilities to meet the BART requirements for the units subject to BART and establish enforceable emission limits for SO2 and NOX. CWLP's Dallman and Lakeside plants, along with Dominion's Kincaid plant, have units subject to BART. Both utilities must reduce emissions to meet the BART limits. The emission limits for Dallman units 31 and 32, Lakeside unit 8, and Kincaid units 1 and 2 are contained in Joint Construction and Operating permits. Illinois evaluated potential controls and what control level the current emission controls can achieve in setting the BART emission limits for the CWLP Dallman and Dominion Kincaid units.

CWLP currently has SCRs and FGD on Dallman units 31 and 32. As of 2010, CWLP has been operating the SCRs to achieve an annual average NOX emission rate of 0.14 lb/MMBTU on both Dallman units, combined. The annual average NOX emission rate will be limited to 0.12 lb/MMBTU by 2015 and then further decreased to 0.11 lb/MMBTU by 2017 for both units, combined. CWLP will operate the controls to achieve an annual average SO2 emissions rate on both Dallman units, combined, of 0.29 lb/MMBTU by 2012, then reduced to 0.25 lb/MMBTU by 2015, and finally to 0.23 lb/MMBTU by 2017. Illinois has determined these emission limits satisfy BART for both units. CWLP permanently shut down Lakeside unit 8 in 2009, which is reflected in the permit.

Dominion's Kincaid facility operates SCRs on its units 1 and 2. The permit for the Kincaid facility limits NOX emissions to an annual average of 0.07 lb/MMBTU by March 1, 2013, on both units, combined. Illinois determined the appropriate SO2 control system for Kincaid is a dry sorbent injection system along with using low sulfur coal. Illinois initially gave the Kincaid facility a SO2 emission limit of 0.20 lb/MMBTU on both units, but found that a stricter limit of 0.15 lb/MMBTU can be achieved with the control system. Illinois thus set the SO2 emission limits for both Kincaid units, combined, at an annual average emission rate of 0.20 lb/MMBTU by January 1, 2014, and reduced the limit further to an annual average emission rate of 0.15 lb/MMBTU beginning on January 1, 2017.

Illinois issued the Joint Construction and Operating permits pursuant to its

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authority in the SIP and submitted the two permits as part of its Regional Haze plan to be incorporated into the SIP. The permits set Federally enforceable NOX and SO2 limits as necessary to meet the Regional Haze requirements of the CAA and effectively mandate that the utilities to run the SCRs year round and for CWLP to shut down its Lakeside unit 8.

Two petroleum refineries, the CITGO and Exxon Mobil refineries, also have units subject to BART: the CITGO refinery in Lemont, Illinois and the Exxon Mobil refinery south of Joliet, Illinois. Both refineries will be required to reduce emissions by a Federal consent decree resolving an enforcement action brought by EPA against a number of refineries. The consent decrees require the CITGO, Exxon Mobil, and the other refineries to operate controls at the Best Available Control Technology level. Illinois evaluated the subject-to-BART units at the CITGO and Exxon Mobil refineries. It found that the NOX and SO2 emission limits on the subject-to-BART units in the consent decrees satisfy BART.

A consent decree between the United States and CITGO Petroleum Corporation was entered in the U.S. District Court for the Southern District of Texas on October 6, 2004 (No. H-04-3883). The consent decree requires the company to operate SCR and a wet scrubbing system at its Fluid Catalytic Cracking Unit (FCCU) that will reduce NOX emissions by more than 90 percent and SO2 emissions by 85 percent. The controls on the FCCU will result in a reduction of NOX emissions from 1,065.7 to 106.6 TPY and SO2 emissions from 10,982.5 to 107.9 TPY by 2013. CITGO has also added a tail gas recovery unit that reduces SO2 emissions from its sulfur train units from 4340.0 to 91.2 TPY, a 98 percent reduction. The emission controls on all units at CITGO's Lemont refinery will reduce NOX emissions by 1,268 TPY and

SO_2 emissions by 15,123 TPY.

A consent decree between the United States and Exxon Mobil Corporation was entered in the U.S. District Court for the Northern District of Illinois on October 11, 2005 (No. O5-C-5809). The consent decree for Exxon Mobil requires SCR operation on its FCCU in addition to maintenance of the existing wet scrubbing system. The controls on the FCCU result in a 1,636.2 TPY decrease in NOX emissions from 1,818.0 to 181.8 TPY and a 9,667.7 TPY decrease in SO_2 emissions from 9,865.0 to 197.3 TPY. Exxon Mobil also has added a tail gas recovery unit on its south sulfur recovery unit. That reduces SO_2 emissions by 9,153.8 TPY to 186.8 TPY. The emission controls at Exxon Mobil's Joliet refinery will reduce 1,695 TPY NOX and 18,821 TPY SO_2.

These two consent decrees are Federally enforceable and also require that the refineries submit permit applications to Illinois to incorporate the required emission limits into Federally enforceable air permits (other than Title V). Therefore, emission limits established by the consent decrees may be relied upon by Illinois for addressing the BART requirement for these facilities.

Based on modeling, MRPO determined that the visibility impact of directly emitted particulate matter from the facilities with subject to BART units is minimal. In particular, MRPO assessed the impact of the directly emitted particulate matter from all facilities potentially subject to BART in the five MRPO states, and found the impact to be less than 0.5 dv at any Class I area as compared to natural background conditions. Illinois therefore concludes that PM emissions from its subset of these BART sources have a negligible visibility impact. Furthermore, these facilities are already subject to federally enforceable PM emission control requirements mandated by SIP-approved state particulate matter regulations, so that there is minimal potential for further PM emission reductions. Therefore, based particularly on the substantial existing controls on these facilities-fabric filters, electrostatic precipitators, and cyclones; and the minimal benefits of further control, Illinois concluded that BART did not include further control of PM emissions from these facilities.

EPA is satisfied with the state's BART determinations. The emission limits that Illinois adopted generally will require state-of-the-art emission controls, not just at the units subject to BART requirements but also at numerous units that are not subject to BART. The Illinois facilities subject to BART are a long distance from any Class I area such that, so the geographical redistributions of emissions within Illinois do not significantly affect visibility and the benefits of alternate control strategies may be judged simply by comparing the net emission reductions. The MPS and CPS provide emission reduction well in excess of simply implementing BART on subject units. The reduction in NOX emissions from the Ameren, Dynegy, and Midwest Generation units by 2015 from MPS and CPS is expected to be 89,882 TPY. Illinois estimated that simply implementing BART on the subject units from these entities would yield 32,992 TPY of NOX emission reductions, which is 56,890 TPY less than from MPS and CPS. Illinois estimated that implementing BART on the subject units at Ameren, Dynegy, and Midwest Generation facilities would require an 117,252 TPY reduction in SO2 emission, but MPS and CPS will require a 214,179 TPY SO2 reduction by 2015. Thus, Illinois estimated that its plan will require 96,927 TPY lower SO2 emissions than simply requiring BART. EPA believes that Illinois has thereby demonstrated the emission limits on the subject to BART units covered by MPS and CPS satisfy the BART requirements.

Illinois did not rely on the Clean Air Interstate Rule (CAIR) for its BART determinations. Illinois is in the CAIR region. However, it used its state rules, permits, and consent decrees to achieve emission reductions that satisfy BART. This means that Illinois is not reliant on CAIR and, thus, it has avoided the issues of other CAIR region states that relied on CAIR. For similar reasons, Illinois' satisfaction of regional haze rule requirements is not contingent on the Transport Rule and thus is not affected by the stay of that rule.

E. Long-Term Strategy

Under section 169A(b)(2) of the CAA and 40 CFR 51.308(d), states' regional haze programs must include an LTS for making reasonable progress toward meeting the national visibility goal. Illinois's LTS must address visibility improvement for the Class I areas impacted by Illinois sources. Section 51.308(d)(3) requires that Illinois consult with the affected states in order to develop a coordinated emission management strategy. A contributing state, such as Illinois, must demonstrate that it has included, in its SIP, all measures necessary to obtain its share of the emissions reductions needed to meet the RPGs for the Class I areas affected by Illinois sources. As described in section III.D. of this proposed rule, the LTS is the compilation of all control measures Illinois will use to meet applicable RPGs. The LTS must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the RPGs for all Class I areas affected by Illinois emissions.

Illinois complied with the consulting requirements by participating in meetings and conference calls with affected Class I states and RPOs to discuss the states' assessments of visibility conditions, analyses of culpability, and possible measures that could be taken to meet visibility goals. Illinois engaged in extensive

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consultations with other MRPO states, including Indiana, Michigan, Ohio, and Wisconsin. Illinois also consulted with Arkansas, Kentucky, Minnesota, Missouri, New Hampshire, New Jersey, and Vermont. As part of the MRPO, Illinois participated in inter-RPO consultation on regional haze. This consultation is detailed in Chapter 9 of the state's plan. EPA finds that the state's consultation with Class I states satisfies applicable consultation requirements.

Illinois's LTS includes the modeling and monitoring results on which it relied to determine its share of emission reductions necessary to meet the reasonable progress goals of impacted Class I areas. This information is provided in Chapter 9 of the Illinois regional haze plan. Portions of this technical work were provided by MRPO as it worked with other RPOs to provide this information on Class I areas outside the Midwest.

At 40 CFR 51.308(d)(3)(v), the RHR identifies seven factors that a state must consider in developing its LTS: (A) Emission reductions due to ongoing programs; (B) measures to mitigate impact from construction; (C) emission limits to achieve the RPG; (D) replacement and retirement of sources; (E) smoke management techniques; (F) Federally enforceable emission limits and control measures; and (G) the net effect on visibility due to projected emission changes over the LTS period. Illinois considered the seven factors in developing its LTS. Chapter 8 of the Illinois regional haze plan provides a full analysis of each factor.

Illinois relied on MRPO's modeling and analysis along with its emission information in developing a LTS. Illinois considered the factors set out in 51.308(d)(3)(v) in developing its LTS. Based on these factors and the MRPO's technical analysis, in conjunction with RPGs that were set by the pertinent Class I states in consultation with Illinois and other contributing states, Illinois concludes that existing control programs, together with the BART controls described above, address Illinois's impact on Class I areas. This is because the combination of the existing controls and the BART controls suffice to meet the impacted Class I areas' RPGs by 2018. These existing control programs include Federal motor vehicle emission control program, reformulated gasoline, emission limits for area sources of VOCs, Title IV, the NOX SIP Call, NOX Reasonable Achievable Control Technology, Maximum Achievable Control Technology standards, and Federal non-road standards for construction equipment and vehicles. As discussed in prior sections, implementation of the existing control programs, supplemented by the control measures in the submission that require power plant and petroleum refinery emission reductions, will satisfy the LTS requirements because, for reasons discussed above, the expected emission reductions will meet requirements both to provide for BART and to provide emission reductions in Illinois that, in combination with emission reductions elsewhere, should improve visibility sufficiently for the pertinent Class I areas to meet their RPGs.

Illinois assessed all point sources in the state that emit at least 1,000 TPY of NOX and SO2 combined and are more than 100 km from a Class I area to determine if the sources could potentially affect visibility in a Class I area. The assessment followed EPA guidance in calculating the ratio of emission rate in TPY (Q) to the distance to the nearest Class I area (d). The exclusions also followed guidance. Illinois found 15 facilities with a Q/d ratio equal to and greater than 10, EPA's recommended threshold. The results of the Q/d assessment are found in Table 8.1 in the Illinois TSD.

Illinois found that it expects the implementation of existing control measures will result in emission reductions from the 15 facilities. As such, Illinois believes that the expected emission reductions will ensure reasonable progress.

F. Monitoring Strategy

Illinois maintains a monitoring network that provides data to analyze air quality problems including regional haze. Illinois's monitoring network includes State and Local Air Monitoring Sites (SLAMS), Special Purpose Monitors (SPM), Photochemical Assessment Monitoring Sites (PAMS), and PM2.5 speciation sites.

Illinois does not operate any sites under the IMPROVE program, but does have a site in Bondville, Illinois that monitors using the IMPROVE procedure method. Illinois is required under 40 CFR 51.308(d)(4) to have procedures for using the monitoring data to determine the contribution of emissions from within the state to affected Class I areas. Illinois developed procedures in conjunction with the MRPO. The procedures are detailed in the MRPO TSD. EPA finds that Illinois's regional haze plan meets the monitoring requirements for the RHR and that Illinois's network of monitoring sites is satisfactory to measure air quality and assess its contribution to regional haze.

G. Federal Land Manager Consultation

Illinois was required to consult with the FLMs under 40 CFR 51.308(i). Illinois consulted with the FLMs electronically and by telephone. The FLMs were also included in discussions with Illinois during MRPO conference calls and meetings. A draft regional haze plan was submitted for FLMs comments on August 6, 2009. Illinois then provided the FLMs a revised regional haze plan on October 7, 2010 for review. That provided the FLMs enough time to comment prior to the December 6, 2010, public hearing on the regional haze plan. Illinois has included comments from the FLMs in Attachment 9 to its regional haze plan, a document providing the comments Illinois received and its responses. The state has committed to consulting the FLMs on future SIP revisions and progress reports.

H. Comments

Illinois took comments on its proposed regional haze plan. It held a public hearing on December 6, 2010. The public comment period ended on January 5, 2011. Evidence of the public notice and evidence of the public hearing were submitted to EPA.

Illinois's submission includes a document, Attachment 9, which summarized the comments it received from both the FLMs and from the public and provides its responses to the comments. The state revised portions of its plan based on the comments to correct errors and clarify portions that caused confusion. Illinois responded to other comments without revising its plan. EPA concludes that Illinois has satisfied the requirements from 40 CFR Part 51, Appendix V to provide evidence that it gave public notice, took comments, and that it compiled and responded to comments.

V. What action is EPA taking?

EPA is proposing to approve revisions to the Illinois SIP, submitted on June 24, 2011, addressing regional haze for the first implementation period. The revisions address CAA and regional haze rule requirements for states to remedy any existing anthropogenic and prevent future impairment of visibility at Class I areas. EPA finds that Illinois has satisfied all the requirements and, thus, is proposing approval of the regional haze plan. EPA is also proposing to approve two state rules, MPS and CPS, and incorporating two permits, issued to City Water, Light, & Power and to Dominion Energy, into the SIP.

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VI. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

Is not a ``significant regulatory action'' subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);

Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 et seq.);

Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.);

Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104-4);

Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);

Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);

Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);

Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272

note) because application of those requirements would be inconsistent with the CAA; and

Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Dated: January 17, 2012.

Susan Hedman,
Regional Administrator, Region 5.

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