7B. Small Business Impact Analysis (RFA/SBREFA)

According to the requirements of the 1980 Regulatory Flexibility Act (RFA) as amended by the 1996 Small Business Regulatory Enforcement Fairness Act (SBREFA), Federal regulatory agencies are required to make initial determinations if proposed regulatory actions may have a "significant economic impact on a substantial number of small entities" (SISNOSE). Small entities include small businesses, small organizations, and small governmental jurisdictions. Agencies are required to conduct a Regulatory Flexibility Screening Analysis (RFSA) to make this determination. This section of the RIA presents the methodology and findings for the RFSA conducted for the proposed rule.

Unless Agencies are able to certify that a particular regulatory action is not expected to have a SISNOSE, the RFA/SBREFA requires a formal analysis of the potential adverse economic impacts on small entities, completion of a Small Business Advocacy Review Panel (proposed rule stage), preparation of a Small Entity Compliance Guide (final rule stage), and Agency review of the rule within 10 years of promulgation.

The small business impact analysis of this RIA follows the four analytic steps described in EPA's RFA/SBREFA analysis guidance[172]:

Step 1: Determine which small entities are subject to the rule's requirements
Step 2: Select appropriate measures for determining economic impacts on these small entities and estimate those impacts
Step 3: Determine whether the rule may be certified as not having a significant impact on small entities (SISNOSE)
Step 4: Document the screening analysis and include the appropriate RFA statements in the preamble

- **Step 1: Identification of Small Entities**

The scope of entities addressed by this analysis includes the affected coal-fired electric utility plants in NAICS code 221112. Not included in the scope of this RFA/SBREFA analysis are offsite commercial landfills which currently receive and dispose CCR generated by electric utility plants. EPA's RCRA statute does not provide EPA with authority to collect information from solid waste facilities; it only provides EPA with authority to collect information from RCRA-regulated hazardous waste management facilities (via the RCRA biennial report). EPA does not know the identity, company size, or other information about the offsite landfills currently used by the electric utility industry. Therefore, this RFA/SBREFA analysis is limited to only electric utility plants. Consistent with EPA's RFA/SBREFA guidance (page 15), this RIA applies the following small size definitions for owner entities of electric utility plants:

Small company: Based on the US Small Business size standard for NAICS code 221112 (fossil fuel electric utility plants): a company which generates less than 4 million megawatt-hours electricity output per year.

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[172] EPA's RFA/SBREFA guidance: "EPA's Action Development Process: Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act", EPA Office of Policy, Economics & Innovation, Nov 2006, 105 pages: http://www.epa.gov/sbrefa/documents/rfaguidance11-00-06.pdf

Small government: Based on the RFA/SBREFA's definition (5 US Code section 601(5)) of small government jurisdiction as the government of a city, county, town, township, village, school district, or special district with population <50,000.

Based on the nameplate megawatt (MW) capacity for all electricity generating units (including those powered by non-coal fuel types) at each electricity plant from the 2007 DOE-EIA 860 database, this RIA estimated annual megawatt-hours electricity generation capacity by multiplying the nameplate capacity by (a) 365 days per year, and (b) 24 hours per day to calculate each owner entity's annual electricity capacity. **Appendix D** of this RIA indicates the assigned size of the owner company or city government for each electric utility plant according to two size categories: "Small" or "Non-small".[173] **Exhibit 7B** below presents the resultant count and summary of the characteristics of the small electric utility entities as estimated in this RIA.

Exhibit 7B
Summary of Characteristics of Small Electric Utility Entities

	A	B	C	D	E (D / B)
Small Entity Sub-Categories	Count of coal-fired electric utility plants (2005/2007)	Estimated count of owner entities (2005/2007)	Estimated 2007 annual megawatt hours (mwh) capacity for all electricity plants owned by all entities	Estimated 2009 annual electricity sales for all entities ($millions/year)	2009 average annual electricity sales revenue per entity ($millions/year)
1. Small City Government	33	33	34.0	$2,592	$78.5
2. Small Company	12	11	10.6	$948	$86.2
3. Small Cooperative	6	6	12.0	$947	$157.8
4. Small County Government	1	1	0.3	$23	$23
Summary:					
All small entities =	**52 plants (11%)**	**51 entities (26%)**	**56.8 (1%)**	**$4,509 (1%)**	**$88.4**
All non-small entities =	443 plants (89%)	149 entities (74%)	5,380.5 (99%)	$419,056 (99%)	$2,812.5
All entities (non-small + small) =	495 plants	200 entities	5,437 million mwh*	$423,565**	$2,118

Notes:
* Annual electricity generation capacity based on all electric plants and types of electric generation units (e.g. coal-fired, oil-fired, hydropower, nuclear, wind, biomass, etc.) owned by these companies, not just coal-fired electricity generation capacity.
** $423.6 billion per year annual electricity sales estimated in this RIA is 73% of the $581.6 billion per year total revenues reported for NAICS code 22 (Utilities sector) in the 2007 Economic Census at: http://factfinder.census.gov/servlet/IBQTable?_bm=y&-geo_id=D&-ds_name=EC0700A1&-_lang=en

[173] It should be noted that some of the companies identified as small using the SBA size standard for NAICS 22 and the utility code specification in the 2007 EIA 860 database to identify each corporate entity may be subsidiaries of a larger holding company (classified under a different NAICS) rather than a larger power company. In addition some of these power companies may have merged. For example, State Line is owned by Dominion Resources of Virginia, Northeastern Power is owned by Suez Energy North America, Inc. (SEGNA), Rio Bravo Poso and Rio Bravo Jasmin are owned by the North American Power Group, Ltd (NAPG), TES Filer City Station LP is owned by TONDU, Public Service Enterprise Group (PSEG) and Excelon are merged. This approach likely overstates the number of small entities.

- **Step 2: Measures for Determining Economic Impacts on Small Entities**

According to Exhibit 1 of EPA's 2006 RFA/SBREFA small business impact analytic guidance, there are the following suggested tests that may be used to determine if small entities may be significantly impacted by a proposed rule:

- Small business impact tests:
  - Sales test: Annualized compliance costs as a percentage of sales
  - Cash flow test: Debt-financed capital compliance costs relative to current cash flow
  - Profit test: Annualized compliance costs as a percentage of profits

- Small government impact tests:
  - Revenue test: Annualized compliance costs as a percentage of annual government revenues
  - Income test: Annualized compliance costs to household (per capita) as a percentage of median household (per capita) income

Based on annual electricity generation data for the small owner entities in the electric utility industry identified in **Appendix D** of this RIA, the annual sales/annual revenue test was used for this analysis. As itemized and estimated for each owner entity in the spreadsheets presented as **Appendix M** to this RIA, for each small entity EPA computed the respective sales revenue test percentages by the equation below:

(AEGC x 1,000) x (ASP) x (CU) = annual $sales or $revenues per small entity

Where:

AEGC = Annual electricity generation capacity per-entity in annual million megawatts (per-entity megawatt data is displayed in **Appendix D**). This estimate involved downloading the annual million megawatt capacity data for each of the 495 electricity plants from the DOE-EIA website (2007), and then multiplying the capacity data by two factors:
  - 365 operating days per year
  - 24 operating hours per day

ASP = February 2009 average statewide retail price to ultimate consumers for electricity (i.e., cents per kilowatt-hour) for the relevant state or states applicable to the location of electric plants owned by each company; electricity price reflects the composite price charged to residential, commercial, industry and transportation sectors[174]

CU = 86.8% electric utility industry capacity utilization from 1972-2008 average reported by the 15 May 2009 Federal Reserve Statistical Release G.17 "Industrial Production & Capacity Utilization" data for Utilities at: http://www.federalreserve.gov/releases/g17/Current/default.htm

[174] DOE's Energy Information Administration (EIA) publishes state-by-state average retail electricity prices for four end-user sectors (i.e., residential, commercial, industrial, transportation) and on a composite basis at: http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_a.html

- **Step 3 & Step 4: Determine and document whether the proposed rule may be certified as having "No SISNOSE"**

EPA determined whether each regulatory option may have a "significant impact on a substantial number of small entities" (i.e., SISNOSE) which may become subject to the requirements of the proposed rule. This determination involved comparing the estimated regulatory compliance costs for each entity as displayed in **Appendix J** of this RIA and as summarized in **Exhibit 7C** below (small entity row items 6, 7, 8, 9), to the respective annual sales and revenues for each entity estimated in Step 2 above. Numerically, this comparison involved calculating the percentage of regulatory compliance costs relative to annual sales and revenues for each company for each of the regulatory options. Then compared the percentage results for each small entity to the following three impact thresholds defined in Table 2 of EPA's RFA/SBREFA analytic guidance. **Exhibit 7D** below displays the numerical results of this analysis and the suggested RFA/SBREFA impact interpretation according to the three thresholds.

<1% threshold:	Annualized regulatory costs may be less then 1% of annual sales or revenues for small entities
1% or more threshold:	Annualized regulatory costs may be 1% or more of annual sales or revenues for affected small entities
3% or more threshold:	Annualized regulatory costs may be 3% or more of annual sales or revenues for affected small entities

Exhibit 7C
Summary of Regulatory Cost Estimates According to Electric Utility Plant Owner Entity Size/Type Category
($millions in 2009 price level; average annual amortized @7% discount rate over 50-year period 2012 to 2061)

Size/Type of Entity*	Count of plants in category***	Subtitle C Hazardous waste	Subtitle D (version 1)	Subtitle C for impoundments Subtitle D for landfills
1. Non-Small City	27 plants	$46.9	$27.1	$43.9
2. Non-Small Company	372 plants	$1,897.2	$378.5	$1,821.2
3. Non-Small Coop	20 plants	$87.7	$34.6	$85.3
4. Non-Small Federal	11 plants	$183.2	$20.8	$181.0
5. Non-Small State**	13 plants	$41.6	$27.1	$39.8
6. Small City	33 plants	$2.8	$1.6	$2.5
7. Small Company	12 plants	$4.1	$1.9	$2.0
8. Small Coop	6 plants	$10.4	$0.3	$0.3
9. Small County	1 plant	$0.004	$0.004	$0.004
Total all 9 categories =	**495 plants*** **	**$2,274**	**$492**	**$2,176**

Notes:
* Size/Type classification methodology defined according to **Exhibit 3B** of this RIA.
** State government costs include costs to (a) state government electric utility plants regulatory costs, plus (b) state government RCRA-authorized programs for option implementation.
*** The total count of coal-fired electric utility plants is shown in the Exhibit; however, only a sub-total of 467 of the 495 may incur these regulatory costs because 28 plants solely supply their CCR for beneficial uses.

Exhibit 7D **Estimated Impact of Regulatory Options on Small Entities (RFA/SBREFA Analysis Results)** ($millions average annualized direct costs @7% discount rate over 50-year period 2012-2061)			
Cost as Percentage of Annual Electricity Revenues	Subtitle C Hazardous waste	Subtitle D (version 1)	Subtitle C for impoundments Subtitle D for landfills
A. Count of Small Entities:			
Annualized cost on small entities:*	$17.3	$3.8	$4.8
Less than 1%	46	50	50
1% or greater	5	1	1
3% or greater	0	0	0
B. % of Small Entities:			
Less than 1%	90%	98%	98%
1% or greater	10%	2%	2%
3% or greater	0%	0%	0%
C. SISNOSE Findings:			
Less than 1%	Presumed No SISNOSE	Presumed No SISNOSE	Presumed No SISNOSE
1% or greater	Presumed No SISNOSE	Presumed No SISNOSE	Presumed No SISNOSE
3% or greater	Presumed No SISNOSE	Presumed No SISNOSE	Presumed No SISNOSE
* Source: Costs for each option based on total cost for the four small entity categories displayed as rows 6 + 7 + 8 + 9 from **Exhibit 7C**.			

- **Limitations of RFA/SBREFA Determination**

Not included in the RFA/SBREFA analysis of this RIA are **two factors** unique to the electric utility industry, which may reduce the small entity impacts relative to the estimates above in this RIA:

- <u>Factor #1 of 2</u>: According to the 2007 DOE-EIA database on electric utility plants, two-thirds of the coal-fired electricity generation units at electric utility plants owned by small entities can switch to at least one of six other fuels:
    1. Agricultural byproducts (database code = AB)
    2. Distillate fuel oil (DFO)
    3. Natural gas (NG)
    4. Petroleum coke (PC)
    5. Propane (PG)
    6. Wood & wood waste solids (WDS)

- Factor #2 of 2: The small business impact analysis in this RIA applies the full industry compliance cost to the revenue and sales tests. However, because consumer demand for electricity is (a) highly price-inelastic and (b) projected go grow by 30% by year 2025[175], electric utility plants may be expected to pass-thru much, if not all, of their regulatory costs (pending state government utility rate hike approval). The next section of this RIA evaluates the possibility of regulatory compliance cost pass-thru.

- **Compliance Cost Pass-Thru Analysis**

  - Ability to Raise Electricity Prices

Traditionally, the electric utility industry has functioned as a regulated monopoly, providing essential electrical services under an exclusive franchise in exchange for having rates closely regulated by State public utility commissions (PUCs; sometimes called PSC public service commissions) and the Federal Energy Regulatory Commission (FERC). The FERC regulates rates charged for sales of bulk power between utilities, even if they are in the same state. It also regulates the pricing and use of transmission for wheeling, and asset transfers, including mergers. In most states (California de-regulated electricity in 1998), the PUCs/PSCs set allowable rates upon application by the utility, with other affected parties allowed to present testimony. By law the utility must recover its cost of service, which includes "prudently" incurred expenses and a "fair" return on equity.[176]

Based on the electricity ratemaking process described by the Pennsylvania PUC[177]as a case example, when an electric utility company seeks a price increase (aka rate hike), it must file a request with the PUC showing the proposed new rates and effective date, and must prove that the increase is needed. The utility also must notify customers at least 60 days in advance. The notice must include the amount of the proposed rate increase, the proposed effective date, and how much more the ratepayer can expect to pay. Under the law, the utility is entitled to recovery of its reasonably incurred expenses and a fair return on its investment. The PUC evaluates each utility's request for a rate increase based on those criteria. During the investigation, hearings are held before an Administrative Law Judge (ALJ) at which the evidence in support of the rate increase is examined and expert witnesses testify. In addition, consumers are offered an opportunity to voice their opinions and give testimony. Briefs may be submitted by the formal parties. A recommendation to the PUC is made by the ALJ. Finally, the matter is brought before the Commissioners for a vote and final decision. Together with the 60-day notice period, the rate increase process takes about nine months. Recent (2008) examples of requested or PUC-approved electricity rate hikes are summarized in **Exhibit 7E** below:[178]

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[175] 30% additional electricity demand forecst for year 2025 relative to year 2005, from slide 17 of "Energy & Water: Emerging Issues and Trands" by Richard Kottenstette and Mike Hightower, Sandia National Laboratories, at: http://www.ct-si.org/Summit2007/spk/RKottenstette.pdf

[176] Source: "Electric Utility Regulation" by Robert J. Michaels in the Concise Encyclopedia of Economics at: http://www.econlib.org/library/Enc1/ElectricUtilityRegulation.html

[177] Source: Pennsylvania Public Utility Commission, "The PUC Ratemaking Process and the Role of Consumers", January 2008 at: http://www.puc.state.pa.us/general/consumer_ed/pdf/Ratemaking_Complaints.pdf

[178] Source: "Recent Examples of Rate Increases in Vertically Integrated States", The Compete Coalition, Washington DC, 05 November 2008 at: http://www.competecoalition.com/resources/recent-examples-rate-increases-vertically-integrated-states

Exhibit 7E Summary of 2008 US Electricity Price Hikes			
Item	State	Effective date	Requested or approved price hike
1	AL	Oct 2008	14.6%
2	CO	Feb 2008	28%
3	FL	July to Oct 2008	10 to 37% (8 companies)
4	KS	2008	15%
5	MO	Jan 2008	28%
6	NC	Sept 2008 to Jan 2009	10% to 17.7% (3 companies)
7	SC	July to Oct 2008	6% to 10% (4 companies)
8	TVA (7 states)	Oct 2008	20%
	Overall range =	Jan to Oct 2008	6% to 37%
		Average (20 electricity plant owner entities) =	**19%**

Some state governments have deregulated the electric utility industry, thereby allowing multiple electric suppliers, not just a monopoly electricity supplier, to compete and set their own retail prices in those state markets. As of 2003, 18 states have deregulated and six states may soon deregulate:[179]

- Deregulated states (18): AZ, CT, DE, DC, IL, ME, MD, MA, MI, NH, NJ, NY, OH, OR, PA, RI, TX, VA (11 of these states no longer have a price cap)
- May soon deregulate (6): AR, MT, NM, NV, OK, WV (note: CA deregulated in 1998 but has suspended)

While average prices rose 21% in regulated states from 2002 to 2006, prices increased 36% during that period in 11 of the 18 deregulated states where rate caps expired, suggesting greater pricing flexibility in deregulated states.[180]

- Inelastic Demand for Electricity

At the wholesale level, as a result of technological and regulatory barriers, the majority of electricity pricing plans do not allow end users to see and react to the actual market value of their electricity consumption/ conservation. Since end-users do not face the real-time market price in making their consumption decisions, there is little demand reaction to changes in real time wholesale electricity prices.[181] At the retail level, consumer demand for electricity has been largely inelastic. The lack of real time metering at the retail level means that consumers don't know

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[179] Source: "Status of State Electric Industry Restructuring Activity as of February 2003", US Dept of Energy, Energy Information Administration at: http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf

[180] Source: "Shocking Electricity Prices Follow Deregulation", USA Today, 10 Aug 2007 at: http://www.usatoday.com/money/industries/energy/2007-08-09-power-prices_n.htm

[181] Source: page 1 of "Demand Responsiveness in Electricity Markets", Ronald Lafferty et al., Office of Markets, Tariffs and Rates, 15 Jan 2001 at: http://www.naseo.org/committees/energyproduction/documents/demand_responsiveness_in_electricity_markets.pdf

how much they use or indeed how much electricity costs until after the fact. Thus consumers cannot react to high prices easily by cutting consumption.[182]

- Cost Pass-Thru Conclusion

Based on the above three cost pass-thru factors consisting of (a) 20 examples of recent (2008) PUC-regulated rate hikes which average almost 19% per company which far exceeds the 1% and 3% SISNOSE screening analysis thresholds defined by EPA's guidance, (b) 11 of the 18 deregulated states which have de-regulated the price of electricity, and (c) the fact that consumer demand for electricity has been relatively inelastic, this RIA concludes that it is likely that electric utility suppliers could pass-thru all, or nearly all, of the future average annual regulatory compliance costs for the CCR proposed rule such that a significant impact on small entities and non-small entities would not occur.

[182] Source: "Power Price Volatility and Risk Management: An Introduction", Anne Ku, Sept 2000 (this is the original, unedited article, later submitted to Global Energy Business magazine Sept/Oct 2000) at: http://www.analyticalq.com/energy/volatility/default.htm

Chapter 7
Supplemental Analyses Required by Congressional Statutes or White House Executive Orders

Note: The computations presented in this Chapter are based on the cost estimates for the October 2009 draft RIA regulatory options using the larger dry conversion cost estimate prior to its update in **Chapter 4**. Because the high-end cost of the October 2009 draft RIA regulatory options (i.e., for the Subtitle C "hazardous waste" option) is larger than the high-end cost for the 2010 options (i.e., for the Subtitle C "special waste" option), the effects estimated in this Chapter are proportionately over-estimated.

7A. Electricity Price Impact (Executive Order 13211)

The 2001 Executive Order 13211[168] "Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use" requires Federal agencies to evaluate and prepare a statement on any potential adverse effects of economically-significant rulemakings on energy supply, distribution or use, including:

- Shortfall in energy supply
- Energy price increases
- Increased use of foreign energy supplies

The OMB's 13 July 2001 Memorandum M-01-27[169] guidance for implementing this Executive Order identifies nine numerical indicators (thresholds) of potential adverse energy effects, three of which are relevant for evaluation in this RIA:

- Increases in the cost of energy production in excess of 1%
- Increases in the cost of energy distribution in excess of 1%
- Other similarly adverse outcomes.

Because this RIA did not collect and analyze data on energy production cost or energy distribution cost, this RIA evaluated the potential impact of the CCR regulatory options on electricity prices relative to the 1% threshold of both indicators as an indicator of "other similarly adverse outcome". This RIA calculated the potential increase in statewide electricity prices that the industry compliance costs might induce under each CCR regulatory option. This calculation involved plant-by-plant annual revenue estimates and annualized compliance cost estimates, and respective statewide average electricity prices for the 495 electric utility plants, according to the following four steps.

[168] The 18 May 2001 EO-13211 is available at: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=2001_register&docid=fr22my01-133.pdf
[169] OMB's 13 July 2001 Memorandum M-01-27 is available at: http://www.whitehouse.gov/omb/memoranda_m01-27/

- Step 1: Downloaded the annual million megawatt capacity data for each of the 495 plants from the DOE-EIA website (2007), and estimated annual electricity output for each plant, by multiplying the capacity data by three factors:
    - 365 operating days per year
    - 24 operating hours per day
    - 86.8% capacity utilization per year[170]

- Step 2: Estimated the annual electricity sales revenue for each plant by multiplying the estimated annual electricity output sold by each plant (from Step 1), by the respective statewide average retail price (May 2009) of electricity for all sectors (i.e., residential, commercial, industrial, transportation) from DOE-EIA at http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_a.html

- Step 3: Added the estimated incremental regulatory costs on a plant-by-plant basis, to the estimated annual electricity sales revenue for each plant, to obtain a hypothetical future annual revenue target, which represents a 100% cost pass-thru scenario. This simple scenario represents an upper-bound case of potential electricity price increase. Furthermore, if this 100% cost pass-thru is averaged over the entire electricity supply in each state, not just averaged over the 495 coal-fired electricity plants as done in this RIA, the potential percentage increase in electricity price would be less than this upper-bound case presented in this RIA.

- Step 4: Divided the hypothetical future annual revenue target by the estimated annual electricity output for each plant, to obtain a hypothetical future (higher) target price for each plant, which incorporates the added regulatory cost. Compared the higher target price to the current price to calculate the potential price increase on a percentage basis for each of the 495 plants.

Exhibit 7A below presents the findings of this energy price evaluation on a state-by-state basis. As displayed in the bottom row of **Exhibit 7A**, none of the options have an expected nationwide average energy price increase >1%. **Appendix L** presents the plant-by-plant calculation spreadsheet used for this electricity price impact analysis.

Exhibit 7A
State by State Breakout of Average Electricity Price Increases Per Option

Item	Number of Plants	State	May 2009 statewide average electricity price ($ per kilowatt hour)	**Subtitle C hazardous waste** Average Price Increase	**Subtitle D (version 1)** Average Price Increase	**C - impoundments D - landfills** Average Price Increase
	Average annualized cost (from **Exhibit 4F**) =			**$2,274**	**$492**	**$2,176**
1	2	AK	$0.1518	1.30%	1.23%	1.25%
2	10	AL	$0.0856	1.43%	0.189%	1.419%

170 Source: 86.8% capacity utilization is the 1972-2008 annual average published in the 15 May 2009 Federal Reserve Statistical Release G.17 "Industrial Production & Capacity Utilization" data for Utilities at http://www.federalreserve.gov/releases/g17/Current/default.htm

Exhibit 7A State by State Breakout of Average Electricity Price Increases Per Option						
Item	Number of Plants	State	May 2009 statewide average electricity price ($ per kilowatt hour)	**Subtitle C hazardous waste** Average Price Increase	**Subtitle D (version 1)** Average Price Increase	**C - impoundments D - landfills** Average Price Increase
3	3	AR	$0.0762	0.293%	0.225%	0.283%
4	6	AZ	$0.1002	1.141%	0.622%	1.113%
5	6	CA	$0.1337	0.717%	0.676%	0.687%
6	14	CO	$0.0797	0.121%	0.006%	0.017%
7	2	CT	$0.1712	0.074%	0.000%	0.000%
8	0	DC	$0.1337			
9	3	DE	$0.1236	0.156%	0.127%	0.129%
10	15	FL	$0.1136	0.131%	0.077%	0.113%
11	11	GA	$0.0859	1.160%	0.163%	1.152%
12	2	HI	$0.1892	0.245%	0.171%	0.174%
13	19	IA	$0.0710	0.548%	0.198%	0.537%
14	0	ID	$0.0602			
15	25	IL	$0.0924	0.531%	0.099%	0.488%
16	26	IN	$0.0766	1.387%	0.207%	1.348%
17	8	KS	$0.0822	0.545%	0.190%	0.532%
18	21	KY	$0.0640	2.307%	0.593%	2.237%
19	4	LA	$0.0748	0.464%	0.040%	0.462%
20	4	MA	$0.1534	0.027%	0.000%	0.000%
21	8	MD	$0.1316	0.080%	0.017%	0.037%
22	1	ME	$0.1222	0.520%	0.346%	0.352%
23	22	MI	$0.0986	0.459%	0.052%	0.455%
24	16	MN	$0.0804	2.013%	0.471%	1.993%
25	20	MO	$0.0757	0.817%	0.116%	0.798%
26	5	MS	$0.0893	0.197%	0.106%	0.193%
27	5	MT	$0.0720	5.582%	1.193%	5.531%
28	22	NC	$0.0839	1.122%	0.148%	1.102%
29	7	ND	$0.0698	0.994%	0.012%	0.982%
30	7	NE	$0.0705	0.223%	0.206%	0.210%
31	2	NH	$0.1544	0.055%	0.004%	0.004%
32	7	NJ	$0.1421	0.118%	0.045%	0.045%
33	3	NM	$0.0769	2.103%	0.407%	1.729%
34	2	NV	$0.0960	0.548%	0.518%	0.526%
35	13	NY	$0.1543	0.024%	0.000%	0.000%
36	26	OH	$0.0930	1.193%	0.132%	1.157%
37	6	OK	$0.0698	0.151%	0.050%	0.081%
38	1	OR	$0.0751	0.212%	0.200%	0.204%
39	34	PA	$0.0960	0.702%	0.229%	0.665%

Exhibit 7A State by State Breakout of Average Electricity Price Increases Per Option						
Item	Number of Plants	State	May 2009 statewide average electricity price ($ per kilowatt hour)	**Subtitle C hazardous waste** Average Price Increase	**Subtitle D (version 1)** Average Price Increase	**C - impoundments D - landfills** Average Price Increase
40	0	RI	$0.1343			
41	14	SC	$0.0826	0.394%	0.028%	0.384%
42	2	SD	$0.0742	0.098%	0.084%	0.086%
43	7	TN	$0.0860	0.517%	0.001%	0.504%
44	19	TX	$0.1019	0.292%	0.038%	0.256%
45	6	UT	$0.0690	0.602%	0.336%	0.588%
46	16	VA	$0.0916	0.688%	0.078%	0.629%
47	0	VT	$0.1282			
48	1	WA	$0.0684	0.000%	0.000%	0.000%
49	17	WI	$0.0918	0.082%	0.063%	0.078%
50	16	WV	$0.0668	1.441%	0.615%	1.379%
51	9	WY	$0.0602	1.396%	0.315%	1.351%
Summary:						
		Minimum =	$0.0602	0.0000%	0.0000%	0.0000%
		Maximum =	$0.1892	5.5822%	1.2259%	5.5313%
		Average =	$0.0985	0.7489%	0.2259%	0.7076%
		Median =	$0.0860	0.5205%	0.1316%	0.4876%
		Nationwide =	**$0.0884**	**0.795%**	**0.172%**	**0.761%**

Because this price analysis is based only on the 495 potentially affected coal-fired electric utility plants (with 333,500 megawatts nameplate capacity) rather than on all electric utility and independent electricity producer plants in each state using other fuels such as natural gas, nuclear, hydroelectric, etc. (with 678,200 megawatts nameplate capacity), these price effects are higher than would be if the regulatory costs were averaged over the entire electric utility and independent electricity producer supply (totaling 1,011,700 megawatts, not counting the 76,100 megawatts of combined heat and electricity producers).[171]

- **Electricity Impact Findings**

On a nationwide basis for all 495 plants, compared to the estimated average electricity price of $0.0884 per kilowatt-hour across the 495 plants, the 100% regulatory cost pass-thru scenario may increase prices for the 495 plants by **0.172% to 0.795%** across the regulatory options. None of the regulatory options exceed the 1% threshold of EO 13211, thus this RIA does not include a “Statement of Energy Effect” as would be required by Section 1 of EO 13211 if the price impact indicator as estimated in this RIA exceeded 1%.

[171] Source: 2007 megawatt nameplate capacity data from the Energy Information Administration “Table 2.3. Existing Capacity by Producer Type, 2007” at http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile2_3.pdf

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

AUG 13 2010

OFFICE OF CONGRESSIONAL AND
INTERGOVERNMENTAL RELATIONS

The Honorable Heath Shuler
Chairman
United States House of Representatives
Committee on Small Business
Subcommittee on Rural and Urban Entrepreneurship
Washington, D.C. 20515

Dear Chairman Shuler:

Thank you for your questions and the questions from other subcommittee members posed to the U.S. Environmental Protection Agency (EPA) during the July 22, 2010, Committee on Small Business, Subcommittee on Rural and Urban Entrepreneurship hearing title, "Coal Combustion Byproducts: Potential Impact of a Hazardous Waste Designation on Small Businesses in the Recycling Industry."

Please find enclosed responses to these questions. I hope this information will be useful to you and members of the Subcommittee. If you have further questions, please contact me or your staff may contact Amy Hayden in EPA's Office of Congressional and Intergovernmental Relations at (202) 564-0555.

Sincerely,

David G. McIntosh
Associate Administrator

Enclosure

cc: Ranking Member Blaine Luetkemeyer

Committee on Small Business
Subcommittee on Rural and Urban Entrepreneurship
U.S. Environmental Protection Agency Responses to Questions for the Record
July 22, 2010

Question from Chairman Shuler: Why hasn't EPA looked at all indirect costs? If CCR is considered a hazardous waste, won't that impact small businesses? Would EPA calculate the indirect impact to recyclers?

Answer: As stated in testimony provided by the U.S. Environmental Protection Agency (EPA), the Agency has not made a decision on whether to regulate the disposal of coal combustion residuals under subtitle C of the Resource Conservation and Recovery Act (RCRA). Rather, EPA has co-proposed two options. Under the first regulatory alternative, EPA would list these residuals, when destined for disposal in landfills and surface impoundments as a "special waste" subject to regulation under subtitle C of RCRA, which would create a comprehensive program of federally enforceable requirements. Under the second alternative, EPA would regulate the disposal of coal combustion residuals under subtitle D of RCRA by issuing national minimum criteria, which would be enforced through citizen suits or by the states. Under both alternatives, EPA is not proposing to change the 2000 Regulatory Determination for coal combustion residuals that are beneficially used and thus, these residuals would remain exempt from federal regulation.

EPA conducted two economic analyses in support of the proposed rule – one that looked broadly at the costs and benefits of the proposed rule (the regulatory impact analysis), and one that was focused on the direct impacts to small business (small business analysis). The regulatory impact analysis for the proposed rule examined both direct and significant indirect economic impacts of the proposed rule for both Subtitle D and Subtitle C options. The analysis estimated direct costs to the utilities, ancillary costs to the government, the benefits of ground water protection, the benefits of avoided structural failures of impoundments, the indirect effects on beneficial use, as well as the indirect effects on electricity prices. EPA also looked at the potential indirect impacts on beneficial use with respect to their aggregate benefits to society. The Agency analyzed three scenarios for the potential effect of RCRA regulation of CCR disposal under subtitle C on future CCR beneficial use. The scenarios analyzed were: an induced increase in beneficial use of CCRs; an induced decrease in beneficial use; and no impact on beneficial use. Under each of these three scenarios, EPA evaluated the resource consumption, pollution, and economic impacts.

As part of the small business analysis (see Attachment A), EPA analyzed the direct impact of the rule on entities subject to the requirements of the rule, i.e., coal-fired electric utility plants. EPA reached a conclusion that none of the proposed alternatives (including the Subtitle C option) would have a significant economic impact on small entities. EPA did not calculate the impacts on small recyclers of CCR, because under EPA's proposal, the Agency's 2000 Regulatory Determination would remain unchanged and the existing beneficial uses of CCR would remain exempt from RCRA regulation, and thus the regulation would not have a direct effect on such entities, nor would recyclers be subject to the requirements of the rule. Moreover, according to Section 2.5 of EPA's November 2006 guidance on the Regulatory Flexibility Act, EPA does not usually evaluate (a) impacts on small entities which are not "subject to the requirements of the rule" and (b) impacts on small entities which are only indirectly affected by the rule. Nevertheless, as Deputy Assistant Administrator Lisa Feldt stated during the hearing, EPA welcomes the submission of any additional information or data on the impacts to individual recyclers or other entities, including small businesses, during the public comment period. EPA will consider such comments as it develops the final rule.

Question from Representative Bright and Representative Dahlkemper: If EPA estimates a 6% increase in utility rates as a result of the proposed rule, this concerns me. I would like more information about this. Did EPA consider the potential effect on industry of a C designation?

Answer: EPA did not estimate a "6% increase in utility rates." EPA estimated a potential increase of 0.172% under the Subtitle D option (i.e., 0.015 cents per kilowatt-hour) to 0.795% under the Subtitle C option (i.e., 0.070 cents per kilowatt-hour) in potential average electricity prices charged by coal-fired electric utility plants on a nationwide basis. EPA estimated the potential impact of the proposed rule on electricity prices assuming that 100% of the costs of the rule would be passed through to coal-fired electric utility customers,--that is, no electricity generation by nuclear, oil, natural gas, hydroelectric, etc, and that all 495 existing plants (as of 2005) would continue operation

Here are illustrative examples of potential monthly electricity cost increases ***on a nationwide basis*** for three types of customers (i.e., residential, commercial, and industrial) of coal-fired electric utility plants:
1. Residential: According to the Energy Information Agency, the average consumption for a U.S. residential utility customer in 2008 was 920 kilowatt-hours per month at a cost of $103.67 per month, suggesting a potential increase in the average residential monthly electric utility cost for customers of coal-fired electric utility plants of (920 kWh) x (0.07 cents per kWh) resulting in a potential increase of 64.4 cents per month.
2. Commercial: According to the Energy Information Agency, the average monthly electricity consumption and cost to a U.S. commercial customer in 2008 was 6,339 kilowatt-hours per month at a cost of $657.02 per month, suggesting a potential increase in the average monthly electric cost for commercial customers of coal-fired electric utility plants of (6,339 kWh) x (0.07 cents per kWh) resulting in a potential increase of $4.44 per month.
3. Industrial: According to the Energy Information Agency, the average monthly electricity consumption and cost to a U.S. industrial customer in 2008 was 108,567 kilowatt-hours per month at a cost of $7,413.54 per month, suggesting a potential increase in the average monthly electric cost for industrial customers of coal-fired electric utility plants of (108,567 kWh) x (0.07 cents per kWh) resulting in a potential increase of $76 per month.

In addition to calculating the potential average increase in electricity prices nationwide, EPA's electricity price analysis (see Attachment B) also looked at the potential effect in individual states (local markets). As stated by Deputy Assistant Administrator Lisa Feldt during the hearing, the potential statewide average electricity price increases ranged from 0.0% to 5.58% (or 0.00 to 0.49 cents per kilowatt-hour) under the Subtitle C option. On a state-by-state basis, potential increases in electricity prices charged by coal-fired electric utility plants could increase from 0% (Connecticut, Massachusetts, New York) to 1.22% (Montana) under the Subtitle D option, and could increase from 0% (Washington) to 5.58% (Montana) under the Subtitle C option.

Thirty-four states are projected to experience less than a 1 ***percent*** increase in electricity rates***, 18 states and territories are projected to experience an increase of between 1 and 2 percent, while*** four states would have potential price increases greater than 2 percent under this analysis. In the case of Pennsylvania, EPA estimated that the potential price increase would be 0.702% under the Subtitle C option.

As noted above, the regulatory impact analysis for the proposed rule examined both direct and significant indirect economic impacts of the proposed rule for both Subtitle D and Subtitle C options.

Question from Representative Thompson: EPA estimates an increased electricity cost of approximately 6%. Does this include other realities such as cap and trade and other EPA regulations that could increase the cost of fossil fuels? Coal accounts for 60% of power in Pennsylvania.

Answer: As already noted, EPA did not estimate "an increased electricity cost of approximately 6%." EPA's electricity price analysis considered the potential economic impacts attributable to this rule. As stated above, EPA estimated the potential increase in average electricity prices charged by coal-fired electric utility plants on a nationwide basis could be 0.172% to 0.795%. On a state-by-state basis, the potential increases in electricity prices charged by coal-fired electric utility plants could increase from 0.0% to 5.582% in individual states. In the case of Pennsylvania, EPA estimated that the potential price increase would be 0.702% or 0.00063 cents per kwh under the Subtitle C option. EPA's analysis also did not consider the potential effect of possible future legislation or other EPA regulations if passed. However, EPA recognizes that major regulations have either been proposed (e.g., Transport Rule) or are in process of being proposed (e.g. Utility MACT and Section 316b of Clean Water Act). These regulations would have an impact on coal-fired electric utility plants. However, because EPA does not have complete impact estimates for these other rules, EPA restricted the price analysis for the CCR proposed rule to only the information that was generated for this RCRA proposed rule.

Question from Representative Dahlkemper: I am concerned that the C2P2 information has been taken down from the EPA website. I would like EPA to explain why they did this.

Answer: The Agency continues to support the beneficial use of coal combustion residuals. EPA is not proposing to change the 2000 Regulatory Determination for coal combustion residuals regarding beneficial use and thus, these residuals would remain exempt from RCRA regulation. The proposed rule did, however, discuss and seek comment on certain uses of coal combustion residuals, particularly when used in an unencapsulated form. Consequently, EPA decided to remove the C2P2 pages from the website for review to ensure they are consistent with the language in the proposed rule. Materials that were on the C2P2 website that are germane to the coal combustion residual rulemaking have been placed in the rulemaking docket and are available to the public.