Agency: Exhibit A

TITLE 35: ENVIRONMENTAL PROTECTION
SUBTITLE G: WASTE DISPOSAL
CHAPTER I: POLLUTION CONTROL BOARD
SUBCHAPTER j: COAL COMBUSTION WASTE SURFACE IMPOUNDMENTS

PART 841
COAL COMBUSTION
WASTE SURFACE IMPOUNDMENTS AT POWER GENERATING FACILITIES

SUBPART A: GENERAL

SUBPART B: MONITORING

SUBPART C: CORRECTIVE ACTION

SUBPART D: CLOSURE

SUBPART E: AGENCY REVIEW PROCEDURES

SUBPART F: FINANCIAL ASSURANCE

AUTHORITY: Implementing Sections 12 and 22 of the Environmental Protection Act [415 ILCS 5/12 and 22] and authorized by Sections 13, 22, 27, and 28 of the Environmental Protection Act [415 ILCS 5/13, 22, 27, and 28].

SOURCE: Adopted in R__-__ at __ Ill. Reg._____, effective _________.

SUBPART A: GENERAL

Section 841.100 Purpose

This Part establishes criteria, requirements and standards for site characterization, groundwater monitoring, preventive response, corrective action and closure of, and design standards and financial assurance requirements for surface impoundment units containing coal combustion waste or leachate from coal combustion waste at power generating facilities.

Section 841.105 Applicability

a) Except as specified in subsection (b) of this Section, this Part applies to all surface impoundment units at power generating facilities containing coal combustion waste or leachate from coal combustion waste.~~ that are:~~

~~1) operated on or after the effective date of these rules, or~~

~~2) not operated after the effective date of these rules, but whose coal combustion waste or leachate from coal combustion waste causes or contributes to an exceedence of the groundwater quality standards on or after the effective date of these rules.~~

b) Except for the requirements of subsection (c) of this Section, ~~T~~this Part does not apply to any surface impoundment unit:

~~1) operated under a solid waste landfill permit issued by the Agency;~~

~~2) operated pursuant to procedural requirements for a landfill exempt from permits under 35 Ill. Adm. Code 815;~~

1) subject to 35 Ill. Adm. Code 840;

2) that has initiated closure pursuant to a closure plan that will require the removal of all coal combustion waste and leachate, or cover with a final cover system meeting the standards of Section 841.420, before the effective date of these rules, that is not operated after the effective date of these rules, and whose coal combustion waste or leachate from coal combustion waste does not cause -or contribute to an exceedence of the groundwater quality standards;~~.~~

3) used to store coal combustion waste or leachate from coal combustion waste when all of the following conditions are met:

A) at least two feet of material with a permeability equal or superior to 1 $X10^{-7}$ centimeters per second, or an equivalent synthetic liner lines the bottom of the unit;

B) the coal combustion waste or leachate from coal combustion waste remains in the unit for no longer than one year; and

C) the unit's maximum volume is no more than 25 cubic yards; or

4) that does not contain more than one cubic yard of CCW and is used to only collect stormwater runoff that~~, which~~ does not contain leachate.

~~BOARD NOTE:~~

c) A unit ~~not subject to~~that is otherwise exempt from the requirements of this Part under the operation of subsection-s (b)(2), (3), and/or (4) of this Section ~~should~~ shall maintain records demonstrating how an~~the~~ exemption in subsection (b) of this Section applies and comply with the closure requirements of Subpart D of this Part.~~ or how the unit is outside the scope of application set forth in subsection (a)~~. Justification for an exemption under subsections (b)(2), (3), and/or (4) of this Section also shall be included in any hydrogeologic site characterization for the exempted unit's power generating facility, the groundwater monitoring plan for any unit at the same power generating facility, and each statistical analysis for any unit at the same power generating facility.

Section 841.110 Definitions

Unless otherwise specified, the definitions of the Environmental Protection Act (Act) [415 ILCS 5] apply to this Part. The following definitions also apply:

"Agency" means the Illinois Environmental Protection Agency.

"Aquifer" means saturated (with groundwater) soils and geologic materials which are sufficiently permeable to readily yield economically useful quantities of water to wells, springs, or streams under ordinary hydraulic gradients. [415 ILCS 55/3(b)]

"Board" means the Illinois Pollution Control Board.

"Certified Laboratory" means any laboratory certified pursuant to Section 4(o) of the Act [415 ILCS 5/4(o)], or certified by USEPA.

"Coal combustion waste" means any fly ash, bottom ash, slag, or flue gas or fluid bed boiler desulfurization by-products generated as a result of the combustion of:

(1) coal, or

(2) coal in combination with: (i) fuel grade petroleum coke, (ii) other fossil fuel, or (iii) both fuel grade petroleum coke and other fossil fuel, or

(3) coal (with or without: (i) fuel grade petroleum coke, (ii) other fossil fuel, or (iii) both fuel grade petroleum coke and other fossil fuel) in combination with no more than 20% of tire derived fuel or wood or other materials by weight of the materials combusted; provided that the coal is burned with other materials, the Agency has made a written determination that the storage or disposal of the resultant wastes in accordance with the provisions of item (r) of Section 21 would result in no environmental impact greater than that of wastes generated as a result of the combustion of coal alone, and the storage disposal of the resultant wastes would not violate applicable federal law. [415 ILCS 5/3.140]

"Compliance point" means any point in groundwater designated at a lateral distance of 25 feet measured parallel to the land surface from the outer edge of the unit and projected vertically downward, or property boundary, whichever is ~~less~~closer to the unit, and a depth of 15 feet from the bottom of the unit or 15 feet into the groundwater table, whichever is greater. If the owner or operator has a GMZ pursuant to 35 Ill. Adm. Code 620.250 for the site or unit, compliance point means any point as specified in an approved corrective action process~~in the groundwater at which a contaminant released from the unit could pass beyond the Agency approved GMZ boundary~~. There may be more than one compliance point for a particular unit(s)/GMZ.

"Contaminant" means any solid, liquid or gaseous matter, any odor, or any form of energy, from whatever source. [415 ILCS 5/3.165]

"Groundwater" means underground water which occurs within the saturated zone and geologic materials where the fluid pressure in the pore space is equal to or greater than atmospheric pressure. [415 ILCS 5/3.210]

~~"High priority resource groundwater" means Class I groundwater under 35 Ill. Adm. Code 620.210(a)(1), (a)(2), or (a)(3), or Class III groundwater under 35 Ill. Adm. Code 620.230.~~

–"Leachate" means any liquid, including any suspended components in the liquid, that has been or is in direct contact with, percolated through or drained from coal combustion waste. Leachate does not include stormwater runoff that may come into contact with fugitive ash.

"Nearby" means that the surface water or pumping well could be impacted by groundwater contaminated by the unit.

"Off-site" means not on-site.

"On-site", "on the site", or "on the same site" means the same or geographically contiguous property which may be divided by public or private right-of-way, provided the entrance and exit between the properties is at a crossroads intersection and access is by crossing as opposed to going along the right-of-way. Noncontiguous properties owned by the same person but connected by a right-of-way which he controls and to which the public does not have access is also considered on-site property.

"Operate" means receiving waste or stormwater flow. A surface impoundment that is open to receive stormwater as direct precipitation, runoff, or process water is "receiving waste or stormwater flow".

"Operator" means the person responsible for the operation and maintenance of a unit.

"Owner" means a person who has an interest, directly or indirectly, in land, including a leasehold interest, on which a person operates and maintains a unit. The "owner" is the "operator" if there is no other person who is operating and maintaining a unit.

"Person" is any individual, partnership, co-partnership, firm, company, limited liability company, corporation, association, joint stock company, trust, estate, political subdivision, State agency, or any other legal entity, or their legal representative, agent or assigns. [415 ILCS 5/3.315]

"Practical Quantitation Limit" or "PQL" means the lowest concentration or level that can be reliably measured within specified limits of precision and accuracy during routine laboratory operating conditions in accordance with "Test Methods for Evaluating Solid Wastes, Physical/Chemical Methods", EPA Publication No. SW-846, incorporated by reference at Section 841.120.

"Professional engineer" means -*a person licensed under the laws of the State of Illinois to practice professional engineering.* [225 ILCS 325].

"Professional geologist" means *an individual who is licensed under* the Professional Geologist Licensing Act *to engage in the practice of professional geology in Illinois.* [225 ILCS 745]

"Release" means any spilling, leaking, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, or disposing into the environment. [415 ILCS 5/3.395]

"Site" means any location, place, tract of land and facilities, including but not limited to buildings, and improvements used for purposes subject to regulation or control by the Act or regulations thereunder. [415 ILCS 5/3.460]

"Statistically significant" means the application of a statistical method pursuant to Section 841.225 of this Part to determine whether consecutive groundwater sampling data showing greater or lesser concentrations of chemical constituents represents a pattern rather than chance occurrence.

~~"Storm" means a maximum 24-hour precipitation event with a probable recurrence interval of once in 25 years, as defined by the National Weather Service in NOAA Atlas 14 Precipitation Frequency Atlas of the United States, Volume 2, Version 3.0 (2004), found at http://hdsc.nws.noaa.gov/hdsc/pfds/orb/il_pfds.html.~~

"Surface impoundment" means a natural topographical depression, man-made excavation, or diked area ~~where earthen materials provide structural support for the containment of liquid wastes or wastes containing free liquids~~that is designed to hold liquid waste or wastes containing free liquids, and which is not a landfill~~, as defined in 35 Ill. Adm. Code 810.103~~ permitted under Illinois Solid Waste Disposal rules at 35 Ill. Adm. Code, Parts 813 or 814.

"Unit" means any surface impoundment at a power generating facility that contains coal combustion waste or leachate from coal combustion waste.

"Waters" means all accumulations of water, surface and underground, natural, and artificial, public and private, or parts thereof, which are wholly or partially within, flow through, or border upon this State. [415 ILCS 5/3.550].

"Wetlands" means those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include swamps, marshes, bogs, and similar areas.

"Woody species" means perennial plants with stem(s) and branches from which buds and shoots develop.

"25-year, 24-hr Storm" means the maximum 24-hour precipitation event with a probable recurrence interval of once in 25 years, as defined by NOAA Atlas 14; Precipitation Frequency Atlas of the United States, incorporated by reference in Section 841.120.

Section 841.115 Abbreviations and Acronyms

~~Agency~~	~~Illinois Environmental Protection Agency~~
CQA	Construction Quality Assurance
GMZ	Groundwater Management Zone
Mg\L	Milligrams per Liter
NPDES	National Pollutant Discharge Elimination System
TDS	Total Dissolved Solids
PQL	Practical Quantitation Limit

Section 841.120 Incorporations by Reference

a) The Board incorporates the following material by reference:

NTIS. National Technical Information Service, 5285 Port Royal Road, Springfield VA 22161, (703) 605-6000.

"Methods for Chemical Analysis of Water and Wastes," March 1983, Doc. No. PB84-128677. EPA 600/4-79-020 (available on-line at http://nepis.epa.gov/).

"Methods for the Determination of Inorganic Substances in Environmental Samples," August 1993, Doc. No. PB94-120821 (referred to as "USEPA Environmental Inorganic Methods"). EPA 600/R-93-100 (available online at http://nepis.epa.gov/).

"Methods for the Determination of Metals in Environmental Samples," June 1991, Doc. No. PB91-231498. EPA 600/4-91-010 (available on-line at http://nepis.epa.gov/).

"Methods for the Determination of Metals in Environmental Samples Supplement I," May 1994, Doc. No. PB95-125472. EPA 600/4-94-111 (available on-line at http://nepis.epa.gov).

"Methods for the Determination of Organic and Inorganic Compounds in Drinking Water: Volume I," EPA 815-R-00-014 (August 2000) (available on-line at http://nepis.epa.gov).

"Practical Guide for Ground-Water Sampling," EPA Publication No. EPA/600/2-85/104 (September 1985), Doc. No. PB 86-137304,

"Test Methods for Evaluating Solid Waste, Physical/Chemical Methods," USEPA Publication No. SW-846, as amended by Updates I, II, IIA, IIB, III, IIIA, and IIIB (Doc. No. 955-001-00000-1), (available on-line at http://www.epa.gov/epaoswer/hazwaste/test/main.htm).

USEPA, NSCEP. United States Environmental Protection Agency, National Service Center for Environmental Publications, P.O. Box 42419, Cincinnati, OH 45242-0419 (accessible on-line and available by download from http://www.epa.gov/nscep/).

2009 Unified Guidance. "Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities—Unified Guidance," March 2009, EPA 530/R-09-2007.

USEPA, United States Environmental Protection Agency, Region IV Science and Ecosystem Support Division.

"Operating Procedure: Pore Water Sampling" (Feb. 28, 2013).

USGS. United States Geological Survey, 1961 Stout St., Denver CO 80294, (303) 844-4169.

"Field Techniques for Estimating Water Fluxes Between Surface Water and Ground Water," Techniques and Methods 4-D2 (2008).

"Techniques of Water Resources Investigations of the United States Geological Survey, Guidelines for Collection and Field Analysis of Ground-Water Samples for Selected Unstable Constituents," Book I, Chapter D2 (1976).

"NOAA Atlas 14: Precipitation-Frequency Atlas of the United States," United States Department of Commerce, National Oceanic and Atmospheric

Administration, National Weather Service, Volume 2, Version 3.0 (2004), revised 2006. Available from NOAA, NWS, Office of Hydrologic Development, 1325 East West Highway, Silver Spring, MD 20910 (Available online at http://www.nws.noaa.gov/oh/hdsc/PF_documents/Atlas14_Volume2.pdf)

b) This Section incorporates no later editions or amendments.

Section 841.125 Groundwater Quality Standards

a) The owner or operator shall comply with the groundwater standards in 35 Ill. Adm. Code 620 at all times~~, including the corrective action process in 35 Ill. Adm. Code 620.250~~.

b) Compliance with the groundwater quality standards shall be measured at the compliance point, or compliance points if more than one compliance point exists.

d) The number and kinds of samples collected to establish compliance with the groundwater quality standards must be appropriate for the form of statistical test employed, as prescribed in Section 841.225 of this Part and the 2009 Unified Guidance, incorporated by reference in Section 841.120 of this Part.

Section 841.130 Compliance Period

a) Except as provided in this Section, the~~The~~ compliance period for this Part begins when the unit first receives coal combustion waste, or leachate from coal combustion waste, or on the effective date of this Part~~one year after the effective date of this rule~~, whichever occurs later, and ends when the post-closure care period ends. The post-closure care period for a unit is the time period described in Section 841.440(a) of this Part.

b) If the unit was in operation on or before the effective date of this Part, the~~The~~ owner or operator shall conduct a hydrogeologic site characterization, establish background values, develop a groundwater monitoring system, and submit a groundwater monitoring plan, closure plan, and post-closure care plan within one year of the effective date of this Part~~before the compliance period begins~~. If the owner or operator wishes to use previous site investigations or characterization, plans or programs to satisfy the requirements of this Part ~~pursuant to Section 841.145~~, the owner or operator must submit the previous investigations, characterizations, plans or programs in accordance with Section 841.140 of this Part to the Agency for approval pursuant to Section 841.145 of this Part within one year of the effective date of this Part.~~to the Agency for approval of this Part before the compliance period begins~~.

Section 841.135 Recordkeeping

a) The owner or operator of the unit must maintain paper copies of the following on-site:

1) groundwater monitoring plan;

2) all monitoring data, including inspection reports, for 10 years following generation of the data;

3) corrective action plan, until completion of the corrective action;

4) corrective action report for 10 years following Agency approval of the report;

5) closure plan until the end of the post-closure period;

6) closure report for 30~~10~~ years following Agency approval of the report;

7) post-closure care plan for 10 years following the certification of the post-closure report;

8) post-closure report for 10 years following Agency approval of the report; and

9) any CQA reports for 2 years following the completion of the construction.

b) All information required to be maintained by an owner or operator under this Part must be made available to the Agency upon request for inspection and photocopying during normal business hours.

Section 841.140 Submission of Plans, Reports and Notifications

a) All reports, plans, modifications and notifications required under this Part to be submitted to the Agency must be submitted in writing to the Bureau of Water, Division of Public Water Supplies, Attn: Hydrogeology and Compliance Unit, 1021 North Grand Avenue East, P.O. Box 19276, Springfield, Illinois 62794-9276 or electronically as authorized by the Agency.

b) Whenever any of the following documents are submitted to the Agency, the document must contain the seal and signature of either a professional engineer or professional geologist.

1) hydrogeologic site characterization;

2) groundwater monitoring system; and

3) groundwater monitoring plan;

c) Whenever any of the following documents are submitted to the Agency, the document must contain the seal and signature of a professional engineer.

1) corrective action plan, corrective action report and corrective action certification;

2) closure plan, closure report and closure certification; and

3) post-closure care plan, post-closure report and post-closure certification.

Section 841.145 Previous -Investigations, Plans and Programs

The Agency may approve the use of any hydrogeologic site investigation or characterization, groundwater monitoring well or system, groundwater monitoring plan, groundwater management zone or preventive response plan, compliance commitment agreement, or court or Board order existing prior to the effective date of these rules to satisfy the requirements of this Part.

Section 841.150 Modification of Existing Permits

The owner or operator of the unit must submit to the Agency an application to revise any state operating permits or NPDES permits issued by the Agency as necessary as a result of preventive response, corrective action, or closure under this Part. If any activities required under the proposed preventive response, corrective action, or closure plan cannot be completed because of the denial of an operating permit or NPDES permit revision, then the owner or operator must submit a revised preventive response, corrective action, or closure plan to the Agency within 90 days of the denial or the conclusion of an unsuccessful subsequent appeal by the owner or operator, whichever is later. ~~-~~

Section 841.155 Construction Quality Assurance Program

a) The following components of a preventive response plan pursuant to Subpart B of this Part, a corrective action plan pursuant to Subpart C of this Part and a closure plan pursuant to Subpart D of this Part must be constructed according to a CQA program, if applicable:

1) Installation of the groundwater collection system and discharge system;

2) Compaction of the final cover system subgrade and foundation to design parameters;

3) Application of final cover, including installation of the geomembrane; ~~and~~

4) Construction of ponds, ditches, lagoons and berms; and

5) Removal of CCW.

b) The CQA program must meet the following requirements, if applicable:

1) The owner or -operator must designate a CQA officer who is an Illinois licensed professional engineer.

2) At the end of each week of construction until construction is complete, a summary report must be prepared either by the CQA officer or under the supervision of the CQA officer. The report must include descriptions of the weather, locations where construction occurred during the previous week, materials used, results of testing, inspection reports, and procedures used to perform the inspections. The CQA officer must review and approve the report. The owner or operator of the unit shall retain all weekly summary reports approved by the CQA officer pursuant to Section 841.135 of this Part.

3) The CQA officer must certify the following, when applicable:

A) the bedding material contains no undesirable objects;

B) the preventive response, closure plan or corrective action plan has been followed;

C) the anchor trench and backfill are constructed to prevent damage to a geosynthetic membrane;

D) all tears, rips, punctures, and other damage are repaired;

E) all geosynthetic membrane seams are properly constructed and tested in accordance with the manufacturer's specifications;

F) the groundwater collection system is constructed to intersect the water table;

G) a groundwater collection system is properly constructed to slope toward extraction points, and the extraction equipment is properly designed and installed;

H) appropriate operation and maintenance plans for the groundwater collection system and extraction and discharge equipment are provided;

I) proper filter material consisting of uniform granular fill, to avoid clogging, is used in construction; ~~and~~

J) the filter material as placed possesses structural strength adequate to support the maximum loads imposed by the overlying materials and equipment used at the facility;

K) CCW stabilization, transport, and disposal; and

L) site restoration, if any.

4) The CQA officer must supervise and be responsible for all inspections, testing and other activities required to be implemented as part of the CQA program under this Section.

5) The CQA officer must be present to provide supervision and assume responsibility for performing all inspections of the following activities, when applicable:

A) Compaction of the subgrade and foundation to design parameters;

B) Application of final cover, including installation of the geomembrane;

C) Installation of the groundwater collection system and discharge system; and

D) Construction of ponds, ditches, lagoons and berms.

6) If the CQA officer is unable to be present as required by subsection (b)(5) of this Section, the CQA officer must provide the following in writing:

A~~i~~) the reasons for his or her absence;

B~~ii~~) a designation of a person who must exercise professional judgment in carrying out the duties of the CQA officer-in-absentia;

C~~iii~~) and a signed statement that the CQA officer assumes full responsibility for all inspections performed and reports prepared by the designated CQA officer-in-absentia during the absence of the CQA officer.

7) The CQA program must ensure, at a minimum, that construction materials and operations meet design specifications.

Section 841.160 Photographs

When photographs are used to document the progress and acceptability of work performed under this Part, each photograph shall be identified with the following information:

a) the date, time and location of photograph;

b) the name of photographer; and

c) the signature of photographer.

Section 841.165 Public Notice

a) The Agency shall post all proposed alternative cause demonstrations, corrective action plans, ~~and~~ closure plans, and post-closure care plans, or modifications thereto, on the Agency's webpage for a period not shorter than 60~~30~~ days.

b) The Agency shall accept written comments for a period of 60~~30~~ days beginning on the day the proposed alternative cause demonstration, corrective action, ~~or~~ closure plan, or post-closure care plan, or modification thereto, was posted on the Agency's webpage.

c) The Agency shall hold a public informational meeting whenever it finds a significant degree of public interest in a proposed alternative cause demonstrations, corrective action plans, closure plans, or post-closure care plans, or modifications thereto~~plan~~ on the basis of public comment.

d~~c~~) While the Agency may respond to the comments received pursuant to subsection (b) of this Section, such response is not required.

e~~d~~) The Agency shall take any comments received into consideration in making its final decision and shall post its final decisions on the proposed alternative cause demonstration, corrective action plans, ~~and~~ closure plans, and post-closure care plans, or modifications thereto, on the Agency's webpage on the postmarked date that the notice is mailed and maintain it there for a period not shorter than 35 consecutive~~0~~ days.

Section 841.170 Inspection

a) While a unit is in operation, the owner or operator must inspect it~~it must be inspected~~ at least once every seven days and after each 25-year, 24-hour Storm to detect evidence of any of the following:

1) Deterioration, malfunctions or improper operation of overtopping control systems;

2) Sudden drops in the level of the unit's contents;

3) Severe erosion (eg. rills, gullies, and crevices six inches or deeper) or other signs of deterioration (eg. failed or eroded vegetation in excess of 100 square feet or cracks) in dikes or other containment devices; and

4) A visible leak.

b) The owner or operator shall promptly perform repairs necessary to correct any problem observed during an inspection.

c) The owner or operator shall prepare a report for each inspection which includes the date of the inspection, condition of the unit, any repairs made to the unit and the date of the repair and shall maintain a record of such reports pursuant to Section 841.135 of this Part.

e~~d~~) The owner or operator shall notify the Agency when a visual inspection shows the level of liquids in the unit suddenly and unexpectedly drops and the drop is not caused by changes in the influent or effluent flows.

e) At all units that have incorporated in their design an earthen dam, the owner or operator shall install, maintain, and monitor instruments to monitor the water content or pore water pressures within the earthen dam.

SUBPART B: MONITORING

Section 841.200 Hydrogeologic Site Characterization

a) The owner or operator of any unit must design and implement a hydrogeologic site characterization to determine the nature and extent of the stratigraphic horizons that are potential contamination migration pathways, and to develop hydrogeologic information for the uses set forth in this Section.

b) The uses of the hydrogeologic site characterization shall include, but not be limited to:

1) Providing information to define hydrogeology, including a map of the potentiometric surface and background groundwater quality concentrations, and to assess whether there are any impacts to groundwater quality or surface water quality attributable to any releases from the unit;

2) Providing information to establish a groundwater monitoring system; and

3) Providing information to develop and perform modeling to assess possible changes and benefits of potential groundwater and surface water impact mitigation alternatives, including but not limited to corrective action and closure of the unit.

c) Hydrogeologic site characterization shall include but not be limited to the following:

1) Geologic well logs/boring logs;

2) Climatic aspects of the site;

3) Identification of nearby surface water bodies and downgradient hyporheic zones where exchanges between groundwater and surface water occurs;

4) Identification of nearby pumping wells including but not limited to all down gradient or downstream community water supplies;

5) Identification of any potential hydrologic connection between the unit and nearby surface water bodies and pumping wells;

6~~5~~) Geologic setting;

7~~6~~) Structural characteristics;

8~~7~~) Geologic cross-sections;

9~~8~~) Soil characteristics;

10~~9~~) Identification of confining layers;

11~~10~~) Identification of potential migration pathways;

12~~11~~) Groundwater quality data;

13~~12~~) Vertical and horizontal extent of the geologic layers to a minimum depth of 100 feet below land surface;

14~~13~~) Chemical and physical properties of the geologic layers to a minimum depth of 100 feet below land surface;

15~~14~~) Hydraulic characteristics of the geologic layers to a minimum depth of 100 feet below the land surface, including:

A) Water table depth;
B) Hydraulic conductivities;

C) Porosities;

D) Direction and velocity of groundwater flow; and

E) Map of the potentiometric surface;~~ and~~

16~~15~~) Identification of any unit at the same power generating facility that is subject to an exemption under Section 841.105(b) of this Part, including the justification for the exemption's applicability; and

17) Any other information requested by the Agency.

Section 841.205 Groundwater Monitoring System

a) The owner or operator of a unit must develop and submit a proposal for a groundwater monitoring system as a part of the groundwater monitoring plan required by Section 841.210 of this Part. If the site contains more than one unit, separate groundwater monitoring systems are not required for each unit, provided that provisions for sampling the groundwater will enable detection and measurements of contaminants that enter the groundwater from all units.

b) Standards for monitoring well design and construction.

1) All monitoring wells must be cased in a manner that maintains the integrity of the bore holes.

2) Wells must be screened to allow sampling only at a specified interval.

3) All wells must be covered with vented caps, unless located in flood-prone areas, and equipped with devices to protect against tampering and damage.

c) The groundwater monitoring system must consist of a sufficient number of wells, installed at appropriate locations and depths to yield water level measurements and groundwater samples to:

1) represent the background quality of groundwater that has not been affected by the unit;

2) represent the quality of groundwater at the compliance point or points;

3) determine compliance with applicable groundwater quality standards in 35 Ill. Adm. Code Part 620; ~~and~~

4) distinguish between chemical constituent concentrations attributable to a regulated unit and other activities;

5) assess the overall groundwater flow and direction at the site, as well as changes to the flow regime due to leachate from the unit; and~~.~~

6) establish the hydraulic gradient between the unit and any nearby surface water, including as necessary the installation and/or identification of monitoring points for measuring water levels and collecting water samples from multiple depths within the hyporheic zone where exchange between groundwater and surface water occurs.

d) The groundwater monitoring system must include monitoring~~Monitoring~~ well(s) ~~must be~~ located in stratigraphic horizons that are potential contamination migration pathways as identified by the hydrogeologic site characterization conducted pursuant to Section 841.200.

e) The groundwater monitoring system must be approved by the Agency pursuant to Subpart E of this Part as a part of the groundwater monitoring plan.

Section 841.210 Groundwater Monitoring Plan

a) The owner or operator of a unit must develop a groundwater monitoring plan to monitor and evaluate groundwater quality to demonstrate compliance with the groundwater quality standards in 35 Ill. Adm. Code Part 620, ~~and~~ to determine the full extent, measured or modeled, of the presence of any contaminant monitored pursuant to Section 841.215 of this Part above background concentrations, if any, and to determine the potential for any release of a contaminant to surface water through groundwater contaminated by the unit.

b) The groundwater monitoring plan must contain the following:

1) A groundwater monitoring quality assurance program for sample collection, preservation and analysis.

2) A site map that identifies the following:

A) all the units located at the site;

B) all existing and proposed groundwater monitoring wells;

C) all buildings and pertinent features; and

D) other information if requested by the Agency.

3) A description of the unit(s), including but not limited to:

A) the date each unit began operation;

B) a description of the contents of each unit, specifying, to the extent practicable and where such information is available:

i) ~~i)~~ the date when each unit began receiving coal combustion waste, or leachate from coal combustion waste,

~~i)~~ii) ~~and~~ the date ~~or anticipated date~~ of the installation of any pollution control technology that affects~~ed, or will affect,~~ the type or composition of coal combustion waste received by the unit;

ii) changes in the coal source (e.g. Powder River Basin versus Illinois Basin) including dates and/or tons of material from each coal source;

iii) changes in the type of coal combustion waste, or leachate deposited (e.g. fly ash versus flue gas desulfurization sludge) including dates and/or tons of each material deposited; and

iv) if applicable, the date when the unit stopped receiving coal combustion waste or leachate.

C) the estimated volume of material contained in each unit; and

D) a description of the engineered liner, if any, including the date of installation for each unit.

4) A description and results of all hydrogeologic site characterizations performed at the site, including a description of all potential hydrogeologic connections between each unit at the site and surface waters, a map of the potentiometric surface, and an identification of any unit at the same power generating facility that is subject to an exemption under Section 841.105(b) of this Part, including the justification for the exemption's applicability.

5) Plans, specifications, and drawings for the groundwater monitoring system developed pursuant to Section 841.205 of this Part.

6) A maintenance plan for the groundwater monitoring system.

7) An explanation of sample size, sample procedure and statistical method used to determine background concentrations and the potentiometric surface, and to conduct monitoring.~~., assessment monitoring and compliance monitoring.~~

8) The location of compliance points.

9) A schedule for submission of annual reports pursuant to Section 841.235 of this Part.

c) Representative samples from the groundwater monitoring system must be collected and analyzed in accordance with the procedures for groundwater monitoring and analysis set forth in the following documents, incorporated by reference at Section 841.120 of this Part, or other procedures approved by the Agency in the groundwater monitoring program plan:

1) "Methods for Chemical Analysis of Water and Wastes";

2) "Methods for the Determination of Inorganic Substances in Environmental Samples";

3) "Methods for the Determination of Metals in Environmental Samples";

4) "Methods for the Determination of Metals in Environmental Samples – Supplement I";

5) "Methods for the Determination of Organic and Inorganic Compounds in Drinking Water: Volume I";

6) "Practical Guide for Ground-Water Sampling";

7) "Test Methods for Evaluating Solid Wastes, Physical/Chemical Methods" (SW-846), as amended by Updates I, II, IIA, IIB, III, IIIA, and IIIB;

8) "Techniques of Water Resources Investigations of the United States Geological Survey, Guidelines for Collection and Field Analysis of Ground-Water Samples for Selected Unstable Constituents";

9) "Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities—Unified Guidance."

10) "Field Techniques for Estimating Water Fluxes Between Surface Water and Ground Water."

11) "Operating Procedure – Pore Water Sampling."

d) Sampling and analysis data from groundwater monitoring must be reported to the Agency within 60 days after completion of sampling.

e) All groundwater samples taken pursuant to this Section must be analyzed for the chemical constituents listed in Section 841.215 of this Part by a certified laboratory.

f) When pollution control technology that affects the type or composition of coal combustion waste received by the unit is installed, the owner or operator shall update the groundwater monitoring plan to include the date of installation.

g) The groundwater monitoring plan and any modifications to the groundwater monitoring plan must be approved by the Agency pursuant to Subpart E of this Part.

Section 841.215 Chemical Constituents and Other Data to Be Monitored

The owner or operator of a unit shall monitor for all chemical constituents identified in 35 Ill. Adm. Code 620.410(a) and (e) except, perchlorate, radium-226 and radium-228. Field parameters of specific conductance, groundwater elevation, monitoring well depth and field pH must be determined and recorded with the collection of each sample, and does not need to be analyzed by a certified laboratory.

Section 841.220 Determining Background Values

a) The owner or operator of a unit must determine the background values of the chemical constituents to be monitored pursuant to Section 841.215 of this Part and must submit the background value determination with the ~~annual~~ statistical analysis pursuant to Section 841.235 of this Part.

b) The number and kinds of samples collected to establish background must be appropriate for the type of statistical test employed, as prescribed in Section 841.225 of this Part and the 2009 Unified Guidance, incorporated by reference in Section 841.120 of this Part.

c)~~b)~~ Where wells up-gradient of the unit could be affected by activities at the site, the owner or operator may, with Agency approval, use the intrawell statistical method as specified in the 2009 Unified Guidance to determine background values.

d)~~c)~~ The owner or operator shall recalculate background chemical constituent concentrations consistent with the recommendations contained in the 2009 Unified Guidance, but no less often than every ~~five~~three -years.

e) Detections of chemical constituents for which monitoring has been reduced pursuant to Section 841.230(c) shall be included by the owner or operator in background calculations.

Section 841.225 Statistical Methods

a) When determining background values and when conducting ~~compliance or assessment~~ monitoring, the owner or operator of the unit must specify one or more of the following statistical methods to be used. The statistical test chosen must be conducted separately for each monitored chemical constituent in each well as necessary to demonstrate compliance with this Part and Part 620. Where PQLs are used in any of the following statistical procedures to comply with subsection (b)(5) of this Section, the PQL must be proposed by the owner or operator and approved by the Agency. Use of any of the following statistical methods must adequately protect human health and the environment and must comply with the performance standards outlined in subsection (b) of this Section.

1) A parametric analysis of variance followed by multiple comparisons procedures to identify statistically significant evidence of contamination.

2) An analysis of variance based on ranks followed by multiple comparisons procedures to identify statistically significant evidence of contamination.

3) A tolerance or prediction interval procedure in which an interval for each chemical constituent is established from the distribution of the background data, and the level of each chemical constituent in each compliance well is compared to the upper tolerance or prediction limit. In the case of pH, the upper and lower limits shall be considered.

4) A control chart approach that gives control limits for each chemical constituent.

5) Another statistical test method submitted by the owner or operator and approved by the Agency.

b) Any statistical method chosen pursuant to subsection (a) of this Section must comply with the following performance standards, as appropriate:

1) The statistical method used to evaluate groundwater monitoring data must be appropriate for the distribution of chemical constituent concentrations. If the distribution of the chemical constituent concentrations is shown by the owner or operator to be inappropriate for a normal theory test, then the data should be transformed or a distribution-free theory test should be used. If the distributions for the chemical constituent concentrations differ, more than one statistical method may be needed.

2) If an individual well comparison procedure is used to compare an individual compliance well chemical constituent concentration with background chemical constituent concentrations, the test must be done at a Type I error level no less than 0.01 for each testing period. If a multiple comparisons procedure is used, the Type I experiment-wise error rate for each testing period must be no less than 0.05; however, the Type I error of no less than 0.01 for individual well comparisons must be maintained. This performance standard does not apply to tolerance intervals, prediction intervals or control charts.

3) If a control chart approach is used to evaluate groundwater monitoring data, the specific type of control chart and its associated parameter value must be proposed by the owner or operator and may be approved by the Agency if the Agency finds it to adequately protect human health and the environment.

4) If a tolerance interval or a prediction interval is used to evaluate groundwater monitoring data, the levels of confidence and, for tolerance intervals, the percentage of the population that the interval must contain, must be proposed by the owner or operator and may be approved by the Agency if the Agency finds these parameters to adequately protect human health and the environment. These parameters will be determined after considering the number of samples in the background database, the data distribution, and the range of the concentration values for each constituent of concern.

5) The statistical method must account for data below the limit of detection with one or more statistical procedures that adequately protect human health and the environment. Any PQL approved by the Agency pursuant to subsection (a) of this Section that is used in the statistical method must be the lowest concentration level that can be reliably achieved within specified limits of precision and accuracy during routine laboratory operating conditions that are available to the facility.

6) The statistical method must include procedures to control or correct for seasonal and spatial variability, as well as temporal correlation in the data.

c) Sample Size: The sample size must be as large as necessary to ensure with reasonable confidence that a contaminant release to groundwater from a facility will be detected while achieving the performance criteria in 841.225(b). Consistent with the 2009 Unified Guidance, an evaluation of this statistical power should be made as part of the justification for using a particular statistical test.

Section 841.230 Sampling Frequency

a) Semi-Annual Monitoring. Except as provided by this Section, all~~All~~ chemical constituents monitored pursuant to this Part shall be sampled at least semi-annually if allowed by the statistical method selected pursuant to Section 841.225 of this Part.

b) Quarterly Monitoring. ~~In addition to semi-annual monitoring required under subsection (a) of this Section, the following shall apply:~~

1) An owner or operator must increase semi-annual monitoring to quarterly monitoring under the following circumstances.

A) If any chemical constituents monitored pursuant to this Part exceed the standards set forth in 35 Ill. Adm. Code 620.Subpart D the owner or operator shall sample each well on a quarterly basis for those chemical constituents that exceed the standards in 35 Ill. Adm. Code 620.Subpart D.

B)~~2)~~ Pursuant to Section 841.235(c)(2) of this Part, when a unit(s) may be the cause of a statistically significant increasing concentration, the owner or operator shall sample each well on a quarterly basis for any chemical constituents with a statistically significant increasing concentration.

C)~~3)~~ If any chemical constituents monitored pursuant to this Part have a concentration that differs to a statistically significant degree from the concentrations detected in the up-gradient wells, the owner or operator shall sample each well on a quarterly basis for those chemical constituents that differ to a statistically significant degree.

2)~~c)~~ ~~Reduction of Quarterly Monitoring.~~ Any owner or operator of a unit conducting quarterly sampling pursuant to subsection (b)(1) of this Section may reduce the quarterly sampling to semi-annual sampling when:

A)~~1)~~ the monitored chemical constituent is not detectable in the down-gradient wells for four consecutive quarters;

B)~~2)~~ the monitored chemical constituent has a concentration that does not differ to a statistically significant degree from the concentration detected in the up-gradient wells for four consecutive quarters; or

C)~~3)~~ the Agency has approved the owner or operator's alternative cause demonstration pursuant to Sections 841.305 -or 841.235(c)(1) of this Part.

c) Reduced monitoring. Monitoring frequency may be reduced for individual monitoring wells for particular chemical constituents. Reduced monitoring is prohibited when any unit that is up gradient of or is otherwise associated with ~~the the unit or units associated with~~ the monitoring well doesoes not have a liner that complies with the surface impoundment design standard in Section 841.450 of this Part or that ~~with two feet of compacted earthen material with a hydraulic conductivity of less than or equal to 1 x10^{-7} centimeters per second or a synthetic liner that~~ provides equivalent protection.

1) If the monitoring well is up gradient from a unit, the monitoring frequency for that monitoring well may be reduced to once every ~~five~~ year~~s~~ for a chemical constituent that has not been detected in that monitoring well in the last five years so long as the chemical constituent has not been detected in all monitoring wells located down gradient from the unit.

2) If the monitoring well is down gradient from a unit, the monitoring frequency for that monitoring well may be reduced to once every ~~five~~ year~~s~~ for a chemical constituent that has not been detected in that monitoring well in the last five years.

3) Monitoring frequency may not be reduced pursuant to this subsection (c) for the following chemical constituents: arsenic, boron, manganese, sulfate, and total dissolved solids.

d) The owner or operator of the unit must modify the groundwater monitoring plan and obtain Agency approval pursuant to Subpart E of this Part before reducing monitoring.

e) The owner or operator of a unit may discontinue groundwater monitoring upon Agency approval of the certified post-closure report for that unit required by Section 841.440 of this Part.

Section 841.235 ~~Annual~~ Statistical Analysis

a) The owner or operator of a unit must perform a~~n annual~~ statistical analysis using the appropriate statistical method pursuant to Section 841.225 of this Part for each monitoring well located down-gradient of any unit for all chemical constituents monitored in accordance with Section 841.215 of this Part, every time that monitoring is conducted pursuant to Section 841.230 of this Part.

b) When a chemical constituent monitored pursuant to Section 841.215 of this Part does not exceed the numerical groundwater standards in 35 Ill. Adm. Code 620, the ~~annual~~ statistical analysis shall determine whether any increase of the chemical constituent's concentration is statistically significant.

c) If the increase is statistically significant, the owner or operator of the unit must investigate the cause.

1) If an investigation attributes a statistically significant increasing concentration to an alternate cause, the owner or operator must notify the Agency in writing within 60 days after submission of the ~~annual~~ statistical analysis, stating the cause of the increasing concentration and providing the rationale used in that determination. The procedures in Section 841.305 of this Part shall apply to the alternative cause demonstration made pursuant to this subsection.

2) If there is not an alternative cause for the statistically significant increasing concentration, then the owner or operator must:

A) sample any chemical constituent with statistically significant increasing concentration on a quarterly basis;

B) conduct further investigation that includes groundwater flow and contaminant transport modeling; ~~when the unit is located over a high priority resource groundwater 35 Ill. Adm. Code 620.210(a)(1), (a)(2), or (a)(3), or Class III groundwater under 35 Ill. Adm. Code 620.230; Class I groundwater under 35 Ill. Adm. Code 620.210(a)(1), (a)(2), or (a)(3), or Class III groundwater under 35 Ill. Adm. Code 620.230~~;

C) determine whether the statistically significant increasing concentration demonstrates that a release attributable to the unit threatens a ~~resource~~ groundwater such that:

i) Treatment or additional treatment is necessary to continue an existing use or to assure a potential use of such groundwater; or

ii) An existing or potential use of such groundwater is precluded; and

D) notify the Agency in writing of the findings within 30 days of making the determinations.

3) When the owner or operator determines pursuant to subsection (c)(2)(C) of this Section that a release attributable to a unit causes, threatens or allows an impairment or exclusion of existing or potential use, ~~, and the groundwater is and the groundwater is a high priority resource groundwater Class I groundwater under 35 Ill. Adm. Code 620.210(a)(1), (a)(2), or (a)(3), or Class III groundwater under 35 Ill. Adm. Code 620.230~~ ~~Class I groundwater under 35 Ill. Adm. Code 620.210(a)(1), (a)(2), or (a)(3), or Class III groundwater under 35 Ill. Adm. Code 620.230~~, the owner or operator of the unit shall develop a preventive response plan to control, minimize and prevent migration of any release from the unit to the ~~resource~~ groundwater. This preventive response plan shall:

A) be consistent with the requirements of 35 Ill. Adm. Code 620.310;

B) be submitted to the Agency within 180 days after the submission of the ~~annual~~ statistical analysis; and

C) require the owner or operator to conduct a hydrogeologic investigation or additional site investigation if the statistically significant increasing concentration continues over a period of two or more consecutive years.

D) be approved by the Agency pursuant to Subpart E of this Part.

d) The statistical analysis shall include an updated potentiometric surface map for the unit's site.

e~~d~~) If a groundwater management zone is established pursuant to 35 Ill. Adm. Code 620.250, the ~~annual~~ statistical analysis shall be conducted as set forth in the groundwater management zone or as otherwise approved by the Agency.

f~~e~~) For the purposes of this Section, detections of chemical constituents for which monitoring has been reduced pursuant to Section 841.230(c) shall be considered statistically significant increases, and the owner or operator must investigate the cause pursuant to subsection (c) of this Section and notify the Agency within 60 days of the cause of the detection. If the chemical constituents exceed the numerical groundwater standards of 35 Ill. Adm. Code 620, Subpart D, then the owner or operator shall monitor the chemical constituents pursuant to Section 841.230(b)(1).

g~~f~~) The ~~annual~~ statistical analysis shall be submitted to the Agency in accordance with a schedule approved by the Agency in the groundwater monitoring plan pursuant to Section 841.210 of this Part.

~~**Section 841.240 Inspection**~~

~~a) While a unit is in operation, it must be inspected at least once every seven days and after each storm to detect evidence of any of the following:~~

~~1) Deterioration, malfunctions or improper operation of overtopping control systems;~~

~~2) Sudden drops in the level of the unit's contents;~~

~~3) Severe erosion (eg. rills, gullies, and crevices six inches or deeper) or other signs of deterioration (eg. failed or eroded vegetation in excess of 100 square feet or cracks) in dikes or other containment devices; and~~

~~4) A visible leak.~~

~~b) The owner or operator shall prepare a report for each inspection which includes the date of the inspection, condition of the unit, any repairs made to the unit and the date of the repair and shall maintain a record of such reports pursuant to Section 841.135 of this Part.~~

~~c) The owner or operator shall notify the Agency when a visual inspection shows the level of liquids in the unit suddenly and unexpectedly drops and the drop is not caused by changes in the influent or effluent flows.~~

SUBPART C: CORRECTIVE ACTION

Section 841.300 Confirmation Sampling

a) If the results of groundwater monitoring conducted pursuant to this Part show an exceedence of the groundwater quality standards in 35 Ill. Adm. Code 620 at the compliance point(s), the owner or operator shall confirm the detection by resampling the monitoring well or wells. For purposes of this Section, concentrations of chemical constituents due to natural causes are not considered in determining the applicable groundwater standard. This resampling shall be analyzed for each chemical constituent exceeding the groundwater quality standards in the first sample. The confirmation sampling results must be submitted to the Agency within 30 days after the date on which the original sample analysis was submitted to the Agency pursuant to Section 841.210(d) of this Part.

b) If confirmation sampling confirms the detection of concentrations above any groundwater quality standard, the owner or operator shall:

1) submit to the Agency an alternative cause demonstration pursuant to Section 841.305 of this Part that shows the exceedence of the groundwater quality standard at a compliance point is not attributable to a release from a unit or units on-site; or

2) submit to the Agency a corrective action plan as provided in Section 841.310 of this Part~~;~~ and close all units, releases from which have caused an exceedence of the groundwater quality standard at the compliance point, as provided in Subpart D of this Part in accordance with Section 841.405 of this Part.

c) When an exceedence of the groundwater quality standards has been confirmed, the owner or operator must notify the Agency of the owner or operator's intended action pursuant to subsection (b) of this Section. This notification must indicate in which wells and for which chemical constituents a groundwater standard has been exceeded, and must be submitted within 30 days after submitting the confirmation sample results.

Section 841.305 Alternative Cause Demonstration

An owner or operator may demonstrate that an exceedence of a groundwater quality standard confirmed at a compliance point is not attributable to a release from a unit. A release is not attributable to a unit when any exceedence is due to error in sampling, analysis or evaluation, any exceedence is due to natural causes, or any exceedence is due to a source other than the unit.

a) In making such demonstration, the owner or operator shall submit a report to the Agency that demonstrates an alternative cause within 180 days after the date of submission of the confirmation samples pursuant to Section 841.300 of this Part. In order to demonstrate an alternative cause, the report must describe and justify a specific cause, with documentation that establishes the existence of the asserted error, natural cause, or alternate contamination source.[1]

b) The Agency shall provide a written response within 90 days to the owner or operator based upon the written demonstration and any other relevant information submitted by the owner or operator that specifies either:

1) Concurrence with the written demonstration; or

2) Non-concurrence with the written demonstration and the reasons for non-concurrence.

c) An owner or operator who receives a written response of non-concurrence pursuant to subsection (b) shall

1) submit a corrective action plan in accordance with the requirements of this Subpart ~~and initiate closure or a closure plan in accordance with the requirements of Subpart D of this Part~~ within 90 days of the day the Agency's non-concurrence was mailed to the owner or operator and close all units, releases from which have caused an exceedence of the groundwater quality standard at the compliance point, as provided in Subpart D of this Part and in accordance with Section 841.405 of this Part; or

2) appeal the Agency's decision of non-concurrence to the Board within 35 days of the day the Agency's non-concurrence was mailed to the owner or operator.

Section 841.310 Corrective Action Plan

Whenever any applicable groundwater quality standards under 35 Ill. Adm. Code 620.Subpart D are exceeded, this exceedence is confirmed pursuant to Section 841.300 of this Part, and

[1] Alternatively, the Environmental Groups propose the following language for 841.305(a):

a) In making such demonstration, the owner or operator shall submit a report to the Agency that demonstrates an alternative cause and provides the rationale used in such a determination within 180 days after the date of submission of the confirmation samples pursuant to Section 841.300 of this Part.

the owner or operator has not made an alternative cause demonstration pursuant to Section 841.305 of this Part, ~~and the owner or operator does not elect to close the unit(s),~~ the owner or operator shall undertake the following corrective action:

a) Sample and analyze on a quarterly basis according to the provisions of Section 841.230(b) of this Part.

b) If a release from a unit has impacted a potable water supply well that is in use, the owner or operator of the unit shall act to replace the water supply with a supply of equal or better quality and quantity within 30 days of discovering that such impact has occurred. For the purposes of this Section, a potable water supply well is impacted if the concentration of any chemical constituent monitored pursuant to this Part exceeds the groundwater quality standards in 35 Ill. Adm. Code 620.Subpart D within the well's setback zone.

c) The owner or operator shall take corrective action that results in compliance with the groundwater quality standards.

d) The owner or operator shall submit a corrective action plan within 180 days after submission of confirmation sampling results. This requirement is waived if no groundwater quality standard is exceeded in the samples taken pursuant to subsection (a) of this Section for two consecutive quarters.

e) The corrective action plan must contain the following:

1) description of the activities to be performed at the site, in accordance with the requirements of this Part, to mitigate the groundwater quality standard exceedence;

2) proposed plans, specifications, and drawings for the proposed corrective action;

3) proposed timeline for implementation and completion of all proposed corrective actions;

4) a copy of the following plans and investigations:

A) groundwater monitoring plan required pursuant to Section 841.210 of this Part,

B) hydrogeologic site characterization required by Section 841.200 of this Part and any other hydrogeological site investigation performed under this Part; and

C) a copy of the most recent ~~annual~~ statistical analysis required by Section 841.235 of this Part;

5) an assessment of alternatives to the proposed corrective action, including whether any alternative corrective action would result in greater protection of human health and the environment;

6) if the corrective action would lead to a new or increased loading of pollutants to surface waters, an antidegradation demonstration as required by 35 Ill. Admin. Code 302.105(f);

~~6~~7) estimates of the cost of the corrective action, including of each evaluated corrective action alternative;

8~~7~~) a proposal for a GMZ as set forth in 35 Ill. Adm. Code 620.250, if applicable, including but not limited to groundwater modeling results and supporting documentation;

9~~8~~) description of the CQA program required by Section 841.155 of this Part.

10~~9~~) description of institutional controls prohibiting potable uses, if applicable, and copies of the instruments achieving those controls.;

11~~10~~) an evaluation of the effects of a cover, when requested by the Agency;

12~~11~~) description of any preventive response plan developed pursuant to Section 841.235 of this Part or 35 Ill. Adm. Code 620.230, if applicable, including, but not limited to, plans, specifications, and drawings for any structures or devices that were constructed; and

13~~12~~) the signature and seal of the professional engineer supervising the preparation of the corrective action plan.

f) The Agency may request additional information from the owner or operator when necessary to evaluate the proposed corrective action plan.

~~f)~~g) The Agency shall put any antidegradation demonstration submitted under 841.310(e)(6) on public notice as required by 35 Ill. Admin. Code 302.105(f)(3). If required, the antidegradation demonstration must be approved by the Agency before a corrective action plan can be approved. The approved antidegradation demonstration may then be deemed complete for the purposes of a NPDES modification necessary to implement the corrective action plan.

h~~g~~) Upon Agency approval of the corrective action plan, an owner or operator shall implement corrective action in accordance with the timelines approved in the corrective action plan, and shall provide annual progress reports to the Agency regarding implementation of the corrective action plan.

i~~h~~) The owner or operator shall continue corrective action measures to the extent necessary to ensure that no groundwater quality standard is exceeded at the compliance point or points.

j~~i~~) If the owner or operator determines that the corrective action program no longer satisfies the requirements of this Section, the owner or operator shall, within 90 days of that determination, submit a modification of the corrective action plan to the Agency.

k) If the Agency determines that the corrective action program no longer satisfies the requirements of this Section, it shall notify the owner or operator, and the operator shall, within 90 days of that notification, submit a modification of the corrective action plan to the Agency.

l~~j~~) The Agency shall review the corrective action plan, and any modifications, according to the provisions of Subpart E of this Part.

Section 841.315 Groundwater Collection System

a) A groundwater collection system includes, but is not limited to, recovery wells, trenches, sumps or piping.

b) When the corrective action plan includes the use of a groundwater collection system, the owner or operator must:

1) include plans for the groundwater collection system, including, but not limited to, a plan for operation and maintenance, which must be approved by the Agency in the corrective action plan.

2) construct the groundwater collection system in accordance with a CQA program that meets the requirements of Section 841.155 of this Part.

c) Once compliance with the groundwater quality standards set forth in 35 Ill. Adm. Code 620 or in the groundwater management zone established pursuant to 35 Ill.

Adm. Code 620.250 have been achieved, the owner or operator of the unit may discontinue operation of the groundwater collection system.

1) Upon discontinuing operation of the groundwater collection system, the owner or operator must perform four quarterly samples of the groundwater monitoring system wells to ensure compliance with the applicable groundwater quality standards.

2) Results of the four quarterly samples must be included in the corrective action report documentation under Section 841.325. If compliance is not confirmed, operation of the groundwater collection system and discharge system must be resumed, and the owner or operator must notify the Agency.

Section 841.320 Groundwater Discharge System

When the corrective plan includes the use of a groundwater discharge system:

a) Water discharged to waters of the United States must be discharged in accordance with an NPDES Permit.

b) The groundwater discharge system must be constructed according to a CQA program that meets the requirements of Section 841.155 of this Part.

c) Plans for the groundwater discharge system, including, but not limited to, a plan for operation and maintenance, must be approved by the Agency in the corrective action plan.

Section 841.325 Corrective Action Report and Certification

a) No later than 90 days after the completion of all corrective actions contained in the corrective action plan approved by the Agency, the owner or operator must prepare and submit a corrective action report and corrective action certification for Agency review and approval.

b) The corrective action report also must contain supporting documentation, including, but not limited to:

1) Engineering and hydrogeology reports, including, but not limited to, monitoring well completion reports and boring logs, all CQA reports, certifications, and designations of CQA officers-in-absentia required by Section 841.155 of this Part;

2) Photographs of construction activities;

3) A written summary of corrective action requirements and activities as set forth in the corrective action plan and this Part; and

4) Any other information relied upon by the professional engineer in making the corrective action certification.

5) The signature and seal of the professional engineer supervising the implementation of the corrective action plan, and the preparation of the corrective action report.

c) The corrective action certification must be made on forms prescribed by the Agency and must contain a certification by a professional engineer that the release attributable to the unit has been mitigated in accordance with the approved corrective action plan required by Section 841.310 of this Part and the requirements of this Part. The certification must be signed by the owner or operator and by the certifying registered professional engineer.

SUBPART D: CLOSURE

Section 841.400 Surface Impoundment Closure

a) All units shall be closed in a manner that:

1) Controls and ~~,~~ eliminates or minimizes to the greatest extent practicable ~~or eliminates~~ releases from the unit; and

2) Minimizes the need for maintenance during and beyond the post-closure care period;

b) Closure shall~~If closure is to~~ be by removal of all impounded coal combustion waste, and leachate from coal combustion waste, unless the Agency determines that removal is technically infeasible or would not result in greater protection of human health and the environment. If any of the following criteria are present, closure shall be by removal unless technically infeasible:

1) Coal combustion waste from the unit is present in the water table;

2) The unit is located in a 100-year floodplain or wetlands; or

3) The unit is located above an active or inactive shaft or tunneled mine or

within 200 feet of a fault that has had displacement within Holocene time, unless engineering measures have been incorporated into the facility design to ensure that the integrity of the structural components of the facility will not be disrupted by geological processes.

The owner or operator shall remove all coal combustion waste~~, as well as containment system components (liners, etc)~~. If the owner or operator does not also remove the containment system components (liners, etc.), the containment system components left in place shall be cleaned to remove all coal combustion waste and punctured to allow stormwater to cross through the system. All coal combustion waste must be properly disposed in accordance with the applicable laws and regulations unless beneficially reused.

c) If closure is not to be by removal of all impounded coal combustion waste and leachate from coal combustion waste, the owner or operator shall:

1) Eliminate free liquids by removing liquid wastes, either by disposal off-site in accordance with the applicable laws and regulations or by an authorized discharge through a properly permitted outfall, or solidifying the remaining wastes and waste residues.

2) Stabilize remaining wastes to a bearing capacity sufficient to support final cover.

3) Cover the unit with a final cover designed and constructed to meet the requirements of Section 841.420 of this Part.

d) Deed notation

1) Following closure of a unit at a site, the owner or operator shall record a notation on the deed to the facility property or some other instrument that is normally examined during title search. The owner or operator shall place a copy of the instrument in the operating record, and shall notify the Agency that the notation has been recorded and a copy has been placed in the operating record.

2) The notation on the deed or other instrument must be made in such a way that in perpetuity notify any potential purchaser of the property that:

A) The land has been used as a coal combustion waste surface impoundment; and

B) The land's use is restricted pursuant to Section 841.430(h)-(i).

Section 841.405 Closure Prioritization

a) Whenever any applicable groundwater standards under 35 Ill. Adm. Code 620.Subpart D are exceeded, this exceedence is confirmed pursuant to Section 841.300 of this Part, the owner and operator has not made an alternative cause demonstration pursuant to Section 841.305 of this Part,~~ and the owner or operator elects to close the unit(s),~~ the owner or operator shall close the unit according to the following schedule:

1) Category 1: Impact to Existing Potable Water Supply

A) Category 1 applies where an existing potable water supply well is impacted by a release attributable to the unit. An existing potable water supply is impacted if the level of a contaminant attributable to a release from the unit exceeds an applicable groundwater standard in 35 Ill. Adm. Code 620.Subpart D within the setback of an existing potable water supply well.

B) If the unit meets the criteria for Category 1, the owner or operator must take immediate steps to mitigate the impact to any existing potable water supply. The owner or operator of the unit shall act to replace the water supply with a supply of equal or better quality and quantity within 30 days of notice that such impact has occurred.

C) If Category 1 applies, ~~owner or operator shall submit a closure plan to the Agency that meets Section 841.410 of this Part within 180 days from the submission of groundwater monitoring results confirming the impact. The T~~the unit shall be closed within two years of the Agency's approval of the closure plan, or within two years of notice that a release attributable to the unit caused an impact on an existing potable water supply~~ has occurred~~, whichever occurs later, unless the Agency approves a longer timeline.

2) Category 2: ~~Inactive~~ Other Units

A) Unless Category 1 applies~~or 4 apply~~, Category 2 applies.~~ where the unit is inactive~~. ~~For the purposes of this Part, a unit is considered inactive if it has not received coal combustion waste, or leachate~~

~~from coal combustion waste within the most recent period of eighteen months.~~

B) ~~If the unit is inactive, a closure plan must be submitted to the Agency within 180 days from the submission of groundwater monitoring results confirming an exceedence of the applicable groundwater quality standards attributable to a release from a unit at an approved compliance point.~~ The unit shall be closed within five years of the Agency's approval of the closure plan, or within five years from the submission of groundwater monitoring results confirming an exceedence of the applicable groundwater quality standard attributable to a release from the unit at an approved compliance point, whichever occurs later.~~unless the Agency approves a longer timeline.~~ The Agency may allow up to ten years for closure by removal of CCW and leachate in accordance with a closure plan approved by the Agency. The requirement to close the impoundment following the exceedence of an applicable groundwater quality standard is waived if:

i) no groundwater quality standard applicable at the time of the exceedence is exceeded for four consecutive quarters during the five years following the groundwater monitoring results confirming the exceedence; or

ii) the unit meets the requirements of Section 841.450 within five years following the groundwater monitoring results confirming the exceedence.~~e.~~

~~3) Category 3: Active Unit~~

~~A) Unless Category 1 or 4 apply, Category 3 applies where the unit is active. For the purposes of this Part, a unit is considered active if it has received coal combustion waste, or leachate from coal combustion waste within the most recent period of eighteen months.~~

~~B) If the unit is active, a closure plan must be submitted to the Agency within 2 years from the submission of groundwater monitoring results confirming an exceedence of the applicable groundwater quality standards attributable to a release from a unit at an approved compliance point. The unit shall be closed within five years of the Agency's approval of the closure plan, unless the Agency approves a longer timeline.~~

~~4) Category 4: Class IV Groundwater~~

~~A) Unless Category 1 applies, Category 4 applies where the unit is located on a site that has been characterized as Class IV groundwater beyond a lateral distance of 25 feet from the edge of the unit.~~

~~B) If the unit is located in a Class IV groundwater area, a closure plan must be submitted to the Agency within three years from the submission of groundwater monitoring results confirming an exceedence of the applicable groundwater quality standards attributable to a release from a unit at an approved compliance point. The unit shall be closed within six years of the Agency's approval of the closure plan, unless the Agency approves a longer timeline.~~

~~b) Whenever the applicable groundwater standards under 35 Ill. Adm. Code 620.Subpart D are not exceeded and the owner or operator elects to close the unit, the closure schedule shall be determined by the owner or operator and approved by the Agency in the closure plan.~~

Section 841.410 Closure Plan

The owner or operator of any unit must develop and submit to IEPA a closure plan for the unit. Before a unit may be closed, ~~owner or operator must submit a closure plan to the Agency for review and approval~~a closure plan must have been reviewed and approved by the Agency. As appropriate, the owner or operator may submit a combined corrective action and closure plan.

a) The closure plan must contain, at a minimum, the following information or documents:

1) description of the closure activities to be performed in accordance with this Part and any additional activities performed by the owner or operator with regards to closing the unit, including any dewatering;

2) proposed plans, specifications and drawings for the closure of the unit, which may include but are not limited to the following illustrative measures:

A) the groundwater collection system and discharge system, if applicable, set forth in Sections 841.315 and 841.320 of this Part;

B) the final slope design and construction and demonstration of compliance with the stability criteria required in Section 841.415 of this Part;

C) the final cover system required by Section 841.420 of this Part;

D) containment using a low permeability vertical barrier; and

E) other remedial measures approved by the Agency;

3) evaluation of alternatives to the proposed closure activities, including whether any alternative closure activities would result in greater protection of human health and the environment and, if closure is not proposed by removal of all coal combustion waste and leachate from coal combustion waste, an explanation of why removal is technically infeasible or would not result in greater protection of human health and the environment.~~ when requested by the Agency~~

4) if the closure plan would lead to a new or increased loading of pollutants to surface waters, an antidegradation demonstration as required by 35 Ill. Adm. Code 302.105(f);

5~~4~~) proposed timeline for implementation and completion of all proposed closure activities, including an estimate of the time required for hydrostatic equilibrium of groundwater beneath the unit.

6~~5~~) estimates of the cost of closure and post-closure care, including of each evaluated closure alternative;

7~~6~~) a copy of the following plans and investigations:

A) groundwater monitoring plan required pursuant to Section 841.210 of this Part,

B) hydrogeologic site characterization required by Section 841.200 of this Part and any other hydrogeological site investigation performed under this Part; and

C) a copy of the most recent ~~annual~~ statistical analysis required by Section 841.235 of this Part;

8~~7~~) a proposal for a GMZ as set forth in 35 Ill. Adm. Code 620.250, if applicable, and including, but not limited to, plans, specifications, drawings for any structures or devices that must be constructed, and groundwater modeling results and supporting documentation where appropriate;

9~~8~~) description of the CQA program required by Section 841.155 of this Part.

10~~9~~) description of institutional controls prohibiting potable uses, if applicable, and copies of the instruments achieving those controls;

11~~0~~) description of previous preventive response plan developed pursuant to Section 841.235 of this Part or 35 Ill. Adm. Code 620.230, or corrective action pursuant to Subpart C of this Part or 35 Ill. Adm. Code 620.250, if applicable, including, but not limited to, plans, specifications, and drawings for any structures or devices that were constructed; and

12~~1~~) the signature and seal of the professional engineer supervising the preparation of the closure plan.

b) The Agency may request additional information from the owner or operator when necessary to evaluate the proposed closure plan.

c) The Agency shall put any antidegradation demonstration submitted under Section 841.410 (a)(4) of this Part on public notice as required by 35 Ill. Admin. Code 302.105 (f)(3). If required, the antidegradation demonstration must be approved by the Agency before a corrective action plan can be approved. The approved antidegradation demonstration may then be deemed complete for the purposes of a NPDES modification necessary to implement the closure plan.

Section 841.415 Final Slope and Stabilization

When closure is not by removal of all coal combustion waste or leachate from coal combustion waste:

a) All final slopes must be designed and constructed to achieve a minimum static slope safety factor of 1.5 and a minimum seismic safety factor of 1.3, and a grade capable of supporting vegetation and minimizing erosion.

b) All slopes must be designed to drain runoff away from the cover and to prevent ponding, unless otherwise approved by the Agency.

c) The unit must meet the stability criteria of 35 Ill. Adm. Code 811.304.

d) The owner or operator may use coal combustion waste generated at the site in establishing the final grade and slope as provided below:

1) The earthen berms surrounding the unit must be regraded to eliminate any freeboard between the top of the berm and the adjacent surface of the coal combustion waste, unless otherwise approved by the Agency.

2) Additional coal combustion waste may be placed only directly on top of coal combustion waste that is already in place;

Section 841.420 Final Cover System

a) When the unit is closed by means other than removal of all coal combustion waste, the owner or operator shall design and install a final cover system for the unit. The final cover must be designed and constructed to:

1) Provide long-term minimization of the migration of liquids through the closed impoundment unit;

2) Function with minimum maintenance;

3) Promote drainage and minimize erosion or abrasion of the final cover; and

4) Accommodate settling and subsidence so that the cover's integrity is maintained.

b) The final cover system must consist of a low permeability layer and a final protective layer.

1) Standards for the low permeability layer. The low permeability layer must have a permeability less than or equal to 1 X 10^{-7} cm/sec. The low permeability layer must cover the entire unit and connect with the liner system, if the unit has a liner system. If the ~~CCW~~ unit has a liner system, the low permeability layer must have a permeability less than or equal to the permeability of any bottom liner system. ~~In the event that there is no bottom liner present, the cover shall have a permeability of less than or equal to 1 X 10^{-7} cm/sec.~~ The low permeability layer must be constructed in accordance with the following standards in either subsections (b)(1)(A) or (b)(2)(B) of this Section, unless the owner or operator demonstrates that another low permeability layer construction technique or material provides equivalent or superior performance to the requirements of either subsections (b)(1)(A) or (b)(2)(B) of this Section and is approved by the Agency. The permeability of the cover system must be demonstrated by a standard field or laboratory demonstration method.

A) A compacted earth layer constructed in accordance with the following standards:

i) The minimum allowable thickness must be 0.91 meter (3 feet); and

ii) The layer must be compacted to achieve a permeability of 1 x 10^{-7} centimeters per second or less and minimize void spaces.

B) A geomembrane constructed in accordance with the following standards:

i) The geosynthetic membrane must have a minimum thickness of 40 mil (0.04 inches) and, in terms of hydraulic flux, be equivalent or superior to a 3 foot layer of soil with a hydraulic conductivity of 1 x 10^{-7} centimeters per second.

ii) The geomembrane must have strength to withstand the normal stresses imposed by the waste stabilization process.

iii) The geomembrane must be placed over a prepared base free from sharp objects and other materials that may cause damage.

2) Standards for the final protective layer. The final protective layer must, unless otherwise approved by the Agency, meet the following requirements:

A) Cover the entire low permeability layer.

B) Be at least 3 feet thick and must be sufficient to protect the low permeability layer from freezing and minimize root penetration of the low permeability layer.

C) Consist of soil material capable of supporting vegetation.

D) Be placed as soon as possible after placement of the low permeability layer.

E) Be covered with vegetation to minimize wind and water erosion.

3) CQA Program. The final cover system must be constructed according to a CQA program that meets the requirements of Section 841.155 of this Part.

Section 841.425 Closure Report and Certification

a) No later than 90 days after the completion of all closure activities required by this Part and approved in the closure plan, the owner or operator of the unit must prepare and submit to the Agency a closure report and a closure certification for review and approval.

b) The closure report must contain supporting documentation, including, but not limited to:

1) Engineering and hydrogeology reports, including, but not limited to, monitoring well completion reports and boring logs, all CQA reports, certifications, and designations of CQA officers-in-absentia required by Section 841.155 of this Part;

2) Photographs of the final cover system and groundwater collection system, if applicable, and any other photographs relied upon to document construction activities;

3) A written summary of closure requirements and completed activities as set forth in the closure plan and this Part;

4) Any other information relied upon by the professional engineer in making the closure certification; and

5) The signature and seal of the professional engineer supervising the implementation of the closure plan, and the preparation of the closure report.

c) The closure certification must be made on forms prescribed by the Agency and must contain a certification by a professional engineer that the unit has been closed in accordance with the approved closure plan required by Section 841.410 of this Part and the requirements of this Part. The certification must be signed by the owner or operator and by the certifying registered professional engineer.

Section 841.430 Post-Closure Maintenance of Cover System

If a final cover system is used to close the unit, the owner or operator of the unit must maintain the surface of the cover system beginning immediately after construction until approval of the post-closure report by the Agency.

a) After closure, and until completion of the post-closure report, the owner or operator of the unit must conduct inspections of the cover system quarterly and after a 25-year, 24-hour storm ~~events~~.

b) The owner or operator of the unit must fill all rills, gullies, and crevices six inches or deeper. Areas identified as particularly susceptible to erosion must be recontoured.

c) The owner or operator of the unit must repair all eroded and scoured drainage channels and must replace lining material, if necessary.

d) The owner or operator of the unit must fill and recontour all holes and depressions created by settling so as to prevent standing water.

e) The owner or operator of the unit must revegetate all areas of failed or eroded vegetation in excess of 100 square feet, cumulative.

f) The owner or operator of the unit must repair all tears, rips, punctures, and other damage to the geosynthetic membrane.

g) The owner or operator must prevent the growth of woody species on the protective cover.

h) Postclosure use of the property must not disturb the integrity of the final cover, liner, any other components of the containment system, or the function of the monitoring systems, unless necessary to comply with the requirements of this Part.

i) Any disturbance of the final cover, liner or any other components of the containment system, or the function of monitoring systems and post-closure use must be approved by the Agency prior to such disturbance or use.

Section 841.435 Post-Closure Care Plan

a) The owner or operator of the unit must prepare and submit to the Agency a post-closure care plan for review and approval at the same time it submits the closure plan pursuant to Section 841.410 of this Part.

b) The owner or operator must maintain the post-closure care plan on-site or at a location specified in the post-closure care plan.

c) The post-closure care plan, or modification of the plan, must include, at a minimum, the following elements:

1) description of the post-closure care activities required by Section 841.430 of this Part;

2) description of the operation and maintenance that will be required for the groundwater collection system and discharge systems, if applicable;

3) the information and documents required in the closure plan pursuant to Section 841.410 of this Part; and

4) a description of the planned uses of the property during the postclosure care period.

5) The signature and seal of the professional engineer supervising the preparation of the post-closure care plan.

Section 841.440 Post-Closure Report and Certification

a) Post-closure care must continue until

1) compliance with the groundwater quality standards set forth in 35 Ill. Adm. Code 620 or in a groundwater management zone established pursuant to 35 Ill. Adm. Code 620.250; and

2) a minimum of ~~ten~~ thirty years from the Agency's approval of the closure report.

b) The owner or operator of the unit must prepare and submit to the Agency for review and approval a post-closure report and post-closure certification within 90 days after the post closure period specified in subsection (a) of this Section.

c) A professional engineer or professional geologist may supervise post-closure care activities as appropriate under the Professional Engineering Practice Act [225 ILCS 325] or the Professional Geologist Licensing Act [225 ILCS 745].

d) The post-closure report also must contain supporting documentation, including, but not limited to:

1) Engineering and hydrogeology reports, including, but not limited to, documentation of compliance with the applicable groundwater quality standards;

2) Any photographs relied upon to document construction activities, including but not limited to, photographs of the final cover system and groundwater collection system, if applicable;

3) A written summary of post-closure care requirements and activities as set forth in the post-closure care plan and their completion;

4) Any other information relied upon by the professional engineer or professional geologist, as appropriate for the activity, in making the post-closure care certifications;

5) The signature and seal of the professional engineer or professional geologist supervising the implementation of the post-closure care plan; and

6) The signature and seal of the professional engineer supervising preparation of the post-closure report.

e) The post-closure certification must be made on forms prescribed by the Agency and must contain a certification by a professional engineer that the post-closure care period for the unit was performed in accordance with the specifications in the approved post-closure plan required by Section 841.435 of this Part and the requirements set forth in this Part. The certification must be signed by the owner or operator and by the certifying registered professional engineer.

Section 841.445 Closure and Post-Closure Annual Reporting

a) The owner or operator of the unit must file an annual report with the Agency no later than January 31 of each year during the closure of the unit and for the entire post-closure care period. Once the requirements of Section 841.440 of this Part have been met, annual reports are no longer required.

b) All annual reports must contain the following information:

1) A certification that the owner or operator has performed all post-closure maintenance activities required by Section 841.430 of the Part during the preceding year, including a certification that there are presently no "tears, rips, punctures, and other damage to the geosynthetic membrane" and no "disturbance of the final cover, liner, or any other components of the containment system," unless approved by the Agency prior to the disturbance;

2) ~~Annual~~sStatistical analyses as required by Section 841.235 of this Part of all groundwater monitoring data generated by the groundwater monitoring program required by Section 841.210 of this Part;

3~~2~~) A copy of any notice submitted to the Agency pursuant to Section 841.235(c)(1) of this Part;

4~~3~~) A discussion of any statistically significant increasing concentrations and actions taken to mitigate such increases in accordance with Section 841.235(c)(3) of this Part; and

54) The completed closure or post-closure activities performed during the preceding year.

Section 841.450 Design Standards for New and Existing Impoundments

a) No later than five years after the effective date of this Part, all operating units shall be constructed:

1) With a composite liner, as defined in paragraph (a)(2) of this section, and a leachate collection system, or with a liner system of equivalent or superior performance. The design shall be in accordance with a design prepared by, or under the direction of, and certified by an independent registered professional engineer.

2) For purposes of this section, "composite liner" means a system consisting of two components; the upper component must consist of a minimum 30-mil flexible membrane line (FML), and the lower component must consist of at least two-foot layer of compacted soil with a hydraulic conductivity of no more than 1×10^{-7} cm/sec. FML components consisting of high density polyethylene (HDPE) shall be at least 60-mil thick. The FML component must be installed in direct and uniform contact with the compacted soil component.

3) Any impoundment that was in operation on or before the effective date of this Part shall be lined with a composite liner system as defined in paragraph (a)(2) of this Section and leachate collection system, or with a liner system of equivalent or superior performance, within five years of the effective date of this Part or have been closed in accordance with this Subpart.

b) Any new unit that begins operation after the effective date of this Part must be constructed:

1) With a composite liner, as defined in paragraph (a)(2) of this section, and a leachate collection system, or with a liner system of equivalent or superior performance. The design shall be in accordance with a design prepared by, or under the direction of, and certified by an independent registered professional engineer.

2) For purposes of this section, "composite liner" means a system consisting of two components; the upper component must consist of a minimum 30-mil flexible membrane line (FML), and the lower component must consist of at least two-foot layer of compacted soil with a hydraulic conductivity of no more than 1×10^{-7} cm/sec. FML components consisting of high density polyethylene (HDPE) shall be at least 60-mil thick. The FML component must be installed in direct and uniform contact with the compacted soil component.

Section 841.455~~0~~ Resource Conservation and Recovery Act

Nothing in this Subpart shall be construed to be less stringent than or inconsistent with the provisions of the federal Resource Conservation and Recovery Act of 1976 (P.L. 94-580), as amended, or regulations adopted under that Act. To the extent that any rules adopted in this Subpart are less stringent than or inconsistent with any portion of RCRA or with any regulation adopted under that Act applicable to the closure of a unit, RCRA or the regulation adopted under that Act will prevail.

SUBPART E: AGENCY REVIEW PROCEDURESCOAL

Section 841.500 Plan Review, Approval, and Modification

Any plan prepared and submitted to the Agency pursuant to this Part, and any modifications to those plans, must be reviewed and approved by the Agency prior to implementation.

a) The Agency will have ~~90~~ 120 days from the receipt of a plan or proposed modification to conduct a review and make a final determination to approve or disapprove a plan or modification or to approve a plan or modification with conditions.

1) The Agency's record of the date of receipt of a plan or proposed modification to a plan will be deemed conclusive unless a contrary date is

proved by a dated, signed receipt from the Agency or certified or registered mail.

2) Submission of an amended plan or amended modification to a plan restarts the time for review.

3) The owner or operator may in writing waive the Agency's decision deadline upon a request from the Agency or at the owner's or operator's discretion.

b) A proposed modification to any plan must include the reason for the modification, all the information and supporting documentation that will be changed from or will supplement the information provided in the original or most recently approved plan, and the signature and seal of the professional engineer or professional geologist, as appropriate, supervising the preparation of the proposed modification.

c) When reviewing a plan or modification, the Agency must consider:

1) Whether the plan or modification contains, at a minimum, all the elements required pursuant to this Part and has been accompanied by the information and supporting documentation necessary to evaluate the compliance of the proposed plan relative to the standards and requirements of this Part;

2) Whether the activities, structures and devices proposed are in accordance with the applicable standards and requirements of this Part and are otherwise consistent with generally accepted engineering practices and principles of hydrogeology, accepted groundwater modeling practices, appropriate statistical analyses, and appropriate sampling techniques and analytical methods;

3) When reviewing a corrective action plan, closure plan or post closure plan, or modification to any of these plans:

A) The likelihood that the plan or modification will result in the containment of the coal combustion waste or leachate from coal combustion waste and the attainment of the applicable groundwater quality standards set forth in 35 Ill. Adm. Code 620.

B) The management of risk relative to any remaining contamination, including, but not limited to, provisions for the use of long-term restrictions on the use of groundwater as a potable water supply, if appropriate;

C) The likelihood that the plan or modification will protect human health and the environment, including surface water quality, and the possibility that alternative plans or modifications would be more protective.

4~~5~~) Whether the plan or modification contains the required professional signatures and seals.

d) Upon completion of the review, the Agency must notify the owner or operator in writing of its final determination on the plan or proposed modification. The notification must be post-marked with a date stamp. The Agency's final determination will be deemed to have taken place on the post-marked date that the notice is mailed. If the Agency disapproves a plan or modification or approves a plan or modification with conditions, the written notification must contain the following information, as applicable:

1) An explanation of the specific type of information or documentation, if any, that the Agency deems the owner or operator did not provide;

2) A list of the provisions of the Act, this Part, or other applicable regulations that may be violated if the plan or modification is approved as submitted;

3) A statement of the specific reasons why the Act, this Part, or other applicable regulations may be violated if the plan or modification is approved as submitted; and

4) A statement of the reasons for conditions if conditions are required.

e~~f~~) If the Agency disapproves a plan or modification, or approves a plan or modification with conditions, the owner or operator may, within 35 days after the date of service of the Agency's final decision~~after the post-marked date that the notice is mailed~~ or after the expiration of the review period specified in subsection (a) of this section, file an appeal with the Board. Appeals to the Board are subject to review under Section 40 of the Act [415 ILCS 5/40]. The Agency's failure to issue a final determination within the applicable review time shall be considered a disapproval of the plan or modification.

f) The Agency's approval of a plan or modification submitted to it pursuant to this Part 841 shall not be a defense to violations of the Act or the Board's Regulations.

Section 841.505 Review and Approval of Reports and Certifications

The corrective action report, certification of corrective action, closure report, certification of closure, post-closure report, and certification of completion of post-closure care prepared and submitted to the Agency in accordance with this Part must be reviewed and approved by the Agency prior to the completion of corrective action, closure, or post-closure care.

a) Corrective action, closure and post-closure activities will not be deemed complete until the reports are approved by the Agency.

b) Submission, review, and approval procedures and deadlines, notification requirements, and rights of appeal shall be the same as those set forth in Section 841.500 of this Part.

c) When reviewing a corrective action report and certification of corrective action, the Agency must consider whether the documentation demonstrates that the activities, structures and devices approved in the corrective action plan have been completed, operated and maintained in accordance with this Part and the approved corrective action plan.

d) When reviewing a closure report and certification of completion of closure, the Agency must consider whether the documentation demonstrates that the activities, structures and devices approved in the closure plan have been completed in accordance with this Part and the approved closure plan.

e) When reviewing a post-closure report and certification of completion of post-closure care plan, the Agency must consider whether the documentation demonstrates that the activities, structures and devices approved in the post-closure care plan have been completed, operated and maintained in accordance with this Part and the approved post-closure care plan.

f) The Agency's approval of a report or certification submitted to it pursuant to this Part 841 shall not be a defense to violations of the Act or the Board's Regulations.

SUBPART F: FINANCIAL ASSURANCE

Section 841.600 Mechanisms for Providing Financial Assurance

a) Any of the following mechanisms may be utilized to provide financial assurance under this subpart: a trust fund, a surety bond guaranteeing payment, a surety bond guaranteeing performance, a letter of credit, closure insurance, self-insurance, a local government financial test, a local government guarantee, a corporate financial test, or a corporate guarantee. These mechanisms shall have the same meanings given in 35 Ill. Adm. Code Part 811 Subpart G.

b) An owner or operator may satisfy the requirements of this subpart by establishing more than one financial mechanism per unit.

c) An owner or operator may use a financial assurance mechanism to meet the requirements of this subpart for more than one unit if the amount of funds available through the mechanism is no less than the sum of funds that would be available if a separate mechanism had been established and maintained for each unit.

Section 841.605 Amount of Financial Assurance Required

a) The amount of financial assurance required under this Subpart shall be equal to the cost estimate to complete the closure and post-closure activities under the closure and post-closure plans approved by the Agency.

Section 841.610 Time Frame for Compliance with Financial Assurance Requirements

a) The owner or operator of any new unit that begins operation after the effective date of this Part must be in compliance with this Subpart prior to beginning operation.

b) The owner and operator of any unit that was in operation on or before the effective date of this Part shall be in compliance with this Subpart no later than 2 years after the effective date of this Part.

Agency: Exhibit B

DEPARTMENT OF
ECOLOGY
State of Washington

High-resolution Porewater Sampling Near the Groundwater/ Surface Water Interface

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This report was prepared by a licensed hydrogeologist. A signed and stamped copy of the report is available upon request.

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High-resolution Porewater Sampling Near the Groundwater/ Surface Water Interface

by
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Table of Contents

List of Figures and Tables

Page

Figures

Tables

Abstract

A complex suite of biogeochemical processes can occur below the sediment surface in aquatic environments. These processes can produce strong vertical concentration gradients in upwelling groundwater, and significantly alter the chemical character of groundwater discharging to surface water. Accurate field measurements of these changes can be important for studies that depend on estimates of groundwater discharge chemistry and pollutant loading.

This paper presents a refined field method for high-resolution water quality sampling of porewater in shallow sediments underlying the groundwater/surface water interface. A programmable syringe pump was coupled with an M.H.E. Inc. PushPoint device to collect porewater samples using an ultra-low-flow (≤2.5 ml/min) approach.

During October 2008, the method was field tested in Lake Whatcom at a location previously sampled using traditional in-water piezometers. This ultra-low-flow method was successful in collecting unbiased, depth-discrete porewater samples at a 5-cm resolution, and revealed a significant reduction in dissolved phosphorus concentration in the uppermost 50 cm of the study area sediments.

The field method described provides a low-cost, easy-to-use alternative to previous methods developed for porewater profile sampling. The method can help to reduce uncertainty and improve the overall accuracy of the Total Maximum Daily Load loading assessments and numerical modeling efforts conducted by the Department of Ecology's Environmental Assessment Program. This technique may also benefit a variety of other projects where groundwater chemical loading to surface water is of concern.

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Introduction

A growing body of technical literature has highlighted the important role that nonpoint (diffuse) groundwater discharge can have in sustaining, or degrading, surface water quality and flow (e.g., Winter et al., 1998; EPA, 1991, 2000, 2008; Jones and Mulholland, 2000). This finding has prompted significant interest in the field study of groundwater/surface water interactions by the Washington State Department of Ecology's (Ecology) Environmental Assessment Program (EAP).

Over the past decade, EAP hydrogeologists have focused on quantifying groundwater's contribution to a number of Washington State surface water systems, both in terms of water volume and chemical mass. This information has been used to help refine numerical models of watershed hydrodynamics and pollutant distribution. These models are often developed in support of surface water loading-capacity evaluations, commonly known as Total Maximum Daily Load (TMDL) studies.

Groundwater/Surface Water Exchange

In settings where groundwater is discharging to a surface waterbody (i.e. *gaining* conditions), estimates of unit area chemical loading via advective groundwater flow are developed by:

$$F_M = Q*C \qquad (1)$$

where:

F_M = mass flux of a chemical loaded to a surface waterbody by groundwater discharge [(mass/time)/unit area].

Q = rate of groundwater discharge [(volume/time)/unit area].

C = concentration of the chemical in the groundwater discharge (mass/volume).

For EAP TMDL studies, flow field analyses using Darcy's Law or water budget approaches are the standard methods for developing estimates of the volume of groundwater discharge (Q). Porewater located beneath (hydraulically upgradient of) the groundwater/surface water interface (GSI) is typically sampled to estimate the chemical concentration of that discharge (C).

The accuracy of the estimate for each of these terms can have a significant bearing on the accuracy of an overall loading-capacity analysis. Depending on the volume of exchange, even small differences in the estimated discharge concentration can significantly modify the final groundwater loading estimate provided to the surface water modeler (Equation 1). As a result, it is important that the measurements collected to support these estimates are as representative of true field conditions as possible.

Changes in Groundwater Chemistry near the Point of Discharge

Research advances in recent years have illustrated the dynamic nature of the transition zone or *membrane* between groundwater and surface water systems (Constanz, 2007; Winter et al., 1998; Ford, 2005, Bridge, 2005; EPA, 2008).[1] A variety of interrelated biogeochemical processes can be active in this transition zone, including reduction-oxidation (redox)-driven sorption reactions, microbial and plant uptake, and mixing with overlying surface water. These processes can create strong vertical solute concentration gradients over short distances and considerably alter the final chemical character of groundwater discharge (EPA, 2000; Ford, 2005; Laskov et al., 2007).

In many cases, processes active near the GSI will decrease or *attenuate* dissolved chemical concentrations as groundwater approaches the point of discharge, potentially by an order of magnitude or more (Ford, 2005; Duff et al., 1998; Charette and Sholkovitz, 2002). These attenuation effects can have a significant bearing on the estimated total groundwater-related chemical load to a surface system, even at a watershed scale (Harvey and Fuller, 1998; Angier and McCarty, 2008; Kuwabara et al., 2009). Two key nutrients of interest for Washington State TMDL studies, phosphorus and nitrogen, can be particularly subject to these attenuation reactions (Charette and Sholkovitz, 2002; Chambers and Odum, 1990; Cox et al., 2005; Maleki et al., 2004; Fisher and Reddy, 2001; Griffioen, 2006; Di Toro, 2001).

Previous investigators have shown that the majority of these attenuation processes can occur within as little as 1 to 50 cm of the sediment surface (Chambers and Odum, 1990; Beck et al., 2007; Berg and McGlathery, 2001; Duff et al., 1998, Martin et al., 2003; Ford, 2005). The monitoring tools and methods that have been used for EAP groundwater/surface water interaction studies are not sufficiently accurate for characterizing changes in groundwater chemistry in this depth range. Without accurate measurements of water quality changes in shallow sediments, EAP estimates of groundwater chemical loading to surface water can have a relatively high degree of uncertainty (e.g., Pitz, 2005; Sinclair and Kardouni, 2009). This uncertainty reduces confidence in how accurately models of groundwater/surface water exchange reflect the natural environment.

Project Objectives

The purpose of this study was to develop and test a high-resolution, porewater sampling method to improve descriptions of groundwater discharge chemistry, particularly in areas where steep chemical concentration gradients are suspected near the GSI.

The success of the test method was judged by its ability to produce:

- Porewater chemical profiles at a vertical resolution of 5 centimeters.
- An adequate sample volume for chemical analysis.
- A sample free of surface water cross-contamination.

[1] In a lake setting such as the one described in this report, this zone is technically referred to as the *hypolentic* zone (EPA, 2008).

- Quality control blanks free of significant contamination.
- Duplicate sample results within acceptable quality objective criteria.
- Water samples in an efficient, low-cost, and field-robust manner.

The study area selected for method testing is currently the subject of an active TMDL nutrient-assimilation modeling effort (Pickett and Hood, 2008). Phosphorus is the primary nutrient of concern for that effort. Because the groundwater phosphorus loading estimates developed for the model did not account for attenuation effects in the upper meter of lake-bed sediment (Pitz, 2005), the findings generated from this study may benefit that modeling work.

Study Area Site Description

During October 2008, method testing was conducted approximately 15 meters off the western shoreline of Lake Whatcom, in Whatcom County, Washington (Figure 1). The site is located immediately downgradient of an active golf course, with moderate-density suburban development further upslope. Prior to development of the golf course in the 1970s, the property adjacent to the lake was used for livestock farming.

Austin Creek flows into the lake less than 100 meters from the test site. The creek drains approximately 5000 acres of the western portion of the Lake Whatcom watershed, and is probably a major source of the sediment observed at the study location.

Surficial sediments at the site are poorly-graded sands with silt (Pitz, 2005), supporting scattered growth of the aquatic macrophyte *Elodea canadensis*. Prior to testing the sampling system, a piezometer-based, constant-head injection test (Pitz, 2006) was conducted at approximately 1.2 meters below the sediment surface. The test results indicate a moderate permeability condition for sub-surface deposits (~ 4.2E-03 centimeters/second). This permeability value suggests the deeper sediments at the study location are similar to sediments observed near the surface.

A 1.4-meter-deep tubing piezometer (LWGW-09) was installed and monitored at the study location during 2002-2003 as part of a Lake Whatcom TMDL support study (Pitz, 2005). The deep piezometer is constructed with a ~15-cm long screened interval. Porewater at this depth has historically exhibited a positive (upward) vertical hydraulic gradient, indicating a groundwater discharge condition in the study area.

Water quality samples collected from the deep piezometer revealed a high dissolved phosphorus concentration in upwelling groundwater, accompanied by sub-oxic to anoxic conditions [<1-2 milligram/liter (mg/L) dissolved oxygen, elevated dissolved iron]. Ammonia as nitrogen (ammonia-N) averaged ~0.3 mg/L, and dissolved organic carbon was highly elevated, averaging >20 mg/L. Negligible levels of nitrite + nitrate as nitrogen (nitrate-N) were measured at this depth (<0.1 mg/L). This piezometer was left in place at the end of the 2002-2003 study, and was used again for the current project to provide boundary conditions for data interpretation.

These conditions suggested the potential for a significant reduction in the phosphorus concentration of discharging groundwater as it moves to shallower portions of the sediment column.

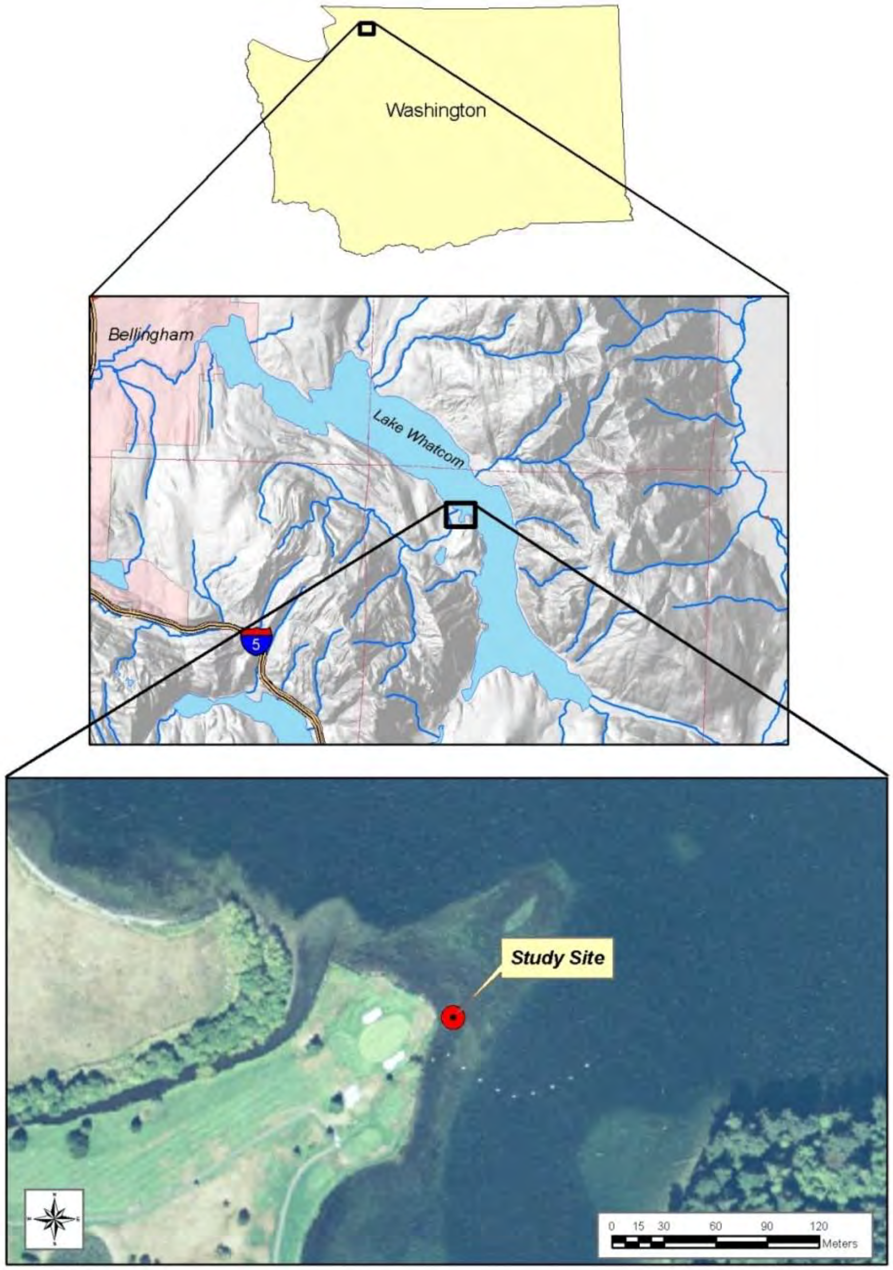

Figure 1. Lake Whatcom Study Location.

Study Methods

A variety of techniques have been used for collecting samples representative of shallow porewater solute gradients (Krupa et al., 1999; Bridge, 2005; Kalbus et al., 2006; ITRC, 2006; Hesslein, 1976; Doussan et al., 1998). Examples of these techniques include permeable membrane diffusion samplers (a.k.a. peepers), porewater extractors, in-situ chambers and probes, and at-surface seepage or benthic flux chambers. These methods were evaluated against the project goals, with a particular focus on finding a low-cost, field-efficient procedure.

The approach ultimately adopted for this study is an ultra-low-flow purge and sampling method using the M.H.E. Inc. PushPoint device coupled to an automated pump. This is a modification of techniques developed and described by Duff et al. (1998), Henry (2003), Zimmerman et al. (2005), Ford (2005), and Berg and McGlathery (2001). A controlled, ultra-low-flow [≤2.5 milliliter/minute (ml/min)] approach was used to minimize the disruption of natural concentration gradients that could lead to cross-contamination of closely-spaced sample intervals. A schematic of the sampling system is presented in Figure 2.

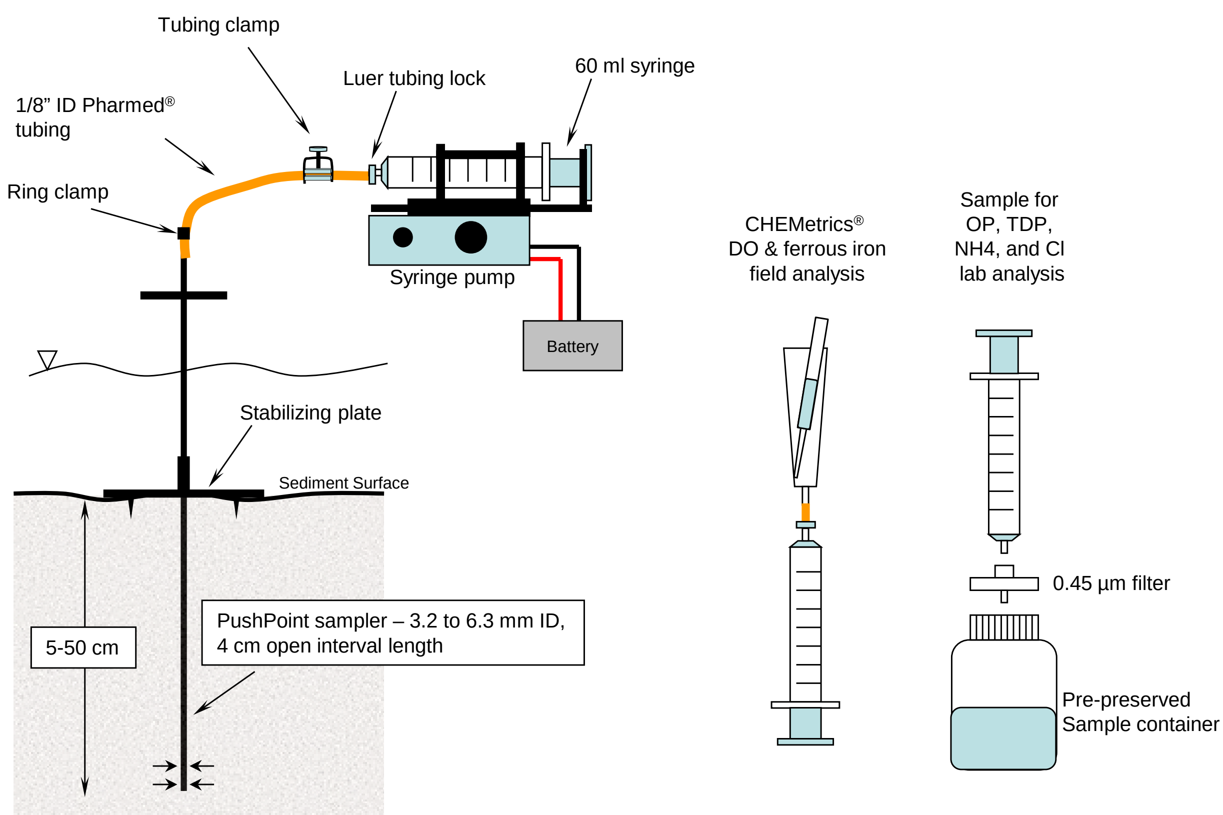

Figure 2. Schematic of the Study Porewater Sampling System.

A full description of the methods used during this project is presented in Pitz (2008). Vertical profiling of porewater quality conditions was focused on the uppermost 50 centimeters (cm) of site sediments (5, 10, 15, 25 and 50 cm intervals). A 3.175 millimeter (mm) interior-diameter, 61 cm long PushPoint was used for the 5 and 10 cm depth intervals; a 6.35 mm interior-diameter, 91 cm long PushPoint was used for the 15, 25, and 50 cm intervals. Both models of the PushPoint device have a 4 cm long slotted open interval; the mid-point of this open 'screen' was used as the position point for each depth interval. Samples were collected in October 2008; water depth at the time of sampling was approximately 3 feet.

PushPoint Installation and Measurement of Hydraulic Gradient

A surface plate was used to stabilize and seal the PushPoint device during insertion into the sediment column. After installation, the PushPoint interior guard rod was removed and a flexible tube was attached to the top of the PushPoint. The hydraulic head observed in the tube was compared to the surface water stage to establish the vertical hydraulic gradient for the various depth intervals, using Equation 2:

$$i_v = \frac{dh}{dl} \qquad (2)$$

where:

i_v = vertical hydraulic gradient (dimensionless).

dh = the difference in head between the lake stage and PushPoint water level (L).[2]

dl = the distance from the lakebed surface to the mid-point of the PushPoint open interval (L).

where (L) is length. By convention, negative hydraulic gradient values indicate potential loss of water from the lake to groundwater, while positive values indicate potential groundwater discharge into the lake.

Water Quality Sampling

Porewater samples were drawn from the PushPoint using a programmable syringe pump (New Era Pump Systems Inc., NE-500) modified for field use. Samples were collected after purging and discarding a minimum of 1.2 times the interior volume of the sampling system. Depth interval samples were collected a minimum of 10 cm apart laterally to avoid cross contamination. Additional samples of lake water from immediately above the GSI, and porewater from the original deep piezometer (140 cm - LWGW-09), were collected to provide boundary conditions for the transition zone.

[2] If the surface water stage is below the PushPoint water level, [*dh*] is recorded as a positive value. If the surface water stage is above the PushPoint water level, [*dh*] is recorded as a negative value. The [*dl*] term is always recorded as a positive value.

Due to time limitations, the surface water sample, the deep piezometer sample, and the 50-cm PushPoint sample were collected one day apart from the remaining depth intervals. The time difference between samples is assumed not to significantly alter the results or conclusions presented here.

All contact sampling equipment, including the PushPoint device, was cleaned between sample intervals by triple rinsing using a pressure sprayer and laboratory-grade, de-ionized water. All samples were filtered and preserved at the time of collection. Analysis of porewater samples included:

- Field analysis for: dissolved oxygen, ferrous iron, temperature, and specific conductance.
- Laboratory analysis for: orthophosphate as phosphorus (OP), total dissolved phosphorus (TDP), nitrogen, and chloride.

All samples for lab analysis were submitted to Ecology's Manchester Environmental Laboratory following standard sample preservation and handling procedures.

Project Quality Assurance

Cross-pumping

Cross-contamination is a significant concern when collecting close-interval samples of porewater, particularly near the sediment surface. Cross-contamination can directly result from two main processes:

- Pumping-induced vertical movement of porewater from a higher or lower sediment horizon into the sampler intake.
- Introduction of surface water into the sample during pumping by leakage down an annular space adjacent to the porewater collection device.

The key field controls for both of these problems are maintaining an ultra low-flow pumping rate, and limiting total withdrawal volumes. These steps help to minimize disturbance of in-situ hydraulic and chemical gradients and limit the spatial extent of the three-dimensional capture zone. Control of annular leakage, probably the problem of greatest concern, can be addressed by packing fine sediments around the entry point of the sampling device into the sediment surface, or using a sealed stabilizing plate to deter downward leakage (Figure 2). Vertical movement of porewater between sediment horizons is also limited by the strong horizontal to vertical permeability contrast typical of deposited sediments (Duff et al., 1998).

To examine the adequacy of these controls in preventing cross-contamination, an annular leakage test was performed at an adjacent location prior to sampling (Pitz, 2008). After installing the PushPoint device and stabilizing plate, hydraulic head and field water chemistry were measured and compared between the underlying porewater and overlying surface water. Measuring a distinct difference in these conditions at the end of an initial purge (intended to remove surface water introduced during the installation of the sampling tube) is considered a reliable indication of hydraulic isolation.[3]

The leakage test was performed at three depth intervals (5, 10, and 25 cm). After measurement and comparison of equilibrated hydraulic head conditions, the PushPoint device was purged using a peristaltic pump (Figure 3).[4] The sample stream was directed through a small-volume flow cell to allow instantaneous measurement of temperature, pH, specific conductance, and dissolved oxygen. Equilibrated, end-of-purge measurement results are presented in Table 1; the end-of-purge field parameter results for the original piezometer (LWGW-09) are also included for comparison.

[3] If there is substantial leakage of surface water down the annular space and into the PushPoint open interval, hydraulic and chemical conditions would quickly equilibrate to match (or nearly match) surface water measurements.

[4] Use of a peristaltic pump for the leakage tests probably provides a worst-case condition for leakage since the minimum pumping rate is greater than the rate for the syringe pump used for sampling. A peristaltic pump was employed for the leakage test to allow the use of a metered flow cell.

The test data indicate that annular leakage was not a significant problem for the sampling system at the test location. Maintenance of a positive hydraulic head difference and distinct specific conductance and dissolved oxygen values between porewater and surface water suggest the PushPoint open interval was hydraulically isolated from the surface even at the 5 cm depth. This conclusion is also supported by water quality data collected during the sampling described later in this report.

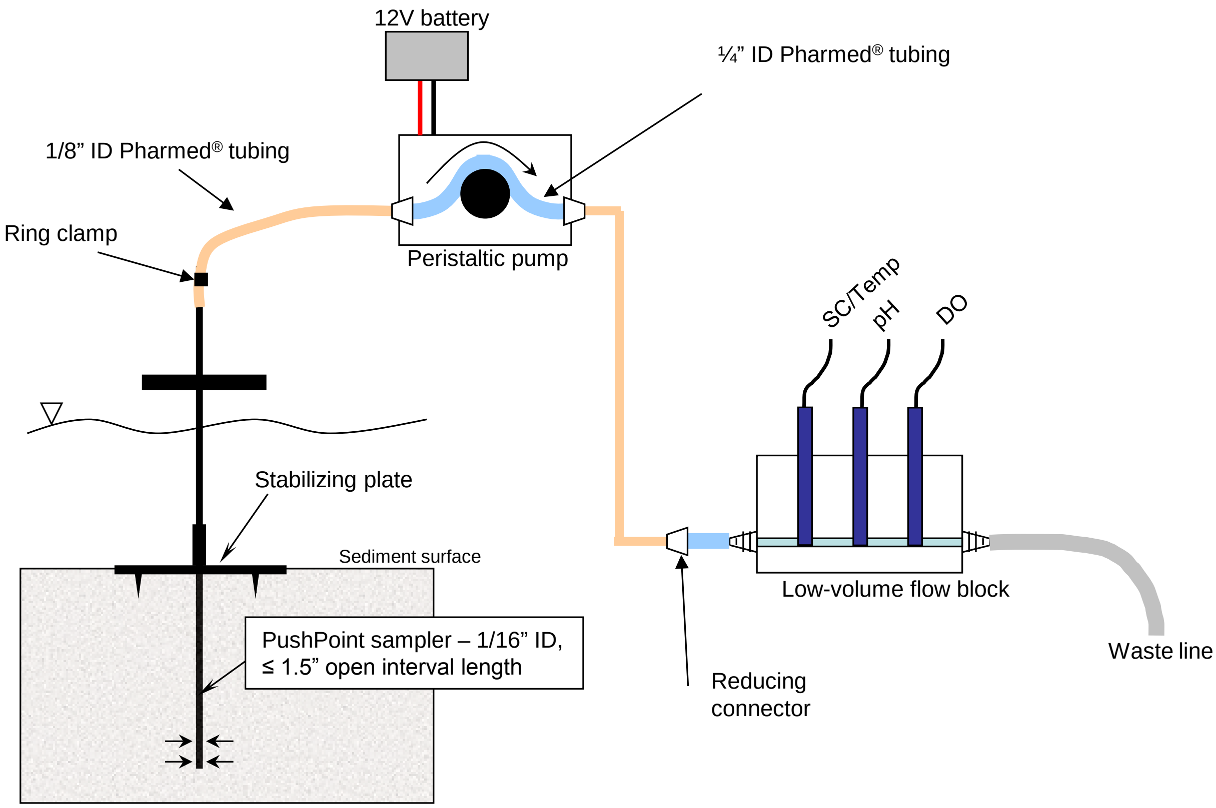

Figure 3. Schematic of Leakage Test System.

Table 1. Leakage Test Results.

Sediment depth (cm)	Vertical hydraulic gradient (i_v) (dimensionless)[(A)]	Temp. (°C)	pH (S.U.)	Specific conductance (µS/cm)	Dissolved oxygen (mg/L)[(B)]
Base of surface water column	NA	16.0	6.18	58	9.4
5	0.01	15.6	6.06	175	1.40
10	0.05	15.6	6.13	170	1.28
25	0.08	15.7	6.17	173	0.68
140 (LWGW-09)[(C)]	0.03	15.8	6.05	399	1.77

(A) Positive values indicate an upward vertical hydraulic gradient.
(B) Dissolved oxygen measured by electrode probe.
(C) Measured separately.

Equipment Bias and Decontamination

The use of ultra low-flow techniques and limited sample quantities requires minimizing the interior volume of the equipment used to collect close-interval porewater samples. This can make decontamination (decon) of equipment between sampling sets more difficult, potentially leading to an indirect source of cross contamination. Low pumping rates also limit the total sample volume that can be collected in a reasonable timeframe. The smaller the volume of sample collected, the greater the influence of equipment contamination on the final sample results.

To quantify bias introduced into the project results by both sampling materials (including the PushPoint device, tubing, syringes, filters, sample containers, and preservatives) and decon procedures, a total of six blank samples were collected and submitted to the laboratory for analysis. Detailed discussion and results from these tests are presented in the Quality Assurance Appendix.

All blank samples collected during the project were reported by the laboratory as non-detect. The results indicate that no measurable positive bias was introduced into the sample results by leaching from sampling materials. The results also indicate that the decon procedures adopted for the sampling method were successful in preventing indirect cross contamination between stations.

Field Split Replicates

To evaluate overall sampling and analytical precision, split-replicate sample sets were collected and submitted as blind samples for analysis. Split samples were collected from three of the sampling intervals (10, 25, and 50 cm). A detailed comparison of the replicate pair results is presented in the Quality Assurance Appendix. All replicate pairs were well within the target percent relative standard deviation for all parameters (Pitz, 2008), indicating excellent project data precision.

Laboratory Quality Assurance

All analytical results reported by Manchester Laboratory were subject to quality assurance testing and review by a laboratory chemist prior to delivery to the author. With the exception of the ammonia-N results, all sample concentrations were reported without qualification. Due to the use of excess preservative relative to the small sample volume collected, ammonia-N results were reported as estimates by the laboratory (potentially biased low by matrix interference effects). The qualification of the ammonia-N values does not significantly change the interpretation of the final data results.

Results

Table 2 presents a summary of the project field and laboratory measurements. The October 2002 results for the deep piezometer LWGW-09 are included in the table for comparison purposes. Figure 4 presents vertical concentration profiles for the tested water quality analytes.

The results show a consistently positive vertical hydraulic gradient (i_v) between 10 and 140 cm below the GSI, indicating the potential for upward transport of porewater solutes to the lake by advective flow. Reducing conditions are present from depth to within 5 cm of the GSI, as indicated by limited dissolved oxygen (≤1 mg/L), elevated dissolved ferrous iron, and nitrogen occurring as ammonia. Surface water immediately above the GSI, by contrast, exhibited well oxygenated conditions (>8 mg/L dissolved oxygen, <1 mg/L ferrous iron), and no detectable concentrations of OP, TDP, or ammonia-N. Results from the deep piezometer (LWGW-09) are consistent with those observed during the 2002-2003 period (Pitz, 2005).

At depth, both OP and TDP concentrations are highly elevated with respect to surface water, but both parameters decline by two orders of magnitude between the 140 cm and 5 cm depths (Figure 4). OP concentrations represent between approximately 8 to 17% of the TDP in porewater, indicating phosphorus occurs primarily in an organic form in this phase.[5] Chloride, a conservative tracer, exhibits a concentration decrease between the deep piezometer and the surface, with a slight increase in the concentration gradient above 50 cm. The concentration profile for ammonia-N is less uniform than the other parameters, showing both increases and decreases with position. There is a distinct ammonia-N concentration peak between 5 and 15 cm.

[5]The concentration of the organic phosphorus fraction observed at this site is significantly higher than observed in organic-rich sediments located in less-developed areas of the lake (Pitz, 2005). Possible origins for the unusually high dissolved organic phosphorus presence include breakdown of phosphorus-containing organic pesticides, animal manure sources, or deposits of organic plant matter incorporated into the sediment matrix (Turner et al., 2005). Austin Creek has likely played a role in delivering organic material to this area of the lake.

Table 2. Field and Laboratory Project Results.

Station ID	Depth (cm)	Sample Date	Vertical Hydraulic Gradient (i_v) (dimensionless)	Dissolved Oxygen (mg/L)[A]	Ferrous Iron (mg/L)[B]	Orthophosphate-P (mg/L)[C]	Total Phosphorus (mg/L)[C]	Ammonia-N (mg/L)[C]	Chloride (mg/L)[C]
SW-01	Surface water	10/13/08	NA	8.5	0.5	0.0030 U	0.010 U	0.020 UJ	2.50
HR-PP-05	5	10/14/08	NM	0.4	9	0.0031	0.038	1.14 J	3.01
HR-PP-10	10	10/14/08	0.05	0.25	>10	0.0057	0.056	1.28 J	3.26
HR-PP-15	15	10/14/08	0.02	0.5	>10	0.0409	0.236	1.29 J	4.04
HR-PP-25	25	10/14/08	0.08	1.0	>10	0.0360	0.227	0.362 J	4.48
HR-PP-50	50	10/13/08	0.1	0.8	>10	0.0910	0.736	0.829 J	6.07
LWGW-09	140	10/13/08	0.03	1.0	>10	0.192	2.13	0.411 J	7.02
LWGW-09	140	10/15/02	0.007	2.54[D]	35.7	0.298 J	2.18	0.272	3.27

NA – Not applicable
NM – Not measurable
U – Analyte not detected at or above the reporting limit.
J – Result considered an estimate.
[A]Dissolved oxygen measurement by CHEMetrics® low-concentration colorimetric analysis.
[B]Ferrous iron measurement by CHEMetrics® colorimetric analysis.
[C]All samples field-filtered @ 0.45 µm.
[D]Dissolved oxygen measured by membrane dissolved oxygen probe.

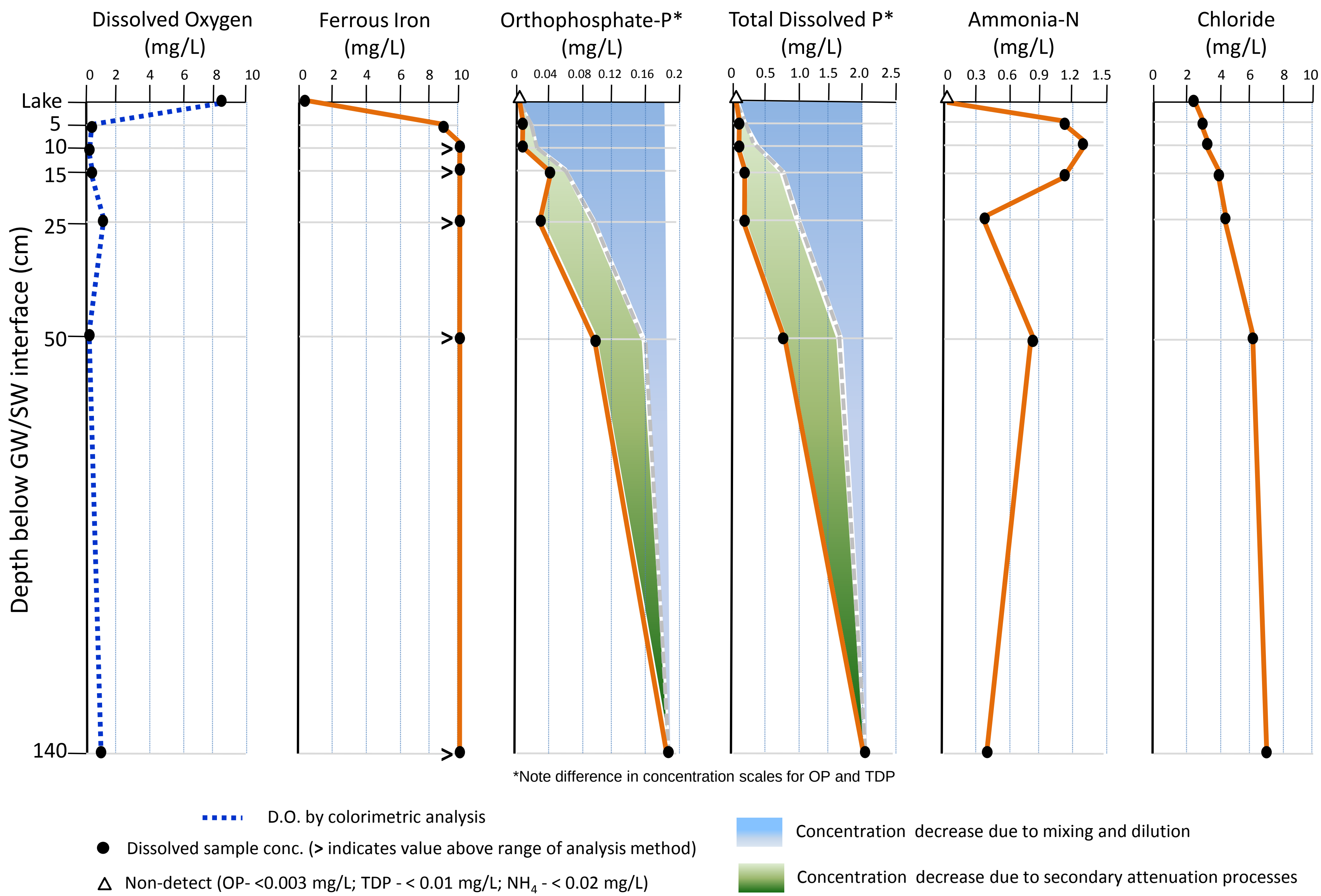

Figure 4. Porewater Concentration Profiles.

Discussion

Method Testing

The results demonstrate that the proposed sampling method was successful in meeting all of the criteria outlined in the Project Objectives section. Results indicate that the method is capable of retrieving an adequate volume of porewater sample, free of cross-contamination, to within 5 cm of the GSI.

Quality Control

Field quality control testing indicated no significant bias due to cross-pumping of surface water into the sample stream. Additional measures such as replicate testing and blank sample analysis further establish that the samples collected were within acceptable quality control limits for precision, material bias, and decon 'carryover'. The ultra-low flow rates were an effective control on sample turbidity, and 1 or 2 small volume (25-mm) syringe filters were adequate for filtering samples prior to analysis.

Field Application

The sampling system is judged to be portable, low cost, and simple to use. Total equipment and fabrication cost for the system depicted in Figure 2 was approximately $650. The time required for sample collection from each sampling interval is dictated by the low pumping rate and the number of analytes of interest (which dictate the total volume of sample required for analysis). Purge and sample collection for each depth interval took 30 to 45 minutes. To speed the overall process, a multi-channel syringe pump and sampler frame could be substituted for the equipment described in this report to allow simultaneous collection from multiple depth intervals (similar to Duff et al., 1998).

The simplicity of the method compares favorably with the cost, level of effort, and equipment and handling requirements of approaches used by other authors (e.g., Krupa et al., 1999; Hesslein, 1976; ITRC, 2006). The approach is also considered to be better suited for characterizing shallow solute gradients in settings where solute transport is dominated by advection (vs. diffusion) (Duff et al., 1998).

The small diameter and wall thickness of the PushPoint device would probably make the device too fragile for installations in very coarse-grained or well-consolidated sediments.[6] Capillary action and air trapping can make accurate observations of hydraulic head difficult with the smaller diameter (~3-mm) PushPoint device; the larger diameter (~6-mm) PushPoint could be installed separately for this purpose. Due to the need to handle the equipment and attach tubing, use of the PushPoint is best suited for shallow-water settings. Deeper water installations would require snorkeling or diving equipment (true for nearly all other techniques).

[6] Due to higher fluid velocities and smaller relative contact surface area, coarse-grained settings are also less likely to exhibit strong porewater concentration gradients and attenuation affects.

Although the sample volume collected for each laboratory parameter (15-20 ml) is significantly smaller than normally requested, Manchester Laboratory was successful in analyzing all samples, while still providing low-limit detection levels. For future projects, the amount of preservative used in the sample containers should be decreased to avoid the matrix interference problems encountered during the study. Momohara (2008) recommends using 15%-20% of the normal preservative volume when submitting low-volume samples to Manchester Laboratory.

The sampling procedure described in this report is intended to complement, rather than replace, the field monitoring conducted using deeper (3-8 feet), larger-diameter piezometers. While the PushPoint device is well suited to highly detailed measurements of porewater quality conditions near the GSI, larger-diameter piezometers probably provide more accurate measurements of hydraulic gradient conditions, at least at depth. Larger diameter piezometers also allow the use of additional instrumentation and testing not possible with the small diameter equipment described here (e.g., thermistors, hydraulic testing).

The sampling system described here can be used for rapid reconnaissance measurements of porewater quality conditions near the interface at multiple locations. This approach may be best for cases where researchers are most interested in mapping groundwater discharge conditions over large areal scales. Alternatively, the method can be used to provide highly detailed descriptions of vertical concentration gradients at a limited number of locations to help determine specific mechanisms of solute attenuation. Depending on sediment character, it may be possible to collect porewater samples from even shallower intervals than attempted for this study, if the total length of the PushPoint open interval were reduced.

While this study focused on characterizing high-resolution porewater nutrient conditions, the techniques are easily adapted to the study of other water quality constituents such as metals, chlorinated solvents, and petroleum products that may undergo changes at the end of the groundwater flow path (e.g., Zimmerman et al., 2005; Ford, 2005, Dean et al., 1999).

Profiling Data Results

Profiling results indicate the presence of a strong vertical concentration gradient in porewater phosphorus in the upper portions of the test area sediment column. While natural heterogeneity may explain some of the data variation, the observed gradient is interpreted primarily as the result of dilution by mixing, and immobilization or uptake of phosphorus below the GSI.

Dilution and Mixing Influences on Porewater Concentrations

In the vicinity of the GSI, porewater concentration reductions may be attributable, in part, to dilution by mixing of overlying lower-concentration surface water with underlying higher-concentration porewater. Mixing itself may be the result of a combination of factors, including diffusion exchange with the water column, advective movement of surface water into sediments during hydraulic gradient reversals, and burial of surface water during reworking and deposition of sediments. The concentration of upwelling porewater may also be diluted as a result of an increase in the bulk water content of sediments at increasingly shallower depths.

To determine the extent of these influences on the observed phosphorus concentrations, the results from Table 2 were evaluated using a one-dimensional mixing equation for a chemically conservative tracer (Walecka-Hutchison and Walworth, 2005; Schuster et al., 2003).[7] This model can be used to determine the proportion of one water type in a mixture of two distinct end-point water types by:

$$C_c = C_a X + C_b(1 - X) \qquad (3)$$

where:

C_a = initial tracer concentration of water type A (*mg/L-chloride in lake water, SW-01*).
C_b = initial tracer concentration of water type B (*mg/L-chloride in groundwater, piezometer LWGW-09, assumes no dilution by surface water at this depth*).
C_c = the concentration of the tracer in a mid-point mixture of water types A and B (*mg/L-chloride in porewater between 5-50 cm*).
X = the volume fraction of water $[V_a/(V_a + V_b)]$, where V_a is the volume of water type A, and V_b is the volume of water type B.

Rearranging to solve for *X*, Equation 3 becomes:

$$\frac{C_c - C_b}{C_a - C_b} = X \qquad (4)$$

The calculated value for *X* from Equation 4 can be used to develop a dilution factor (*DF*) by:

$$\frac{1}{(1-X)} = DF \qquad (5)$$

For a reactive (non-conservative) parameter of interest such as phosphorus, the DF value can in turn be used to quantify what proportion of an observed concentration decline from an initial condition is attributable to dilution. If the field-measured mid-point concentration of the parameter is lower than expected by dilution alone, the remaining concentration decrease is assumed to be the result of one or more secondary attenuation processes.

Tables 3 and 4 present the results of the mixing analysis for OP and TDP for each mid-point depth interval. The results of the analysis suggest that a significant portion of the observed decline in TDP and OP concentration at each interval is due to mixing and dilution by surface water, particularly at depths $\leq$ 25 cm (the blue shaded areas on Figure 4). Phosphorus concentrations at all mid-point intervals, however, were lower than expected due to dilution alone. This suggests that additional phosphorus uptake or immobilization processes may be active throughout the tested portion of the sediment column. The mixing analysis indicates a range between 10 to 67% of the phosphorus concentration decline is attributable to these attenuation processes at any given depth interval, with an average of ~30%.

[7] A conservative tracer (in this case, chloride) is one that does not react or degrade as it moves through a sediment matrix. A reduction in tracer concentration is assumed to be due solely to dilution by mixing with water with a lower tracer concentration.

Nutrient Cycling and Secondary Concentration Controls

Phosphorus and nitrogen cycling in shallow aquatic sediments can involve a complex suite of both biotic and abiotic controls which influence the transport and ultimate release of nutrients to the surface water column. As upwelling groundwater enters this transition area by advective flow, dissolved-phase nutrients can be subjected to a variety of inter-related processes. These processes include microbially-mediated sorption and precipitation reactions, mineralization of organic forms to inorganic forms, uptake by macrophytes and periphytic biofilm, and molecular diffusion to the water column (Wetzel, 1983; Turner et al., 2005; Berg and McGlathery, 2001; Duff, 2008; Hendricks and White, 2000; Holman et al., 2008; Bostrom et al., 1988; Spiteri et al., 2005; Carlyle and Hill, 2001; MacDonald et al., 2009, Walter et al., 1996).

The study was not designed to identify the specific reasons for the extra phosphorus concentration reduction (the green shaded area on Figure 4). However, the presence of reducing conditions to within 5 cm of the GSI (dissolved oxygen ≤ 1 mg/L; >8 mg/L dissolved iron; elevated ammonia-N) suggests that sorption of dissolved phosphorus onto precipitated ferric iron surfaces is not a primary explanation of the observed decline.[8] MacDonald et al. (2009) have noted that phosphorus sorption can still occur in predominantly reducing environments at oxic micro-sites adjacent to the roots of aquatic plants.[9] MacDonald and his coauthors have also recently reported evidence of removal of phosphorus from the dissolved phase under reducing conditions by co-precipitation with ferrous iron solids.

Collectively, these immobilization processes can cause phosphorus to accumulate as a solid phase in the uppermost portion of the sediment profile, reducing the dissolved phase concentration exiting to the water column (Wetzel, 1983; Di Toro, 2001; Carlyle and Hill, 2001). A significant change in the redox condition of the sediments can result in a later release of phosphorus from this 'reservoir'.

The ammonia-N concentration profile exhibits a dilution-related decrease similar to the phosphorus profiles between the 50 and 25 cm intervals, but then increases significantly between 15 and 5 cm. This peak is consistent with observations of nitrogen profiles in aquatic sediments observed by other authors (Duff et al., 2002; Sheibley et al., 2003; Berg and McGlathery, 2001; Hendricks et al., 2008). This suggests that mineralization of organic matter is maximized at this interval, coincident with the macrophyte rooting zone. Sheibley et al. (2003) and Duff (2008) report that once the ammonia encounters an aerobic boundary (presumably at some point above the 5 cm interval) it may be quickly converted to nitrate via nitrification, then further attenuated via denitrification, or transported to the water column.

[8] Rapid precipitation and coupling of dissolved phosphorus with ferric iron could still occur at a redox front located between 0 and 5 cm.
[9] Maximum rooting depth for Elodea canadensis is typically ~15 cm (Parsons, 2008).

Table 3. Mixing Analysis Results for Orthophosphate (OP).

Measurement Point	Chloride tracer concentration C_c (mg/L)	Percent surface water (%)	Dilution factor (DF)	Measured OP concentration (mg/L)	Concentration decline from initial condition (mg/L)	Concentration decline due to dilution (mg/L)	Concentration decline due to attenuation (mg/L)	Percent concentration decline due to dilution (%)	Percent concentration decline due to attenuation (%)
Surface water	2.5	100.0	-	ND	-	-	-	-	-
5 cm	3.01	88.7	8.86	0.0031	0.189	0.170	0.019	90.2	9.8
10 cm	3.26	83.2	5.95	0.0057	0.186	0.160	0.027	85.7	14.3
15 cm	4.04	65.9	2.94	0.0409	0.151	0.127	0.025	83.8	16.2
25 cm	4.48	56.2	2.28	0.036	0.156	0.108	0.048	69.2	30.8
50 cm	6.07	21.0	1.27	0.091	0.101	0.040	0.061	40.0	60.0
140 cm (Groundwater)	7.02	0.0	1.00	0.192	-	-	-	-	-
							Average	73.8	26.2

ND – not detected

Table 4. Mixing Analysis Results for Total Dissolved Phosphorus (TDP).

Measurement Point	Chloride tracer concentration C_c (mg/L)	Percent surface water (%)	Dilution factor (DF)	Measured TDP concentration (mg/L)	Concentration decline from initial condition (mg/L)	Concentration decline due to dilution (mg/L)	Concentration decline due to attenuation (mg/L)	Percent concentration decline due to dilution (%)	Percent concentration decline due to attenuation (%)
Surface water	2.5	100.0	-	ND	-	-	-	-	-
5 cm	3.01	88.7	8.86	0.038	2.092	1.890	0.202	90.3	9.7
10 cm	3.26	83.2	5.95	0.056	2.074	1.772	0.302	85.4	14.6
15 cm	4.04	65.9	2.94	0.236	1.894	1.404	0.490	74.1	25.9
25 cm	4.48	56.2	2.28	0.227	1.903	1.197	0.706	62.9	37.1
50 cm	6.07	21.0	1.27	0.736	1.394	0.448	0.946	32.1	67.9
140 cm (Groundwater)	7.02	0.0	1.00	2.13	-	-	-	-	-
							Average	69.0	31.0

ND – not detected

The coincidence of the rapid drop in the OP/TDP ratio between 15 and 5 cm (Figure 5) suggests the possibility of plant uptake of available inorganic phosphorus in this zone as well. The ratio of dissolved OP to TDP reaches a maximum at 15 cm, and rapidly decreases at 10 cm and 5 cm depths (Figure 5).

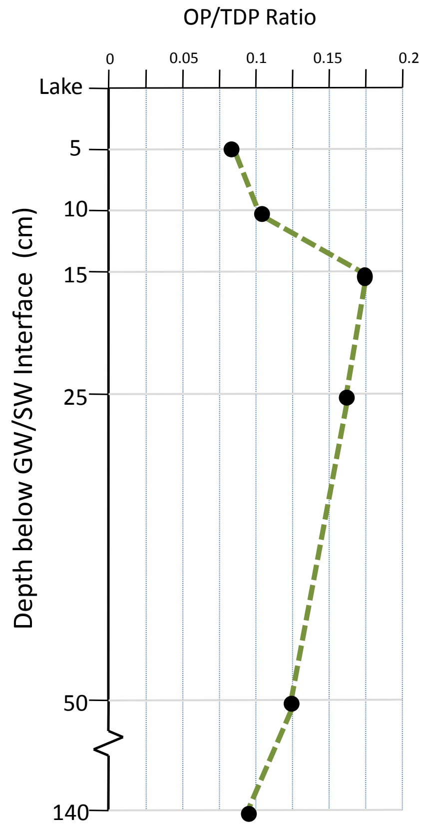

Figure 5. Vertical Profile of the Ratio of Dissolved Orthophosphate-P (OP) to Total Dissolved Phosphorus (TDP).

Implications for Loading Evaluations

The data indicate that the *concentration* of phosphorus delivered to the GSI by advective groundwater transport at this site is lower than originally estimated from the deep piezometer data alone. This concentration reduction appears to be due to a combination of the removal of phosphorus from the dissolved phase by various attenuation processes active prior to discharge, and simple dilution by mixing.

Since dilution and mixing processes are not *mass* destructive or immobilizing, this portion of the porewater phosphorus is assumed to still be available for transport to the overlying water column. This suggests that the phosphorus concentration assumed for mass loading calculations (Equation 1) should be adjusted downward only by an amount equivalent to the phosphorus removed from the porewater by attenuation processes. For this particular site, the data indicates the phosphorus concentrations used in Equation 1 may need to be reduced by between 10 to 67% of the original piezometer (LWGW-09) concentration values.

The detailed profiling of only one location at Lake Whatcom limits the ability to draw broader conclusions about phosphorus attenuation processes active near the GSI at other locations around the lake. However, most of the other piezometers sampled during the 2002-2003 study (Pitz, 2005) exhibited conditions that are probably less favorable to significant near-surface phosphorus concentration reduction (e.g., oxidized porewater at depth, coarser-grained sediment matrix, higher permeabilities, few established surface macrophytes, low organic content). If further refinement of the groundwater phosphorus load to the lake is critical to the TMDL modeling work, profile sampling at additional sites may be of benefit.

Conclusions

The dynamic biogeochemical processes often active in the near vicinity of the groundwater/ surface water interface (GSI) can generate strong vertical solute concentration gradients and alter the chemistry of discharging groundwater. Traditional piezometer designs used by Ecology's Environmental Assessment Program (EAP) to characterize water exchange across the interface are not well suited to accurately describe these changes. The high-resolution profiling method described in this report should be a useful additional tool for this purpose.

The methods described here are intended to complement, rather than replace, other in-water monitoring methods developed and used by EAP staff. The sampling system is low cost and simple to use, and is capable of providing unbiased, depth-discrete porewater samples at a 5-cm resolution. The method can be used to provide rapid reconnaissance data at multiple locations, or highly detailed descriptions of contaminant attenuation in focused areas. The method should be considered for use wherever steep concentration gradients near the GSI are suspected.

The tools and methods described here should help to reduce uncertainty and improve the overall accuracy of the TMDL loading assessments and numerical modeling efforts conducted by EAP. These procedures also have potential for application in a variety of other investigations of groundwater discharge to surface water (e.g., mapping toxic or nutrient groundwater plume entry/attenuation to Puget Sound; e.g., Pitz, 1999; Simonds et al., 2008).

The results collected during the October 2008 method testing indicate that the concentration of phosphorus delivered to the water column by advective groundwater flow in the Sudden Valley area of Lake Whatcom is likely lower than suggested by the 2002-2003 monitoring data.

Recommendations

Based on the results of this study, the following recommendations are suggested:

- Adopt the techniques described in this report for use in Ecology's Environmental Assessment Program studies where groundwater-related solute loading is of concern and site conditions are favorable. The method should be used as a *complement* to other monitoring approaches. Site conditions most favorable to generating strong concentration gradients near the groundwater/surface water interface (GSI) include: reducing conditions at depth, highly elevated porewater concentrations in comparison to surface water conditions, presence of macrophytes or near-surface biological activity, high organic content, fine overall sediment-column grain size, and low to moderate permeability.

- Reduce the standard volume of preservative added to sample containers for the small volume samples generated by the methods described in this report to avoid interferences with laboratory analysis.

- Adopt the use of a long-shaft temperature probe to improve and speed characterization of vertical hydraulic gradients and groundwater flux at sites where the PushPoint device is used (Conant, 2004; Duff, 2002; Kuwabara et al., 2009).

- Use a multi-channel syringe pump to speed sample collection at multi-interval study sites.

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Appendices

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Appendix A. Quality Assurance

Equipment Blanks

To determine the bias due to sample-contact materials and field handling, three replicate field equipment blanks were collected at the beginning of the project. Equipment blanks were collected by pumping reagent-grade de-ionized (DI) water through the sampling system. New parts were used in all contact portions of the system (e.g., tubing, fittings, filters, and sample containers). Equipment blanks were submitted to the laboratory as blind samples, and were analyzed for all target parameters. Table A-1 presents the results for these samples. No detections were reported by the laboratory for any of the parameters evaluated, indicating the sampling system did not introduce a bias into the results.

Table A-1. Equipment Blank Results.

Sample ID	Date	Orthophosphate-P	Ammonia-N	Total Dissolved Phosphorus	Chloride
HR-PP-75	10/13/08	0.003 U	0.02 UJ	0.01 U	0.1 U
HR-PP-80	10/13/08	0.003 U	0.02 UJ	0.01 U	0.1 U
HR-PP-85	10/13/08	0.003 U	0.02 UJ	0.01 U	0.1 U

U – the analyte was not detected at or above the reported result.
UJ – the analyte was not detected at or above the reported estimated result.

Decontamination Blanks

To determine the effectiveness of field equipment decontamination (decon) procedures in preventing cross-contamination between sample sets, three decon blanks were collected and submitted to the laboratory for analysis (as blind samples). Each decon blank was collected between real sampling intervals by pumping reagent-grade DI water through the sampling system after the equipment had been field cleaned.

Sample contact equipment was decontaminated between sample intervals by triple rinsing using a pressure sprayer and DI water. Decon blanks were analyzed for all target parameters. Table A-2 presents the results for these samples. No detections were reported by the laboratory for any of the parameters evaluated, indicating the decon procedures were effective in preventing cross contamination between sample sets.

Table A-2. Decon Blank Results.

Sample ID	Date	Orthophosphate-P	Ammonia-N	Total Dissolved Phosphorus	Chloride
HR-PP-90	10/14/08	0.003 U	0.02 UJ	0.01 U	0.1 U
HR-PP-95	10/14/08	0.003 U	0.02 UJ	0.01 U	0.1 U
HR-PP-100	10/14/08	0.003 U	0.02 UJ	0.01 U	0.1 U

U – the analyte was not detected at or above the reported result.
UJ – the analyte was not detected at or above the reported estimated result.

Field Replicates

To assist in evaluating the random variability introduced into the sample results by a combination of field and laboratory influences, three field split replicates (from the 10 cm, 25 cm, and 50 cm depth intervals) were collected and submitted to the laboratory as blind samples. Split replicates were collected by splitting the sample stream between like containers. Replicate samples were analyzed for all target laboratory parameters. Tables A-3 through A-6 present the results for these samples. The data indicates precision between replicate pairs was well within the target relative standard deviations (RSDs) (as % of mean) for all parameters (Pitz, 2008).

Table A-3. Field Replicate Results for Orthophosphate-P.

Station	Concentration	Units	Qual.	RSD as % of mean
HR-PP-10	0.0057	mg/L		
HR-PP-12.5 (Rep.)	0.0053	mg/L		5.1
HR-PP-25	0.036	mg/L		
HR-PP-30 (Rep.)	0.0375	mg/L		2.9
HR-PP-50	0.091	mg/L		
HR-PP-60 (Rep.)	0.103	mg/L		8.7
			Mean RSD	5.6

Table A-4. Field Replicate Results for Ammonia-N.

Station	Concentration	Units	Qual.	RSD as % of mean
HR-PP-10	1.28	mg/L	J	
HR-PP-12.5 (Rep.)	1.39	mg/L	J	5.8
HR-PP-25	0.362	mg/L	J	
HR-PP-30 (Rep.)	0.346	mg/L	J	3.2
HR-PP-50	0.829	mg/L	J	
HR-PP-60 (Rep.)	0.788	mg/L	J	3.6
			Mean RSD	4.2

J – The analyte was positively identified; the associated concentration result is an estimate.

Table A-5. Field Replicate Results for Total Dissolved Phosphorus.

Station	Concentration	Units	Qual.	RSD as % of mean
HR-PP-10	0.056	mg/L		
HR-PP-12.5 (Rep.)	0.053	mg/L		3.9
HR-PP-25	0.227	mg/L		
HR-PP-30 (Rep.)	0.231	mg/L		1.2
HR-PP-50	0.736	mg/L		
HR-PP-60 (Rep.)	0.736	mg/L		0.0
			Mean RSD	1.7

Table A-6. Field Replicate Results for Chloride.

Station	Concentration	Units	Qual.	RSD as % of mean
HR-PP-10	3.26	mg/L		
HR-PP-12.5 (Rep.)	3.3	mg/L		0.9
HR-PP-25	4.48	mg/L		
HR-PP-30 (Rep.)	4.47	mg/L		0.2
HR-PP-50	6.07	mg/L		
HR-PP-60 (Rep.)	6.02	mg/L		0.6
			Mean RSD	0.5

Appendix B. Glossary, Acronyms, and Abbreviations

Advective flow (advection): The transport of a solute by the bulk motion of flowing groundwater.

Annular space: Open space between the outer casing of a well or piezometer and the adjacent sediments.

Anoxic: Depleted of oxygen.

Biotic: Produced or caused by living organisms.

Diffusion: The net transport of molecules from a region of higher concentration to one of lower concentration by random molecular motion.

Dissolved oxygen: A measure of the amount of oxygen dissolved in water.

Downgradient: The direction of flow, as defined by the hydraulic gradient.

Groundwater: Water in the subsurface that saturates the rocks and sediment in which it occurs. The upper surface of groundwater saturation is commonly termed the water table.

Groundwater discharge: The movement of groundwater from the subsurface to the surface by advective flow.

Hydraulic gradient: The difference in hydraulic head between two measuring points, divided by the distance between the two points.

Hydraulic head: The pressure exerted by a water mass at any given point. Total head is the sum of elevation head, pressure head, and velocity head.

pH: A measure of the acidity or alkalinity of water. A low pH value (0 to 7) indicates that an acidic condition is present, while a high pH (7 to 14) indicates a basic or alkaline condition. A pH of 7 is considered to be neutral. Since the pH scale is logarithmic, a water sample with a pH of 8 is ten times more basic than one with a pH of 7.

Piezometer: A small-diameter, non-pumping well used to collect groundwater quality samples and hydraulic head measurements.

Porewater: The water filling the spaces between grains of sediment.

Redox: Any chemical reaction which involves oxidation and reduction.

Specific conductance: A measure of water's ability to conduct an electrical current. Specific conductance is related to the concentration and charge of dissolved ions in water; reported here in units of µS/cm @ 25°C.

Total Maximum Daily Load (TMDL): A water cleanup plan. A distribution of a substance in a waterbody designed to protect it from exceeding water quality standards. A TMDL is equal to the sum of all of the following: (1) individual wasteload allocations for point sources, (2) the load allocations for nonpoint sources, (3) the contribution of natural sources, and (4) a margin of safety to allow for uncertainty in the wasteload determination. A reserve for future growth is also generally provided.

Acronyms and Abbreviations

Ammonia-N	ammonia as nitrogen
Decon	decontamination
EAP	Environmental Assessment Program
Ecology	Washington State Department of Ecology
EPA	U.S. Environmental Protection Agency
GSI	groundwater/surface water interface
GW	groundwater
N	nitrogen
Nitrate-N	nitrite + nitrate as nitrogen
OP	orthophosphate as phosphorus
P	phosphorus
RSD	relative standard deviation
SC	specific conductance
S.U.	standard unit
SW	surface water
TDP	total dissolved phosphorus

Agency: Exhibit C

State of Illinois
Pat Quinn, Governor

Illinois Environmental Protection Agency
Douglas P. Scott, Director

COAL COMBUSTION RESIDUE MANAGEMENT IN ILLINOIS

Long before the TVA ash pond failure in 2008 in Tennessee, the Illinois EPA recognized that coal combustion residue, often referred to as coal ash, might be an environmental concern. The Illinois EPA has taken a proactive approach in regulating coal ash. Since the early 1990s, new ash ponds (surface impoundments) have been required to be lined and groundwater monitoring wells have been installed at many of these new ash impoundments.

The Illinois EPA agrees with the U.S. EPA current proposal to regulate coal combustion residue in landfills and surface impoundments. Their "Subtitle D option" proposal is very similar to what we are already doing in Illinois. At this point, it is unclear if U.S. EPA groundwater standards are as stringent as Illinois non-degradation requirements.

There are 24 power plants in Illinois with a total of 83 impoundments and one permitted landfill where the coal ash is being disposed. There are also older ash ponds at many of these facilities. Starting two years ago Illinois EPA initiated an aggressive strategy to assess the geologic vulnerability of groundwater at the 24 power plants considering the presence of potable wells identified near the plants to determine the potential contamination threat to those wells. For many years, Illinois EPA has required the installation of groundwater monitoring well systems and hydrogeologic assessments at these facilities. Further, where groundwater contamination has been found we have required that cleanup/remediation be implemented. For detailed information on Illinois EPA's Ash Impoundment Strategy, dated August 4, 2010, go to:
http://www.epa.state.il.us/water/groundwater/publications/ash-impoundment-progress.pdf

What is coal ash?
Basically, anything that remains after coal is burned such as fly ash, bottom ash, slag, etc.

Is all coal the same?
No. Coal is a rock formed from the remains of ancient plant life. It is not a uniform substance and can contain a wide variety of minerals depending on the nature of its vegetation source and how it was affected over time by temperature and pressure. For example, much of the coal mined in Illinois has high sulfur content, while "western coal" has a lower heat value (Btu).

Is all coal ash the same?
No. Coal ash can vary depending on the source of the coal, the processing of the coal, the burning of the coal and the method of the collection of the ash. The coal ash collected as bottom ash (clinker, boiler slag, etc.) is different from the coal ash collected as fly ash from the smoke stack and the air pollution controls. Groundwater contaminants found in the monitoring wells installed adjacent to surface impoundments in Illinois show non-hazardous contaminants such as boron, total dissolved solids, and sulfates. Cadmium, a hazardous contaminant, has been detected in only one surface impoundment.

How is coal ash managed in Illinois?
Power plants can determine how to manage their coal ash, but it all must meet the applicable Illinois regulations. The options include: on-site disposal cell (dry); off-site disposal cell (dry); disposal in surface coal mines (dry); disposal in underground coal mines (wet or dry); disposal in special waste landfills (dry); and beneficial reuse.

Is there any beneficial reuse of coal ash?
Fly and bottom ash have been used in the manufacture of cement, concrete blocks, wallboard, snow and ice control, aggregate in cement, soil stabilization and as a sub-layer in road construction. Coal residue that can be used is identified as a coal combustion byproduct or a coal combustion product and must meet specific standards. It is estimated that up to 40 percent of coal combustion residue goes to beneficial reuse nationally.

How is coal ash regulated by Illinois EPA?
Each Illinois EPA Bureau has a set of regulations covering coal ash:

> **Bureau of Air:** Some coal ash is captured through air emissions equipment. As technology improves, air pollution laws continue to become stricter in limiting what can be released into the air.
>
> **Bureau of Water:** State construction and operating permits issued in conjunction with National Pollution Discharge Elimination System permits require surface impoundments to be in compliance with the Illinois groundwater and surface water quality standards including non-degradation requirements. Permit conditions require low permeable liners and groundwater monitoring. Older impoundments over important aquifers were required to install a groundwater monitoring system and to submit compliance reports to the Illinois EPA.
>
> **Bureau of Land:** Coal combustion residue can be disposed in special waste landfills with a proper permit. Again, permit conditions require low permeable liners and groundwater monitoring. Older impoundments over important aquifers were required to install a groundwater monitoring system and to submit compliance reports to the Illinois EPA.

Does any other State Agency Regulate Coal Ash?
The Illinois Department of Natural Resources Office of Mines and Minerals would have a role in coal combustion residue if a permitted mine or permit applicant plans onsite disposal or if there are plans to use ash as part of a reclamation project.

Does the Illinois EPA support the USEPA initiative for stricter controls on coal ash?
The Agency welcomes all initiatives that will support our mission to better protect the citizens and environment in Illinois. The USEPA proposal for coal combustion residues in surface impoundments at coal fired electric generating plants is very similar to Illinois EPA's existing approach.

Illinois Pollution Control Board
R2014-10

Agency: Exhibit D

Dredge Applications

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Beach Restoration
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Fly Ash Dredging
Lake Dredging
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Coal Power Plant Uses Ellicott Series 370 Dredge to Produce Four Beneficial Use Materials

Operator Calls Dredge "The Most Cost-Effective Piece of Equipment Ever Used"

In an unusual feat for a hydraulic dredge, a Series 370 Ellicott "DRAGON™" cutterhead dredge excavated four different materials from two power plant settling ponds: fly ash, bottom ash, lime, and lime mixed with fly ash. The dredge moved over 100,000 cubic yards in just three months.

The City of Springfield, Illinois owns and operates the City Water Light & Power (CWLP) Dahlmann Generating Station. Burning coal generates three waste products: fly ash, bottom ash, and lime from the water purification plant. In the past, these waste materials were stored permanently in ponds in a dry or wet state. Recently, beneficial uses have been found for these products. Bottom ash is used to manufacture blasting media and roof shingles; fly ash is used as a fill material for highway construction; lime is used on Illinois farm fields to neutralize acid soils and improve crop yields.

There is one great problem however: all of these products are flushed to the settling ponds with water, and hence they tend to settle out over large areas in the pond, making them very hard to recover. Previously the City excavated these materials using back-hoes located along the edges of the ponds, but this equipment has only limited reach so the bulk of the material — up to 90% — remained in the ponds under water.

The CWLP, after investigation into numerous excavation technologies, opted to mine the material using an Ellicott Series 370 "DRAGON™" cutterhead dredge. They decided to dredge first their largest settling pond (approximately 3000 feet long x 1000 feet wide) which contained both bottom ash and fly ash. The City leased the dredge from Ellicott, and operated it with its own personnel who had been trained "on-site" by Ellicott field service engineers at no additional cost to the City.

With the dredge the CWLP could mine material under water up to 2000 feet away from the staging area where the material was removed from the pond for stacking and drying. Because the 12-inch pipeline was discharging up to 50% solids in the slurry to this area at up to 4000 gpm, and the City did not know if the material would settle out in the staging area or flow back to the main pond, a decision to start there first was difficult. However, after two weeks of dredging, the City determined that the bottom ash and fly ash were settling out very well in the staging area and could be easily excavated by the back-hoes, which could now work in just one area. This was a major breakthrough in the recycling program since 100% of the material in the ponds could be excavated with the dredge and dried for beneficial use.

Dredge Efficiency Saves Over $200,000
Because a portion of the fly ash had migrated to the large pond spillway structure, the dredge was also used to clean out this area to permit better settling of solids in the pond and hence a cleaner effluent. Mr. Mark Shea, project manager of the dredging operation for the City, had nothing but praise for the Ellicott Series 370 dredge. "Not only are we dredging material for recycling, but we are getting a cleaner effluent stream at costs far below that of conventional excavation using back-hoes and dozers. During this short dredging period, the City has saved over $285,000 vs. conventional techniques, a 50% savings."

The City spent just $1.80 per cubic yard of material removed compared to the lowest outside contractor quote of $3.85 per yard.

The second and smaller pond, which receives effluent water from the larger fly ash/bottom ash pond, also contains lime slurried-in from their SO2 water purification process. The City did not know how well the Series 370 dredge would perform in the very viscous, thick lime consolidated in the pond. There was also 2000 feet of pipeline involved, so the city installed a flow meter (to measure slurry gpm) and a nuclear density gauge to measure the percentage of solids in the slurry. At the discharge point 2000 feet away, the flow was 4100 gpm, and the lime slurry consistency in the pipeline was 50% solids by weight. Even though the 370 can dredge to a 20-foot depth, dredging depths were held to 15 feet. The City also found that the lime was mixed with fly ash, and the Series 370 pumped this material at 50% solids by weight.

Because of the ability of the dredge to move the lime at high solids content, it may be possible to transport the lime in liquid form and place it directly onto surrounding farm fields. This is now common practice in the mid-west, and the process is growing.

Mark Shea commented, "We have proven that the Ellicott Series 370 dredge can move three of our products very cost-effectively, and we have a market for these products. There was virtually no dredge downtime even though we were working in the colder winter months. It was probably the most cost-effective piece of equipment ever brought onto this property."

Dredging fly ash, bottom ash, and lime, once almost impossible to recover, and doing it all with just one piece of machinery was a major breakthrough for the City of Springfield, Illinois. Not only was this done with 50% cost savings compared to conventional techniques, but also in many situations where conventional techniques will not work at all.

Mud Cat™ Division
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Back To Case Studies

Dredge Equipment

Booster Pumps
Pump Barges
360 SL Swinging Dragon® Dredger
460 SL Swinging Dragon® Dredger
370HP Dragon® Dredger
670 Dragon® Dredger
860 SL Swinging Dragon® Dredger
870 JD Jet Dragon® Dredger
1170 Dragon® Dredger
1270 Dragon® Dredger
1870 Dragon® Dredger
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Ellicott Dredges, LLC
1611 Bush Street Baltimore MD 21230, U.S.A.
Email: Sales Department
Toll Free: 888-870-3005 Phone (410) 625-0808 Fax (410) 545-0293

Affiliated Dredging Companies:

Agency: Exhibit E

370 HP "DRAGON®" CUTTERHEAD DREDGE - POWER-PACKED PORTABILITY

One truck. One crane. One operator.
The most efficient portable dredging system available.

This portable dredge represents a revolutionary breakthrough in dredge design and construction. Adaptation of the hull, ladder, and spud extensions for various digging depths, added to the modular design concept of the "DRAGON®" Series Dredge provides the most efficient and flexible dredging equipment on the market. Tailored to suit your company's requirements, this dredge will give the greatest return on your investment dollar.

Series	Discharge Diameter	Maximum Digging Depth	Total Power	Pump Power	Cutter Power	Nominal Pump Capacity Range
370HP**	10-12"	20-42' (*)	440 HP	320 HP	40 HP	up to 250 cu yds/hr
	245-304 mm	6.1-12.8 m	328 kW	239 kW	30 kW	190 m3/hr

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Affiliated Dredging Companies:

Illinois Pollution Control Board
R2014-10

Board: Exhibit A

Regulatory Impact Analysis
For EPA's Proposed RCRA Regulation
Of Coal Combustion Residues (CCR)
Generated by the Electric Utility Industry

Prepared by:

US Environmental Protection Agency
Office of Resource Conservation & Recovery (ORCR)
(formerly Office of Solid Waste)
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30 April 2010

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EPA ORCR staff contributing to this RIA: Rachel Alford, Richard Benware, Mark Eads, Christina Kager, and Scott Palmer.

Table of Contents

Table of Appendices

Note: Because of its large number of pages (>400 pages), the Appendix is provided as a separate companion document to this RIA.

Executive Summary

This RIA evaluates the expected regulatory compliance costs, economic and environmental benefits, and potential impact on CCR beneficial use, of EPA's proposed regulation of coal combustion residual (CCR) disposal by coal-fired electric utility plants. The CCR disposal regulatory options evaluated in this RIA are based on EPA's statutory authority contained in the 1976 Resource Conservation and Recovery Act (RCRA). The main findings of this RIA are summarized below according to six sections:

ES-1: Regulatory Options Evaluated in this RIA
ES-2: Benefits of Avoided Future Groundwater Contamination (Human Health Protection & Avoided Remediation Costs)
ES-3: Benefits of Avoided Future CCR Impoundment Structural Failures (Avoided Cleanup Costs)
ES-4: Economic and Environmental Benefits from Future Increase in CCR Beneficial Uses by Other Industries
ES-5: Regulatory Compliance Costs
ES-6: Comparison of Regulatory Benefits to Costs

ES-1: Regulatory Options Evaluated in this RIA

This RIA evaluates three options for RCRA regulation of CCR disposal at coal-fired electric utility plants. All options (a) maintain the existing Bevill regulatory exclusion for CCR beneficial uses, and (b) propose the same set of 10 custom-tailored engineering controls (i.e., technical design and operating standards) for CCR disposal units:

1. <u>Subtitle C "Special Waste" Option</u>: Regulate CCR landfills and impoundments as a "*special waste*" under Subtitle C requirements, and would require phase out of impoundments within five years.

2. <u>Subtitle D Option (version 2)</u>: Composite liners required for all (i.e., existing and future new) CCR impoundments but only for new landfills. For any CCR landfills and impoundments that closed before the effective date, there would be no regulatory controls over those units, unless the states choose to adopt controls over such units. Also, all surface impoundments (existing and new) would need to have composite liners within 5-years of the effective date.

3. <u>Subtitle "D prime" Option</u>: Composite liners required only for new impoundments and landfills; unlined units could continue to operate. This approach would be the same as the Subtitle D option above, except that existing impoundments would not be required to retrofit and install a composite liner, or close.

ES-2: Benefits of Avoided Future Groundwater Contamination (Human Health & Avoided Remediation Costs)

By establishing management and permit standards for CCR disposal units under RCRA, the proposed regulatory options will reduce uncontrolled releases and cancer risks, and improve detection and, if necessary, response to future groundwater contamination. This RIA quantifies two components of groundwater protection benefits: (a) human cancer risks avoided from drinking contaminated groundwater, and (b) groundwater contamination remediation costs avoided. **Summary Exhibit 1** below presents the monetized results of this evaluation.

- Estimate of avoided human cancer risks from avoided future groundwater contamination by CCR disposal units:
    - Individual skin cancer risks avoided (by eliminating the groundwater pathway for arsenic at CCR impoundments) are estimated up to 2×10^{-2} (i.e., a probability equal to 2 individual human skin cancer incidence risks for every 100 persons exposed) using the current IRIS skin cancer slope factor for arsenic.
    - 30,400 people use drinking water wells within one mile of coal-fired electric utility plants; of which 8,150 (27%) are children.
    - Taking into account current CCR disposal unit designs, an estimated **145** (using the IRIS cancer slope factor) to **2,509** (using the NRC lung and bladder cancer slope factor[1]) future human cancer risks are expected to occur in absence of the proposed RCRA regulation, based on drinking water exposure to arsenic in CCR.
- Other human health risks from CCR disposal units not quantified in this RIA:
    - Human non-cancer risks, including from selenium, cobalt, nitrate/nitrite, and molybdenum, which may be released to groundwater at levels above the MCL or 3 times the human hazard quotient (HQ).
    - Cancer and non-cancer risks from arsenic and other metals released in effluent from CCR impoundments to surface waters.

Summary Exhibit 1
Future Avoided Human Cancer Risks & Avoided Groundwater Remediation Cost Benefits
($millions present value @7% discount rate over 50-years)

Groundwater Protection Benefit Category	Subtitle C special waste	Subtitle D (version 2)	Subtitle "D prime"
Groundwater Remediation Costs Avoided	$466	$168	$84
Monetized Value of Cancer Risks Avoided	$504	$207	$104
Total =	$970	$375	$188

ES-3: Benefits of Avoided Future CCR Impoundment Structural Failures (Avoided Cleanup Costs)

This RIA estimated future avoided cleanup costs from catastrophic impoundment failures, like the one that occurred at TVA's Kingston TN coal-fired electricity plant in December 2008, which would be prevented under the proposed rule. Given the increasing age of CCR

[1] EPA calculated a new cancer slope factor for arsenic from data in the National Research Council report "Arsenic in Drinking Water: 2001 Update" at http://www.nap.edu/openbook.php?isbn=0309076293

impoundments, the relative number that present high or significant hazard potential, and the history of CCR impoundment failures to date, this RIA presents three alternative scenarios of future catastrophic failures, the result for which are displayed in **Summary Exhibit 2** below:

- Failure Scenario #1: Extrapolation of future CCR impoundment failure probability based on the relative (a) recent historical occurrence frequency, (b) CCR quantity release magnitude, and (c) cleanup costs, associated with three recent (2005, 2008, 2009) CCR impoundment failures which exceeded 1 million gallons in release quantity each.
- Failure Scenario #2: Assumes 10% of CCR impoundments in the high failure risk group (i.e., above 40 feet tall and over 25 years old) fail over the next 20 years in absence of RCRA regulation.[2]
- Failure Scenario #3: Assumes 20% of CCR impoundments in the high failure risk group (i.e., above 40 feet tall and over 25 years old) fail over the next 20 years in absence of RCRA regulation.

Summary Exhibit 2
Avoided Future CCR Impoundment Catastrophic Failure Cleanup Costs
($millions present value @7% discount rate)

Impoundment Failure Scenarios	Subtitle C special waste	Subtitle D (version 2)	Subtitle "D prime"
Failure Scenario #1: Extrapolation of three recent (2005, 2008, 2009) CCR impoundment failure events	$5,285	$2,378	$1,216
Failure scenario #2: Assuming 10% of 96 high-risk impoundments fail	$8,366	$3,795	$1,897
Failure Scenario #3: Assuming 20% of 96 high-risk impoundments fail	$16,732	$7,590	$3,795

The proposed regulation has categories of other benefits from avoiding future CCR impoundment structural failures which this RIA did not quantify and monetize, including potential avoided costs associated with a few possible benefit categories:

1. Litigation costs: Avoided litigation and related costs associated with such damage events.
2. Riparian damages: Reduction of toxic chemical contaminated effluent discharges from CCR impoundments to surface waters (i.e., rivers and lakes) through future phase-out of surface impoundments.[3]
3. Non-cancer health risks: Reduction in human health risks from future reduction in human exposure to non-carcinogenic but otherwise toxic chemicals contained in CCR, such as selenium, cobalt, nitrate/nitrite, and molybdenum, which, as currently managed in CCR

[2] Based on the responses to our CERCLA 104(e) information requests to utilities with impoundments, there are 96 impoundments that meet these criteria. However, this RIA estimates that 16 of these impoundments have closed or are expected to close before the CCR rule is finalized and goes into effect. Therefore, this analysis removed these 16 impoundments and based the estimated future impoundment failure cleanup costs on a subset of 80 CCR impoundments meeting the 'at risk' criterion.

[3] EPA is developing a regulatory proposal under the Clean Water Act to revise the current effluent guidelines for steam electric utilities. Current guidelines only control pH, total chlorine, and total suspended solids (TSS). EPA's proposed CCR rule would eliminate CCR surface impoundments, eliminating much of the risk that would be addressed under revisions to the effluent guidelines, including risks posed by arsenic, selenium, mercury, cadmium, copper, chromium, and nickel.

disposal units, can exceed the human health hazard quotient (HQ) or Maximum Contaminant Limit (MCL). **Chapter 5** of this RIA provides a list of contaminants of concern in CCR surface impoundment effluent and potential human health and environmental effects.

4. Dry CCR disposal risks: Human health effects from improperly managed dry disposal, which are based on ongoing research by EPA's Office of Research & Development (ORD), may pose greater risks than previously estimated by EPA in 2000 and 2007.

ES-4: Economic & Environmental Benefits from Future Increase in CCR Beneficial Uses by Other Industries

This RIA evaluated the potential impact that the CCR proposed rule may have on beneficial uses of CCR by other industries. Baseline CCR beneficial use at the current 62 million tons per year rate (2009) is estimated in this RIA to provide $26 billion per year in nationwide social benefits consisting of: (a) materials cost savings, plus (b) lifecycle avoided pollution benefits, plus (c) avoided CCR disposal costs to the electric utility industry. On a present value basis over the 50-year future period-of-analysis (2012-2061) applied in this RIA, the present value of CCR beneficial use amounts to $778 billion (@7% discount). Although the industries which use CCR for beneficial uses are not subject to the requirements of the CCR proposed rule, this RIA presents three alternative scenarios of potential induced effect of the CCR rule on future CCR beneficial use, consisting of increased use (scenario #1), decreased use (scenario #2), and no change (scenario #3). This RIA quanfities both scenario #1 and scenario #2 incrementally in relation to the "no change" scenario #3. EPA believes the increasing beneficial use scenario #1 is most likely because (a) the proposed CCR regulation is targeted at CCR disposal not at CCR beneficial uses, (b) all CCR regulatory options retain the existing RCRA Bevill exemption for CCR beneficial uses, and (c) the added cost of regulatory compliance will make beneficial use relatively more cost-effective and represent an "*avoided disposal cost incentive*"[4] to electric utility plants to increase their supply of CCR to industrial markets for CCR as a raw or intermediate input into industrial manufacturing and construction activities. Furthermore, EPA does not believe that market "stigma" of CCR regulation under RCRA Subtitle C --- as alleged in numerous stakeholder letters to the EPA in 2009 --- will result in a reduction in future annual CCR beneficial use, because the proposed rule designates the Subtitle C option as a "*special waste*" rather than as a "*hazardous waste*." **Summary Exhibit 3** below presents the results for both the increase scenario #1 and the decrease scenario #2.

[4] The concept of "*avoided disposal cost incentive*" is recognized and defined by the American Coal Ash Association (ACAA) on its website as follows:

> "*If a [coal-fired electric utility] plant markets its [CCR] into commercial applications, then disposal of this [CCR] is not required. Not only is a revenue stream created for the [coal-fired electricity plant] but also the need to dispose of the [CCR] is avoided. As discussed above, disposal is not just the transportation and placement of [CCR] in a disposal site. The need for future space is a concern. If [CCR is] marketed, then the need to develop future [CCR disposal] sites (including land acquisition, permitting, design and construction costs) is avoided …. It is not uncommon for a company to help offset the costs of transportation or placement at construction sites by providing the contractor or trucking firm a payment of some sort. For example, if the cost of disposal at a plant is normally four dollars a ton, then the company may arrange a payment of four dollars or less to the contractors to cover transportation and placement costs. The difference between the amount of this payment and the cost of disposal is also referred to as "avoided disposal costs*." Source: ACAA Frequently Asked Question nr. 14 webpage at: http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q14

Summary Exhibit 3 Induced Effect of RCRA Regulation of CCR Disposal on Future Annual CCR Beneficial Use ($millions present value @7%)			
Scenarios	Subtitle C special waste	Subtitle D (version 2)	Subtitle "D prime"
Scenario #1: Induced Increase in CCR Beneficial Use			
Percentage increase relative to baseline CCR beneficial use	+11%	+4%	+2%
Economic market value	+$5,560	+$2,224	+$890
Lifecycle social value	+$84,489	+$33,796	+$13,518
Scenario #2: Induced Decrease in CCR Beneficial Use			
Percentage decrease relative to baseline CCR beneficial use	-18%	No impact	No impact
Economic market value	-$18,744	No impact	No impact
Lifecycle social value	-$233,549	No impact	No impact

ES-5: Regulatory Compliance Costs

Chapter 4 of the RIA presents the estimated costs for industry compliance (and for government implementation) of each regulatory option. **Summary Exhibit 4** below presents the estimated costs on a present value basis. The RIA presents three categories of regulatory compliance cost. These regulatory costs are incremental to an estimated $5,556 million per year average annual baseline (i.e., current) cost to the electric utility industry for CCR disposal, which represents a baseline cost of $76,678 million in present value on a 7% and 50-year discounting basis.

Summary Exhibit 4 Estimate of Regulatory Implementation & Compliance Cost ($millions present value @7% over 50-years)			
Cost Category	Subtitle C special waste	Subtitle D (version 2)	Subtitle "D prime"
1. Engineering controls	$6,780	$3,254	$3,254
2. Ancillary costs	$1,480	$5	$5
3. Dry conversion cost	$12,089	4,836	$0
Total Cost (1+2+3) =	$20,349	$8,095	$3,259
Increase over baseline CCR disposal cost =	+27%	+11%	+4%

The dry conversion cost estimate incorporates projection of the recent (1995-2009) electric utility industry trend converting away from wet CCR disposal to dry CCR disposal. In fact, there are several upcoming EPA regulations which could accelerate this trend but are not reflected in the cost estimate of this RIA. These are anticipated rules under the Clean Air Act which will increase the installation of air pollution scrubbers and other air emission control technology at coal-fired power plants, as well as new wastewater effluent guidelines under the Clean Water Act which will require installation of treatment technology for wastewater discharges from CCR impoundments to surface waters.

ES-6: Comparison of Regulatory Benefits to Industry Compliance Costs

The set of three **Summary Exhibits 5, 6 and 7** below compare the estimated regulatory costs to estimated regulatory benefits, using "net benefits" and "benefit-cost ratio" comparison indicators. The three Exhibits are based on the three alternative scenarios about the potential induced impact of the CCR rule on future annual CCR beneficial use as presented in Section 5C of this RIA (i.e., increase, decrease, and no change, respectively). All three Summary Exhibits below present costs, benefits, and net benefits on both a present value and average annualized equivalent basis, based on a 7% discount rate. A set of exhibits in **Chapter 6** of this RIA present these values based on a 3% rate.

Summary Exhibit 5
Comparison of Regulatory Benefits to Costs
Scenario #1 – Induced Increase in Future Annual CCR Beneficial Use
($Millions @2009$ Prices and @7% Discount Rate over 50-Year Future Period-of-Analysis 2012 to 2061)

Impact Element	Subtitle C "Special Waste"	Subtitle D (version 2)	Subtitle "D prime"
A. Present Values:			
1. Regulatory Costs (1A+1B+1C):	$20,349	$8,095	$3,259
1A. Engineering Controls	$6,780	$3,254	$3,254
1B. Ancillary Regulatory Requirements	$1,480	$5	$5
1C. Conversion to Dry CCR Disposal	$12,089	$4,836	$0
2. Regulatory Benefits (2A+2B+2C+2D):	$87,221 to $102,191	$34,964 to $41,761	$14,111 to $17,501
2A. Monetized Value of Human Cancer Risks Avoided	$504 (726 cancer risks)	$207 (296 cancer risks)	$104 (148 cancer risks)
2B.Groundwater Remediation Costs Avoided	$466	$168	$84
2C. CCR Impoundment Failure Costs Avoided	$1,762 to $16,732	$793 to $7,590	$405 to $3,795
2D. Induced Impact on Future CCR Beneficial Use	$84,489	$33,796	$13,518
3. Net Benefits (2 - 1)	$66,872 to $81,842	$26,869 to $33,666	$10,852 to $14,242
4. Benefit/Cost Ratio (2 / 1)	4.286 to 5.022	4.319 to 5.159	4.330 to 5.370
B. Average Annualized Equivalent Values:*			
1. Regulatory Costs (1A+1B+1C)	$1,474	$587	$236
1A. Engineering Controls	$491	$236	$236
1B. Ancillary Regulatory Requirements	$107	<$1	<$1
1C. Conversion to Dry CCR Disposal	$876	$350	$0
2. Regulatory Benefits (2A+2B+2C+2D):	$6,320 to $7,405	$2,533 to $3,026	$1,023 to $1,268
2A.Monetized Value of Human Cancer Risks Avoided	$37	$15	$8
2B. Groundwater Remediation Costs Avoided	$34	$12	$6
2C. CCR Impoundment Failure Cleanup Costs Avoided	$128 to $1,212	$58 to $550	$29 to $275
2D. Induced Impact on Future CCR Beneficial Use	$6,122	$2,450	$980
3. Net Benefits (2 - 1)	$4,845 to $5,930	$1,947 to $2,439	$786 to $1,032
4. Benefit/Cost Ratio (2 / 1)	4.286 to 5.022	4.319 to 5.159	4.330 to 5.370

* Note: Average annualized equivalent values calculated by multiplying 50-year present values by a 50-year 7% discount rate "capital recovery factor" of 0.07246.

Summary Exhibit 6 Comparison of Regulatory Benefits to Costs Scenario #2 – Induced Decrease in Future Annual CCR Beneficial Use ($Millions @2009$ Prices and @7% Discount Rate over 50-Year Future Period-of-Analysis 2012 to 2061)			
Impact Element	Subtitle C "Special Waste"	Subtitle D (version 2)	Subtitle "D prime"
A. Present Values:			
1. Regulatory Costs (1A+1B+1C)	$20,349	$8,095	$3,259
1A. Engineering Controls	$6,780	$3,254	$3,254
1B. Ancillary Costs	$1,480	$5	$5
1C. Conversion to Dry CCR Disposal	$12,089	4,836	$0
2. Regulatory Benefits (2A+2B+2C+2D):	($230,817) to ($215,847)	$1168 to $7,965	$593 to $3,983
2A. Monetized Value of Human Cancer Risks Avoided	$504 (726 cancer risks)	$207 (296 cancer risks)	$104 (148 cancer risks)
2B. Groundwater Remediation Costs Avoided	$466	$168	$84
2C. CCR Impoundment Failure Costs Avoided	$1,762 to $16,732	$793 to $7,590	$405 to 3,795
2D. Induced Impact on CCR Beneficial Use	($233,549)	$0 (no impact)	$0 (no impact)
3. Net Benefits (2-1)	($251,166) to ($236,196)	($6,927) to ($130)	($2,666) to $724
4. Benefit/Cost Ration (2/1)	(11.343) to (10.607)	0.144 to 0.984	0.182 to 1.222
B. Average Annualized Equivalent Values:*			
1. Regulatory Costs (1A+1B+1C)	$1,474	$587	$236
1A. Engineering Controls	$491	$236	$236
1B. Ancillary Costs	$107	$0.36	$0.36
1C. Dry Conversion	$876	$350	$0
2. Regulatory Benefits (2A+2B+2C+2D):	($16,725) to ($15,640)	$85 to $577	$43 to $289
2.A Monetized Value of Human Cancer Risks Avoided	$37	$15	$8
2.B Groundwater Remediation Costs Avoided	$34	$12	$6
2.C CCR Impoundment Failure Cleanup Costs Avoided	$128 to $1,212	$57 to $550	$29 to $275
2.D Induced Impact on CCR Beneficial Use	($16,923)	NA	NA
3. Net Benefits (2-1)	($18,199) to ($17,115)	($502) to ($9)	($193) to $52
4. Benefit/Cost Ration (2/1)	(11,347) to (10.610)	0.145 to 0.983	0.182 to 1.225
* Note: Average annualized equivalent values calculated by multiplying 50-year present values by a 50-year 7% discount rate "capital recovery factor" of 0.07246.			

Summary Exhibit 7 **Comparison of Regulatory Benefits to Costs** **Scenario #3 – No Impact on Future Annual CCR Beneficial Use** ($Millions @2009$ Prices and @7% Discount Rate over 50-Year Future Period-of-Analysis 2012 to 2061)			
Impact Element	Subtitle C "Special Waste"	Subtitle D (version 2)	Subtitle "D prime"
A. Present Values:			
1. Regulatory Costs (1A+1B+1C)	$20,349	$8,095	$3,259
1A. Engineering Controls	$6,780	$3,254	$3,254
1B. Ancillary Costs	$1,480	$5	$5
1C. Conversion to Dry CCR Disposal	$12,089	4,836	$0
2. Regulatory Benefits (2A+2B+2C+2D):	$2,732 to $17,702	$1168 to $7,965	$593 to $3,983
2A. Monetized Value of Human Cancer Risks Avoided	$504 (726 cancer risks)	$207 (296 cancer risks)	$104 (148 cancer risks)
2B. Groundwater Remediation Costs Avoided	$466	$168	$84
2C. CCR Impoundment Failure Costs Avoided	$1,762 to $16,732	$793 to $7,590	$405 to $3,795
2D. Induced Impact on CCR Beneficial Use	$0 (no change)	$0 (no change)	$0 (no change)
3. Net Benefits (2-1)	($17,617) to ($2,647)	($6,927) to ($130)	($2,666) to $724
4. Benefit/Cost Ration (2/1)	0.134 to 0.870	0.144 to 0.984	0.182 to 1.222
B. Average Annualized Equivalent Values:*			
1. Regulatory Costs (1A+1B+1C)	$1,474	$587	$236
1A. Engineering Controls	$491	$236	$236
1B. Ancillary Costs	$107	$0.36	$0.36
1C. Dry Conversion	$876	$350	$0
2. Regulatory Benefits (2A+2B+2C+2D):	$198 to $1,283	$85 to $577	$43 to $289
2.A Monetized Value of Human Cancer Risks Avoided	$37	$15	$8
2.B Groundwater Remediation Costs Avoided	$34	$12	$6
2.C CCR Impoundment Failure Cleanup Costs Avoided	$128 to $1,212	$57 to $550	$29 to $275
2D. Induced Impact on CCR Beneficial Use	$0	$0	$0
3. Net Benefits (2-1)	($1,277) to ($192)	($502) to ($9)	($193) to $52
4. Benefit/Cost Ration (2/1)	0.134 to 0.870	0.145 to 0.983	0.182 to 1.225
* Note: Average annualized equivalent values calculated by multiplying 50-year present values by a 50-year 7% discount rate "capital recovery factor" of 0.07246.			

Chapter 1
Problem Statement: The Need for RCRA Regulation of CCR Disposal

1A. Institutional Context

For purpose of evaluating Federal regulations, the 1993 Executive Order 12866 "Regulatory Planning and Review" (Section 1(b)(1)) requires each Federal regulatory agency to identify the problem that it intends to address, including where applicable, the failures of private markets or public institutions that warrant new agency action, as well as to assess the significance of the problem. In line with this requirement, this Chapter provides a problem statement consisting of the institutional context (i.e., prior EPA actions), significance of the problem (i.e., evidence of environmental damages), and characterization of market failure.

In September 2003, the White House Office of Management and Budget (OMB) updated its guidance to federal agencies on the development of regulatory analysis required under Section 6(a)(3)(c) of the 1993 Executive Order 12866[5] "Regulatory Planning and Review." The updated guidance is OMB's September 17, 2003 "Circular A-4 Regulatory Analysis."[6] Section A (Introduction) of Circular A-4 defines three key elements of good regulatory analysis:

1. Statement of the need for the proposed regulation.
2. Examination of alternative approaches.
3. Evaluation of the benefits and costs (quantitative and qualitative) of the proposed regulation and the main alternatives.

Concerning the first basic element listed above (i.e., statement of the need for regulation), Section B of Circular A-4 requires federal agencies to demonstrate that the proposed regulation is necessary. The Circular defines four categories of possible regulatory need:

1. Required by law: If the need results from statutory or judicial directive, agencies should describe the:
    a. specific authority for the proposed regulation
    b. extent of discretion available to the agency
    c. regulatory instruments available
2. Necessary to interpret law.
3. Market failure: Three examples cited in Circular A-4 (pages 4 & 5) are:
    a. externality, common property resources and public goods
    b. non-competitive market power
    c. inadequate or asymmetric information
4. Other social purposes: Six examples cited in Circular A-4 (page 5) are:
    a. make government operate more efficiently

[5] 1993 Executive Order 12866 (11 pages) is available at: http://www.whitehouse.gov/OMB/inforeg/eo12866.pdf
[6] 2003 OMB Circular A-4 (48 pages) is available at: http://www.whitehouse.gov/OMB/Circulars/a004/a-4.pdf

b. redistribute resources to select groups
c. prohibit discrimination
d. protect privacy
e. permit more personal freedom
f. promote other democratic aspirations

As explained below, EPA's proposed RCRA[7] regulation of coal combustion residual (CCR) disposal at coal-fired electricity plants is both **required by law** and will **correct market failure**.

1B. EPA's Proposed Regulation of CCR Disposal Is Required by Law

In 1976, Congress amended the 1965 Solid Waste Disposal Act (the first federal statute that specifically focused on improving solid waste disposal methods) by adding industrial hazardous waste management requirements as Subtitle C, among other new requirements. This amendment is the 1976 Resource Conservation & Recovery Act (RCRA). The EPA's regulatory evaluation of coal combustion residues (CCR) dates back to 1978, two years after enactment of RCRA. In December 1978, the EPA proposed the first industrial hazardous waste regulations to implement Subtitle C (i.e., Sections 3001 to 3020 of RCRA). At that time, the EPA recognized that certain large-volume industrial wastes, including wastes from the combustion of fossil fuels (aka "CCR" as named in this RIA), might warrant special treatment under RCRA regulation. On 18 December 1978, EPA proposed but deferred and never finalized a relatively limited set of ten RCRA Subtitle C industrial hazardous waste regulations for the management of CCR.[8] Included in this deferral of hazardous waste requirements were six categories of industrial wastes --- which EPA termed "special wastes"[9] --- until further study and assessment could be completed by EPA to determine their risk to human health and the environment. The six categories of special wastes included:

1. Cement kiln dust
2. Mining waste
3. Oil and gas drilling muds and oil production brines
4. Phosphate rock mining, beneficiation, and processing waste
5. Uranium waste
6. Utility waste (i.e., fossil fuel combustion waste by electric utility plants)

These wastes typically are generated in large volumes and, at the time, were believed to possess less risk to human health and the environment than the wastes being identified for regulation as RCRA hazardous waste. On 12 October 1980, Congress enacted the Solid Waste Disposal Act Amendments of 1980 (Public Law 96-482) which amended RCRA in several ways. Pertinent to "special wastes" were the Bentsen and

[7] RCRA = Resource Conservation & Recovery Act of 1976: http://www.epa.gov/waste/laws-regs/rcrahistory.htm
[8] Federal Register, Vol. 43, No. 243, 18 December 1978, page 59015, section 250.46-2 "Utility Waste" of "Hazardous Waste Guidelines and Regulations." This action proposed the following ten regulatory conditions: (a) waste analysis standards, (b) waste site selection standards, (c) waste site security, (d) waste shipment manifesting, (e) recordkeeping, (f) reporting, (g) waste site visual inspections, (h) waste site closure, (i) waste site post-closure care, and (j) groundwater monitoring.
[9] To learn more about these six "special wastes" see EPA's special waste website at http://www.epa.gov/osw/nonhaz/industrial/special/index.htm

Bevill Amendments[10] which exempted "special wastes" from regulation under Subtitle C of RCRA until further study and assessment of risk could be performed:

- 1980 Bentsen Amendment (RCRA 3001(b)(2)(A)): Exempted drilling fluids, produced waters, and other wastes associated with the exploration, development, and production of crude oil or natural gas or geothermal energy.
- 1980 Bevill Amendment (RCRA 3001(b)(3)(A)(i-iii)): Exempted **fossil fuel combustion waste**; waste from the extraction, beneficiation, and processing of ores and minerals (including phosphate rock and overburden from uranium ore mining); and cement kiln dust.

The Bevill and Bentsen Amendments required EPA to complete full assessments of each exempted waste and submit a formal report to Congress on its findings. As itemized in **Appendix A** to this RIA, since 1978, EPA continued to evaluate CCR (as well as the other five waste categories) for different possible RCRA hazardous and non-hazardous waste regulatory approaches. The proposed RCRA regulation this RIA supports is a continuation of those prior evaluations.

1C. EPA's Proposed Regulation of CCR Disposal Will Correct Market Failure

OMB's 2003 Circular A-4 "Regulatory Analysis" guidance (pages 4 to 5) to Federal agencies for implementation of Executive Order 12866 identifies three major types of market failure:

1. Externality, common property resource, and public good
2. Market power (i.e., lack of market competition from monopolies)
3. Inadequate or asymmetric information

The CCR proposed rule which this RIA supports may be characterized as addressing the "negative externality" of environmental pollution and damages from CCR disposal landfills and impoundments. As summarized in the "Benefits" **Chapter 5** of this RIA, there are a number of historical and recent environmental damage cases which represent externalities, in that some or all of the (a) human health damages (i.e., human cancer cases from contaminated groundwater near CCR disposal sites) and (b) environmental damages (i.e., ecological damages, natural resource damages, and socio-economic damages from CCR spills/releases from structural failures in CCR disposal impoundments) may be external to the capital and operating costs of the electric utility plants. If implemented, the CCR proposed rule may be expected to reduce this market failure externality, by internalizing into the capital and operating costs of the electric utility plants, the added costs of installing engineering controls and oversight of the physical integrity of CCR disposal units.

Firms are sometimes held accountable for some of the external costs through lawsuits brought by affected citizens. However, the system of accountability can be imperfect. The primary human bearers of the external costs from CCR disposal are households residing disposal units. When an unorganized group of households suffer external costs, they face a host of obstacles to having their costs recuperated. They must

[10] These 1980 RCRA "special waste" amendments are named after US Senator Lloyd Bentsen (D-TX; Senate service years 1971-1993) and US House Congressman Tom Bevill (D-AL; House service years 1967-1997). Source: Biographical Directory of the US Congress at http://bioguide.congress.gov/biosearch/biosearch.asp

form a coherent organization and they must have enough funding to launch and maintain a lawsuit. On the other side of such litigation, households usually face a single firm often with greater legal funding resources. This imbalance suggests that external costs of leachate contamination from industrial waste disposal sites (such as CCR landfills and impoundments) may not be recuperated.

The CCR proposed rule also addresses a second source of market failure – inadequate or asymmetric information. Citizens residing near CCR disposal sites may be unaware of exposure to chemical contaminants contained in CCR leaching from disposal units. Thus, while nearby citizens may have the right to legal lawsuits to recuperate health and property damages, citizens may not be aware of the need to do so until health risks (and health costs) have already been incurred.

A very recent example of negative externalities associated with structural failures is the ecological and socio-economic damages and costs associated with a large environmental disaster involving the collapse of a CCR impoundment in 2008. On 22 December 2008, over a billion gallons (i.e., 5.4 million cubic yards) of CCR was unintentional environmental released over 300 acres from the collapse of a Tennessee Valley Authority (TVA) coal-fired electric utility surface impoundment in Kingston TN. This event caused significant damage to 40 homes, the Emory River, a nearby recreational lake, community roadways, a gas pipeline, and a railroad. As indicated in **Exhibit 5B-2** of this RIA, the estimated cleanup costs to the TVA --- not including social costs of ecological damages and community socio-economic damages --- are estimated at $933 million to $1.2 billion. This event attracted major citizen, national press, and Congressional interest in the subject of CCR management and the urgent need for prevention of such future environmental and community damages. In the wake of this disaster, during her 14 January 2009 Senate confirmation hearing, EPA Administrator-designate Lisa P. Jackson, testified[11]:

> "*I think that you've put your finger on a very important thing that EPA must do right away, which is to assess the hundreds of other sites that are out there. Many of them … are … up hill from schools or from areas where just the physical hazard of having this mountain of wet coal ash, if there's a break, can endanger lives immediately. So I would think that EPA needs to first and foremost assess the current state of what's out here and where there might be another horrible accident waiting to happen … EPA currently has and has in the past, assessed its regulatory options with respect to coal ash, and I think it's time to re-ask those questions and re-look at the state of regulation of them from an EPA perspective*."

According to a 23 January 2009 news report,[12] there was growing Congressional interest for either the EPA with its existing RCRA regulatory authorities, or the Congress with potential new legislation, to regulate CCR disposal units:

> "*Several lawmakers have introduced, or announced plans to introduce, competing legislation to regulate CCR. For example, Senate Environment & Public Works Committee Chairwoman Barbara Boxer (D-CA) said she would introduce legislation compelling EPA to regulate CCR in the event the Obama EPA fails to act soon. "If we are not satisfied with action we may move legislatively," Boxer told EPA Administrator-designate Lisa Jackson at a January 14 [2009] confirmation hearing. "I don't want to get to that point because I think you have the authority to regulate this. It needs to be done*.""

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[11] Lisa Jackson's 14 January 2009 Senate confirmation hearing testimony and webcast is available from the US Senate Committee on Environment and Public Works' website at: http://epw.senate.gov/public/index.cfm?FuseAction=Hearings.Hearing&Hearing_ID=ae2c3342-802a-23ad-4788-d1962403eb76

[12] Source: Waste Business Journal, "EPA Vows to Act on Coal Waste," 23 January 2009, http://www.wastebusinessjournal.com/news/wbj20090127B.htm

Just three weeks after the TVA's Kingston TN CCR impoundment disaster, House Natural Resources Committee Chairman Nick Rahall (D-WV) introduced legislation requiring federal standards to regulate the engineering of CCR impoundments.[13] Introduced on 14 January 2009, the Coal Ash Reclamation and Environmental Safety Act of 2009 (H.R. 493) directs the Department of Interior to impose uniform federal design, engineering, and performance standards on CCR impoundments to avoid a repeat of the damage done in Kingston TN. The legislation, which requires minimum design and stability standards for all surface impoundments constructed to hold coal ash, draws on the regulatory model for impoundments that is used for coal slurry management under the Surface Mining Control and Reclamation Act of 1977 (SMCRA).

In a letter dated 02 March 2009, the Environmental Integrity Project and Earthjustice, joined by the National Resources Defense Council, the Sierra Club, Environmental Defense, and 104 other environmental groups requested EPA Administrator Lisa Jackson "*to act as soon as possible*" to regulate CCR. A letter signed by the groups and delivered to EPA on 03 March 2009 identified 12 principles to guide the development of EPA standards. These include the phase-out of CCR surface impoundments, locating CCR disposal sites away from groundwater or surface water, requiring liners, leachate collection systems and adequate monitoring, and requiring industry to assume long term liability for cleanup:

> "*The recent disaster at TVA's Kingston Plant stands as a startling reminder that federal standards for CCR are long overdue. For too long, power companies have been able to dump CCR, laden with a host of toxic metals like arsenic, selenium, lead, mercury, and boron, in unlined mines, quarries, landfills, and surface impoundments. Without federal standards governing disposal practices, contaminants can leak or spill from these dump sites, threatening human health, natural resources and wildlife.*"[14]

On 04 March 2009, US Senators Barbara Boxer (D-CA) and Tom Carper (D-DE) submitted Senate Resolution 64 to the Senate Committee on Environment and Public Works. This resolution calls on the EPA to "immediately" inspect all CCR impoundments and landfills operating at coal-fired electricity plants, and to propose and finalize "as quickly as possible" rules to regulate CCR under RCRA.[15]

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[13] The text of the 14 January 2009 H.R. 493 bill is available at: http://www.govtrack.us/congress/billtext.xpd?bill=h111-493
[14] Source: http://www.environmentalintegrity.org/pub608.cfm
[15] US Senate Resolution 64 is available at: http://www.govtrack.us/congress/bill.xpd?bill=sr111-64&tab=committees

Chapter 2
Potentially Affected Industries & RCRA Regulatory Options

2A. Identity of Potentially Affected Industries

There are two categories of industries which may be directly affected by the CCR regulatory options. "Directly affected entities" are entities potentially subject to any of the rule's requirements.[16] In addition, there are 14 or more industries which beneficially use CCR.

1. Coal-Fired Electric Utility Industry

The scope of industrial plants directly affected by the regulatory options is classifiable according to at least two different glossary systems:

- Classification #1 of 2: The scope of industrial plants is classifiable as "**coal-fired electric utility plants**" under the US Census Bureau's North American Industrial Classification System" NAICS code 22 "Utilities" economic sector, and in that sector, as a subgroup of the 1,245 establishments within the NAICS 221112 "Fossil Fuel Electric Power Generation" industry:[17]

  NAICS 221112: *This industry comprises establishments primarily engaged in operating fossil fuel powered electric power generation facilities. These facilities use fossil fuels, such as coal, oil, or gas, in internal combustion or combustion turbine conventional steam process to produce electric energy. The electric energy produced in these establishments is provided to electric power transmission systems or to electric power distribution systems.*

- Classification #2 of 2: The scope of industrial plants is classifiable as "**electric utilities plus independent power producers**" under the Energy Information Administration (EIA) categorization system for its coal combustion electric power sector statistics:[18]

  Electric utility: *Any entity that generates, transmits, or distributes electricity and recovers the cost of its generation, transmission or distribution assets and operations, either directly or indirectly, through cost-based rates set by a separate regulatory authority (e.g., State Public Service Commission), or is owned by a governmental unit or the consumers that the entity serves. Examples of these entities include: investor-owned entities, public power districts, public utility districts, municipalities, rural electric cooperatives, and State and Federal agencies.*

  Independent power producer: *A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility.*

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[16] Source: "EPA's Action Development Process: Final Guidance for EPA Rulewriters: Regulatory Flexibility Act", OPEI Regulatory Development Series, Nov 2006, see footnote 14 at http://www.epa.gov/sbrefa/documents/rfafinalguidance06.pdf
[17] Source: NAICS codes are defined at http://www.census.gov/cgi-bin/sssd/naics/naicsrch?chart=2007
[18] Source: EIA glossary of terms at http://www.eia.doe.gov/glossary/index.html

2. Waste & Environmental Management Services Industries

In addition, because some electric utility plants transport their CCR to either company-owned or to commercial offsite landfills, and because some regulatory options may trigger RCRA facility-wide corrective action, the regulatory options of the proposed rule may also affect:

NAICS 562211:	Hazardous waste treatment and disposal industry (may be affected under the RCRA Subtitle C regulatory options evaluated in this RIA).
NAICS 562212:	Solid waste landfill industry (may represent baseline offsite CCR landfills to which the estimated 149 of the 495 electric utility plants may transport some or all of the 15 million tons per year CCR for offsite disposal).
NAICS 562219:	Other non-hazardous waste treatment and disposal industry (may represent baseline offsite CCR landfills to which some or all of 149 of the 495 electric utility plants may transport some or all of the 15 million tons per year CCR for offsite disposal).
NAICS 562910:	Environmental cleanup/remediation services industry.

3. Industries Which "Beneficially Use" CCR

According to the American Coal Ash Association (ACAA)[19] as of 2007 there are over 15 industries which "beneficially use" CCR for industrial applications. These industrial applications are listed below with corresponding NAICS[20] codes estimated by EPA ORCR. Because the regulatory options evaluated in this RIA establish CCR disposal requirements, industries which beneficially use CCR are characterized in this RIA as potentially "indirectly" affected by the proposed rule rather than "directly" affected (i.e., subject to the rule's requirements).

1. Concrete/concrete products/grout	NAICS 3273 Cement & Concrete Product Manufacturing
2. Blended cement/raw feed for clinker	NAICS 3273 Cement & Concrete Product Manufacturing
3. Flowable fill	NAICS 23 Construction
4. Structural fills/embankments	NAICS 23 Construction
5. Road base/sub-base	NAICS 237310 Highway, Street & Bridge Construction
6. Soil modification/stabilization	NAICS 23 Construction
7. Mineral filler in asphalt	NAICS 324121 Asphalt Paving Mixture & Block Manufacturing
8. Snow and ice control	NAICS 488490 Other Support Activities for Road Transportation
9. Blasting grit/	NAICS 212319 Other Crushed & Broken Stone Mining & Quarrying
Roofing granules	NAICS 324122 Asphalt Shingle & Coating Materials Manufacturing
10. Mining applications	NAICS 212 Mining

[19] Source: American Coal Ash Association (ACAA) "2007 Coal Combustion Product (CCP) Production & Use Survey Results (Revised)" at http://www.acaa-usa.org/associations/8003/files/2007_ACAA_CCP_Survey_Report_Form%2809-15-08%29.pdf

[20] NAICS = North American Industrial Classification System; NAICS codes definitions are available at http://www.census.gov/cgi-bin/sssd/naics/naicsrch?chart=2007

- 2-digit codes represent economic sectors
- 3-digit codes represent economic sub-sectors
- 4-digit codes represent industry groups
- 5-digit and 6-digit codes represent single industries

11. Gypsum panel products (e.g., wallboard)	NAICS 327420 Gypsum Product Manufacturing
12. Waste stabilization/solidification	NAICS 5622 Waste Treatment & Disposal
13. Agriculture	NAICS 111 Crop Production
14. Aggregate	NAICS 23 Construction
15. Miscellaneous/other (unidentified industries)	NAICS not identified

2B. Other Industries with CCR Disposal Units Not Covered by the Proposed Rule

The scope of the proposed rule excludes two other categories of CCR disposal units from the regulatory options. These other two categories are identified here to provide a rough estimate of potential additional cost for regulation if they were added to the scope of the rulemaking or addressed in a separate but similar rulemaking.

- **Inactive/Abandoned CCR Disposal Units Excluded from Scope**

The scope of the proposed rule only covers active (i.e., operating) CCR disposal units used by electric utility plants. There are two other operating status categories consisting of an estimated count of at least 197 additional CCR disposal units excluded from the scope of the rule:[21]

- Inactive units: CCR impoundments and landfills not in operation or not receiving CCR. Inactive impoundments may receive CCR in the future, becoming active again, and therefore have not been closed permanently.
- Abandoned units: CCR impoundments and landfills not in operation and closed. These impoundments usually have been filled to capacity and have been permanently closed.

In absence of inventory data on inactive units, the nationwide count of such inactive and abandoned units is indirectly and roughly estimated in this RIA based on known data for large volume coal mining slurry waste impoundments. There are an estimated 1,600 coal waste impoundments in operation across the US in coal-related industries (i.e., coal mining industry plus industries which burn coal). In addition, there are another 670 coal waste impoundments which are no longer in operation but still contain coal waste slurry (i.e., inactive or abandoned).[22] These two counts represent a ratio of 0.42 inactive/abandoned:to:active (i.e., 670:to:1,600).

In absence of national survey data, multiplying the 0.42 inactive:to:active coal waste impoundments ratio by the 158 coal-fired electric utility plants estimated in this RIA using CCR impoundments, yields an estimate of at least 66 inactive/abandoned CCR impoundments may be located at electric utility plants (i.e., (158 impoundment using electric utility plants) x (0.42 ratio) = 66).

[21] Source: Definitions of “inactive” and “abandoned” coal waste impoundments from page 23 of the National Research Council book Coal Waste Impoundments: Risks, Responses and Alternatives, National Academy Press, 2002 at http://www.nap.edu/openbook.php?isbn=030908251X
[22] Source: Counts of 1,600 active coal waste impoundments and 670 inactive or abandoned coal waste impoundments from the prior footnoted source.

This RIA did not discover similar data for coal waste landfills in active and inactive/abandoned status. For purpose of a rough estimate in this RIA, multiplying the 0.42 inactive/abandoned:to:active ratio by the 311 electric utility plants which use landfills, indicates there may be at least 131 inactive or abandoned CCR landfills at or near electric utility plants (i.e., (311 landfill using electric utility plants) x (0.42 ratio) = 131).

As of 2004, the Mine Safety & Health Administration (MSHA) oversees 646 active coal mining slurry impoundments in the US, which implies 954 remainder active coal slurry impoundments (i.e., 1,600 – 646 = 954).[23] Of these, this RIA estimates at least 158 active impoundments at 158 electric utility plants, which implies that a fraction of 796 other active coal waste impoundments (i.e., 954 – 158 = 796) may be located at electric power plants in non-utility industries (see the next sub-section below "Other Industries Excluded from Scope").

- **Other Industries Excluded from Scope**

The scope of the proposed rule only includes NAICS code 22 coal-fired electric utility plants (495 plants). However, there is a range of 139 to 759 non-utility facilities which currently, or have the capacity to, burn coal and thus generate CCR. Adding these facilities to the scope of the proposed rule could increase the cost estimates by 2% to 28%. This range is based on the following two data sources:

Source #1: As displayed below in **Exhibit 2A** based on 2005 data from the DOE-EIA, there are 139 non-utility coal-fired electricity plants owned and operated by 8 other industrial sub-sectors involving 27 industries. **Appendix B** of this RIA contains a list of these other industry plants according to NAICS industry codes. If these other non-utility industries were to be added to the scope of the CCR proposed rule, a rough estimate of potential additional cost and benefit impacts would be between 2% and 28% relative to the impacts estimated in this RIA:

- >2%: Compared to the 369,183 megawatts (MW) nameplate capacity for the coal-fired electricity plants contained in the 2005 DOE-EIA database (which contains data on electricity plants at least 10 MW nameplate capacity in size), the 5,959 MW capacity of the 139 non-utility electricity plants represents about 2% of national coal-fired electricity generation capacity. For purpose of rough estimation – in so far that electricity plant capacity correlates to annual CCR generation and thus to annual CCR disposal costs and to regulatory costs --- this percentage indicates that the additional economic impact of including these additional 139 non-utility plants in the proposed rule might add at least 2% to the cost estimates under each regulatory option.
- <28%: On the other hand, some CCR disposal costs and regulatory costs better correlate to the count and size (footprint) of CCR landfills and impoundments, not to electricity generating capacity. For such costs, adding the 139 non-utility plants to the scope of the proposed rule could increase the cost estimates for each regulatory option by up to 28% (i.e., (495 + 139) / (495)).

[23] Source: MSHA "Supporting Statement" for Information Collection Request (ICR) 1219-0015 "Refuse Piles and Impoundment Structures, Recordkeeping and Reporting Requirements", March 2008: http://www.msha.gov/regs/fedreg/paperwork/2004/04-24046.pdf

Source #2: EPA's 2002 analysis[24] of the results from a 2001 survey of non-utility CCR generation identified 759 non-utility facilities "with the capacity to burn coal, and therefore, generate CCR." The estimated annual CCR generation for these facilities is 7.8 million tons (as of year 2000), which is 5.5% to 6.3% of the 123.1 million to 141.2 million tons CCR generated by electric utility plants in 2005 as estimated in **Exhibit 3D** of this RIA. Allowing for annual growth of the 7.8 million tons since 2000 suggests that adding these 759 facilities to the scope of the proposed rule could increase the cost estimates by 7%.

[24] Source: "Analysis of Non-Utility Coal Combustion Waste Generation and Management Based on the 2001 CIBO Voluntary Survey," prepared for EPA-OSWER by Science Applications International Corp (SAIC) Engineering & Environmental Management Group (Reston VA) under subcontract to Eastern Research Group (Arlington VA), April 2002, EPA contract No. 68-W-02-036, WA 12:.

Exhibit 2A Identity of Other Industries Operating Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA					
2005 Count	NAICS Sector	NAICS Industry	NAICS Industry Code Definition	2005 Boiler count	2005 Plant count
1	21	2122	Ore mining	4	1
2	31	311	Food Manufacturing	63	29
3	31	3122	Tobacco Manufacturing	3	2
4	31	314	Textile Product Mills	11	4
5	32	321	Wood Product Manufacturing	1	1
6	32	322	Paper Manufacturing	9	4
7	32	322122	Newsprint Mills	98	39
8	32	32213	Paperboard Mills	19	9
9	32	325	Chemical Manufacturing	31	6
10	32	325188	All Other Basic Inorganic Chemical Manufacturing	5	3
11	32	325211	Plastics Material and Resin Manufacturing	9	4
12	32	326	Plastics and Rubber Products Manufacturing	4	1
13	32	327	Nonmetallic Mineral Product Manufacturing	8	3
14	32	32731	Cement Manufacturing	2	1
15	33	331	Primary Metal Manufacturing	5	3
16	33	331111	Iron and Steel Mills	1	1
17	33	331312	Primary Aluminum Production	3	1
18	33	333	Machinery Manufacturing	7	2
19	33	3345	Navigational, Measuring, Electromedical, Control Instruments Mfg	10	1
20	33	336	Transportation Equipment Manufacturing	1	1
21	33	337	Furniture and Related Product Manufacturing	1	1
22	33	339	Miscellaneous Manufacturing	1	1
23	48	482	Rail Transportation	2	1
24	48	483	Water Transportation	3	1
25	61	611	Educational Services	37	14
26	62	624	Social Assistance	2	1
27	92	92	Public Administration	14	4
	Count = 8	Count = 27	Column Totals =	354	**139**
			2005 electricity generation nameplate capacity (megawatts) =	5,959	

Notes:
(a) Source: US Dept of Energy, Energy Information Administration (EIA), 2005 Form EIA-860 "Annual Electric Generator Report" "Existing Electric Generating Units in the United States, 2005" at http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html
(b) NAICS codes: The first two digits designate the economic sector, the third digit designates the subsector, the fourth digit designates the industry group, the fifth digit designates the NAICS industry, and the sixth digit designates the national industry. The five-digit NAICS code is the level at which there is comparability in code and definitions for most of the NAICS sectors across the three countries participating in NAICS (the United States, Canada, and Mexico). The six-digit level allows for the United States, Canada, and Mexico each to have country-specific detail. A complete and valid NAICS code contains six digits. Source: http://www.census.gov/eos/www/naics/faqs/faqs.html#q5

2C. RCRA Regulatory Options Evaluated in this RIA

This RIA evaluates three RCRA regulatory options which are defined with reference to the two alternative regulatory authorities --- Subtitle C and Subtitle D --- contained in EPA's 1976 RCRA waste management statutory authority:

Option 1: RCRA Subtitle C "*special waste*":

- Regulate CCR disposed in landfills and surface impoundments as "special wastes" under Subtitle C, and require phase out of surface impoundments within five years. This approach:
- Eliminates health risks from groundwater and surface water contamination for both landfills and surface impoundments, and avoids damages from uncontrolled ground "fill" operations (e.g., Gambrills MD and Chesapeake VA) and attendant environmental remediation costs.
- Eliminates the future threat of catastrophic failures of surface impoundments.
- Provides for corrective action, including at closed units at facilities with surface impoundments or landfills regulated under the rule, and imposes groundwater monitoring requirements.
- Provides for Federal oversight, which EPA experience has shown is necessary for successful implementation of RCRA industrial waste regulations, especially as it relates to ground-water monitoring and corrective action, when needed. Without Federal oversight, it is highly questionable whether CCR will be properly managed, considering EPA's experience with the RCRA program of the last 10 years, which illustrate the limited results that could be expected of a Subtitle D rule.

Option 2: RCRA Subtitle D "*non-hazardous*" industrial waste (version 2):

- Liners required for all (i.e., existing and future new) CCR surface impoundments but only for new landfills. Subtitle D requirements would set national criteria for landfills and surface impoundments that manage CCR after the rule goes into effect. For any CCR landfills and impoundments that closed before the effective date, there would be no regulatory controls over those units, unless the states choose to adopt controls over such units. Also, all surface impoundments (existing and new) would need to have composite liners within 5-years of the effective date. Consistent with the Subtitle C approach, existing landfills would not need to be lined.
- Requirements would not be enforceable by EPA or the states (unless states had similar requirements under state law). Lack of enforcement and Federal oversight may significantly reduce compliance and effective implementation of regulatory requirements.
- Although this option does not require phase-out of existing surface impoundments, it could cause some phase-out because all surface impoundments would need to have composite liners by a certain date, or they would need to close down, assuming the rule is effectively implemented by the states.
- Eliminates some ground-water contamination over the current situation (e.g., because of surface impoundment retrofitting), thus avoiding some damage cases, again assuming effective implementation.

- Require review of surface impoundments for stability by independent experts, but because impoundments could remain in operation (because they are currently lined or owners choose to retrofit line them rather than phase them out), there would still be a risk of future structural failures of impoundments.

Option 3: RCRA Subtitle "D prime":

- Regulation of disposal under subtitle D, with liners required only for new surface impoundments and landfills. This approach would be the same as the subtitle D approach above, except that existing surface impoundments would not be required to retrofit and install a composite liner, or close. Unlined existing impoundments could continue to operate, but new landfills and surface impoundments or expansions of existing landfills must have composite liners.
- Under this approach the potential for catastrophic failure of surface impoundments would remain significant, since phase-out of surface impoundments wouldn't occur.
- Would be less effective than the subtitle C or subtitle D approaches in eliminating groundwater contamination (or in having it be discovered sooner), but would still provide some benefits over no national regulation. (The same caveats on state regulations and enforcement would apply as in the subtitle D option.)
- Would reduce regulatory costs significantly since conversion to dry disposal would not be required, but would also provide fewer benefits.

Evaluation of three regulatory options is consistent with OMB's 2003 "Circular A-4: Regulatory Analysis" best practices guidance for Federal agencies, which requires analysis of at least three regulatory options.[25] All three regulatory options are identical in two ways:

1. Beneficial use: All options propose to replace the 1980 RCRA "Bevill exclusion" under 40 CFR 261.4(b)(4) for CCR disposal with new RCRA waste regulation, but to retain the existing Bevill exclusion for CCR beneficial uses. Beneficial uses of CCR will retain the Bevill exclusion and will not be subject to any regulation, either under Subtitle C or Subtitle D.

2. Engineering controls: All options propose the same set of **10 custom-tailored engineering controls** (i.e., technical design and operating standards) for CCR disposal units. For purpose of launching this RIA in April 2009, the waste disposal "management standards" described in EPA's August 1999 cement kiln dust (CKD) proposed rule[26] were used in absence of uniquely defined controls specific to CCR disposal units. This was a reasonable starting point because the CKD management standards are similar or identical to the technical standards defined in the CCR proposed rule.

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[25] OMB's 2003 Circular A-4 (p.16) directs Federal agencies to analyze at least three regulatory options: http://www.whitehouse.gov/omb/assets/omb/circulars/a004/a-4.pdf
[26] EPA's 20 August 1999 CKD proposed rule (Federal Register, 67 pages).

During EPA's April 2009 launch of this RIA, EPA defined three other RCRA options which are very similar to the above three options. The initial set of options is included in EPA's October, 8 2009 initial draft (165 pages) of this RIA which EPA submitted to OMB for review in mid-October 2009. The regulatory cost estimation in **Chapter 4** and the supplemental analyses in **Chapter 7** of this RIA are based on the initial set of three options, defined as follows:

2009 Option 1: RCRA Subtitle C "*hazardous*" industrial waste:

- Subtitle C provides Federal enforceability.
- RCRA Section 3004(x)[27]custom-tailor engineering controls (i.e., technical standards) for CCR disposal units.
- Subject CCR to Subtitle C land disposal restriction (LDR) treatment standards prior to disposal:
    - Dry CCR (landfills): Moisture conditioning and compaction to attain 95% dry density value.
    - Wet CCR (impoundments): Dewatering and dry disposal within 5 years after rule's effective date.

2009 Option 2: RCRA Subtitle D "*non-hazardous*" industrial waste (version 1):

- This option is different from the 2010 Option 2: Subtitle D option because it does not require liners for existing impoundments as the 2010 Option 2 does, but it only requires liners for new impoundments (and only for new landfills).
- Regulate CCR disposal as RCRA Subtitle D non-hazardous waste based on the same custom-tailored engineering controls as the 2009 Option 1.
- Except under RCRA Section 7003 "*imminent and substantial endangerment*" authority, this option is not Federally enforceable because RCRA Subtitle D directs EPA only to assist state government waste management programs.[28]

2009 Option 3: Hybrid RCRA Subtitle C & Subtitle D:

- Subtitle C regulation of CCR impoundments (same as the 2009 Option 1)
- Subtitle D regulation of CCR landfills (same as the 2009 Option 2)

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[27] The following excerpt from RCRA Section 3004(x) pertains specifically to CCR, by providing EPA with authority "to modify" the RCRA Subtitle C technical standards for regulation of CCR disposal:

> "*Section 3004(x): If… (2) fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels… is subject to regulation under this subtitle, the [EPA] Administrator is authorized to modify the requirements of subsections (c), (d), (e), (f), (g), (o) and (u) and section 3005(j), in the case of landfills or surface impoundments receiving such solid waste, to take into account the special characteristics of such wastes, the practical difficulties associated with implementation of such requirements, and site-specific characteristics, including but not limited to the climate, geology, hydrology and soil chemistry at the site, so long as such modified requirements assure protection of human health and the environment*."

[28] Section 4001 of Subtitle D of the 1976 RCRA statute prescribes the Federal role under Subtitle D as assistance to state governments: "*The objectives of this subtitle are to assist in developing and encouraging methods for the disposal of solid waste… Such objectives are to be accomplished through Federal technical and financial assistance to States or regional authorities for comprehensive planning pursuant to Federal guidelines designed to foster cooperation among Federal, State and local governments and private industry*."

Chapter 3
Baseline CCR Management in the Electric Utility Industry

This Chapter characterizes baseline (i.e., current) CCR management practices within the electric utility industry. This baseline consists of two components described in this Chapter: CCR disposal and CCR beneficial use. This Chapter begins with a description of baseline CCR management quantities (i.e., annual tonnages of CCR) and CCR disposal methods used by the electric utility industry. This Chapter also presents an evaluation of baseline operating conditions (i.e., "engineering controls" and "ancillary costs") of CCR disposal units and an estimate of the associated costs to the electric utility industry. This Chapter concludes with a characterization of baseline CCR "beneficial use" (for CCR which is not disposed) and an estimate of associated net benefits to the environment and the national economy.

3A. Identity of Coal-Fired Electric Utility Plants

This RIA initially identified the sub-group of potentially affected coal-fired electric utility plants using the 2007 US Department of Energy (DOE), Energy Information Agency (EIA) database for electricity power plants from the Form EIA-860 "Annual Electric Generator Report." This data was supplemented with the master list of utility plants from the 2007 EIA-860 database entitled "existingunits2007". [29] This RIA applied three database filters to identify the subset of electricity plants which may potentially be affected by the proposed rule:

- **Database filter #1 of 3**: EPA sorted the 2007 EIA-860 electric plant database by the North American Industry Classification System (NAICS) industrial codes, and deleted all plants not assigned utility sector NAICS code 22 (only 2-digit NAICS codes are provided by the EIA database).

  NAICS 22: *The Utilities sector comprises establishments engaged in the provision of the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Within this sector, the specific activities associated with the utility services provided vary by utility: electric power includes generation, transmission, and distribution; natural gas includes distribution; steam supply includes provision and/or distribution; water supply includes treatment and distribution; and sewage removal includes collection, treatment, and disposal of waste through sewer systems and sewage treatment facilities. Excluded from this sector are establishments primarily engaged in waste management services classified in Subsector 562 Waste Management and Remediation Services. These establishments also collect, treat, and dispose of waste*

[29] The EIA-860 database is itemized on an electricity generator unit basis, not on a per-plant basis. It includes specific information about generators at electric power plants owned and operated by electric utilities and non-utility industries (i.e., including independent power producers, combined heat and power producers, and other industrials). The file contains generator-specific information such as initial date of commercial operation, prime movers, generating capacity, energy sources, status of existing and proposed generators, proposed changes to existing generators, county and State location (including power plant address), ownership, and FERC qualifying facility status. Also included are data related to the ability to use multiple fuels; specifically, data on co-firing and fuel switching are included. The DOE spreadsheet "existingunits2007" is available at http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html.

materials; however, they do not use sewer systems or sewage treatment facilities" Source: US Bureau of Census at: http://www.census.gov/eos/www/naics/

- **Database filter #2 of 3**: EPA deleted all of the units that did not use coal as either a primary or secondary energy source using the coal type codes displayed in **Exhibit 3A** below. In addition to these five categories of coal, examples of other primary or secondary energy sources reported by coal burning electric utility plants are agriculture byproducts, distillate fuel oil, natural gas, petroleum coke, propane, and wood & waste solids.

Exhibit 3A
Types of Coal Used by Electric Utility Plants as Coded in the 2007 DOE-EIA Database

Item	Code	Type of Coal
1	BIT	Anthracite Coal, Bituminous Coal
2	LIG	Lignite Coal
3	SUB	Sub-bituminous Coal
4	WC	Waste/Other Coal (Anthracite Culm, Bituminous Gob, Fine Coal, Lignite Waste, Waste Coal)
5	SC	Coal Synfuel. Coal-based solid fuel that has been processed by a coal synfuel plant, and coal-based fuels such as briquettes, pellets, or extrusions, which are formed from fresh or recycled coal and binding materials.

- **Database filter #3 of 3**: The first two filter criteria resulted in a subset of 506 coal-fired electric utility plants. Based on the reported operating status of the generators at these plants (i.e., OP, OS, SB, RE, OA)[30], 11 plants reported that all generators are out-of-service, 2 plants reported that all generators are on standby and all remaining plants reported that at least one of their generators is operating. Removal of the 11 out-of-service plants from the master list resulted in a total affected plant population of **495 coal-fired electric utility plants**.[31] **Appendix C** presents the list of 495 plants.[32]

For purpose of identifying the types and size classifications for owner entities, this RIA initially used the utility code reported in the 2007 EIA-860 database to identify which plants are owned by the same company. Company owner classifications were also checked for many plants using internet searches by plant and company name which sometimes revealed parent company owners. As summarized in **Exhibit 3B** and

[30] OP = Operating - in service (commercial operation) and producing electricity. Includes peaking units that are run on an as needed (intermittent or seasonal) basis, OS = Out of service – was not used for some or all of the reporting period and is NOT expected to be returned to service in the next calendar year, SB = Standby/Backup - available for service but not normally used (has little or no generation during the year) for this reporting period, RE = Retired - no longer in service and not expected to be returned to service, and OA = Out of service – was not used for some or all of the reporting period but was either returned to service on Dec 31 or will be returned to service in the next calendar year. Note: Units undergoing maintenance or repair of less than 12 months and are expected to be returned to service are assigned operating status.
[31] This RIA filtered out 11 out-of-service electricity plant identification codes: 508, 511, 996, 1732, 2341, 2468, 2529, 2531, 2908, 3419, and 55612.
[32] In comparison, a 2008 EPA Office of Water (OW) study estimated a nationwide total of 497 coal-fired electric plants using the same 2005 EIA-767 database; the 495 plants estimated in this RIA are less than the 2008 EPA OW estimate because this RIA takes account of more recent plant operating status information (i.e., plants which have converted to other non-coal fuels or are not operating). Source: Table 3-1 (page 3-9) of EPA Office of Waster "Steam Electric Power Generating Point Source Category: 2007/2008 Detailed Study Report," report nr. 821-R-08-011, August 2008; http://www.epa.gov/guide/304m/2008/steam-detailed-200809.pdf

Exhibit 3C below, these 495 coal-fired electric utility plants are owned and operated by 200 entities which are listed in **Appendix D** to this RIA. The 495 plants have a combined electricity generation nameplate capacity of 369,183 MW (megawatts), ranging in individual plant size from 2.3 MW to 3,969 MW, with an average size of 746 MW and a median size of 497 MW. This combined capacity represents 34% of the 1.088 million MW total US electricity generation capacity as of 2007.[33]

Exhibit 3B
Summary Classification of 495 Coal-Fired Electric Utility Plants by Type/Size of Owner Entities (2007)

Item	Type of Owner Entity*	Entity Size Class**	Coal-Fired Electric Utility Plant Count	Owner Entity Count
1	Federal government	Non-small	11	1
2	State government jurisdictions (authorities, districts)	Non-small	13	7
3	Medium & large population municipal government jurisdictions	Non-small	27	19
4	Medium & large companies	Non-small	372	110
5	Medium & large cooperatives (this RIA assumes all privately-owned)	Non-small	20	12
6	Small county government jurisdictions (commission)	Small	1	1
7	Small municipal government jurisdictions (agencies, commissions)	Small	33	33
8	Small companies	Small	12	11
9	Small cooperatives (this RIA assumes all privately-owned)	Small	6	6
Summary:				
		Column totals =	**495**	**200**
		Private sector sub-total (items 4+5+8+9) =	410 (83%)	139 (70%)
		State/local government sub-total (items 2+3+6+7) =	74 (15%)	60 (30%)
		Small entity sub-total (items 6+7+8+9) =	52 (11%)	51 (26%)

Notes:
* Type of owner entity estimated and assigned by EPA ORCR based on owner name or internet research on type of ownership.
** Size class determined according to the following numerical threshold criteria consistent with EPA's Nov 2006 guidance for Regulatory Flexibility Act (RFA) Small Business Regulatory Enforcement Fairness Act (SBREFA) compliance:

- Small non-government = Based on the US Small Business Administration NAICS code 221112 small business size standard of <4 million megawatt hours per year total annual electricity generation by all plants owned by the entity).
- Non-small non-government = entity's total annual electricity generation >4 million megawatt hours per year.
- Small government = Based on the RFA'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 a population of less than 50,000.
- Non-small government = entity's jurisdiction population >50,000 people.

[33] Source: US Dept of Energy (DOE), Energy Information Administration (EIA) website at http://www.eia.doe.gov/cneaf/electricity/epa/epat2p2.html

Exhibit 3C
State-by-State Electric Utility Plant Counts by Type/Size of Owner Entity (2007)

Item	State	Count of Plants Owned by Non-Small Entities					Count of Plants Owned by Small Entities				Row total plants
		Federal government	State Government	Non-small municipal	Non-small company	Non-small cooperative	County government	Small municipal	Small company	Small cooperative	
1	AK								2		2
2	AL	2			7	1					10
3	AR				3						3
4	AZ		2		3	1					6
5	CA				6						6
6	CO		1	2	11						14
7	CT				2						2
8	DC										0
9	DE				3						3
10	FL			5	9	1					15
11	GA				10		1				11
12	HI				2						2
13	IA			1	13			3		2	19
14	ID										0
15	IL			2	21					2	25
16	IN				21			5			26
17	KS			2	6						8
18	KY	2		1	14	3		1			21
19	LA				4						4
20	MA				4						4
21	MD				8						8
22	ME				1						1
23	MI			2	13			5	2		22
24	MN			1	10			5			16
25	MO			5	10	2		2		1	20
26	MS				3	1		1			5
27	MT				4				1		5
28	NC				19				3		22
29	ND				2	5					7
30	NE		4					3			7
31	NH				2						2
32	NJ			1	6						7
33	NM				3						3
34	NV				2						2
35	NY				11			1	1		13
36	OH			2	20			4			26
37	OK		1		4	1					6
38	OR				1						1

Exhibit 3C State-by-State Electric Utility Plant Counts by Type/Size of Owner Entity (2007)											
		Count of Plants Owned by Non-Small Entities					Count of Plants Owned by Small Entities				
Item	State	Federal government	State Government	Non-small municipal	Non-small company	Non-small cooperative	County government	Small municipal	Small company	Small cooperative	Row total plants
39	PA				32				2		34
40	RI										0
41	SC		4		10						14
42	SD				2						2
43	TN	7									7
44	TX		1	2	14			1		1	19
45	UT			1	4	1					6
46	VA				15				1		16
47	VT										0
48	WA				1						1
49	WI				12	3		2			17
50	WV				16						16
51	WY				8	1					9
Column totals=		11	13	27	372	20	1	33	12	6	**495**

The annual amount of coal burned by these 495 operating plants is 1.036 billion tons per year as reported in the 2007 EIA-923 database, according to the following five types of coal fuel categories:

- Bituminous coal (DOE-EIA data code = BIT): 330 plants (67% of 495 plants)
- Lignite coal (LIG): 21 plants (4%)
- Coal-based synthetic fuel (SC): 19 plants (4%)
- Sub-bituminous coal (SUB): 201 plants (41%)
- Waste/other coal (WC): 33 plants (7%)

Many plants use more than one coal fuel type so the above percentages exceed 100%. **Appendices B & C** present the quantity of coal burned and the types of coal burned for the list of 495 plants. As displayed in the state-by-state **Exhibit 3D** below, 47 states have coal-fired electric utility plants (3 states --- ID, RI, VT --- and DC do not have electric utility plants). The top-5 state coal-fired electric utility plant counts are:

1. PA 34 plants
2. IN & OH 26 plants each
3. IL 25 plants
4. MI & NC 22 plants each
5. KY 21plants

Exhibit 3D
State-by-State Count of NAICS Code 22 Electric Utility Plants and Associated CCR Generation

Item	State	Count of Plants (2007)	% of Plants	CCR Generated (tons as of 2005)	% of CCR Generation
1	AK	2	0.40%	46,179	0.03%
2	AL	10	2.02%	3,210,337	2.27%
3	AR	3	0.61%	744,267	0.53%
4	AZ	6	1.21%	3,334,030	2.36%
5	CA	6	1.21%	159,927	0.11%
6	CO	14	2.83%	1,704,432	1.21%
7	CT	2	0.40%	172,280	0.12%
8	DC	0	0%	0	0%
9	DE	3	0.61%	251,205	0.18%
10	FL	15	3.03%	6,132,345	4.34%
11	GA	11	2.22%	6,077,700	4.30%
12	HI	2	0.40%	58,968	0.04%
13	IA	19	3.84%	1,136,290	0.80%
14	ID	0	0%	0	0%
15	IL	25	5.05%	3,856,748	2.73%
16	IN	26	5.25%	8,798,844	6.23%
17	KS	8	1.62%	1,495,099	1.06%
18	KY	21	4.24%	9,197,567	6.51%
19	LA	4	0.81%	1,614,800	1.14%
20	MA	4	0.81%	363,150	0.26%
21	MD	8	1.62%	1,932,740	1.37%
22	ME	1	0.20%	48,000	0.03%
23	MI	22	4.44%	2,369,673	1.68%
24	MN	16	3.23%	1,525,979	1.08%
25	MO	20	4.04%	2,679,742	1.90%
26	MS	5	1.01%	1,229,400	0.87%
27	MT	5	1.01%	1,830,624	1.30%
28	NC	22	4.44%	5,504,531	3.90%
29	ND	7	1.41%	3,038,100	2.15%

Exhibit 3D
State-by-State Count of NAICS Code 22 Electric Utility Plants and Associated CCR Generation

Item	State	Count of Plants (2007)	% of Plants	CCR Generated (tons as of 2005)	% of CCR Generation
30	NE	7	1.41%	614,473	0.44%
31	NH	2	0.40%	176,900	0.13%
32	NJ	7	1.41%	735,214	0.52%
33	NM	3	0.61%	3,983,300	2.82%
34	NV	2	0.40%	391,500	0.28%
35	NY	13	2.63%	1,479,792	1.05%
36	OH	26	5.25%	10,429,446	7.39%
37	OK	6	1.21%	1,490,800	1.06%
38	OR	1	0.20%	99,900	0.07%
39	PA	34	6.87%	15,359,680	10.88%
40	RI	0	0%	0	0%
41	SC	14	2.83%	2,178,359	1.54%
42	SD	2	0.40%	103,753	0.07%
43	TN	7	1.41%	3,240,120	2.29%
44	TX	19	3.84%	13,165,728	9.32%
45	UT	6	1.21%	2,582,144	1.83%
46	VA	16	3.23%	2,388,527	1.69%
47	VT	0	0%	0	0%
48	WA	1	0.20%	1,405,220	1.00%
49	WI	17	3.43%	1,412,534	1.00%
50	WV	16	3.23%	9,231,718	6.54%
51	WY	9	1.82%	2,224,848	1.58%
	Total	**495**	100%	**141.2 million***	100%

* Note: In comparison to this estimate based on DOE-EIA databases cited in this RIA, the American Coal Ash Association (ACAA) estimated 123.1 million tons CCR generated in 2005 based on its annual voluntary participation survey : http://acaa.affiniscape.com/associations/8003/files/2005%20CCP%20Survey%20%2809-19-06%29Corrected-11-09-07.pdf

3B. Types of CCR Disposal Units

- **Estimated Plant Counts by Type of CCR Disposal Unit**

The scope of CCR disposal units covered by this RIA is active units (i.e., operational units which were receiving CCR as of year 2005). Inactive or abandoned units (i.e., non-operating units) are excluded from the scope of this RIA. The data source used to identify baseline CCR management practices and active units is the 2005 U.S. Department of Energy (DOE) Energy Information Administration (EIA) Form EIA-767 "Steam-Electric Plant Operation and Design Report" database.[34] The EIA-767 database is the primary data source for reporting annual CCR disposition for plants generating greater than 100 MW (megawatts) of electricity. Plants smaller than 100 MW are not required to report CCR tonnage and disposition (i.e., type of disposal and beneficial use) data to the EIA-767 database. Schedule 3 of the EIA-767 database contains the annual disposition of CCR in one or more of the following five forms of CCR management categories, according to annual tons disposed for each plant. EIA-767 does not contain counts of CCR disposal units for each plant:

1. Company-owned landfill
2. Company-owned disposal ponds (i.e., surface impoundments)
3. Onsite use and storage (this RIA assumes all of this quantity eventually goes to beneficial use, not disposal)
4. Sold (for beneficial use)
5. Disposed off site

The 2005 EIA-767 database contained annual CCR disposal data for 363 of the 495 plants identified in the 2007 EIA-860 database. The 363 plants are over 100 MW in size and thus are covered by the EIA-767 database. For the 132 plants which did not report CCR disposal practices in the 2005 EIA-767 database because they are less than 100 MW in size, disposal of CCR is assumed to take place in on-site or off-site landfills (whichever is the lowest-cost method as assigned by the CCR disposal engineering control cost model used for this RIA). For each of the 495 coal-fired utility plants identified in the prior section of this RIA using the 2007 EIA-860 database, baseline CCR disposal practices were assigned using the methodology and data sources presented below. Based on this analysis, **467 of the 495 plants dispose CCR** using the following methods. The 28 remainder of the 495 plants do not dispose because they solely supply their CCR for beneficial uses. A total of 272 of the 495 plants supply CCR for beneficial uses. The total count of disposal methods exceeds the 467 total count of disposing plants because some plants use more than one disposal method. The EIA-767 database does not contain counts of disposal units for each plant so only plant counts are summarized below according to disposal method, not CCR disposal unit counts. Because some plants use more than one disposal unit, the total count of CCR disposal units – although unknown for purpose of this RIA -- exceeds the 467 total count of disposing plants.

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[34] Source: The EIA-767 database includes annual data from organic-fueled or combustible renewable steam-electric plants with a generator nameplate rating of 10 or more megawatts (MW) regardless of current ownership and/or operation. However, it contains annual tonnage CCR generation, CCR disposal, and CCR beneficial use data only for plants over 100MW in size. The EIA terminated the EIA-767 database after year 2005. Beginning with calendar year 2007 data, two other surveys, the Form EIA-860 and the Form EIA-923, will collect most of the data formerly collected by Form EIA-767. No data will be collected for 2006. The following weblink provides a crosswalk of the data elements previously collected on the Form EIA-767 for 2005 with the corresponding data elements to be collected beginning with calendar year 2007 on the Form EIA-860 or the Form EIA-923: http://www.eia.doe.gov/cneaf/electricity/2008forms/consolidate.html

- Onsite landfills: **311 plants** operate onsite CCR landfills (this RIA refers to these as "onsite" landfills although some may be located off plant property). This estimate consists of two sources (i.e., 212 plants + 99 plants):
  - 212 plants: dentified through actual data reporting of 363 coal-fired electric plants in size >100 MW contained in the 2005 EIA-767 database, out of the total 495 plants identified using the 2007 EIA-860 database (as described in the previous section above).
  - 99 plants: This estimate is based on the remainder 132 electric utility plants (i.e., 495 minus 363 plants = 132 plants) between 1 MW and 100 MW size for which there is no CCR disposal data in the EIA-767 database, and for which the CCR disposal engineering control cost model used in this RIA assigned the lowest-cost of three landfill options: (1) onsite dug landfill, (2) onsite pile landfill, or (3) offsite landfill. The cost model assignment was dependent upon the level of baseline engineering controls assumed required by each plant's state location and annual CCR disposal tonnage. The cost model estimated that 99 of the 132 plants without data dispose CCR in onsite landfills.

- Onsite impoundments: **158 plants** operate onsite CCR surface impoundments (aka "ponds," "embankments," "dams," "dikes," "wet dumps," "constructed wetlands"). This RIA assumes that all impoundments are "onsite" although some may be located off plant property.

  The non-duplicative count of plants using onsite landfills and/or onsite impoundments is **383 plants**.

- Offsite disposal: **149 plants** assigned as sending CCR offsite for disposal to commercial landfills (of which 84 plants solely ship CCR for offsite disposal). Off-site landfills receiving CCR are assumed to already be in compliance with EPA's RCRA Subtitle D guidance. The 149 plants assigned as using offsite landfills consist of the following assignments according to data sources (i.e., 116 plants + 33 plants):
  - <u>116 plants</u>: Electric utility plants >100 MW size (source: 2005 EIA-767 database): Final disposition of wastes is reported as either (a) company-owned landfill, (b) company-owned disposal pond, (c) on-site use & storage, (d) sold, or (e) off-site disposal. This RIA assumes that off-site disposal means offsite commercial landfill. Plants could have reported offsite minefill in this category if it was not "sold" (e.g., they paid to dispose it in a mine or it was used as minefill and no payment was made to the electric utility). However, it is unknown the sub-quantity of "offsite disposal" which includes plants reporting tonnages for non-sold uses as offsite minefill.[35]

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[35] In July 2009, ORCR contacted the DOE-EIA Form 767 questionnaire contact person (Natalie Ko, Electric Power Division) to clarify this RIA's assignment of all "offsite disposal" tonnages as commercial landfills. The DOE-EIA contact person responded with additional information from four 2005 Form EIA-767 questionnaires regarding how electricity plant respondents optionally characterized the fly ash and bottom ash reported in the Form EIA-767 survey questionnaire as "Off Site Disposal" :
· "This quantity of fly ash was given away at no cost"
· "The fly ash was sent off site for beneficial use"
· "The fly ash is injected into the nearby mines for recharging the mines"
· "Ash is recycled as a beneficial re-use product for flowable fill in the construction industry"

- 92 plants Offsite landfill fly ash
- 76 plants Offsite landfill bottom ash
- 4 plants Offsite landfill gypsum
- 16 plants Offsite landfill FGD
- 7 plants Offsite landfill other CCR (i.e., coal combustion by-products)
- Sub-total = 116 plants (non-duplicative count)

▪ 33 plants: This estimate is based on the 132 electric utility plants between 1 MW and 100 MW size for which there is no CCR disposal data in the EIA-767 database, and for which the CCR disposal engineering control cost model used in this RIA assigned the lowest-cost of three landfill options: (1) onsite dug landfill, (2) onsite pile landfill, or (3) offsite landfill. The cost model assignment was dependent upon the level of baseline engineering controls assumed required by each plant's state location and annual CCR disposal tonnage.

- **Estimated Counts of CCR Disposal Units**

The methodology of this RIA does not estimate or use secondary information about the actual count of CCR disposal units (i.e., landfill units and impoundment units) used by these 467 onsite or offsite disposing plants. However, there are two sources of CCR disposal unit counts:

- Source #1 of 2: ASTSWMO: The February-March 2009 ASTSWMO voluntary participation survey[36] of 42 states (which is incomplete coverage of the 47 states identified in this RIA for the 495 coal-fired electric plants) estimates a total of 484 electric utility plant CCR disposal units:

  - 227 electric utility plant CCR landfill units in 41 states
  - 257 electric utility plant CCR impoundment units in 33 states
  - Total electric utility plant CCR disposal units = 484 (i.e., 227 landfills + 257 impoundments)

But it is not clear whether the ASTSWMO CCR disposal unit counts (a) are restricted in the ASTSWMO survey to electric utility plants in NAICS code 221112, (b) may also include counts of CCR disposal units associated with other industries which generate coal-fired electricity in the surveyed states, (c) may include inactive/abandoned as well as active CCR disposal units, or (d) may include landfills or impoundments operated by electric utility plants which contain other types of waste streams (e.g. waste water treatment ponds without co-mingled CCR).

Source #2 of 2: EPA: In March 2009 EPA sent letters[37] to 210 coal-fired electric plant facilities and owner companies in order to identify the location of CCR impoundments and evaluate their structural integrity in the wake of the December 2008 CCR impoundment collapse and

[36] Source: Association of State and Territorial Solid Waste Management Officials (ASTSWMO), 01 April 2009 letter to Matt Hale, Director, EPA Office of Resource Conservation and Recovery: http://www.astswmo.org/files/publications/Positionpapers/ASTSWMO-CCB-letter-attachments.pdf

flooding at the TVA Kingston TN electricity plant. Although not used in this RIA other than for reference here, the responses received to the March 2009 EPA letters resulted in identification of 584 CCR impoundments units at electric utility plants. The letters did not collect information about CCR landfills[38]

3C. Types of CCR and Annual Quantities

As of 2008, coal-fired utilities burn approximately 1.036 billion tons of coal per year using a variety of conventional combustion technologies. NAICS 22 electric utility coal combustion results in the generation of five types of CCR:

1. Fly ash
2. Bottom ash
3. Flue gas desulfurization (FGD) sludge
4. Gypsum
5. Other residues (including boiler slag)

These wastes may be (a) disposed in onsite landfills and surface impoundments (i.e., ponds, dams, embankments, lagoons), or (b) may be applied to beneficial uses, or (c) disposed offsite. At the time of preparing this RIA in 2009, waste generation and disposition data from Schedule 8, Part A of the 2007 DOE EIA database for the Form EIA-932 "Power Plant Operations Report" database had yet to be finalized. Instead, the most currently available waste data was from the 2005 DOE EIA Form 767 "Steam-Electric Plant Operation and Design Report" database. Therefore, the 2005 EIA-767 database is the primary source used in this RIA to quantify CCR generation and identify the ultimate disposition of CCR (i.e., type of disposal or beneficial use). CCR generation and final disposition are reported under the above five CCR type categories in the 2005 EIA 767 database. As estimated in this RIA and displayed below in **Exhibit 3E**, the 495 electric utility plants generated **141.2 million tons per year** of CCR (2005/2007 mixed data).

Interpretive Note: This RIA's CCR generation estimate of 141.2 million tons is 15% and 8% higher, respectively, than the **123.1 million tons (2005)** and the **131.1 million tons (2007)** annual CCR generation estimates published by the American Coal Ash Association (ACAA).[39] The numerical discrepancy between this RIA's estimate and the ACAA estimates may be explained by the fact that both estimates (i.e., this RIA and the ACAA) are based on incomplete CCR tonnage disposition data for less than the "universe" of all known operating

[37] Source: Additional information about these March 2009 EPA letters is available at http://www.epa.gov/osw/nonhaz/industrial/special/fossil/coalashletter.htm
[38] Source: EPA's 584 CCR impoundment unit count is documented at http://www.epa.gov/osw/nonhaz/industrial/special/fossil/surveys/faqs.htm#18
[39] As of the date of this RIA, ACAA's "Coal Combustion Products Production & Use Statistics" website contains annual CCR generation and annual CCR beneficial use tonnage estimates for the US electric utility industry for years 2001, 2002, 2003, 2004, 2005, 2006, 2007, and 2008. As reported in footnotes on ACAA's annual survey results data tables, ACAA's CCR generation and CCR beneficial use annual tonnage estimates are based on the following survey coverages: 2001 coverage not indicated on data table; 2002 2/3rd coal burn; 2003 60% coal burn; 2004 60% coal burn; 2005 54% coal burn; 2006 57% coal burn reported by 58 electric utilities; 2007 161 plants; and 2008 274 plants. ACAA's annual CCR tonnage data webpage is at http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=3

electric utility plants in the data year, extrapolated to plants for which there is no CCR tonnage data in the EIA database (in the case of this RIA's estimation methodology) and in the case of the ACAA estimates, extrapolated to plants not covered by ACAA's annual utility industry survey by supplementing with EIA data.

The estimate of CCR generation developed in this RIA consists of the following breakout of generation estimates according to two electric utility plant size categories, which correspond to the CCR tonnage disposition data reporting cut-off requirement in the EIA-767 database:

- >100 MW plants: **Exhibit 3E** below presents CCR disposition data for a sub-total of **120.9 million tons** CCR generated per year as reported by plants with annual electricity generation >100 MW from Schedule 3A of the 2005 EIA-767 database for each plant.
  - Ash generation data (fly ash and bottom ash) were available for 385 plants.
  - FGD sludge generation data were available for 72 plants.
  - Gypsum generation data were available for 31 plants.
  - Other byproduct generation data were available for 40 plants.

  If plants > 100 MW reported either company landfill, company disposal ponds, sold for beneficial use, or off-site disposal of CCR in the EIA-767 database, these final disposition practices are assumed in this RIA for the baseline. A total 179 plants with company-owned CCR landfills and 158 plants with company-owned CCR surface impoundments were reported in the 2005 EIA-767 database (i.e., 337 of the 495 electric plants).[40] 112 of the 495 plants reported 8.2 million "on-site use and storage" which this RIA assigned as beneficial use not as disposal. This assumption is supported by (a) DOE's August 2006 report[41] "Coal Combustion Waste Management at Landfills and Surface Impoundments 1994-2004" which interpreted the entire "onsite use & storage" quantity as beneficial use, and (b) the American Coal Ash Association (ACAA) which indicates that 49.6 million tons of coal ash were beneficially used in 2005[42]. However, the beneficial use estimate in **Exhibit 3E** below is much less at 38.8 million tons which is based on the EIA-767 "Sold" (i.e., beneficial use) CCR tonnage category. But adding the 8.2 million tons reported as "onsite use & storage" yields an estimate of 47.0 million tons (**Exhibit 3G**), which nearly matches the ACAA beneficial use estimate of 49.6 million tons. This suggests it is valid to assign the tonnage reported in the EIA-767 database as "onsite use & storage" to beneficial use rather than to disposal.

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[40] In the 2005 DPRA Report, an additional step was included after step 1 that identified additional disposal practices using landfill and surface impoundment as reported in the 1995 EPRI Comanagement Survey. This data source was not used to identify CCR management units in this RIA given it dates back to 1995. The data source is only used to identify existing engineering controls for the units identified in the 2005 EIA 767 database. In the 2005 DPRA Report, 14 additional landfills and 10 surface impoundments were identified using this information source.

[41] Source: Footnote c of Table 1 on page 6 of DOE's August 2006 report at http://www.ead.anl.gov/pub/dsp_detail.cfm?PubID=2008

[42] Source: ACAA's 2005 beneficial use data are available at http://acaa.affiniscape.com/associations/8003/files/2005%20CCP%20Survey%20%2809-19-06%29Corrected-11-09-07.pdf

- 1MW to 100 MW **Exhibit 3F** below presents an additional sub-total of **20.3 million tons** per year of CCR generated by 132 electric utility plants between 1 MW and 100 MW in capacity which had no CCR management information in the EIA767 database, because plants less than 100 MW are not required to report their CCR management annual tonnages in the EIA-767 database. Therefore, this RIA formulated an estimate for this size category of plants based on the following approach. Coal use and percent ash content data from Schedule 4A of the 2005 EIA-767 database were used to estimate ash generation quantities for 102 plants within this smaller size category. For 5 plants for which EIA-767 coal use data were unavailable for 2005, coal use data from Schedule 4A of the 2007 EIA-923 database were used to estimate CCR generation quantities for those 5 plants. FGD sludge generation data obtained from Schedule 8[43] of the 2005 EIA-767 database were used for 115 plants. Landfill (either on-site or off-site whichever is more economical) is the assumed CCR disposal practice. No gypsum or other byproduct generation quantities were estimated. For plants between 1 MW and 10 MW, ash generation quantities estimated using generator nameplate capacity rating data from the 2007 DOE Form 860 database. This 1 MW to 100 MW subtotal of 132 plants consists of two sub-categories:

  - <u>10 MW to 100 MW</u>: 5.4 million tons of CCR for 110 plants estimated by multiplying the quantity of coal they burned by the percent CCR content of the coal data from Schedule 4A of the 2005 EIA-767 database and 2007 DOE EIA 923 database, or using generator nameplate rating data from the 2007 EIA-860 database and an average percent ash content.
  - <u>1 MW to 10 MW</u>: 14.9 million tons of FGD sludge reported for 22 plants in Schedule 8 of the 2005 EIA-767 database that did not report any FGD sludge in Schedule 3A of the 2005 EIA-767 database.

[43] In general, data obtained from Schedule 8 of the 2005 EIA-767 database reflects information reported by plants between 10 MW and 100 MW. However, if a plant greater than 100 MW reported no final disposition quantities for FGD sludge in Schedule 3A of the 2005 EIA-767 database, the reported FGD sludge quantity in Schedule 8 is assumed in this RIA to be placed in a landfill for that plant.

Exhibit 3E
Annual CCR Disposition for NAICS 22 Electric Utility Plants >100 MW Capacity (tons per year as of 2005)

Item	CCR Category	A Company-Owned Landfill (Dry Disposal)	B Company-Owned Disposal Ponds (Wet Disposal)	C Onsite Use & Storage (assumed as beneficial use)	D Sold for Beneficial Use	E Offsite Disposal (assumed offsite landfills)	F (A+…+E) Row Totals
1	Fly Ash	21,324,280	15,212,590	3,744,370	20,760,230	9,314,540	70,356,010
2	Bottom Ash	5,707,740	4,311,630	3,487,660	5,453,717	1,907,480	20,868,227
3	Flue Gas Desulfurization Sludge	9,526,400	1,886,200	465,600	408,910	2,506,540	14,793,650
4	Gypsum (salable)	54,620	872,100	372,100	8,437,400	782,800	10,519,020
5	Other CCR	226,510	82,900	108,830	3,729,400	247,680	4,395,320
6	Totals	36.8 million	22.4 million	8.2 million	38.8 million	14.8 million	120.9 million

Exhibit 3F
Annual CCR Disposition for NAICS 22 Electric Utility Plants 1 MW to 100 MW Capacity (tons per year as of 2005)

Item	CCR Category	A Fly Ash Disposed in Off-site Landfill (Plants 1 MW to 100 MW)	B Fly Ash Disposed in Company-owned Landfill (Plants 1 MW to 100 MW)	C FGD Disposed in Company-Owned Landfill (Plants >10 MW)	D (A+B+C) Row Totals
1	Fly Ash	274,917	5,147,468	NA	5,422,385
2	Bottom Ash	Included under Fly Ash	Included under Fly Ash	NA	Included under fly ash
3	Flue Gas Desulfurization Sludge	NA	NA	14,852,300	14,852,300
4	Gypsum (salable)	NA	NA	Included in row 3	Included in FGD
5	Other Byproducts	Included under Fly Ash	Included under Fly Ash	NA	Included under fly ash
6	Totals	0.3 million	5.1 million	14.9 million	20.3 million

Exhibit 3G
Annual CCR Disposition for NAICS 22 Electric Utility Plants All Sizes (tons per year as of 2005)
(Source: **Exhibit 3E** + **Exhibit 3F**)

Item	CCR Category	A Company-Owned Landfill (Dry disposal)	B Company-Owned Disposal Ponds (Wet disposal)	C Beneficial Use (onsite BU + offsite BU + storage for BU)	D Offsite Disposal (assumed offsite commercial landfills)	E (A+B+C+D) Row Totals
1	Fly Ash	26,471,748	15,212,590	24,504,600	9,589,457	70,356,010
2	Bottom Ash	5,707,740	4,311,630	8,941,377	1,907,480	20,868,227
3	Flue Gas Desulfurization Sludge	24,378,700	1,886,200	874,510	2,506,540	14,793,650
4	Gypsum (salable)	54,620	872,100	8,809,500	782,800	10,519,020
5	Other CCR	226,510	82,900	3,838,230	247,680	4,395,320
6	Totals	**56.8 million**	**22.4 million**	**47.0 million**	**15.0 million**	**141.2 million**
	Percentages	40%	16%	33%	11%	100%

Exhibit 3H below summarizes the respective plant counts, annual tonnage CCR disposal, and electricity generation nameplate capacities of the 467 plants which dispose CCR, according to type of CCR disposal method (i.e., CCR landfills and CCR impoundments). Because some plants reported more than one management method, the sum of the plants across each disposal method exceeds the total count of 467 disposing plants.

Exhibit 3H
Summary of Plant Size and CCR Disposal Methods Estimated in this RIA

	A	B	C	D
	Plants Using CCR Landfills (dry disposal)		Plants Using CCR Impoundments*** (wet disposal)	Row Totals (non-duplicative)
Characterizing Metrics	Onsite Landfills	Offsite**		
1. 2007 Count of Coal-Fired Electric Utility Plants which Dispose CCR	311 plants (63% of 495)	149 plants (30% of 495) (84 plants solely use offsite landfills)	158 plants (32% of 495)	**467 plants dispose CCR** (94% of 495) (CCR from the remainder 28 plants is solely for beneficial uses)
2. Annual CCR Disposal (2005) • Minimum per plant = • Maximum per plant = • Mean per plant = • Median per plant =	56.8 million tons (60%) • 400 tons • 1.82 million tons • 205,196 tons • 90,700 tons	15.0 million tons (16%) • 20 tons • 1.28 million tons • 100,899 tons • 33,000 tons	22.4 million tons (24%) • 500 tons • 1.04 million tons • 141,550 tons • 67,300 tons	**94.2 million tons** (100%) • 110 tons • 2.11 million tons • 201,796 tons • 89,300 tons
3. Nameplate capacity* (2007) • Minimum per plant = • Maximum per plant = • Mean per plant = • Median per plant =	213,978 MW (58%) • 11 MW • 3,969 MW • 772 MW • 538 MW	90,547 MW (25%) • 2 MW • 2,911 MW • 608 MW • 350 MW	180,901 MW (49%) • 75.3 MW • 3,564 MW • 1,145 MW • 893 MW	369,183 MW (100%) • 2 MW • 3,969 MW • 746 MW • 497 MW

Notes:
* Nameplate capacity = electricity generation output potential in megawatts (MW).
** This RIA assumes all reported "non-company offsite disposal" in the EIA-767 database involves offsite landfill dry disposal, because it is expensive to transport large volumes of wet (i.e., watery) CCR long distances.
*** Surface impoundments are reported in the EIA-767 database as "company-owned ponds." This RIA assumes all are located onsite.

3D. Size of CCR Disposal Units

The size of CCR disposal units ranges from modest to very large, with some impoundments covering 1,500 acres or more. Sizing of the units is based on the annual tonnage of CCR placed in the unit. CCR disposal unit size assumptions for this RIA are adopted from Section 4.4.1 of the 2005 DPRA Report:

- Landfills sizes:
  Designed as "combination fill landfills"
  - 3.8 million cubic yards capacity
  - 50% of the capacity excavated below grade
  - 40-year capacity (i.e., operating lifespan)[44]
  - Per-unit surface area size ranges from 12 acres for 10,000 tons per year to over 2,000 acres for 2,000,000 tons per year.

  Designed as "pile fill landfills"
  - 3.4 million cubic yards capacity
  - 5% of the capacity excavated below grade
  - 40-year capacity (i.e., operating lifespan)
  - Per-unit surface area ranges from 16 acres for 10,000 tons per year to over 3,000 acres for 2,000,000 tons per year.

- Surface impoundment sizes:
  - 100% of capacity below grade
  - 40-year capacity
  - Per-unit surface area ranges from 30 acres for 10,000 tons per year, 140 acres for 50,000 tons per year, 500 acres for 200,000 tons per year, 1,400 acres for 500,000 tons per year, and 5,500 acres for 2,000,000 tons per year.

[44] For the 30 Nov 2005 DPRA report ("Estimation of Costs for Regulating Fossil Fuel Combustion Ash Management at Large Electric Utilities Under Part 258", docket document ID nr. EPA-HQ-RCRA-2006-0796-0469), the EPA asked utility industry representatives for the typical lifespan years of CCR landfills and impoundments. Industry representatives provided a 40-year estimate for both. This estimate is supported by data provided by industry in the 1995 EPRI Comanagement Survey. In the EPRI Survey, data describing six CCR landfills noted the year the unit was opened and the estimated date of closure. The average life expectancy is 34 years and the median life expectancy is 38 years. Similarly, data provided for 18 CCR impoundments indicate an average life expectancy of 45 years and a median life expectancy of 46 years. Therefore, this RIA assumes a 40-year lifespan for both landfills and impoundments.

3E. Cost of Baseline CCR Disposal

This Chapter presents characterizing data and estimates of the costs to the electric utility industry and to government, for baseline (i.e., current) industry engineering controls and other costs associated with CCR disposal. OMB's 2003 Circular A-4 "Regulatory Analysis" (page 15) requires RIAs to measure the benefits and costs of regulations against a baseline defined as:

Baseline = "*[T]he best assessment of the way the world would look absent the proposed rule.*"

The baseline developed here uses the most recent data year available and relies solely on publicly available data used in prior studies and reports, updated using empirically-justifiable factors. For purpose of this RIA, the possible types of baseline costs include:

A. Baseline "engineering control "costs for CCR disposal units:

1. Ground water monitoring
2. Bottom liners
3. Leachate collection system
4. Dust controls – applicable to landfills only
5. Rain and surface water run-on/run-off controls – applicable to landfills only
6. Financial assurance for disposal unit closure and post-closure
7. Disposal unit location restrictions (6 types: water tables, floodplains, wetlands, fault areas, seismic zones, karst terrain)
8. Closure capping to cover unit
9. Post-closure monitoring requirements
10. Storage design and operating standards (tanks, containers, containment buildings) – not evaluated in this RIA

B. Baseline "ancillary costs" directly related to CCR disposal:

11. Offsite disposal
12. Structural integrity inspections – impoundments only
13. RCRA facility-wide investigation (RFI)
14. Corrective action
15. Waste disposal permits
16. Inspection & enforcement
17. Remediation of environmental releases

- **Characterization of Industry Baseline CCR Disposal**

For each of the 467 operating electric utility plants which currently (2007) dispose CCR onsite or offsite (28 of the 495 total plants solely send their CCR for beneficial uses not disposal), this RIA estimated baseline engineering controls at disposal units and associated baseline disposal costs for each type of disposal (note: the sum of plant counts for each disposal category below exceeds 467 because some plants use more than one type of CCR disposal method):

- 311 plants with active onsite CCR landfills
- 158 plants with active onsite CCR surface impoundments
- 149 plants which offsite dispose (assumed all involve offsite landfills)

For this RIA, the "baseline" is defined as existing conditions plus projection of future conditions over the 50-year future period-of-analysis 2012 to 2061 applied in this RIA (this RIA assumes year 2012 represents the first year when the final rule could take effect, if promulgated). Baseline engineering controls were estimated using the following 2-step method which is based on two alternative and complementary sources of information:

- Step 1: If the plant reported controls in the 1995 EPRI Comanagement Survey, 1996 CIBO Survey, or the 1994-2004 DOE-EPA Study, the stricter of these controls or state-specified controls are assumed for the baseline. These studies contained control data for 89 plants with CCR landfills and 50 plants with CCR impoundments (i.e., 139 of the 495 electric utility plants). State regulations added additional controls at 69 of the 89 landfill plants and 43 of the 50 impoundment plants with plant specific information (e.g., the EPRI Survey data may have indicated that the unit had a liner only but state regulations required groundwater monitoring and capping so these additional controls were added).
- Step 2: Controls specified under state regulations for 34 states are assumed for all other plants in those 34 states for the baseline if no 1995 EPRI Comanagement Survey data, 1996 CIBO Survey data, or 1994-2004 DOE-EPA Study data are available for that plant. This step resulted in assigning state-required controls to 201 plants with CCR landfills and 55 plants with CCR impoundments (i.e., 256 of the 495 plants). Overall state regulations were added to 270 plants with CCR landfills and 98 plants with CCR impoundments.

  For the 100 plants (i.e., 47 plants with landfills and 53 plants with impoundments) for which there are no data from the three studies, and no state-regulatory data on controls from Step 1, no controls are assumed under baseline for on-site landfills and impoundments; this represents a worst case (i.e., high cost) assumption.

The associated data sources and findings for each baseline characterization step are described below.

- **Step 1: Baseline Installed CCR Disposal Engineering Controls Identified in Prior Industry Surveys (1995, 1996, 2004)**

The controls identified through the Step 1 prior studies were more stringent than the state government requirements discussed in Step 2 for:

- <u>Landfills</u>: Voluntary controls for 25 plants with landfills (9% of 227 plants landfills) receiving 6.4 million tons per year (i.e., 9% of total landfill CCR quantity) in 12 states (some are identified as voluntary because state regulations were not reviewed for the state): AR, AZ, CA, IA, IN, KS, MD, MN, NE, SD, SI, WV.

- Impoundments: Voluntary controls for 39 plants with impoundments (25% of 158 plants with impoundments) receiving 5.5 million tons per year (i.e., 25% of total CCR impoundment quantity) in 14 states (some are identified as voluntary because state regulations were not reviewed for the state): AL, FL, IA, IL, IN, LA, MN, MS, NM, OH, SC, TX, UT, WY.

- **Step 2: Baseline State Government CCR Disposal Engineering Control Requirements for Landfills & Impoundments (2008)**

Several states have already established certain CCR disposal unit design and operating requirements that are required to be implemented either upon the effective date of the regulation (e.g., groundwater monitoring), upon retirement of the disposal unit (e.g., post-closure monitoring), or for newly constructed units only. **Appendix E** of this RIA provides a summary of the state government requirements for both landfills and impoundments. Current CCR disposal regulations have been reviewed for the top 34 states that utilize coal for producing electricity for required engineering controls at landfills and impoundments. The plants located in these states account for 99% of the annual quantity of CCR managed in company-owned (i.e., onsite) landfills and impoundments. State regulations were reviewed for the following 34 states: AL, AZ, CO, FL, GA, IA, IL, IN, KS, KY, LA, MD, MI, MN, MS, MO, MT, NV, NM, NY, NC, ND, OH, OK, PA, SC, TN, TX, UT, VA, WA, WV, WI, WY. Below is a synopsis of the baseline state government requirements according to the engineering controls listed above.

1. Groundwater monitoring requirements:

- Point-of Compliance:
  Two options for point-of-compliance groundwater monitoring include installing monitoring wells at the unit boundary or within 150 meters of the unit boundary. Recent changes to state regulations suggest that states typically require unit boundary monitoring.
- Number of Wells:
  Certain states specify a minimum number of monitoring wells: FL (3 wells for impoundments), IA (1 well for landfill), IL (multiple wells for landfills), KY (3 wells for landfills), LA (3 wells for impoundments and landfills), MO (4 wells for impoundments and landfills), ND (3 wells for impoundments), OK (3 wells for impoundments and 4 wells for landfills), TN (3 wells for landfills), UT (3 wells for landfills), WV (3 wells for impoundments and 4 wells for landfills). Well spacing design criteria for landfill boundary detection wells for FL, IA, and KS were reviewed. FL requires a minimum of one down-gradient detection well every 500 feet placed within 50 feet of the unit. Iowa requires a minimum of one detection well every 600 feet placed within 50 feet of the unit. KS recommends a minimum of one-down-gradient detection well every 500 feet.
- Monitoring Parameters:
  Two options for sampling include testing for chemical indicators and testing for RCRA hazardous waste Appendix VIII constituents (i.e., 40 CFR 261 Appendix VIII). Of the 34 state regulations reviewed, three states require chemical indicator monitoring for surface impoundments [CO, PA, WV] and 11 states require chemical indicator monitoring for landfills [IA, FL, KY, MI, OH, OK, PA, TN, UT, WI, WV]. Three states require RCRA Appendix VIII constituent monitoring for impoundments [MO, PA, WV], and 10 states require RCRA Appendix VIII constituent monitoring for landfills [GA, FL, IA, IL, MI, MO, OH, TN, UT, WV].
- Monitoring Frequency:
  Three options for groundwater sampling frequency include quarterly, semi-annual and annual. Of the 34 state regulations reviewed, one state requires quarterly sampling for surface impoundments [CO (depending on the ground-water classification)] and three states require quarterly monitoring for landfills [IA (until baseline conditions are established), IL (first 5 years), MI]. Five states require semi-

annual sampling for surface impoundments [LA, MO, ND, PA (chemical indicators), WV] and 12 states require semi-annual monitoring for landfills [FL, GA, KY, LA, MO, OH (chemical indicators), OK, PA (indicator parameters), TN (chemical indicators), UT, WV, WY]. Three states require annual sampling for surface impoundments [CO (depending on the ground-water classification), PA (metals and VOCs), WV] and five states require annual sampling for landfills [IA (after baseline established), IL (after 5 years), OH (metals, TOC, TDS, chloride, sodium and radionuclides), PA (metals and VOCs), TN (RCRA Appendix VIII constituents)].

- Timing of State Regulation Implementation**:**
  In the baseline, certain states require groundwater monitoring only for newly constructed units. These baseline costs are tracked as future baseline cost streams in the cost model. Of the 34 state regulations reviewed, nine states require immediate compliance with monitoring requirements for impoundments: LA, MN, MO, ND, NV, NY, OK, SC, UT. Eight states that only require groundwater monitoring only at newly constructed surface impoundments: CO, FL, KY, MI, NC, PA, WI, WV. 21 states require immediate compliance with monitoring requirements for landfills: AL, CO, GA, IA, IN, KS, KY, MI, MN, MT, NC, ND, NY, OH, PA, SC, TN, UT, VA, WA, WY. Ten states require groundwater monitoring only at newly constructed landfills: FL, IL, LA, MS, MO, NV, OK, TX, WV, WI.

2. Bottom liner requirements:

- Impoundments:
  Of the 34 state regulations reviewed, 10 states require immediate compliance with liner requirements for surface impoundments: FL (composite), KS (composite), KY (composite), LA (composite), MO (composite), ND (clay or synthetic), NV (composite), NY (composite), OK (composite), and PA (composite). Six states require liners only at newly constructed surface impoundments: CO (clay or soil), MI (clay or composite), NC (composite), WI (composite, synthetic or clay), WV (composite), WY (composite).
- Landfills:
  Of the 34 state regulations reviewed, 19 states require immediate compliance with liner requirements for landfills: AL (composite), CO (clay or synthetic), GA (composite), IN (clay), KS (composite), LA (composite), MI (composite), MN (clay), MT (composite), NC (composite), ND (clay or synthetic), NY (composite), OH (composite), PA (composite), SC (composite or clay), TN (composite), UT (composite), VA (composite), and WA (composite). 10 states require liners only at newly constructed landfills: FL (composite or double), IL (clay or composite), MS composite), MO (composite), NV (composite), OK (composite), TX (composite), WI (composite), WV (composite), WY (composite).

3. Leachate collection/detection system requirements:

- Impoundments:
  Of the 34 state regulations reviewed, nine states require immediate compliance with leachate collection/detection system requirements for surface impoundments: FL, KS, KY, LA, MO, ND, NV, NY, PA. Five states require leachate collection/detection systems only at newly constructed surface impoundments: CO, MI, NC, WV, WI.
- Landfills:
  Of the 34 state regulations reviewed, 18 states require immediate compliance with leachate collection system requirements for landfills: AL, CO, GA, IN (karst areas only), KS, MI, MN, MT, NC, ND, NY, OH, PA, SC, TN, UT, VA, WA. 11 states require leachate collection systems at newly constructed landfills: FL, IL, LA, MS, MO, NV, OK, TX, WI, WV, WY.

4. Dust control requirements: (landfills only)

Of the 34 state regulations reviewed, 16 states require immediate compliance with dust control requirements (wetting and truck covers and/or compaction) for landfills: CO, GA (compaction only), IA, IN, KS, MI, MN (includes compaction), ND (includes compaction), NY, OH, PA, SC, TN, UT, VA, WA. Nine states require dust controls only at newly constructed landfills: FL, IL (includes compaction), LA, MO, NM, OK, WI, WV, WY (includes compaction).

5. Run-on/run-off control requirements: (landfills only)

Of the 34 state regulations reviewed, 18 states require immediate compliance with run-on/run-off control requirements for landfills: AL, CO, GA, IA, IN, KS, MD, MN, MT, NC, NY, OH, PA, SC, TN, UT, VA, WA. 11 states require run-on/run-off only at newly constructed landfills: FL, IL, LA, MS, MO, NV, OK, TX, WI, WV, WY.

6. Financial assurance for CCR disposal unit closure & post-closure care

- Impoundments:
  Of the 34 state regulations reviewed, 11 states require immediate compliance with financial assurance requirements for surface impoundments: AZ, KY, LA, MN, MO, ND, NM, NV, OK, TN, and UT. Four states require financial assurance requirements only at newly constructed surface impoundments: CO, MI, NC, WI.
- Landfills:
  Of the 34 state regulations reviewed, 22 states require immediate compliance with financial assurance requirements for landfills: CO, FL (new construction), GA, IA, IN, KS, KY, MI, MN, MO, MT, NC, ND, NY, OH, SC, TN, UT, TX, VA, WA, WY. Eight states require financial assurance requirements only at newly constructed landfills: FL, IL, LA, MS, NV, OK, WI, WV.

7. Disposal Unit Location Restrictions (6 categories)

State regulations for the top-25 coal usage states (for electricity) were reviewed back in year 2000 for any location restrictions. These regulations were not updated as part of this RIA. The following is a synopsis of state government location restrictions on locating CCR surface impoundments and landfills, according to six categories of location restrictions (water table, floodplains, wetlands, fault areas, seismic zones, unstable karst terrain).

- 7-1: Below the natural water table:
  - Of the 25 state regulations reviewed, five states have location restrictions below the natural water table for surface impoundments: NC (4 feet above seasonal water table), ND (within aquifer), OK (if less than 15 feet above ground-water table), WV (5 feet above ground-water table), WY.
  - Of the 25 state regulations reviewed, eight states have location restrictions below the natural water table for landfills: FL, IA (5 feet above ground water), MI (4 feet above ground water), MN (5 feet above ground water), NC (4 feet above seasonal water table), ND (within aquifer), OH (5 feet above water table for wastes with higher leachate concentrations), TN (if less than 5 feet above water table).
- 7-2: Floodplains:

  - Of the 25 state regulations reviewed, eight states have location restrictions in floodplains for surface impoundments: KS (under permit), KY, MO (if closed with waste in place), NC, ND, OK (if dike not at least 1 foot above 100-year flood elevation), PA, WV.
  - Of the 25 state regulations reviewed, 20 states have location restrictions in floodplains for landfills: AZ, CO, FL, IL, IN, IA, KS, KY, MI, MN, MO, NC, ND, OH, OK, PA, TN, WV, WI, WY.
- 7-3: Wetlands
  - Of the 25 state regulations reviewed, five states have location restrictions in wetlands for surface impoundments: KY, MO (if closed with waste in place), ND, PA, WV.
  - Of the 25 state regulations reviewed, 17 states that have location restrictions in wetlands for landfills include AZ, CO, FL, IL, IN, IA, KY, MI, MN, MO, ND, OK, PA, TN, WV, WI, WY.
- 7-4: Fault areas:
  - Of the 25 state regulations reviewed, two states have location restrictions in fault areas for surface impoundments: MO (if closed with waste in place), WV.
  - Of the 25 state regulations reviewed, seven states have location restrictions in fault areas for landfills: AZ, CO, MO, OH, TN, WV and WI.
- 7-5: Seismic zones:
  - Of the 25 state regulations reviewed, two states have location restrictions in seismic impact areas for surface impoundments: include MO (if closed with waste in place), WV.
  - Of the 25 state regulations reviewed, eight states have location restrictions in seismic impact areas for landfills: AZ, CO, IL, MO, OK (if within 5 miles of epicenter of 4.0 earthquakes), TN, WV, WI.
- 7-6: Karst areas:
  - Of the 25 state regulations reviewed, five states have location restrictions in unstable areas for surface impoundments: KY, MO (if closed with waste in place), ND, PA, WV (1,000 feet away).
  - Of the 25 state regulations reviewed, 12 states have location restrictions in unstable areas for landfills: AZ, CO, IN, IA, KY, MN, MO, ND, PA, TN, WV (1,000 feet away), WI.

8. Closure cap controls

- Of the 34 state regulations reviewed, nine states require immediate compliance with closure control requirements for surface impoundments: AZ (synthetic cap), KY (synthetic cap), LA (clay cap), MO (soil cap), ND (clay or synthetic cap), NM (synthetic cap), OK (clay or synthetic cap), PA (clay or synthetic), TN (synthetic cap). Four states require closure controls only at newly constructed surface impoundments: CO (clay or synthetic cap), MI (clay or synthetic cap), NC (soil cap), WI (synthetic cap).
- Of the 34 state regulations reviewed, 23 states require immediate compliance with closure control requirements for landfills: AL (synthetic cap), CO (clay cap), GA (soil cap), IA (clay cap), IN (clay cap), KS (soil cap), KY, MD (clay cap), MI (clay or synthetic cap), MN (clay cap), MO (soil cap), MT (clay cap), NC (soil cap), ND (clay or synthetic cap), NY (synthetic cap), OH (synthetic cap), PA (synthetic cap), SC (synthetic cap), TN (clay cap), TX (synthetic cap), UT (soil cap), VA (synthetic cap), and WA (synthetic cap). Nine states require closure controls only at newly constructed landfills: FL (synthetic cap), IL (clay or synthetic cap), LA (clay cap), MS (soil cap), NV (soil cap), OK (clay cap), WI (clay cap), WV (soil or clay cap), WY (synthetic cap).

9. Post-closure monitoring requirements

- Of the 34 state regulations reviewed, 11 states require immediate compliance with post-closure groundwater monitoring requirement for surface impoundments: AZ, LA, MO, ND, NM, NV, NY, OK, SC, TN, UT. Seven states require post-closure groundwater monitoring only at newly constructed surface impoundments: CO, KY, MI, NC, PA, WI, WV.
- Of the 34 states reviewed, 22 states require immediate compliance with post-closure groundwater monitoring requirements for landfills: AL, CO, GA, IA, KS, KY, MD, MI, MN, MO, MT, ND, NY, OH, PA, SC, TN, TX, UT, VA, WA, WY. Eight states require post-closure groundwater monitoring at newly constructed landfills: FL, IL, LA, MS, NV, OK, WI, WV.

10. Baseline storage tank/container design and operating standards

The baseline storage tank /container design and operating standards were not evaluated in this RIA because of a lack of data about the baseline count and conditions of CCR storage or treatment tanks, containers, and containment buildings at electric utility plants

- **Industry Baseline CCR Disposal Characterization Findings**

Appendix F of this RIA presents on a plant-by-plant basis the baseline engineering controls assumed for each of the 383 of the 495 electric utility plants which onsite dispose CCR (84 plants solely dispose CCR offsite; this RIA assumes that all offsite CCR disposal units are landfills, and further assumes that all of those offsite landfills currently comply with the engineering controls described in this RIA for the regulatory options). **Exhibits 3I** (for landfills) and **Exhibit 3J** (for impoundments) below summarize the assignment of baseline conditions in this RIA for these 411 plants which dispose CCR onsite.

Exhibit 3I
Baseline Compliance with State Government Engineering Control Requirements: CCR Landfills

Current or State Regulated Engineering control		A	B	C	D	E	F	G	H
		Future new CCR landfills				Existing CCR landfills			
		No. of Plants	Percent of 311 plants with LFs	Volume of CCR diposed in landfills (tons/year)	% of 71.8 million tons onsite + offsite LF	No. of Plants	Percent of 311 plants with LFs	Volume of CCR disposed in landfills (tons/year)	% of 71.8 million tons onsite + offsite LF
1. Groundwater Monitoring		302	97%*	69,706,646	97%*	272	81%	60,623,231	85%
2. Bottom Liner		302	97%*	69,706,646	97%*	238	71%	52,505,314	73%
3. Leachate Collection System		273	81%	62,696,310	88%	222	66%	49,213,424	69%
4. Dust Controls		215	64%	40,634,681	57%	205	61%	42,781,444	60%
5. Run on/Run off Controls		261	77%	60,342,426	84%	209	62%	46,232,440	65%
6. Financial Assurance		266	79%	56,861,231	79%	231	69%	49,487,222	69%
7. Site restrictins	1. Water table	98	29%	18,878,963	26%	ND	ND	ND	ND
	2. Floodplains	232	69%	50,072,235	70%	ND	ND	ND	ND
	3. Wetlands	199	59%	40,227,659	56%	ND	ND	ND	ND
	4. Fault areas	72	21%	18,816,363	26%	ND	ND	ND	ND
	5. Seismic zone	66	20%	13,056,165	18%	ND	ND	ND	ND
	6. Karst areas	152	45%	33,970,045	47%	ND	ND	ND	ND
8. Cap	Synthetic or Clay	245	73%	52,234,482	73%	213	63%	46,031,621	64%
	Soil	48	14%	10,990,166	15%	50	15%	12,094,140	17%
	Clay/Soil	13	4%	5,419,918	8%	5	1%	3,022,219	4%
9. Post Closure Monitoring		271	80%	61,444,140	86%	232	69%	53,249,880	74%
10. Storage design standards		ND	ND	ND	ND	ND	ND	ND	ND

Notes:
ND = Not determined. Comparisons have not been made comparing the date the state site restriction regulation became effective and the date of existing landfill construction for each plant.
* According to the August 2006 DOE/EPA report "Coal Combustion Waste Management at Landfills and Surface Impoundments, 1994-2004" report nr. DOE/PI-0004, 286 pp; http://www.ead.anl.gov/pub/dsp_detail.cfm?PubID=2008:
- 97% of newly constructed CCR landfills have groundwater monitoring (Table 14, p.35)
- 97% of newly constructed CCR landfills have liners (Table 13, p.33)

These percentages reflect a mix of state government permit requirements for some surveyed electricity plants, plus industry voluntary actions for other plants.

Exhibit 3J
Baseline Compliance with State Government Engineering Control Requirements: CCR Surface Impoundments

Current or State Regulated Engineering control		A	B	C	D	E	F	G	H
		Future new CCR impoundments				Existing CCR impoundments			
		No. of Plants	Percent of 158 plants with SIs	Volume of CCR disposed in impoundments (tons/year)	% of 22.4 million tons CCR disposed in impoundments	No. of Plants	Percent of 158 plants with SIs	Volume of CCR disposed in impoundments (tons/year)	% of 22.4 million tons CCR disposed in impoundments
1. Groundwater Monitoring		123	78%*	17,472,000	78%*	78	49%	9,216,470	41%
2. Bottom Liner		158	100%*	22,400,000	100%*	62	39%	6,920,820	31%
3. Leachate Collection System		61	39%	7,676,710	34%	48	30%	5,338,110	24%
4. Dust control		NA	NA	NA	NA	NA	NA	NA	NA
5. Runon/runoff control		NA	NA	NA	NA	NA	NA	NA	NA
6. Financial Assurance		63	40%	7,694,010	34%	58	37%	7,327,410	33%
7. Site restrictns	1. Water table	28	18%	3,039,860	14%	ND	ND	ND	ND
	2. Floodplains	51	32%	6,902,610	31%	ND	ND	ND	ND
	3. Wetlands	34	22%	5,347,550	24%	ND	ND	ND	ND
	4. Fault areas	15	9%	1,675,350	7%	ND	ND	ND	ND
	5. Seismic zone	15	9%	1,675,350	7%	ND	ND	ND	ND
	6. Karst areas	34	22%	5,347,550	24%	ND	ND	ND	ND
8. Cap	Synthetic	38	24%	5,911,760	26%	31	20%	4,298,660	19%
	Soil	27	17%	2,490,050	11%	23	15%	2,293,550	10%
	Clay	3	2%	254,800	1%	3	2%	254,800	1%
9. Post Closure Monitoring		78	49%	9,520,360	43%	65	41%	7,181,760	32%
10. Storage design standards		ND	ND	ND	ND	ND	ND	ND	ND

Notes:
NA = Not applicable to surface impoundments.
ND = Not determined. Comparisons have not been made comparing the date the state site restriction regulation became effective and the date of existing surface impoundment construction for each plant.
* According to the August 2006 DOE/EPA report "Coal Combustion Waste Management at Landfills and Surface Impoundments, 1994-2004" report nr. DOE/PI-0004, 286 pages; http://www.ead.anl.gov/pub/dsp_detail.cfm?PubID=2008:
- 78% of newly constructed CCR impoundments have groundwater monitoring (Table 14, p.35)
- 100% of newly constructed CCR impoundments have liners (Table 13, p.33)

These percentages reflect a mix of state government permit requirements for some surveyed electricity plants, plus industry voluntary actions for other plants.

- **Baseline CCR Disposal Cost Estimation**

This section presents baseline cost estimates for both onsite and offsite CCR disposal units (i.e., landfills and impoundments) for 467 of the 495 electric utility plants which dispose CCR (CCR from the remainder 28 of the 495 plants is solely beneficially used).

- **Cost Estimation Framework**

- Cost calculations: This RIA contains three types of cost estimates (with decreasing relative degrees of expected accuracy):
    - Data-based estimates: Based on a landfill and impoundment engineering controls cost estimation model using relatively robust and recent data inputs (e.g., 2005 or newer) pertaining to CCR quantities and disposal methods for individual electric utility plants. The cost model was first developed by EPA in 1988 to support EPA's 1991 final criteria for municipal solid waste RCRA Subtitle D landfills, and EPA's 1999 proposed rule cement kiln dust landfill requirements.[45] The cost model consists of two software components; **Appendix G** to this RIA provides additional details about the model:
        - 1st of 2 cost model components: Unit Cost Component: The first component is a Fortran computer programmed cost model which dates back to 1988. This model specifies the various steps and physical units (e.g., square footage sizes and associated quantities of labor, equipment and materials for the specified sizes) involved in designing, constructing, operating, and closing a landfill or impoundment. Then it combines the physical component data inputs, with input data on the prices/ costs/ fees for the physical components to estimate as model outputs, the capital and annual O&M costs of specified sizes of landfills and impoundments. The unit prices/ costs/fees used as input data include a wide range of items, such as the per-acre cost of land, clearing, excavation, equipment, labor, bottom liner materials, and cover materials. For this RIA, the model was run multiple times to generate individual cost estimates for a series of five alternatively-sized CCR landfills and impoundments with varying types of engineering controls to represent the range of sizes and engineering controls in the population of 495 electric utility plants. The size categories are defined in tons per day of CCR disposed. Each CCR landfill or

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[45] The 1988 cost model is documented in the "User's Manual for the Subtitle D Municipal Landfill Cost Model" draft report prepared for EPA's Office of Solid Waste by DPRA Inc, Sept 1988, 129 pages which is available from the Federal docket as document ID nr EPA-HQ-RCRA-2006-0796.

EPA previously publicly referenced this cost model in the following six publications: (a) "Draft Regulatory Impact Analysis for Proposed Revisions to Subtitle D Criteria for Municipal Solid Waste Landfills," prepared for US EPA Office of Solid Waste by Temple, Barker & Sloane, Inc., ICF Incorporated, Pope-Reid Associates (now DPRA Inc.) and American Management Systems, Inc., 05 Aug 1988 (this document includes about a 4-page summary of the cost model); (b) "Regulatory Impact Analysis for the Final Criteria for Municipal Solid Waste Landfills," prepared for US EPA Office of Solid Waste by Temple, Barker & Sloane/Clayton Environmental Consultants, ICF Inc, DPRA Inc, and American Management Systems, Inc., Dec 1990 (this document includes about a 4-page summary of the cost model); (c) "Addendum to the Regulatory Impact Analysis for the Final Criteria for Municipal Solid Waste Landfills," prepared for US EPA, Office of Solid Waste by Temple, Barker & Sloane/Clayton Environmental Consultants and ICF Inc, August 1991; (d) "40 CFR Parts 257 and 258 Solid Waste Disposal Facility Criteria: Proposed Rule," Federal Register, Vol.53, No.168, pp.33314-33422, 30 Aug 1988; (e) "Revised Criteria for Municipal Solid Waste Landfills," Federal Register Volume 56, pp. 50978, 09 Oct 1991; (f) "Technical Background Document: Compliance Cost Estimated for the Proposed Land Management Regulation of Cement Kiln Dust," prepared for the US EPA, Office of Solid Waste by DPRA Inc, 10 April 1998.; and (g) "40 CFR Parts 259, 261, 266, and 270 Standards for the Management of Cement Kiln Dust; Proposed Rule," Federal Register Vol.64, No.161, pp. 45632-45697, 20 Aug 1999.

impoundment is assumed to operate 300 days per year (average number of operating days for coal-fired boilers based on 2005 DOE EIA 767 database). The size categories are 10,000, 50,000, 200,000, 500,000 and 2,000,000 tons of CCR per year. Size is the primary determinant of overall cost; however, landfills and impoundments exhibit increasing returns to scale: the larger the landfill or impoundment, the lower the cost per ton of CCR managed. The cost equations generated by these unit cost model runs are used as inputs in the second component of the cost model to compute landfill and impoundment cost curves (equations) based on size for each combination of engineering controls, so that a unique cost estimate may be assigned to each of the 495 electric utility plants according to each plant's unique annual CCR disposal tonnage.

- 2nd of 2 cost model components: Plant-by-Plant & Aggregate Cost Component: The second component of the model is an Excel spreadsheet with Visual Basic programming used to estimate unique baseline (i.e., current) and regulatory option costs for each electric utility plant. The spreadsheet is populated with plant-by-plant data including plant location, known disposal and beneficial reuse practices, known or estimated baseline engineering controls on CCR disposal units, annual CCR disposal tonnages, and known or estimated CCR landfill and impoundment future closure years. The spreadsheet is also populated with the cost equations generated by the first component of the model for the various engineering controls (e.g., groundwater monitoring and safety inspections) and for off-site landfill disposal costs. The Visual Basic programming is used for this RIA to estimate engineering control costs for both the (a) baseline and (b) regulatory options for each plant over a 50-year future period-of-analysis (i.e., 2012 to 2061). The plant-by-plant estimated costs are then aggregated in this second component of the model on an average annualized basis.

- Assumption-based estimates: These are based on relatively limited data, and/or older data (e.g., older than 2005), or meta-analysis transfer of results from other studies, or data from case studies, or based mostly on professional judgment assumptions rather than data, for some of the major factors used in cost calculations.
- Scenario-based estimates: These are applied in absence of data, case studies, or assumptions for purpose of illustrating potential lower- and upper-bound costs (i.e., bounding estimates). EPA defines "scenarios" as qualitative projections of possible future conditions based on variations in key drivers of change, including social, technological, economic and institutional drivers. Scenario construction is a futures analysis method; as such, scenario-based estimates do not strive to predict the future with absolute certainty, but to explore uncertainties, possible consequences, and possible outcomes.[46]

- 2009 price level: Costs are normalized to beginning-of-year 2009 dollars using inflation factors developed by Engineering News-Record (ENR) Construction Cost Index, and using regional cost adjustment factors applied to each plant cost estimate involving on-site construction. These regional factors account for the variability between states in site work and landscape construction costs. Cost adjustment factors are derived from the Means Building Construction Costs Year 2003 city factors. All the cities for each state were averaged together to derive a state average.

[46] "Source: EPA Office of Science Policy, "Shaping Our Environmental Future: Foresight in the Office of Research & Development," report nr. EPA 600/R-06/150, 2006 at: http://www.epa.gov/osp/futures/FuturesHandbook.pdf

- Before-tax costs: Baseline disposal costs estimated on a before-tax basis to approximate the overall economic cost (i.e., real resource allocation for the economy as a whole, rather than on an after-tax basis which would approximate a relatively narrower financial cost to the electric utility industry because after-tax costs subtract business expense tax deductions and depreciation of capital expenditures for pollution control equipment.

- 50-year period: A 50-year future time horizon (aka period-of-analysis) was applied because new construction for replacement of all CCR disposal units and end of existing lifespan is estimated to have occurred at least once by that time.

- 7% discount rate: A 7% discount rate was applied for calculating both net present value cost and average annualized cost for the engineering control unit costs applied in this RIA. Because both the annualized baseline cost and annualized incremental proposed rule costs estimated in this RIA consist of primarily (i.e., >95%) industry cost rather than government cost, this RIA applies a 7% discount rate rather than a lower (e.g., 3%, 2%, 1% or 0%) discount rate to represent the opportunity cost of business capital investment and business expense financing (i.e., the average rate of return to corporate capital). This is consistent with OMB's 2003 Circular A-4[47] (page 33) and 1992 Circular A-94[48] (page 8) which indicate that a 7% discount rate base-case should be used for regulatory analyses when regulation is expected to primarily and directly affect businesses and industries.

- 0.73% growth: Baseline cost estimates increased 0.73% per year over the 50-year future time horizon to reflect a 0.73% annual growth in coal consumption at electric utility plants (which is a proxy for future annual growth in the annual tonnage of CCR generation needing disposal from those plants). The 0.73% annual growth factor is based on DOE-EIA's January 2009 "Annual Energy Outlook 2009" forecast change in US coal consumption for electricity generation between year 2010 (22.91 quadrillion Btus) and 2030 (26.41 quadrillion Btus), available at: http://www.eia.doe.gov/oiaf/aeo/index.html

- Beneficial use: If reported in the baseline by any particular plant, beneficial use was assumed to continue in the future by that plant under the baseline projection over the 50-year future period-of-analysis. Section 5C in **Chapter 5** of this RIA evaluates potential changes to this beneficial use baseline under alternative regulatory impact scenarios.

- Offsite disposal: If reported in baseline by any particular plant, offsite disposal was assumed to continue in the future by that plant. Offsite disposal landfill cost estimated under both baseline and regulatory options using the engineering control cost model. Truck operating cost estimated separately outside of the model.

- Existing unit closure: One set of years for the opening and closure of disposal units are assumed for each facility. If data for initial year of operation were provided in the 1995 EPRI Comanagement Survey, these data were used. If the plant had more than

[47] 2003 OMB Circular A-4: http://www.whitehouse.gov/omb/circulars_a004_a-4/
[48] 1992 OMB Circular A-94: http://www.whitehouse.gov/omb/circulars_a094/

one disposal unit and more than one reported date for initial year of operation, the years were averaged. For example, if a facility had three disposal units (2 landfills and 1 impoundment) with installation dates of 1970, 1980, and 1990, this RIA assumed the installation date of all the units was 1980. This assumption simplified the cost calculations on a per facility basis instead of a per disposal unit basis. If no disposal unit installation data were available, the installation year is assumed to be equal to the earliest boiler installation year reported in either the 2007 EIA 860 database for that plant or 1998 EIA 767 database, whichever was older. If no disposal unit or boiler installation year data were available, an installation year of 1980 was assumed. If the 1995 EPRI Comanagement Survey provided a forecasted closure year for a unit, new unit installation is assumed to occur in that year. Otherwise, if no closure forecast year is provided, closure is assumed to occur 40 years after the year of installation (assumed average lifespan for CCR landfills and impoundments).

- New unit construction: The timing of when baseline state regulatory requirements for newly constructed units begin to be incurred depends on the installation and closure date for the existing disposal units. Baseline state regulatory cost requirements are incurred at the closure date of the disposal unit when new unit construction occurs. For example, if a plant's disposal unit is assumed in this RIA to close in 2019; new unit construction costs required under state regulations are incurred over its assumed 40-year future lifespan beginning in 2020.
    - <u>New landfills</u>: The most economic of three landfill options – (1) combination landfill with 50% of waste below ground and 50% above ground, (2) pile landfill with 5 % of waste below ground and 95% above ground, or (3) offsite landfill -- is determined within the cost model. The cost for the most economical approach is assigned to that plant unless available data specify otherwise. The choice is dependent upon on estimated engineering control costs and annual CCR disposal tonnage.
    - <u>New impoundments</u>: If currently used as a disposal unit, this RIA assumes a landfill will be constructed as the future new disposal unit as impoundments reach end of lifespan, because the model calculates that new landfills are more economical to construct for two cost reasons: (a) if no pre-existing land depressions for use as a new impoundment, the cost for a larger excavation for a new impoundment rather than a smaller excavation for a landfill is necessary, and (b) the primary determinant of many of the cost for engineering controls is the footprint of the disposal unit such that the same set of engineering controls for a new impoundment would be more expensive than for a new landfill. However, the cost model does not estimate the associated capital and annual O&M costs for future conversion of existing wet ash and wet scrubber boilers and conversion of wet CCR conveyance equipment used for moving CCR to disposal units. These conversion costs are estimated separately outside of the cost model in this RIA.

- **Baseline "Engineering Control" Cost Estimates**

1. Baseline ground water monitoring

Groundwater monitoring costs are based on the Remedial Action Cost Engineering and Requirements (RACER) cost estimating software (2002) with costs based on the R.S. Means, Environmental Cost Handling Options and Solutions (ECHOS), Environmental Remediation Cost Data (2002).

- Assumes same groundwater monitoring requirements for both landfills and impoundments
- Point of compliance:
  Placement at the unit boundary is assumed in the cost estimates. Unit boundary point-of-compliance monitoring complies with the "within 150 meter point-of-compliance" criterion. Plants monitoring at the unit boundary will incur no additional costs under the within 150 meter placement criteria.
- Number of wells:
  EPA's March 1985 "Ground Water Technical Enforcement Guidance" Document (pages 2-8 to 2-16) recommends a maximum of 150 feet spacing between down-gradient wells. EPA's December 1980 SW-611 "Procedures Manual for Groundwater Monitoring at Solid Waste Disposal Facilities" (pages 40 to 43) recommends a maximum of 250 feet spacing between down-gradient wells. Assuming the technical documents are the most stringent and the state regulation minimums are the least stringent, a middle ground within the range is anticipated and used in the cost estimates. This RIA does not evaluate the cost differences between the upper and lower bounds of well spacing. Groundwater monitoring well costs in this analysis assume a minimum of 2 down-gradient wells for the first 800 feet of length along two sides of the landfill or impoundment unit, which is assumed to be square, plus additional wells spaced every 400 feet. In addition, one up-gradient well is assumed.
- Constituents:
  The cost estimates include monitoring for the following chemical indicators and metals, which represents a reasonable "likely-case" scenario between indicators only and RCRA 40 CFR 261 Appendix VIII constituent monitoring which includes about 500 chemical substances:
  - Chemical indicators: Based on EPA's 1999 cement kiln dust proposed rule parameters (i.e., pH, conductivity, total dissolved solids, potassium, chloride, sodium, and sulfate) as a cost proxy.
  - Metals: Metals with primary and secondary Maximum Contaminant Levels (MCLs) (i.e., Al, Cu, Fe, Mn, Ag, Zn, Sb, As, Ba, Be, Cd, Cr, Pb, Hg, Se, Tl).
- Frequency:
  The cost estimates only include semi-annual sampling (most-likely case) analogous to EPA's 1999 cement kiln dust proposed rule and to many current state regulations, even if some states require a quarterly or annual basis.
- Unitized cost estimate: Dividing the average annual cost estimate result displayed in **Exhibit 3L** below (row item 1) for baseline ground water monitoring, by the count of electric utility plants estimated in **Exhibit 3I** (row 1, column A) and **Exhibit 3J** (row 1, column A) above to conduct that activity under state government requirements, yields an average annual per-plant (i.e., unitized) cost estimate of $64,000. In comparison, EPA's most recent (2008) Information Collection Request (ICR) No. 0959.13 "Ground-Water Monitoring Requirements" (renewal) for the RCRA Subtitle C 40 CFR 264.92 and 265.92 TSDF "ground-water protection standard" provides an estimate of $28,130

per year.[49] The $64,000 unitized cost for groundwater monitoring generated by the above assumptions applied in the engineering control cost model used for this RIA is 2.3 times larger and more appropriate to this RIA because it reflects a larger number of wells per-plant to monitor the groundwater under the larger sized CCR disposal units compared to the average sizes of other types of industrial waste disposal units.

2. Baseline bottom liners

- Same bottom liner requirements for both new landfills and new impoundments
- The cost estimates include a composite (2-foot compacted clay-synthetic) liner for the more stringent design and a 2-foot compacted clay liner, single-synthetic liner, and a 2-foot compacted ash liner for less stringent baseline designs.

3. Baseline leachate collection system

- No leachate collection is assumed from beneath the impoundment liner
- The cost estimate is comprised of perforated pipes spaced approximately 300 feet apart along the base of the unit. It includes a wet well for leachate collection. Leachate is shipped by truck for off-site treatment.
- Assumes 3-inches of leachate per year collected in landfill leachate collection systems.

4. Baseline dust controls

Cost estimate includes CCR compaction equipment, water trucks for spraying CCR during compaction and for spraying unpaved landfill roads, and covers for landfill trucks:

- Compaction Equipment

  Ash is assumed to be compacted in the waste management area by self-propelled rollers for regulatory scenarios including dust controls. A model cost assumption is that four passes are made by the roller in 6-inch lifts. With these assumptions, the roller can compact approximately 1,300 cy of ash per day. The operating life of purchased compaction equipment is assumed to be five years. The number of sheepsfoot rollers required is estimated as follows:

$$\text{Rollers} = \frac{(\text{tons/yr})(2{,}000\ \text{lb/ton})(16.02\ \text{kg/m3 / lb/cf})}{(1{,}190\ \text{kg/m3})(27\ \text{cf/cy})(1{,}300\ \text{cy/day})(300\ \text{days/yr})}$$

  The cost of a sheepsfoot roller is assumed to be $75,000 in 1995 dollars.
  Plants will incur annual costs for equipment operation ($0.63/cy) and maintenance.
  Maintenance costs are assumed to be 5% of capital costs. Annual costs for compaction are estimated as follows:

$$\text{Annual Cost} = \frac{(\text{tons/yr})(2{,}000\ \text{lb/ton})(16.02\ \text{kg/m3 / lb/cf})(\$0.63/\text{cy})}{(1{,}190\ \text{kg/m3})(27\ \text{cf/cy})} + \$75{,}000*0.05*\text{Rollers}$$

- Water Truck for Compaction:

Ash is assumed to be wetted in the waste management area by water trucks to facilitate compaction and to control dust. A model assumption is that FFC plants currently use water trucks 50% of the operational day to control dust on roads (see Water Spray on Roads). It is reasonable to

[49] $28,130 per year per-facility average cost derived for purpose of this RIA by dividing the reported $27.818 million annual cost by the reported 989 TSDFs from the EPA ICR 0959.13, Federal Register, Vol.73, No.103, page 30617; 28 May 2008; http://edocket.access.gpo.gov/2008/pdf/E8-11888.pdf

assume that the same water trucks will be used for the roads and the ash management unit. Therefore, it is assumed that an existing water truck is available for compaction 50% of the operational day. Additional water trucks are assumed to be necessary to facilitate compaction for large facilities. The cost of tarps, tarp mechanisms, and installation of the mechanisms, as well as the life of each tarp were estimated by ICF in "Cost Functions for Alternative CKD Control Technologies" (Draft), 19 July 1996. A model assumption is that a water truck will be necessary for compaction 50% of the time required by the compaction equipment. The water truck time for compaction is estimated as follows:

$$\text{Water Truck Time for Compaction} = \frac{(\text{tons/yr})(2{,}000\ \text{lb/ton})(16.02\ \text{kg/m3 / lb/cf})(8\ \text{hr/day})(0.5)}{(1{,}190\ \text{kg/m3})(27\ \text{cf/cy})(1{,}300\ \text{cy/day})}$$

One existing water truck for compaction and water spray on roads is estimated to be sufficient for plants managing less than 391,000 tons per year of ash. Facilities managing between 391,000 and 1,173,000 tons per year are assumed to purchase one additional water truck. Facilities managing between 1,173,000 and 1,955,000 tons per year are assumed to purchase two additional water trucks. Facilities managing more than 1,955,000 tons per year to the maximum facility size modeled of 2,000,000 tons per year are assumed to purchase three additional water trucks. The cost of a water truck is assumed to be $101,000 in 1995 dollars. The water truck operating life is assumed to be five years. The operating costs for water spray for compaction are estimated assuming that the truck travels approximately five miles per day, for each day used, with a fuel consumption of five miles per gallon at a fuel cost of $1.15 per gallon. The truck is assumed to operate 50% of the hours required for compaction. The daily water volume used is assumed to be 10,000 gallons, at a cost of $2 per 1,000 gallons. The annual cost associated with ash management is estimated as follows:

$$\text{Annual Cost} = \frac{(\text{tons/yr})(2{,}000\ \text{lb/MT})(16.02\ \text{kg/m3 / lb/cf})(0.5)}{(1{,}190\ \text{kg/m3})(27\ \text{cf/cy})(1{,}300\ \text{cy/day})} * [(8\text{hr/day})(\$31.50/\text{hr}) + (5\ \text{mi/day})(\$1.15/\text{gal})/(5\ \text{mi/gal}) + (10{,}000\ \text{gal/day})(\$2/1{,}000\ \text{gal})]$$

- Covers on Trucks:

Covers on hauling trucks as a fugitive dust control technology is an option for the compliance scenarios. Capital costs for this dust control technology include the cost of the roll-on tarp mechanism and the installation of this mechanism. Capital costs for covers on trucks are estimated as follows: Capital Cost = [(tons/year) x (2,000 lb/ton) x (16.02 kg/m3 / lb/cf) x (0.65 hr/load)] x ($4,800)
Water truck capacity, refill time, and spray width were estimated by ICF in "Cost Functions for Alternative CKD Control Technologies" (Draft), dated July 19, 1996.
(1,190 kg/m3)(0.80)(27 cf/cy)(9 cy/load)(2,400 hr/yr)
Annual costs for this dust control technology include the cost of the tarps and the cost to replace the tarps. Tarps are estimated to be replaced every 150 loads. Replacement of a tarp is estimated to require 15 minutes. Annual costs for covers on trucks are estimated as follows:

$$\text{Annual Cost} = \frac{(\text{tons/yr})(2{,}000\ \text{lb/ton})(16.02\ \text{kg/m3 / lb/cf})(\$155/\text{tarp} + 0.25\text{hr/tarp}*\$19/\text{hr})}{(1{,}190\ \text{kg/m3})(0.80)(27\ \text{cf/cy})(9\ \text{cy/load})(150\ \text{load/tarp})}$$

- Water Spray on Roads:

Water spray on roads is required as a fugitive dust control technology for the compliance scenarios. A model assumption is that FFC plants currently have water trucks and use water spray on roads as a baseline management practice. A model assumption is that dust control is required for a road length of 1.5 miles (3 miles roundtrip), with a road width of 10 meters. The water truck capacity is assumed to be 5,000 gallons and requires approximately one hour to fill. The water truck can spray a width of five meters at an assumed speed of 10 miles per hour. For the baseline scenario, a model assumption is that the entire water volume (5,000 gallons) will be sprayed on each pass of the truck along one side of the road (i.e., 1.5 miles x 5 meters). The resulting water volume per road area, averaged over the 1.25 hours required to spray the road and refill the truck, is approximately 2.5 times that of the average hourly daytime evaporation rate. Therefore, water spray on roads will be required 3 times per day. The water volume sprayed per road area is estimated as follows:

Water per Area = (1.5 mi)(5,280 ft/mi)(0.3048 m/ft)(10 m)(5,000 gal)(3.785 L/gal) = 0.784 L/m2

The time required for the water truck to be filled, spray along both sides of the road, and return for refilling is estimated as follows:

Time = (1 hour) + (3 miles)/(10 miles/hour) = 1.3 hour

Therefore, the total time for one pass is assumed to be 1 hour and 15 minutes. The average rate of water spray is estimated as follows:

$$\text{Spray Rate} = \frac{(0.784\ \text{L/m2})(1{,}000\ \text{ml/L})(\text{cm3/ml})(1{,}000\ \text{mm/m})}{(100\ \text{cm/m})3(1.25\ \text{hr})} = 0.6272\ \text{mm/hr}$$

The average hourly daytime evaporation rate is approximately 0.25 mm/hr. Therefore, the water spray rate is approximately 2.5 times the evaporation rate. Since the total time required for water spray (1.25 hour) times 2.5 is approximately 3, a model assumption is that water spray on roads is required approximately every 3 hours. In order to coordinate the water truck use for road spray and ash compaction, it is assumed that the truck alternates between these two requirements during the day. Therefore, over a nine-hour day (eight working hours plus one hour for lunch), roads are sprayed 3 times, requiring a total of approximately 4 hours, or 50% of the operational day. Because it is assumed that FFC facilities currently spray water on roads for dust control, the incremental cost from the baseline to the compliance scenarios is zero.

5. Baseline rain and surface water run-on/run-off controls (landfills only)

The cost estimates assume that stormwater run-on/run-off control is comprised of a ditch surrounding active area of landfill and an excavated bermed basin for water collection.

6. Baseline financial assurance for CCR disposal unit closure and post-closure care

Financial assurance helps assure that the owners and operators of CCR landfills and impoundments have adequately planned for the future cost of closure, post-closure care, and corrective action for known releases, and to assure that adequate funds will be available when needed to cover these costs if the owner or operator is unwilling or unable to do so. Financial assurance helps protect future generations from paying for damages caused by or the prevention of damages potentially created from current waste management activities. Requiring provision of financial assurance during operation of landfills and impoundments places the cost burden on the current owner and consumer, and prevents costs from being passed from the current generation to future generations.

The cost estimate includes the costs for selecting a financial mechanism, establishing a financial test, and establishing a letter of credit. The differences between RCRA Subtitle C and Subtitle D financial assurance mechanisms are not assessed. This RIA assumes the same requirements for both landfills and impoundments:

- Capital cost includes selection of financial assurance mechanism, establishment of financial test, and establishment of letter of credit. The letter of credit is assumed to be most available to utilities and will be utilized in most circumstances. This is amortized in the annual cost.
- Annual cost includes maintenance of financial test and maintenance of letter of credit. Establishment and annual maintenance of the letter of credit is estimated to be 1% to 3% of the nominal value of the letter of credit (i.e., total cost of closure and post closure). This RIA applied the 2% midpoint of this range. Implementation costs are estimated on the assumption that an outside consulting firm and legal assistance will assist in obtaining and maintaining the letter of credit ($692 per year in 1995 dollars or $1,051 per year inflated to 2009 dollars). Estimate obtained from Mohammad Iqbal and John Collier, ICF, Inc., "Local Government Financial Test Economic Analysis,"

memorandum to George Garland, EPA, 30 April 1995. Additional supporting information obtained from EPA "Estimating Costs for the Economic Benefits of RCRA Noncompliance," September 1997.

7. Baseline disposal unit location restrictions
Baseline cost not estimated in this RIA.

8. Baseline closure capping to cover unit
The cost estimate for this engineering control does not include the closure plan cost or closure certification costs. Capping costs are a large capital expense. So, if a unit is expected to close in one year the total capping cost is assigned to the last year in the life of the unit. However, businesses are likely to borrow money from a bank for these large capital costs and annualize them over a set period of time, for example, 10 or 20 years. Incremental cost estimates in the cost model are overestimated for large capital expenditures applied to existing units that have been added over short time periods. In addition, owners are likely to close these units prior to the proposed rule coming into effect if promulgated as a final rule. This RIA assumes the same requirements for both landfills and impoundments:

- Synthetic cap with drainage layer is comprised of a 60 mil HDPE synthetic liner, 1 foot sand, filter fabric, 1.5 foot slope and earth fill, 0.5 foot topsoil, and vegetation. It includes a perforated pipe for drainage collection.
- Synthetic cap without drainage layer is comprised of a 60 mil HDPE synthetic liner, 1.5 foot slope and earth fill, 0.5 foot topsoil, and vegetation.
- Clay cap is comprised of 2 feet of off-site clay, 0.5 foot topsoil, and vegetation. Cover costs would be lower if on-site clay is available.
- Soil/clay cover is comprised of 0.5 foot clay, 0.5 foot earthfill, and 0.5 foot topsoil, and vegetation. Cover costs would be lower if on-site clay is available.
- Soil cap is comprised of a 1.5 foot slope and earth fill, 0.5 foot topsoil, and vegetation. The slope of the cap is assumed to be 0.02:1 (rise:run) with a cover toe slope of 4:1 (run:rise).

9. Baseline post-closure groundwater monitoring requirements

- Same requirements for both landfills and impoundments
- Baseline post-closure monitoring is assumed to comprise 30 years of groundwater monitoring and surface water monitoring on a semi-annual basis. The physical parameters (i.e., point of compliance, number of wells, sets of chemical indicators and sets of chemical constituents monitored, and semi-annual frequency) and unit cost are assumed identical as defined in the baseline groundwater monitoring cost item 1 above in this section of the RIA.
- However, post-closure monitoring costs are estimated in this RIA assuming an annual sum is placed in a fund by affected entities (i.e., electric utility owners) during the assumed average 40-year operating life of the CCR disposal unit. At the time of closure sufficient monies will be available in the fund to cover post-closure monitoring for the next 30 years beyond end-of-lifespan, assuming an annual interest rate of 7%.

10. Baseline storage tank/container design and operating standards
Baseline cost not estimated in this RIA

- **Baseline "Ancillary Costs" Estimates**

11. Baseline offsite disposal

The baseline cost for engineering controls at offsite CCR disposal sites (assumed in this RIA to be commercial Subtitle D landfills) is estimated using the same cost model as the engineering controls for onsite disposal units. In addition, the offsite disposal baseline cost includes the cost for truck transport from the electric utility plant to the offsite landfill, calculated as follows:

- Baseline Assumptions:
  - 12% (15 million tons/year) CCR currently trucked offsite to non-haz LFs (2005)
  - 6 miles average one-way trucking distance to offsite LFs[50]
  - $0.10/ton/mile non-haz waste truck operating cost
  - 12 tons CCR per full truckload (source: Gambrills MD case study); (15 million tons/year) / (12 tons/load) = 1.25 million truckloads per year
- Baseline Cost Calculations:
  - Manifest cost: $0
  - Trucking cost: (15 million tons/year) x (6 miles) x ($0.10/ton/mile truck operating cost for non hazmat) = $9.0 million/year

12. Baseline structural integrity inspections

Assumptions:

Baseline assumption is that 82% of CCR disposal units at electric utility plants are inspected (source: page 36 of joint DOE/EPA report "Coal Combustion Waste Management at Landfills and Surface Impoundments, 1994-2004", report nr. DOE/PI-0004, Aug 2006 at: http://www.ead.anl.gov/pub/dsp_detail.cfm?PubID=2008). Per-plant cost for inspections estimated in **Exhibit 3K** below.

Cost Calculation:

Industry cost: ($10,829/year per facility) x (82% inspected) x (495 plants) = $4.40 million per year

State government cost: ($599/year per facility) x (82% inspected) x (495 plants) = $0.24 million per year

Total (industry + state) = $4.64 million per year

[50] Source: based on actual distance reported for a MD plant at http://www.rachel.org/en/node/445). Note: a broader range of 2.4 miles to 25 miles in one-way offsite landfill distance was reported by an OH plant at http://www.columbusdispatch.com/live/content/local_news/stories/2008/04/14/Powerfills.ART_ART_04-14-08_B1_FF9TI0U.html?sid=101, and a WI plant, respectively at http://www.lacrossetribune.com/articles/2007/09/21/news/03landfill0921.txt

Exhibit 3K Summary of Industry & State Government Labor Costs for MSHA Surface Impoundment Safety Plan & Annual Inspections & Estimate of Annual Costs for Similar Structural Integrity Activities for Electric Utility Plant Surface Impoundments					
Item	Paperwork Burden Element*	Labor hours	Cost (2006)	Cost per facility	Annualized
Industry Costs					
1	Impoundment Safety Plan prepared by mining company engineer >>> Purpose: To evaluate geotechnical, hydrologic, hydraulic & other engineering factors to construct or improve surface impoundment structures to avoid structural failures	1,300	$70.07/hr	$91,091	$9,109
2	Revisions to Impoundment Safety Plan prepared by mining company engineer[2]	40	$70.07/hr	$2,803	$280
3	Fire Extinguishing Plan prepared by mining company engineer or supervisor	20	$70.07/hr	$1,401	$140
4	Annual Status Report & Annual Certification prepared by company engineer >>> Purpose: To determine whether impoundments are operated and maintained according to approved engineering safety plan	2	$70.07/hr	$140	$14
5	Recordkeeping and weekly inspections[3] >>> Purpose: To determine whether any signs of instability have developed	2.5 hrs per inspectn x 17 inspect = 42.5	$30.27/hr	$1,286	$1,286
			Subtotal (Industry costs):	$10,829 per facility per year	
State Government Costs					
6	Review of Impoundment Safety Plans	160 hrs tech review + 2 hrs admin review	$30.57/hr	$4,952	$495
7	Review of revisions to Impoundment Safety Plans	30 hrs tech review + 2 hrs admin review	$30.57/hr	$978	$98
8	Review and prepare responses for impoundment abandonment plans	1	$30.57/hr	$31 per plan	$3
9	Review of annual inspection Status Reports and Certifications	1	$30.57/hr	$31 per report	$3
			Subtotal (State government costs):	$599 per facility per year	
Total Cost					
			Total industry + state government cost:	$11,428 per inspection	

Notes:
* Elements, labor hours, and labor costs are based on the "Supporting Statement" for the March 2008 DOL/MSHA ICR 12-19-0015, "Refuse Piles and Impounding Structures, Recordkeeping, and Reporting Requirements" at: http://www.msha.gov/regs/fedreg/paperwork/2004/04-24046.pdf
1. Assumes plans are valid for 10-years similar to the length of RCRA permits.
2. Assumes one revision to the plan will be made during 10-years.
3. Average labor hours per inspection between inspections at sites with monitoring instruments (3 hours) and at sites without monitoring instruments (2 hours).

13. Baseline RCRA facility-wide investigations (RFI)
Baseline cost assumed to be $0 because this RIA assumes that all baseline CCR disposal units used by electric utility plants are not regulated under RCRA Subtitle C.

14. Baseline facility-wide corrective action
Because CCR is not regulated as Subtitle C hazardous waste, there are no existing facility-wide (i.e., CCR disposal units plus other waste units also located at the same plant) corrective action requirements, although some state governments have the following unit-specific corrective action requirements affecting CCR disposal units.
State regulations for the top 25 coal usage states (for electricity) were reviewed for correction action requirements in 2000. These regulations were not updated as part of this RIA. Corrective action requirements were identified in 21 of the 25 states.

- Surface impoundments: 71% of CCR impoundments representing 67% of CCR impoundment annual tonnage have state government baseline corrective action requirements:
  - AZ, IN, and IA establish a corrective action alert level and response action in site-specific state permits
  - CO requires corrective action for new units
  - 9 states (FL, GA, KY, MI, NC, ND, PA, UT, WI) require corrective action
  - IL, MN, TX, WV, WY do not allow groundwater degradation, but specific enforcement mechanisms are not specified in state regulations
  - MO requires corrective action for units closed with waste in place, otherwise, corrective action may be established under a permit
  - NM requires an abatement plan.
- Landfills: 66% of CCR landfills with 81% of CCR landfill annual tonnage have state government corrective action requirements:
  - AZ establishes corrective action alert level and response action in site-specific state permits
  - 15 states (CO, FL, GA, IL, KY, MI, NC, ND, OH, OK, PA, UT, WV, WI, WY) require corrective action
  - MN, TX do not allow groundwater degradation, but, specific enforcement mechanisms are not specified in state regulations
  - MO, TN require assessment only
  - NM requires an abatement plan

15. Baseline waste disposal permit cost

- Assumptions:
  - 93% of CCR landfills have a state government non-hazardous waste disposal permit and 12% of CCR impoundments have such permits. Source: page 28, Table 9 of "Coal Combustion Waste Management at Landfills and Surface Impoundments, 1994-2004", August 2006 at http://www.ead.anl.gov/pub/dsp_detail.cfm?PubID=2008
- Industry waste disposal permit cost:
  - ($5,000 RCRA Part A permit) + ($50,000 RCRA general facility permit requirements) + ($25,000 average RCRA Part B for impoundment or landfill) = $80,000 per Subtitle C permit
  - Assume RCRA Subtitle D (40 CFR 257, 258) waste permitting activities are less burdensome than RCRA Subtitle C waste permits. Based on factor of 3.3 times more technical standards listed in RCRA Subtitle C (40 CFR 264/265, 268, 270) compared to Subtitle D (40 CFR 257, 258), assume Subtitle D permitting costs are lower by the 3.3 factor:

($80,000 per year average Subtitle C waste disposal permit cost) / (3.3) = $24,300 per non-haz waste disposal permit
[((93% landfills w/permit) x (337 landfills)) + ((12% impoundments w/permit) x (158 impoundments))] x ($24,300 per permit) = $8.1 million

Amortized industry cost with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $0.59 million/year

- State government waste disposal permit cost:
  - Build estimate based on the following four RCRA Subtitle C permit-related state government activities associated with RCRA Subtitle C waste disposal permits:[51]
    (1,215 pre-application activities) + ($27,063 application review) + ($26,846 permit issuance) + ($3,110 permit maintenance) = $58,200 average cost per Subtitle C waste disposal permit.
  - Assume RCRA Subtitle D (40 CFR 257, 258) waste permitting activities are less burdensome than RCRA Subtitle C waste permits. Based on factor of 3.3 times more technical standards listed in RCRA Subtitle C (40 CFR 264/265, 268, 270) compared to Subtitle D (40 CFR 257, 258), assume Subtitle D permitting costs are lower by the 3.3 factor:
    ($58,200 per year average Subtitle C waste disposal permit cost) / (3.3) = $17,600 per non-haz waste disposal permit
  - State Cost Calculation:
    [((93% landfills w/permit) x (337 landfills)) + ((12% impoundments w/permit) x (158 impoundments))] x ($17,600 per permit) = $5.85 million
    Amortized state cost with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $0.42 million/year

Total baseline permit cost (industry + state government) = $1.01 million per year

16. Baseline enforcement inspection

Not estimated in this RIA.

17. Baseline remediation of environmental releases

Not estimated in this RIA.

[51] Source: Based on cost data from page 84 of January 2007 ASTSWMO report "State RCRA Subtitle C Core Hazardous Waste Management Program Implementation Costs Final Report" at: http://www.astswmo.org/files/publications/hazardouswaste/Final%20Report%20-%20RCRA%20Subtitle%20C%20Core%20Project.pdf

- **Baseline CCR Disposal Cost Estimation Results**

Exhibit 3L below displays the average annualized costs for each of the baseline cost components, as well as on an average per-ton and per-plant basis. **Appendix H** provides plant-by-plant and owner entity-by-entity estimates of baseline costs.

Exhibit 3L
Industry Baseline Cost Estimates for CCR Disposal by Electric Utility Plants (Onsite + Offsite)
($millions per year in 2009$ discounted @7% over 50-year period-of-analysis 2012 to 2061)

Baseline Cost Element	CCR Landfills (311 plants)	CCR Impoundments (158 plants)	Row totals (467 of 495 plants)	
A. Engineering controls (onsite disposal):				
1. Ground water monitoring	$19.2	$8.0	$27.2	0.5%
2. Bottom liners	$2,751	$1,219	$3,970	71.5%
3. Leachate collection system	$105.5	$52.2	$157.7	2.8%
4. Dust controls	$24.2	$2.8	$27.1	0.5%
5. Water run-on/run-off controls	$4.8	$0.7	$5.6	0.10%
6..Financial assurance	$61.2	$17.9	$79.2	1.4%
7. Disposal location restrictions	Not estimated	Not estimated	Not estimated	
8. Closure capping to cover unit	$72.7	$15.7	$88.5	1.6%
9. Post-closure groundwater monitoring	$1.3	$0.5	$1.8	0.03%
10. Storage design/operating requirements	Not estimated	Not estimated	Not estimated	
Subtotal Engineering Control costs =	$3,040	$1,317	$4,357	78%
B. Ancillary costs for CCR disposal:				
11. Offsite disposal (commercial landfills)	$1,193	$0	$1,193	21.5%
12. Structural integrity inspections	$2.46	$2.18	$4.64	0.08%
13. RCRA facility-wide investigation (RFI)	$0	$0	$0	0%
14. Corrective action	Not estimated	Not estimated	Not estimated	NE
15. Waste disposal permits	$0.69	$0.32	$1.01	0.02%
16. Enforcement inspection	Not estimated	Not estimated	Not estimated	NE
17. Remediation of environmental releases	Not estimated	Not estimated	Not estimated	NE
Subtotal Ancillary costs =	$1,196	$2.5	$1,199	22%
Cost Summary (A+B)				
Column total annualized cost =	$4,236	$1,320	**$5,556 (includes $1,193 offsite disposal) PV = $76,678 (@7%, 50-years)**	
Average annual cost per plant =	$13.6 million per plant	$8.4 million per plant	$11.9 million per plant	
Average cost per CCR ton disposed =	$59 per ton (71.8 million tons per year)	$59 per ton (22.4 million tons per year)	$59 per ton (94.2 million tons/year disposed)	

- **Validity Check of Baseline Cost Estimate (2 Tests):**
  - **Validity Test #1 of 2: Comparison to ACAA Published Estimate of Average CCR Disposal Cost**

As displayed above in **Exhibit 3L** the estimated baseline (i.e., current) average annualized cost to the 495 coal-fired electric utility plants for disposal of CCR is $5.6 billion per year (2009$). This annualized cost includes amortization of capital investment in construction of disposal units and associated equipment (i.e., in-plant equipment for extracting CCR from boilers, CCR storage equipment, CCR conveyance equipment such as slurry pipelines for wet CCR or trucks and mechanical conveyor belts for dry CCR, and the disposal units themselves), plus annual expenditures for operation, maintenance and replacement/expansion of this equipment and disposal units. On a unitized cost-per-ton basis -- calculated by dividing the annualized baseline cost by the estimated 94.2 million tons per year (as of 2005) CCR disposed in (a) onsite landfills plus (b) offsite landfills plus (c) impoundments annually – the estimated baseline cost represents an average unitized cost of $59 per-ton.

In comparison, the American Coal Ash Association (ACAA) estimates that the average unit cost (per-ton) for baseline disposal of CCR by coal-fired electric utility plants ranges as low as $3 per-ton to higher than $40 per-ton:

> "*As one can see, a variety of factors enter into determining disposal costs. The lowest cost occurs when a disposal site is located near the power plant and the material being disposed can be easily handled. If the material can be piped, rather than trucked, costs are usually lower. In these types of situations, cost may be as low as $3 to $5 per ton. In other areas, when distance is far away and the [CCR] must be handled several times due to its moisture content or volume, costs could range from $20 to $40 per ton. In some areas, the costs are even higher. If new sites are required and extensive permitting processes take place, the total cost of the facility may be increased, resulting in higher disposal costs over time.*"[52]

The reasons the average annualized and unitized baseline CCR disposal cost of $59 per-ton estimated in this RIA, is higher than the baseline cost range of $3 to over $40 per-ton reported by the ACAA, are:

- <u>Low-end unitized cost</u>: The low-end of ACAA's reported cost range is $3 to $5 per-ton. Assuming the cheapest operating surface impoundment does not include a liner and leachate collection costs as estimated in this RIA for impoundments in states with such regulatory requirements, the baseline surface impoundment unitized cost may be as low as $2 per-ton based on the cost elements applied in this RIA. This low-end unitized cost may be derived from the impoundment cost column of **Exhibit 3L** as follows:

  (Column total cost - Row 2 cost - Row 3 cost) / (22.4 million tons per year managed in impoundments) =
  ($1,317 million/year - $1,219 million/year - $52.2 million/year) / (22.4 million tons per year) = **$2.04 per-ton**

- <u>High-end unitized cost</u>: The upper-end of ACAA's reported cost range is $20 to $40 per ton, which applies to offsite disposal. The cost estimation of this RIA incorporates off-site commercial disposal costs on a state-by-state specific basis according to electricity

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[52] Source: ACAA webpage containing Frequently Asked Question nr. 13 at http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q13

power plant location, using commercial landfill tipping fees ($2009) for contaminated soil, which range widely from $11 per-ton to $135 per-ton, with a national average of $50 per-ton. For example, commercial landfill tipping fees for contaminated soil for some of the high coal usage states are: TN = $11.19/ton, IN = $32.73/ton, OH = $35.48/ton, and PA = $57.96/ton. The baseline cost estimation method of this RIA then added a CCR offsite transportation and loading cost of approximately $33 per-ton based on the RACER cost estimation tool. For the estimated 15.0 million tons per-year of CCR disposed in offsite landfills, the estimated baseline cost is $1,193 million per-year, which is equivalent to **$79.53 per-ton** over the 50-year time period of the RIA cost analysis which assumes increasing coal usage (0.73% per-year) by electric utilities and subsequent offsite landfill disposal over the 50 year time period. It is unknown what cost elements are included in the high-end of the ACAA reported cost range (e.g., transportation cost and/or landfill tipping fee cost). In addition, electric utility companies likely have annual or multi-year contracts with offsite landfill operators that offer lower tipping fees than the state-average off-site contaminated soil tipping fees used in this RIA.

- **Validity Test #2 of 2: Comparison to CCR Disposal Costs Contained in the EIA Form 767 Database**

The 2005 Energy Information Administration (EIA) Form 767 database (Schedule 3, Part B) indicates $5,890 million in annual capital and O&M cost reported by steam electric plants with nameplate capacity of 100 MW or greater, including (a) $0.314 million per year for water pollution controls, (b) $0.193 million per year for solid waste disposal, (c) $0.185 million per year for other pollution controls, (d) $3,627 million per year capital expense for air pollution abatement, and (e) $1,546 million per year for collection and disposal O&M costs for fly ash, bottom ash, and FGD. This last cost element --- $1,546 million per year for CCR disposal --- is only 28% of the $5,556 million per year estimate displayed in **Exhibit 3L** above. However, the 2005 EIA Form 767 cost data are associated with only 179 coal-fired electric utility plants, which represent only 36% of the 495 coal-fired electric utility plants addressed by this RIA. Therefore, to facilitate a direct comparison, the $1,546 million per year cost from the data in EIA Form 767 may be extrapolated to all 495 plants by multiplying by the factor 2.765 (i.e., 495 / 179), which produces an estimated extrapolated cost for all 495 plants of $4,275 million per year (i.e., 2.765 x $1,546 million per year). This extrapolated cost is 23% lower than the $5,556 million per year baseline cost estimated in this RIA. This comparison suggests the baseline cost estimated in this RIA may be an over-estimate, but it is not clear whether the cost data in the EIA Form 767 database include baseline costs to the electric utility plants for compliance with existing state government regulations concerning CCR disposal (e.g., the annualized cost for obtaining and maintaining state government disposal permits and the annualized cost for impoundment structural integrity inspections), as does this RIA.

Chapter 4
Estimated Cost for RCRA Regulation of CCR Disposal

Note: EPA formulated cost estimates in this Chapter based on the October 2009 draft RIA regulatory options. Because the high-end cost of those options (i.e., for the Subtitle C "hazardous waste" option) is larger than the high-end cost for the 2010 regulatory options (i.e., for the Subtitle C "special waste" option), the costs in this Chapter are proportionately over-estimated. However, Section 6B of this RIA applies scaling factors to adjust the costs estimated in this Chapter to the 2010 options.

4A. EPA's Prior Cost Estimates for Possible RCRA Regulation of CCR Disposal at Electric Utility Plants

In prior studies, EPA's Office of Solid Waste (which EPA renamed as the ORCR effective 18 January 2009), formulated the following industry compliance cost estimates for different RCRA-based regulatory approaches to CCR disposal by the electric utility industry:

1988: OSW's 1988 Report to Congress on CCR estimated **$2.4 billion to $4.7 billion** per year (1986$) in potential average annualized industry cost (514 plants in 1984) for compliance with technical standards contained in 40 CFR 264 RCRA **Subtitle C** hazardous waste regulations. The range reflects different liner assumptions (i.e., single versus double liners) and whether only unlined CCR units close or all existing units close requiring construction of new units. This cost includes closure costs but not a cost for corrective action excavating and removing CCR to Subtitle C facilities for closure of existing units. This report separately estimated that corrective action "at a cost of about $2.0 billion per plant, industry-wide costs would exceed $1.0 trillion" lump-sum cost, which is equivalent to $43 billion annualized cost (discounted @3% over 40-years). Source: EPA-OSWER report nr. EPA/530-SW-88-002, Feb 1988.

1999: OSW's 1999 Report to Congress focused on the "co-management" (i.e., low-volume mixed with high-volume) subset of CCR units (i.e., 206 units at 353 plants in 1994), constituting 53 million tons (50%) of the 105 million total high-volume electric utility CCR generation in 1997. This report estimated a range of **$800 million to $900 million** per year (1998$) in potential average annualized compliance cost to the electric utility industry to comply with technical standards similar to 40 CFR 258 RCRA **Subtitle D** non-hazardous waste regulations. This cost estimate includes opening new CCR units to replace existing units that do not meet Subtitle D standards, including the following itemized costs: land purchase, site development, liner installation, leachate collection, groundwater wells & monitoring, closure costs, and post-closure costs. This estimate accounted for state CCR management requirements as of 1997. Source: EPA OSWER report nr. EPA 530-R-99-010, March 1999.

2005: In a November 2005 report, an OSW contractor (DPRA Inc) estimated **$304 million to $521 million** per year (2005$) in potential average annualized cost for the electric utility industry (i.e., 470 units at 452 plants in 2003) to comply with regulatory options developed with reference to the "tailored standards" of EPA's 1999 cement kiln dust proposed rule which based many elements on 40 CFR 258 RCRA **Subtitle D** non-hazardous waste regulations. Cost elements in this report included (a) location standards, (b) operating criteria such as cover material, dust control, run-on/run-off control, (c) design criteria such as liner and leachate collection, (d) groundwater monitoring, (e) closure and post-closure standards, and (f) financial assurance for closure, post-closure and corrective action. This estimate accounted for state CCR management requirements as of 2004, but did not include costs for corrective action. Source: EPA-OSWER document ID nr. EPA-HQ-RCRA-2006-0796-0469 at http://www.regulations.gov.

These three prior RCRA regulatory cost estimates range from **$304 million to $4.7 billion** per year. Even without updating these prior cost estimates to the current 2009 price level, all three prior cost estimates exceed the 1993 Executive Order 12866 Section 3(f)(1) "economically significant" $100 million annual effect threshold for Federal rulemakings.

4B. Regulatory Cost Estimation Algorithms & Results

This section presents **incremental cost estimates** for each regulatory option, for both existing active (i.e., operating) and future new CCR landfills and impoundments, and by size/type of affected electric utility plant owner entity. Incremental comparison of the estimated cost of each regulatory option to the baseline (as estimated in **Chapter 3** of this RIA) is consistent with OMB's 2003 "Circular A-4: Regulatory Analysis" best practices guidance to Federal agencies:

> "*Identify a baseline. Benefits and costs are defined in comparison with a clearly stated alternative. This normally will be a "no action" baseline: what the world will be like if the proposed rule is not adopted.*"

As listed below, this RIA estimates 18 potential regulatory costs and the land disposal restriction (LDR) dewatering treatment standard, based on many of the same unit cost data sources and the same framework (i.e., 2009 price level, 50-year period of analysis, etc.), identified in the prior chapter of this RIA for baseline cost estimation. According to three methodological groupings, this RIA estimates three categories of regulatory costs:

A. **Engineering controls** for CCR disposal units – estimated using the cost model described in the prior chapter of this RIA:

1. Ground water monitoring
2. Bottom liners – for future new units only
3. Leachate collection system – for future new units only
4. Dust controls – applicable to landfills only
5. Rain and surface water run-on/run-off controls – applicable to landfills only
6. Financial assurance for disposal unit closure and post-closure
7. Disposal unit location restrictions (6 types: water tables, floodplains, wetlands, fault areas, seismic zones, karst terrain)
8. Closure capping to cover unit
9. Post-closure monitoring requirements
10. Temporary storage requirements – not estimated in this RIA because do not have information on the baseline counts or physical conditions of CCR storage tanks and storage buildings at electric utility plants.

B. **Ancillary costs** for CCR disposal – estimated outside of the engineering control cost model:
11. Offsite disposal (hazmat trucking, RCRA manifesting, offsite RCRA TSDF permits)
12. Structural integrity inspections – impoundments only
13. RCRA facility-wide investigation (RFI)
14. RCRA facility-wide corrective action
15. RCRA TSDF hazardous waste disposal permits for onsite disposal
16. RCRA enforcement inspection
17. Cleanup remediation of future CCR impoundment failures as RCRA hazardous waste
18. EPA administrative reporting & recordkeeping

C. **LDR cost** for land disposal restriction dewatering treatment – Sections 3004(d) and (m) of the RCRA statute require treatment prior to land disposal for Subtitle C hazardous waste listings, but not for Subtitle D non-hazardous waste regulation. The purpose of the treatment is to "substantially diminish the toxicity of the waste or substantially reduce the likelihood of migration of hazardous constituents from the waste so that short-term and long-term threats to human health and the environment are minimized" (source: section 3004(m)):

- Dry CCR disposal (landfills): Moisture conditioning and compaction included in engineering control cost item 4.
- Wet CCR disposal (impoundments): Estimated outside and separately of the engineering controls cost model in this RIA.

This RIA does not include either qualitative or quantitative estimation of the potential effects of the proposed rule on economic productivity, economic growth, employment, job creation, or international economic competitiveness. These potential effects are identified as factors in both the 1993 Executive Order "Regulatory Planning and Review" (section 3(f)(1)) and in the 1995 Unfunded Mandates Reform Act (section 202(a)(4)). These other potential economic effects are excluded from this RIA because the upper-end of the range in average annualized regulatory cost across all regulatory options as estimated in this chapter below, does not exceed the 0.25% to 0.5% of Gross Domestic Product (GDP) threshold identified in OMB's 1995 guidance[53] for attempting to measure such other economic effects for purpose of UMRA economic analysis compliance. Based on the 2008 US GDP of $14.42 trillion,[54] the 0.25% to 0.5% threshold is equal to $36 billion to $72 billion.

4B.1 Regulatory Cost to Industry for RCRA "Engineering Controls"

This RIA assumes that that same set of RCRA 3004(x) custom-tailored engineering controls is required under each of the regulatory options, so the costs for engineering controls for all regulatory options are mostly, but not entirely, based on the same cost estimation formulae described above in **Chapter 3** for estimation of baseline engineering control costs. Furthermore, this RIA assumes that the engineering control costs are

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[53] Source: Section 4.B(3) of OMB's 31 March 1995 guidance for implementing the UMRA state that "*We would note that such macro-economic effects tend to be measurable, in nation-wide econometric models, only if the economic impact of the regulation reaches 0.25 percent to 0.5 percent of Gross Domestic Product. A regulation with a smaller aggregate effect is highly unlikely to have any measurable impact in macro-economic terms unless it is highly focuses on a particular geographic region or economic sector.*"

[54] Source: 2008 3rd quarter estimate of 2008 US GDP as reported in "TABLE B–8.—Gross domestic product by major type of product, 1959–2008" of the 2009 Economic Report of the President at http://www.gpoaccess.gov/eop/tables09.html

similarly specified in EPA's cement kiln dust 20 August 1999 proposed rule.[55] This assumption was required to launch this RIA in April 2009 prior to the initial draft of the CCR proposed rule and its regulatory options. This RIA assumes that liners and leachate collection systems requirements apply only to future new CCR landfills and impoundments. Offsite disposal costs are assumed unaffected under all regulatory options because offsite CCR disposal units are assumed to be commercially-owned units (i.e., owned by the waste management industry) and assumed currently in compliance with the custom-tailored engineering controls. For engineering controls added to existing units the costs are added to the remaining years of the lifespan of the landfill or impoundment.

1. Regulatory groundwater monitoring cost
Same cost estimation formula applied above in **Chapter 3** for baseline cost estimation.

2. Regulatory bottom liner cost
Same cost estimation formula applied above in **Chapter 3** for baseline cost estimation.

3. Regulatory leachate collection cost
Same cost estimation formula applied above in **Chapter 3** for baseline cost estimation.

4. Regulatory fugitive dust control cost
Same cost estimation formula applied above in **Chapter 3** for baseline cost estimation.

5. Regulatory financial assurance cost
Same cost estimation formula applied above in **Chapter 3** for baseline cost estimation.

6. Regulatory closure costs
Same cost estimation formula applied above in **Chapter 3** for baseline cost estimation.

7. Regulatory disposal unit location restriction costs
This cost element is estimated outside of the engineering controls cost model, using the factors, data and calculations below.

- Count of Existing Electric Plants Which May be Affected by Location Restrictions

To estimate the potential cost of location restrictions, this RIA conducted a GIS analysis to determine which facilities may be affected by location restrictions. As summarized below, the GIS analysis was conducted for three of the six possible site restrictions (i.e., using three GIS-based datasets pertaining to fault areas, seismic zones, and karst zones readily available to EPA-ORCR at the 2009 launch of this RIA). This limitation potentially results in under-estimation in this RIA of the number or electric utility plants which may be affected and thus under-estimation of regulatory location restriction costs. On the other hand, the average per-plant cost of $4.1 million applied below for estimating the potential cost of this regulatory element is over five-times higher than the $0.75 million[56] cost per-plant cost estimated by another study for

[55] Federal Register, Vol.64, No.161, 20 Aug 1999, pp.45632-45697.
[56] Source: $0.75 million disposal unit location restriction mitigation cost for a single electric utility plant is from page 10 (slide number TVA-00007496) of "Kingston Fossil Plant Decision Matrix: Pond or Peninsula?," 27 Jan 2005 Plant Managers Conference Room at http://www.tva.gov/kingston/tdec/pdf/TVA-00007487.pdf

location restriction mitigation involving karst mitigation and floodplain/wetland mitigation; this probably overly offsets the possible cost underestimation in this RIA for this regulatory element.

The GIS was based on the DOE-EIA eGRID database to identify the geographic coordinates for 491 of the 495 electric utility plants (disregarding four plants not present in the eGRID database). **Appendix I** of this RIA presents site location data for each electric utility plant used in the GIS analysis. In order to geographically capture both the facilities and their waste units, and to compensate for the fact that there exists uncertainty as to the exact facility location versus the reported geographic coordinates (i.e., depending on whether location was measured by plant centroid, street address, smokestack, etc.), this GIS analysis used both a 1-mile and a 3-mile buffer around the reported facility coordinates. This RIA presumes these buffers are likely to ensure inclusion of the facility's onsite CCR disposal units, and account for uncertainty in the location data. The 1-mile buffer should capture all impoundments; the 3-mile buffer represents an upper-bound to capture all landfills that could reasonably be considered on-site.

1. Water table restrictions: GIS analysis not conducted for this site restriction
2. Floodplain restrictions: GIS analysis not conducted for this site restriction
3. Wetlands restrictions: GIS analysis not conducted for this site restriction
4. Fault area restrictions

To identify fault zones, used the USGS database, "Quarternary Fault and Fold Database for the United States," which contains national scale location data on faults and associated folds.[57] This analysis identified plants including their buffers which fall within 200 feet of fault lines that have exhibited movement in the Holocene era. The USGS dataset includes fault lines that are believed to have been a source of earthquakes greater than magnitude 6 during the Quarternary (the past 1,600,000 years) and it defines "Holocene" as the past 15 thousand years.[58,59]

- 1-mile buffer: 1 plant falls within 200 feet of a fault line.
- 3-mile buffer: 3 plants fall within 200 feet of a fault line. (these three plants are located in NV and UT).

It is important to note that this preliminary analysis has certain limitations and may not capture facilities in other areas of seismic risk. According to the USGS fault line database, no relevant faults are located in the central and eastern US. The USGS states in its database description that this absence of identified faults with movement in the central and eastern US is partly a real phenomena, because the western US has more tectonic activity, but that it is partly a detection problem caused by geological characteristics present in the central and eastern US, such as glacial sediments, that conceal evidence of movement along faults. For this reason, the analysis of seismic zones below, which are defined based on the likelihood of future seismic activity, may represent a more reliable estimate of the number of facilities potentially affected by fault area restrictions.[60]

[57] US Geological Survey, 2006, "Quarternary Fault and Fold Database for the United States" at: http//earthquakes.usgs.gov/regional/qfaults. File used: fitarc.shp

[58] RCRA defines "Holocene" as "the most recent epoch of the Quarternary period, extending from the end of the Pleistocene to the present" (40 CFR 264.18(a)(2)(iii)).

[59] Faults designated by the dataset as showing movement during the Holocene are not necessarily believed to have produced an earthquake of magnitude 6 or greater during the Holocene. Rather, they are believed to have produced an earthquake of magnitude 6 or greater during the Quarternary, but their most recent suspected movement of any degree was during the Holocene.

[60] The USGS data layer used for this analysis indicates that faults with Holocene movement are located only in states in the West and Southwest regions of the US. This appears generally consistent with a separate analysis in *the RCRA Practice Manual* (Garrett, Theodore L., 2004, published by American Bar Association), and the small number of plants affected is not unexpected given the relatively small number of plants in these regions. However, the *RCRA Practice Manual* also notes that virtually all plants in CA and NV, and in parts of AK, AZ, CO, HI, ID, MT, NM, UT, WA, WY would be located within 200 feet of relevant faults. This suggests an upper bound of 54 plants (out of the 491 plants analyzed), if all facilities in the identified states may be affected by fault area restrictions.

5. Seismic zone restrictions:
To identify seismic zones, USGS National Seismic Hazard Maps provide peak horizontal acceleration at different probabilities of exceedance in 50 years.[61] Identified those facilities, including their buffers, which overlap with the seismic impact zones that have a 10% or greater probability of exceeding a maximum horizontal acceleration of 10% the force of gravity (i.e., 0.10 g) in 250 years.[62] The USGS data gives probabilities of exceedance over 50 years; thus used a data layer presenting 2% probability of exceedance, and assumed that this equates to a 10% probability of exceedance in 250 years.

- 1-mile buffer: 151 plants fall within seismic zones
- 3-mile buffer: 152 plants fall within seismic zones

6. Karst zone restrictions:
This analysis used two databases: (1) DOE-EIA's eGRID database to identify the geographic coordinates of 491 of the 495 plants analyzed (disregarding four plants that were not present in the eGRID database), and (2) the USGS's GIS database "Engineering Aspects of Karst," which provides national-scale data on karst coverage.[63] Four types of karst areas are identified in the dataset: (a) long karst features (fissures, tubes, and caves over 1000 feet long and 250 feet deep); (b) short karst (fissures, tubes, and caves less than 1000 feet long and 50 feet deep), (c) areas where karst features are generally absent but present in small isolated areas, and (d) pseudo-karst areas, which have features analogous to karst.

- 1-mile buffer: 138 plants fall within karst zones
- 3-mile buffer: 177 plants fall within karst zones

These counts do not distinguish between the four different types of karst terrain identified in the data set; this analysis represents an initial upper bound of potentially affected facilities.

- Potential Cost for Existing & New Electric Plants to Meet Disposal Unit Location Restrictions

According to the above findings for the three location criteria evaluated in this RIA (i.e., fault areas, seismic zones, karst zones), a maximum count of 177 plants could be affected (this is the upper-end of the affected plant counts across the three location evaluations). The potential cost to these plants of the location restrictions is estimated in this RIA using the cost to retro-fit existing CCR disposal units and to protect new CCR disposal units with a berm (aka levee). A berm is a type of engineering measure which may serve to demonstrate that engineering measures have been incorporated into disposal unit design to mitigate the potential adverse impacts disposal units may have on, or be caused by, these six location considerations.

The cost to construct a berm is based on the cost to construct a 10-foot tall flood berm using US Army Corps of Engineers' publication "Flood Proofing – How to Evaluate Your Options," (July 1993), which provides unit costs in 1993 dollars to construct clay core flood control levees that are two, four, and six-feet high. This RIA inflated these unit costs to 2009 dollars using the ENR Construction Cost Index, and conducted a regression analysis on the unit costs (i.e., extrapolated the cost based on the implied cost curve of the smaller berms) to estimate the cost to construct a 10-foot tall berm. The estimated cost per linear foot to construct a 10-foot tall berm is $375. It is assumed that this unit cost could apply to both existing and new units, and that the berm would be constructed physically separate from the disposal unit, not integral as "freeboard" to the disposal unit's structure.

[61] U.S. Geological Survey, 2008, "National Seismic Hazard Maps," from USGS website: http://gldims.cr.usgs.gov/nshmp2008/viewer.htm. Data file used: pga2pct_p.shp.
[62] This threshold for seismic impact zones is consistent with RCRA's municipal solid waste landfill location restrictions (40 CFR 258.14(a)(b)(1)).
[63] U.S. Geological Survey, 1984, "Engineering aspects of karst," from USGS website: http://pubs.usgs.gov/of/2004/1352. File used: karst.shp.

- Impoundment berms: The average surface impoundment size for existing units in the cost model is 343 acres. Assuming a square impoundment and that the berm would be constructed on three sides of the impoundment the average berm length is 11,594 feet. Therefore, the cost to construct a berm around an average-size impoundment is $4.3 million.[64]
- Landfill berms: Similarly, the average landfill size for existing units in the cost model is 278 acres. Assuming a square landfill and that the berm would be constructed on three sides of the landfill (leaving one side open for truck access), the average berm length is 10,447 feet, and the cost to construct a berm surrounding an average-size landfill is $3.9 million.

Using the 3-mile buffer karst zone finding of 177 plants, the potential cost for constructing berms at those plants plus future plants is:

- Existing units: ($4.1 million average berm cost) x (177 disposal units) = $726 million total cost
  Amortized with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $53 million/year equivalent
- New units: Apply 0.73% average annual growth rate in future CCR generation (cited elsewhere in this RIA) to estimate the count of future new or expanded disposal units over 50-years, and assume 36% (i.e., 177/495) will need berms:
  (495 existing disposal units) x (1.0073% growth rate)^(50 years) = 712 existing plus new units over 50-years
  (712 units over 50-years) – (495 existing units) = 217 future new disposal units
  (217 future new units) x (36% needing berms) x ($4.1 million average berm cost) = $318 million total cost
  Amortized with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $23 million/year equivalent
  Average annualized berm cost for existing + new units = $76 million/year equivalent

8. Regulatory closure cost
Same cost estimation formula applied above in **Chapter 3** for baseline cost estimation.

9. Regulatory post-closure monitoring cost
Same cost estimation formula applied above in **Chapter 3** for baseline cost estimation.

10. Storage design and operating standards for tanks, containers, and containment buildings
Not estimated in this RIA due to lack of baseline information about the count and condition of these units at electric utility plants

4B.2 Ancillary Regulatory Requirement Costs

For estimating most of the "Other Ancillary Costs" in this section, this RIA distinguishes between RCRA Subtitle C and RCRA Subtitle D requirements according to the respective basis of each regulatory option, as well as between costs to electric utility plants and costs to state government RCRA-authorized regulatory programs.

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[64] For purpose of comparison to the $4.3 million (per impoundment) and $3.9 million (per landfill) location restriction mitigation cost estimates above, in 2005 the TVA estimated an "assumed" cost of $500,000 for karst mitigation and $250,000 for floodplain mitigation for a potential new CCR disposal site involving 1,300 linear feet for mitigation. Extrapolation of TVA's $750,000 cost estimate to 11,594 feet (impoundment) yields $6.7 million (i.e., (11,594 feet / 1,300 feet) x ($750,000)), and to 10,447 feet (landfill) yields $6.0 million (i.e., 10,447 feet / 1,300 feet) x ($750,000)). Source for TVA cost estimate: page 10 of "Kingston Fossil Plant Decision Matrix: Pond or Peninsula?", 27 January 2005 Plant Managers Conference, http://www.tva.gov/kingston/tdec/pdf/TVA-00007487.pdf

11. Regulatory offsite disposal costs (hazmat trucking, RCRA manifests, RCRA TSDF permits for offsite)
EPA assumed that Subtitle C options add extra cost to (a) truck hauling to offsite disposal, and (b) all offsite landfills must become RCRA Subtitle C permitted. This cost estimate does not include taxes/trans-state government fees associated with off-site disposal.

11a & 11b. Added truck hauling cost (Subtitle C options)

Assumptions:

- Affects the 12% (15 million tons per year) annual CCR generation currently trucked offsite to non-haz LFs (2005)
- 6 miles average one-way trucking distance to offsite LFs[65]
- $0.19/ton/mile hazardous waste truck operating cost
- 12 tons CCR per full truckload (source: Gambrills MD case study); (15 million tons/year) / (12 tons/load) = 1.25 million truckloads per year

Cost Calculations:

- 11a. RCRA manifest cost: (1.25 million truckloads) x ($53 per manifest per load average cost from EPA 2007 ICR 801.15) = $66 million per year
- 11b. Trucking cost (distance + operating cost): (15 million tons/year) x (6 miles) x ($0.09/ton/mile added truck operating cost for hazardous waste loads) = $8.1 million per year
- Subtotal (11a manifest + 11b trucking): $74.1 million per year

11c. Added cost for RCRA Subtitle C permits for all offsite CCR landfills under Subtitle C

Assumptions:

- Added operating cost to offsite CCR landfills for meeting engineering control requirements under each of the regulatory options evaluated in this RIA are included in the "Engineering Control Costs" section above, so are not again calculated here to avoid double-counting. Only the paperwork burden cost for obtaining a RCRA permit is estimated here.
- Industry average cost per waste disposal permit:

  ($440[66] average RCRA Part A permit application cost per-plant per-year) + ($68,960[67] average RCRA Part B application cost per-facility per-year) = $69,400 per Subtitle C permit per year

  ($69,400 per permit per year) x (3 years ICR annualization period) = $208,200 per permit

  (149 offsite CCR landfills) x ($208,200 per permit) = $31.02 million

  Amortized industry cost with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $2.25 million/year

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[65] Source: based on actual distance reported for a MD plant at http://www.rachel.org/en/node/445). Note: a broader range of 2.4 miles to 25 miles in one-way offsite landfill distance was reported by an OH plant at http://www.columbusdispatch.com/live/content/local_news/stories/2008/04/14/Powerfills.ART_ART_04-14-08_B1_FF9TI0U.html?sid=101, and a WI plant, respectively at http://www.lacrossetribune.com/articles/2007/09/21/news/03landfill0921.txt

[66] $440 unitized cost derived for this RIA from EPA Information Collection Request (ICR) No. 0262.12 "RCRA Hazardous Waste Permit Application and Modification Part A", Federal Register, Vol.74, No.17, 28 Jan 2009, page 4958; http://edocket.access.gpo.gov/2009/pdf/E9-1804.pdf

[67] $68,960 unitized cost derived for this RIA from EPA Information Collection Request (ICR) No. 1573.12 "Part B Permit Application", Federal Register, Vol.74, No.100, page 25237, 27 May 2009; http://edocket.access.gpo.gov/2009/pdf/E9-12285.pdf

- State government average cost per waste disposal permit:
  Average cost for state government review of RCRA Subtitle C permits consists of four activities:[68]
  (1,215 pre-application activities) + ($27,063 application review) + ($26,846 permit issuance) + ($3,110 permit maintenance) = $58,200 per permit
  (149 offsite CCR landfills) x ($58,200 per Subtitle C permit) = $8.67 million
  Amortized state cost with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $0.63 million/year
- Total Subtitle C permit cost (industry + state government) = $2.9 million per year

Total cost for item 11 (11a + 11b + 11c):

- Industry share of cost = $76.35 million per year
- State government share of cost = $0.63 million per year
- Total (industry + states) = $76.98 million per year

12. Regulatory structural integrity inspection cost

- Assumptions:
  EPA assumed that the residual 18% of the non-inspected plants require inspection over the 82% baseline inspection coverage.
  The per-plant cost for inspections is estimated in the **Chapter 3** baseline above.
- Cost Calculation:
  Industry cost: ($10,829/year per facility) x (18% not inspected) x (495 plants) = $0.96 million per year
  State government cost: ($599/year per facility) x (18% not inspected) x (495 plants) = $0.054 million per year

Total (industry + state) = $1.01 million per year

13. Regulatory RCRA facility-wide investigation (RFI) cost

- Industry RFI cost:
- As of 2008, state government corrective action covers 64% of electric utility industry impoundments and 78% of landfills. Thus, assume that 57 plants with impoundments (i.e., 36% x 158 plants with impoundments) plus 74 plants with landfills (i.e., 22% x 337 plants with landfills) may require RFIs, for a total of 131 RFIs.
- The purpose of an RFI is to obtain information to fully characterize the nature, extent and rate of migration of releases of hazardous waste or constituents to determine whether interim corrective measures and/or a Corrective Measures Study may be necessary for other waste units at the facility (source: EPA 530/SW-89-031, May 1989, Vol.I). RFIs may include: rapid field screening using portable field instruments, drilling in soils, excavating test pits, ground-water monitoring, waste testing, biomonitoring, and site surveying, site photography, site mapping.
- RFI average cost:
  $0.75 million average cost for RFIs involving captive industrial landfills

[68] Source: Based on cost data from page 84 of January 2007 ASTSWMO report "State RCRA Subtitle C Core Hazardous Waste Management Program Implementation Costs Final Report" at: http://www.astswmo.org/files/publications/hazardouswaste/Final%20Report%20-%20RCRA%20Subtitle%20C%20Core%20Project.pdf

$0.69 million average cost for RFIs involving captive industrial waste management (assume applies to impoundments)
Source: EPA OSRE memorandum "Transmittal of Average Cost of Investigation Derived from Fund-Lead Superfund Costs, Interim Measures Cost Compendium, and Compendium of Related Guidance Documents", 01 Nov 2004. This memo indicates that Superfund remedial investigation costs can be used as a proxy for RCRA RFI costs.
Industry RFI cost calculations:

- Landfills: (74 landfills) x ($0.75 million average cost per RFI) = $55.5 million total cost
- Impoundments: (57 impoundments) x ($0.69 million average cost per RFI) = $39.3 million total cost

Total = $94.8 million total cost to industry
Amortized industry RFI cost with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $6.9 million/year equivalent

- State government RFI cost:

State government RFI review, approval, oversight average cost per RFI = $76,000[69]
(131 RFIs) x ($76,000 review, approval, oversight average cost per RFI to state governments) = $10 million total cost
Amortized state government RFI cost with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $0.7 million/year equivalent

- RFI total cost (industry + state governments) = $7.6 million per year

14. Regulatory RCRA facility-wide corrective action cost
Average annualized future potential cost was not estimated in this RIA because of a high degree of uncertainty. Through a process called corrective action, RCRA Subtitle C requires RCRA-regulated facilities to investigate and clean-up releases of hazardous wastes or constituents to the environment identified in the RCRA facility-wide investigation (RFI). After the RFI, if the need for cleanup is discovered, the RCRA-regulated facility must perform a "Corrective Measures Study" (CMS) which may range in cost from $100,000 to $800,000 for such a study.[70] State government cost for corrective measures study & corrective action review, approval, oversight is $117,300 per case.[71] The purpose of a CMS is to develop and evaluate the corrective action alternative(s) and to recommend the corrective measure(s) be taken at the facility.[72]

As of 2008 the RCRA corrective action universe is about 3,800 sites nationwide.[73] Relative to the RCRA-regulated universe of 217,500 facilities (consisting of about 16,000 hazardous waste LQG "large quantity generators" plus about 200,000 hazardous waste SQG "small quantity generators" plus about 1,500 hazardous waste TSDF "treatment, storage, disposal facilities" as of 2008), the 3,800 corrective action universe implies a 1.75% relative incidence of occurrence (i.e., 3,800 / 217,500 = 1.75%). Corrective action costs vary from facility-to-facility depending on the number and types of waste management units and other industrial equipment/processes and wastes involved. The

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[69] Source: Divided the $2,200,600 annual RFI cost to 10 state governments by the 29 annual RFIs from page 82 of the January 2007 ASTSWMO report "State RCRA Subtitle C Core Hazardous Waste Management Program Implementation Costs Final Report" at: http://www.astswmo.org/files/publications/hazardouswaste/Final%20Report%20-%20RCRA%20Subtitle%20C%20Core%20Project.pdf
[70] Source: RACER unit cost reported on p.38 of EPA's 2000 "Unit Cost Compendium" , document ID nr. EPA-HQ-RCRA-2002-0031-0429 at : http://www.regulations.gov
[71] Source: derived from cost data contained on page 83 of the ASTSWMO "State RCRA Subtitle C Core Hazardous Waste Management Program Implementation Costs Final Report", January 2007 at: http://www.astswmo.org/files/publications/hazardouswaste/Final%20Report%20-%20RCRA%20Subtitle%20C%20Core%20Project.pdf
[72] Source: "Corrective Measures Study Scope of Work", EPA Region 3 at: http://www.epa.gov/reg3wcmd/ca/pdf/CMSATTC.pdf
[73] Source: 3,800 corrective action cases represents EPA's "2020 Corrective Action Universe" as identified on EPA Hazardous Waste Corrective Action Facility Information website at: http://www.epa.gov/waste/hazard/correctiveaction/facility/index.htm#2020

corrective action remedies usually involve mitigating damages to surface water and groundwater. The General Accountability Office (GAO) reported[74] that RCRA corrective action could cost 3,698 non-Federal hazardous waste treatment, storage, or disposal facilities a total of about $16 billion (1996$) to clean up their properties contaminated by hazardous substances, representing an average $4.327 million corrective action cost per-facility. Updated[75] to 2009$ implies an average of $5.365 million RCRA corrective action cost per facility.

15. Regulatory RCRA TSDF waste disposal permit cost for onsite disposal

RCRA Subtitle C hazardous waste regulations require hazardous waste treatment, storage, disposal facilities (TSDFs) to obtain RCRA permits as described in 40 CFR 270 consisting of a two-part (i.e., Part A and Part B) application process. The paperwork burden cost of this requirement is estimated below. Furthermore, but not included in the cost estimate below, are separate, additional RCRA regulations containing "technical requirements" used by permit issuing authorities (e.g., RCRA-authorized state government waste programs or EPA Regional offices) to determine what technical requirements must be placed in permits. The separate cost of technical requirements is estimated in the "Engineering Controls" regulatory cost section of this RIA above.

- Assumptions:
    - Although 93% of CCR landfills have a state government non-hazardous waste disposal permit and 12% of CCR impoundments have such state permits, assume CCR disposal units will need new RCRA disposal permits under Subtitle C options.
    - 383 of the 495 total electric utility plants currently dispose onsite (i.e., 84 of the 495 plants solely dispose CCR offsite, plus 28 plants solely supply CCR for beneficial uses).
- Industry average cost per waste disposal permit:
    - ($440[76] average RCRA Part A permit application cost per-plant per-year) + ($68,960[77] average RCRA Part B application cost per-facility per-year) = $69,400 per Subtitle C permit per year
      ($69,400 per permit per year) x (3 years ICR annualization period) = $208,200 per permit
      (383 plants) x ($208,200 per permit) = $79.74 million
      Amortized industry cost with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $5.8 million/year
- State government average cost per waste disposal permit:
    - Build estimate based on the following four RCRA Subtitle C permit-related state government activities associated with RCRA Subtitle C waste disposal permits:[78]
      (1,215 pre-application activities) + ($27,063 application review) + ($26,846 permit issuance) + ($3,110 permit maintenance) = $58,200 average cost per Subtitle C waste disposal permit per year.

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[74] Source: page 1 of US General Accountability Office (GAO), "Hazardous Waste: Progress Under the Corrective Action Program is Limited, But New Initiatives May Accelerate Cleanups," report nr. GAO/RCED-98-3, October 1997; http://www.gao.gov/archive/1998/rc98003.pdf

[75] Updated from 1996$ to 2009$ using the NASA "Gross Domestic Product Deflator Inflation Calculator" at http://cost.jsc.nasa.gov/inflateGDP.html

[76] $440 unitized cost derived for this RIA from EPA Information Collection Request (ICR) No. 0262.12 "RCRA Hazardous Waste Permit Application and Modification Part A", Federal Register, Vol.74, No.17, 28 Jan 2009, page 4958; http://edocket.access.gpo.gov/2009/pdf/E9-1804.pdf

[77] $68,960 unitized cost derived for this RIA from EPA Information Collection Request (ICR) No. 1573.12 "Part B Permit Application", Federal Register, Vol.74, No.100, page 25237, 27 May 2009; http://edocket.access.gpo.gov/2009/pdf/E9-12285.pdf

[78] Source: Based on cost data from page 84 of January 2007 ASTSWMO report "State RCRA Subtitle C Core Hazardous Waste Management Program Implementation Costs Final Report" at: http://www.astswmo.org/files/publications/hazardouswaste/Final%20Report%20-%20RCRA%20Subtitle%20C%20Core%20Project.pdf

  - State Cost Calculation:
    (383 electricity plants dispose CCR onsite) x ($58,200 per Subtitle C permit per year) = $22.3 million per year
- Total Subtitle C permit cost (industry + state government) = $28.1 million per year

16. Regulatory RCRA enforcement inspection cost

- Assumptions:
  - State government average cost = $7,900 per Subtitle C inspection (source: hazardous waste LQG large quantity generator average calculated by dividing the $1,517,357 annual enforcement inspection cost to 10 surveyed state governments by 192 annual enforcement cases, from page 87 of the January 2007 ASTSWMO report "State RCRA Subtitle C Core Hazardous Waste Management Program Implementation Costs Final Report"
  - 1.6% average annual enforcement inspection frequency based on dividing the 11,965 LQG "large quantity generator" universe reported by 10 survey states by the 192 hazardous waste LQG enforcement cases reported in the January 2007 ASTSWMO report "State RCRA Subtitle C Core Hazardous Waste Management Program Implementation Costs Final Report"
- Cost calculation:
  ($7,900 per LQG enforcement) x (495 electric utility plants) x (1.6% LQG enforcements annually) = $0.063 million per year

17. Regulatory future remediation added cost

Potential $18.5 million to $376 million per case in added cleanup cost for future surface impoundment failures, if regulated under RCRA Subtitle C rather than Subtitle D, is based on the two example case studies summarized in **Exhibit 4A** below.

Exhibit 4A
Two Case Studies:
Possible Added Cost Under RCRA Subtitle C Regulation of CCR Cleanup at Electricity Plants from CCR Impoundment Failures
(Note: Assumptions or numerical factors unique to each case study are applied in the cost calculations below rather than the national average assumptions and numerical factors applied elsewhere in this RIA)

Case Study #1: TVA Kingston TN (2008)	**Case Study #2: Constellation Energy Gambrills MD (2008)**
If cleanup as non-hazardous waste: Baseline Assumptions: • 3.32 million tons released • $0.10/ton/mile truck operating cost (source: OSW-EMRAD) • 45 miles to Subtitle D LF (source: OSW-EMRAD) • $35/ton tipping fee (source: 2005 Chartwell) • 154,000 truckloads (source: TVA assumes 21.6 tons ash per load) Baseline Cost Calculations: • Trucking cost: (3.32 million tons) x (45 miles) x ($0.10/ton /mile) = $15 million • LF tipping fee: ($35/ton) x (3.32 million tons) = $116 million • Manifest: $0 • Case #1 total = $131 million for event	**If cleanup as non-hazardous waste:** Baseline Assumptions: • 0.25 million tons released • $0.10/ton/mile truck operating cost (source: OSW-EMRAD) • 193 miles to Subtitle D LF (Constellation Energy's mileage estimate to existing VA fly ash LF) • $35/ton tipping fee (source: 2005 Chartwell) • 20,833 truckloads (source: Constellation Energy assumes 12 tons ash per load) Baseline Cost Calculations: • Trucking cost: (0.25 million tons released) x (193 miles) x ($0.10/ton /mile) = $5 million • LF tipping fee: ($35/ton) x (0.25 million.tons) = $9 million • Manifest: $0 Case #2 total = $14 million for event
If cleanup as RCRA Subtitle C hazardous waste Assumptions: • 3.32 million tons released • $0.19/ton/mile truck operating cost (source: TVA) • 370 miles to Subtitle C LF (source: TVA) • $80/ton Subtitle C tipping fee (source: TVA) • 154,000 truckloads (source: TVA assumes 21.6 tons ash per load) Cost Calculations: • Trucking cost: (3.32 million tons) x (370 miles) x ($0.19/ton/mile truck operating cost) = $233 million • LF tipping fee: ($80/ton) x (3.32 million tons) = $266 million • Manifest: (154,000 truckloads) x ($53 manifest cost per load) = $8 million • Case #1 total = $507 million for event	**If cleanup as RCRA Subtitle C hazardous waste** Assumptions: • 0.25 million tons released • $0.19/ton/mile truck operating cost (from TVA) • 179 miles to Subtitle C LF (closest is Envirosafe OH with 0.9 million tons permitted capacity) • $90/ton tipping fee (2004 ETC national median fee) • 20,833 truckloads (source: Constellation Energy assumes 12 tons ash per load) Cost Calculations: • Trucking cost: (0.25 million tons) x (179 miles) x ($0.19/ton/mile truck operating cost) = $8.5 million • LF tipping fee: ($90/ton) x (0.25 million tons) = $23 million • Manifest: (20,833 truckloads) x ($53 manifest cost per load) = $1 million • Case #2 total = $32.5 million for event
Case #1 incremental cost over non-hazardous: $376 million for cleanup event	**Case #2 incremental cost over non-hazardous: $18.5 million for cleanup event**

18. EPA administrative reporting and recordkeeping costs
Three of the regulatory costs itemized above -- item 11 offsite disposal truck manifesting and offsite disposal hazardous waste permits, item 12 structural integrity inspections, and item 13 RCRA facility-wide investigation (RFI) – include the cost of paperwork burden for those items. In addition, certain features of the Subtitle C options of the proposed rule require four other paperwork burden activities:

18a. Notice of Regulated Waste Activity & EPA ID Number
RCRA Subtitle C regulations for hazardous waste "generators" require generators to notify their facilities as such and obtain EPA identification numbers (40 CFR 262.12). According to EPA's most recent (2009) estimate, the average per-facility response burden is $162 per facility.[79] Applied to the 495 electric utility plants yields an estimated one-time notification cost of $80,190 (i.e., (495 electric utility plants) x ($162 per notification)). Amortized with a capital recovery factor of 0.07246 (@7% discount rate & 50-years) = $5,800 per year average annual equivalent.

- Industry share of cost: (86%) x ($5,800/year) = $5,000/year
- State government share of cost: (14%) x ($5,800/year) = $800/year

18b. General Facility Standards for Hazardous Waste TSDFs
This cost item represents a set of paperwork burden activities grouped under 40 CFR 264/265 Subpart B (i.e., 264.10 to 264.19 and 265.10 to 265.19) and includes (1) maintaining records for hazardous waste that is stored, treated, and/or disposed onsite, (2) descriptions of location, design, construction, operating methods, techniques, and practices for onsite hazardous waste storage, treatment, and/or disposal, (3) contingency plans for unanticipated damages from hazardous waste onsite storage, treatment and/or disposal, (4) maintaining qualifications of facility ownership, (5) maintaining continuity and financial responsibility of facility operation, and (6) employee hazardous waste training. According to EPA's most recent (2009) estimate the average per-facility paperwork burden is $27,350 per facility per year.[80] Applied to the 383 electric utility plants which currently dispose onsite (i.e., 84 of the 495 plants solely dispose CCR offsite with other companies, plus 28 plants solely provide CCR for beneficial uses) yields an estimated cost of ($27,350 per facility pre year) x (383 plants which dispose CCR) = $10.48 million/year:

- Industry share of cost: (86%) x ($10.48 million/year) = $9.01 million/year
- State government share of cost: (14%) x ($10.48 million/year) = $1.47 million/year

18c. RCRA Hazardous Waste Biennial Report
RCRA Subtitle C requires hazardous waste LQG large quantity generators (40 CFR 262.41) and hazardous waste TSDF treatment, storage, and disposal facilities (40 CFR 264.75 and 265.75) to submit "Hazardous Waste Report" information on a 2-year repeating cycle (aka "RCRA

[79] $162 per year notification cost derived from EPA Information Collection Request (ICR) No. 0261.16 "Notification of Regulated Waste Activity (Renewal)", Federal Register, Vol.74, No.123, pages 31028-31029, 29 June 2009; http://edocket.access.gpo.gov/2009/pdf/E9-15310.pdf
[80] $27,350 per facility per year average cost derived from EPA Information Collection Request (ICR) No. 1571.09 "General Hazardous Waste Facility Standards", Federal Register, Vol.74, No.23, pages 6152-6154, 05 Feb 2009.

Biennial Report"). According to EPA's most recent (2009) estimate, the average annualized per-facility response burden is $3,410 per year.[81] Extrapolated to 495 electric utility plants produces a cost estimate of $1.69 million per year.

- Industry share of cost: (86%) x ($1.69 million/year) = $1.45 million/year
- State government share of cost: (14%) x ($1.69 million/year) = $0.24 million/year

18d. CERCLA Reportable Quantity (RQ) Spill/Leak Reporting

Section 103(a) of CERCLA requires facilities and vessels to immediately notify the National Response Center (NRC) of a hazardous substance release (e.g., spill, leak) into the environment if the amount of the release equals or exceeds the substance's reportable quantity (RQ) limit. In general there are five RQ categories (1, 10, 100, 1,000 or 5,000 pounds). Subtitle C options may add CCR to the CERCLA list of hazardous substances and assign an RQ of one-pound, as well as allowing the use of concentrations to determine RQ thus resulting in a range of 1,294 pounds to 10,000,000 pounds for 12 chemicals. Using the total count of facilities (i.e., establishments) in the US manufacturing sector (NAICS 31, 32, 33) plus the US waste management sector (NAICS 562) as rough indicators, there are 315,000 industrial facilities in the US which may handle RQ-listed hazardous substances.[82] According to EPA's most recent (2007) estimate, the average per-facility response burden is $122 (i.e., 4.1 burden hours) per facility per response, based on an average annual 25,861 facilities at an annual paperwork burden cost of $3.161 million.[83] Relative to this 300,000 industrial facility universe, this annual count of RQ-reporting facilities represents an 8% fraction. Extrapolated to the 495 electric utility plants yields a rough estimate of 40 possible RQ reports per year, at a cost of $4,900 per year (i.e., (495 electric utility plants) x (8% RQ reports per year) x ($122 per RQ report)).

- Industry share of cost: (86%) x ($4,900/year) = $4,200/year
- State government share of cost: (14%) x ($4,900/year) = $700/year

Sub-total cost item 17 (17a + 17b + 17c + 17d) = $12.94 million per year.

- Industry share of cost: (86%) x ($12.94 million/year) = $11.13 million/year
- State government share of cost: (14%) x ($12.94 million/year) = $1.81 million/year

Exhibit 4B below presents a summary of these "Ancillary Cost" elements numbered from 11 to 18.

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[81] $3,410 per facility per year average cost derived from EPA Information Collection Request (ICR) No. 0976.14 "2009 Hazardous Waste Report", Federal Register, Vol.74, No.93, pages 22922-22924, 15 May 2009; http://edocket.access.gpo.gov/2009/pdf/E9-11410.pdf

[82] 315,000 industrial facilities based on "Number of Establishments" published for NAICS codes 31-33 Manufacturing (293,919 establishments) plus NAICS code 562 Waste management and remediation services (21,254 establishments) from the US Census Bureau in its "2007 Economic Census." Not all manufacturing or waste management facilities necessarily handle hazardous substances so this is an over-estimate, but there are also other economic sectors (e.g., mining, construction, utilities, transporters, and wholesalers), which handle hazardous substances not included in this facility count which offsets this over-estimate.

[83] $122 per facility average cost derived from EPA Information Collection Request (ICR) No. 1049.11 "Notification of Episodic Releases of Oil and Hazardous Substances (Renewal); Federal Register, Vol.72, No.205, 24 Oct 2007, pp.60357-60358; http://edocket.access.gpo.gov/2007/pdf/E7-20934.pdf

Exhibit 4B **Summary of "Ancillary Cost" Estimates Associated with RCRA Regulation of CCR Disposal** ($millions average annualized; 2009$)				
Ancillary Cost Element	Applicability to CCR Regulatory Options	Electric Utility Industry Cost	State Government RCRA-Authorized Program Cost	Row Total Cost
11. Ancillary offsite disposal costs	Subtitle C	$76.35	$0.63	$76.98
12. Impoundment structural integrity inspections	Subtitle C and Subtitle D	$0.96	$0.054	$1.01
13. RCRA facility-wide investigations (RFIs)	Subtitle C	$6.9	$0.7	$7.6
14. RCRA facility-wide corrective action	Subtitle C	Not estimated – historical average cost = $5.4 million per facility	Not estimated	Not est.
15. RCRA TSDF waste disposal permits	Subtitle C	$5.8	$22.3	$28.1
16. RCRA enforcement inspections	Subtitle C	$0	$0.063	$0.063
17. Future disposal unit failure cleanup remediation as RCRA hazardous waste	Subtitle C	Not est. – case study example	Not est. – case study example	Not est.
18. EPA administrative reporting & recordkeeping 18a. EPA regulated waste notification 18b. RCRA TSDF general facility standards 18c. RCRA haz waste biennial report 18d. CERCLA RQ reporting	Subtitle C	Subtotal= $11.13 $0.005 $9.01 $1.45 $0.0042	Subtotal= $1.81 $0.0008 $1.47 $0.24 $0.0007	$12.94 $0.0058 $10.48 $1.69 $0.0049
Column Totals for the three options of the October 2009 draft RIA :				
	Subtitle C hazardous waste	$100.4	$25.6	**$126.7**
	Subtitle D (version 1)	$0.96	$0.05	**$1.0**
	Hybrid C&D*	$7.9	$7.7	**$15.6**
* Hybrid C&D costs for ancillary cost items 13, 14, 15, 16, 17, 18 are proportioned only to the 158 plants with impoundments that would be regulated under Subtitle C for this option, by the proportionate multiplier: (158 plants w/impoundments) / (495 total plants) = 0.319				

4B.3 Land Disposal Restriction Cost (for dewatering treatment of CCR)

This element consists of two components:

- Dry CCR disposal (landfills): Moisture conditioning and compaction to 95% maximum dry density value according to ASTM D 698 or ASTM D 1557 test methods prior to disposal in landfills.
- Wet CCR disposal (impoundments): Dewatering to remove solids prior to disposal in impoundments within 5-years of rule's effective date. The potential cost for this treatment standard is estimated below.

However, only the potential cost for the wet CCR disposal dewatering treatment standard is estimated in this section of the RIA because the potential cost for meeting the dry CCR moisture conditioning and compaction requirements are already estimated in item 4 of the "engineering controls" in this chapter above:

- **Examples of CCR Dewatering Methods**

Based on the following recent (1997-2009) example descriptions of dry CCR disposal practices at existing or planned coal-fired electric utility plants, dry CCR disposal may involve different methods for any given plant:

1. Tanks & chain drag: As described in March 2009 by the Basin Electric Power Cooperative.[84] Bottom ash will be dewatered in tanks and the water will be re-circulated to transport additional bottom ash. Bottom ash will be removed using a chain drag. The ash will then be hauled by truck to a lined landfill offsite. The fly ash will be conveyed in a dry state. Both ashes will be disposed in a landfill close to the plant site.
2. Pressure squeeze conveyor: Another tank-based example apparently similar to the Basin Cooperative method is reported for dry disposal conversion by the coal mining industry, involving the Phoenix Process Equipment company supplier of alternative slurry processing equipment. This second example involves a thickening tank, porous conveyor belt and pressure to squeeze water out of the coal washings, producing a semi-solid, 75% dewatered cake which is scraped off the conveyor belt and stacked like a pile of sand. The cost for this process is reported at $0.50 per ton of coal waste processed.[85]
3. Horizontal belt filters: According to a May 2009 technical paper[86], dewatering gypsum using horizontal belt filters is common in the electric utility industry, and a new modified horizontal belt filter method involving two feedboxes allows fly ash and FGD (gypsum) to be dewatered simultaneously.
4. Storage silos & rail system: As described June 2009[87] for a $10 million conversion project located at Detroit Edison's Monroe Michigan Power Plant -- a four boiler unit, 3,200-megawatt power station originally constructed in 1974. Installation of equipment to collect the coal ash in a dry state, plus dry ash storage facilities (storage silos), and truck/rail loading equipment for distribution of the dry ash to concrete producers in the Midwest United States and Eastern Canada.

[84] Source: March 2009 Basin Electric Power Cooperative examples at http://www.basinelectric.com/News_Center/Feature_Articles/Coal_ash_handling.html
[85] Source: Dave Cooper, "Better, Safer Ways to Handle Coal Slurry Do Exist", page 14 of the Nov 2001 "E"-Notes Newsletter of the Ohio Valley Environmental Coalition at http://www.ohvec.org/newsletters/enotes_97-01_pdf/enotes_2001_11.pdf
[86] Source: May 2009 horizontal belt filter technical paper by Alex Hohne at http://www.flyash.info/2009/036-hohne2009.pdf
[87] Source: June 2009 Detroit Edison Monroe Power Plant example at http://www.headwaters.com/data/upimages/press/6.30.09MonroeAshRelease.pdf

5. Integrated silo system: Integrated with precipitators, vacuum pumps and bag filter/receivers, as described in an engineering report[88] about the 1997 dry fly ash system conversion of Northern Indiana Public Service Company's Michigan City Plant.

For this RIA, EPA ORCR identified four alternative existing studies with cost estimates (dated 1981, 1985, 2005, and 2009) comparing dry and wet CCR disposal at coal-fired electric utility plants. The first three studies provided cost estimates on a per-plant basis, whereas the 2009 study provided an extrapolated nationwide cost estimate. However, only the 2005 study is used in this RIA as a basis for deriving a cost estimate for the wet CCR dewatering land disposal treatment, because the first two studies are over 25-years old (1981 and 1985), and the 2009 study does not provide sufficient details for verification of data and calculations. These three other studies are summarized below in this chapter to illustrate the magnitude of cost estimation uncertainty implied by the other studies, compared to the estimate derived below in this section of the RIA.

- **Summary of 2005 TVA CCR Dry Disposal Cost Study**

- In August 2009 TVA announced a proposed plan to convert its wet CCR disposal to dry disposal. TVA's CEO Tom Kilgore said before a 28 July 2009 US Congressional subcommittee hearing that TVA has developed a 5-year plan to shift CCR disposal from wet impoundments to dry landfills. TVA estimated it will cost between $1.5 billion to $2 billion over 8 to 10 years for its 11 coal-fired electric utility plants.[89] Detailed or semi-detailed calculations of TVA's 2009 cost estimate are not available for this RIA to use for extrapolation nationwide.
- However, a 2005 TVA cost estimate titled "Kingston Fossil Plant Decision Matrix: Pond or Peninsula?" provides detailed cost estimates for dry conversion of the TVA Kingston TN plant.[90] The TVA cost study involves conversion of an existing impoundment currently used to dispose wet fly ash and wet bottom ash at the TVA Kingston TN electric utility plant, for future dry fly ash and dry bottom ash disposal. The FGD stream remains wet-sluiced before and after this hypothetical conversion in the cost study. In addition to the cost of converting the electric plant boilers and the impoundment for dry ash disposal, the cost study also includes the cost for construction of a new storm water runoff management pond (Source: row item 68 of TVA's "Appendix C Detailed Cost Sheets", slide nr. TVA-00007403).
- TVA cost study involves conversion of 475,600 cubic yards of fly ash plus bottom ash per year; this RIA estimates this quantity is equivalent to 880,000 tons per year, assuming 1.85 tons per cubic yard multiplier.[91]

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[88] Source: Dec 1997 NIPSC conversion report at http://www.babcockpower.com/pdf/rst-145.pdf
[89] Source: TVA news release "TVA Coal Combustion Products Remediation Plan Proposed", 20 Aug 2009 http://www.tva.gov/news/releases/julsep09/ccprp_other.htm
[90] Source: TVA 27 January 2005 plant managers conference slide presentation (25 pages).. Wet disposal is presented as "Option 1" and dry disposal is presented as "Option 2" in the TVA cost presentation. Additional details for the TVA cost estimates are available at http://www.tva.gov/kingston/tdec/pdf/TVA-00007402.pdf
[91] "Source: 1.85 tons per cubic yard multiplier represents the midpoint from the following 1.2 to 2.5 range: According to EPA's 1988 Report to Congress ("Wastes from the Combustion of Coal by Electric Utility Power Plants," page 3-14), the dry density of fly ash is 80-90 lbs/cubic ft which translates to a specific density of 1.4. The Federal Highway Administration studied fly ash for use in highway construction and reported its specific gravity may be as low as 1.7 to as high as 3.0. Conversion of this implied 1.4 to 3.0 range in fly ash specific gravities to tons-per-cubic-yard as follows:

- Low-end: (1.4 g/cm3) / (0.000001 m3/cm3) x (0.764 m3/yd3) / (1000 g/kg) x (2.204 lbs/kg) / (2000 lbs/short ton) = 1.2 short tons per cubic yard.
- High-end: (3.0 g/cm3) / (0.000001 m3/cm3) x (0.764 m3/yd3) / (1000 g/kg) x (2.204 lbs/kg) / (2000 lbs/short ton) = 2.5 short tons per cubic yard.

- The TVA cost study did not estimate the cost for dewatering FGD (gypsum) because FGD is already dewatered by most electric utility plants for beneficial uses, thus only four of the 495 electric utility plants (i.e., TVA Widows Creek plant, TVA Paradise plant, Louisville Gas & Electric Co Trimble County plant, and Northern Indiana Public Service Company R.M. Schafer plant) wet dispose 1.9 million tons FGD per year in impoundments as of 2005 (source: column B of **Exhibit 3G** of this RIA).
- Unit cost (i.e., average cost per ton) of conversion from wet to dry disposal estimated from the 2005 TVA cost analysis which provides cost estimates for converting from wet ash disposal to dry ash disposal:

	TVA wet disposal	TVA dry disposal	Added cost for dry	Unitized dry cost
o Capital cost	$13.12 million PV	$38.45 million PV	Cost not incremental	$43.7/ton per year (@20 years)
o Annual O&M cost	$10.63 million PV	$17.51 million PV	$6.88 million PV	$0.60/ton (@13 years)

(Note: PV = present value for TVA's 25-year period of analysis 2005-2029; TVA costs are in 2005$ prices)

- Cost estimate calculation under conversion to dry disposal scenario, calculated based on TVA's per-ton cost extrapolation to 22.4 million tons per year baseline wet CCR (i.e., wet fly ash, wet bottom ash, wet FGD, wet gypsum, wet other CCR) disposal in impoundments at 158 of the 495 electric utility plants:
  - Capital cost: (22.4 million tons per year wet CCR disposal for conversion at 158 plants) x ($43.7/ton per year conversion capital cost) x (20 years capitalization period) x (1.174 price update multiplier[92] to 2009$ price level) = $22,984 million undiscounted capital cost
    Annual equivalent capital: ($22,984 million) x (0.07246 capital recovery factor @7% & 50-years) = $1,665 million per year
  - O&M cost: ($0.60/ton conversion O&M cost) x (22.4 million tons/year wet CCR disposal for conversion at 158 plants) x (45 years future operational period 2017-2061 which assumed to begin 5 years after 2012 final rule promulgation) x (1.174 price update multiplier to 2009$ price level) = $710 million undiscounted total O&M
    PV present value discounted @7% over 50-years = $153 million PV present value O&M
    Annual equivalent O&M: ($153 million) x (0.07246 capital recovery factor @7% & 50-years) = $11 million per year
  - Total annualized cost (capital + O&M) = ($1,665 million/year capital) + ($11 million/year O&M) = $1,676 million/year

- **Uncertainty in Land Disposal Treatment Cost Estimate**

In addition to the 2005 Tennessee Valley Authority (TVA) cost study referenced above, there are three other related cost studies (1981, 1985, and 2009) which are summarized below. The first two studies provide cost estimates on a per-plant basis for a few plant sizes, and the 2009 study provides a nationwide cost estimate. This RIA did not apply these other studies because the first two are over 25-years old (i.e., 1981 and 1985) and the third study does not provide sufficient details for verification of data and calculations. These studies are summarized below and used as a basis for formulating alternative nationwide cost estimates for land disposal treatment, for the purpose of illustrating the potential magnitude of uncertainty in this RIA's cost estimate in relation to these other studies.

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[92] 1.174 price update multiplier represents 2009:to:2005 ratio in the Engineering-News Record Construction Cost Index: (8566 CCI for July 2009) / (7297 CCI for 2005).

- **Study #1 of 3: 1981 TVA/EPA**

- In January 1981, TVA's Energy Demonstrations and Technology Office (Chattanooga TN) co-authored with EPA's Industrial Environmental Research Laboratory (Research Triangle Park NC) a study titled "Economic Analysis of Wet Versus Dry Ash Disposal Systems," Interagency Energy/Environment R&D Program Report, report no. TVA/OP/EDT-81/30 and EPA-600-7-81-013, 126 pages.[93]
- The study compares the relative costs of wet and dry methods of coal ash disposal for five electric plant power size categories (300 MW, 600 MW, 900 MW, 1,300 MW, 2,600 MW) with annual coal ash generation ranging from 0.2 million to 1.7 million per year per plant.
- Per-plant capital and O&M costs estimated based on 35-year assumed plant lifespan in 1980$. Capital costs for (a) in-plant coal ash handling systems, (b) conveyance/transport, and disposal units, were obtained from equipment suppliers.
- The study found (page 67) there is not a significant difference in ash system economics based on the method of analysis. Present worth analysis "*indicates that wet disposal is typically the least cost alternative. However, various dry disposal options are within a 15 percent range of those costs. The costs are, in fact, sensitive to spreading the dry disposal area capital costs over the life of the power station and the in-plant handling system cost. Use of either the lower dilute phase transport system cost or the dense phase collection system cost results in the dry disposal system alternative become the least cost alternative*."
- The study also noted that staged construction may provide 30% saving in system total cost: "*[T]he above analyses assumed construction of all the required facilities upon start-up. In the case of dry disposal, this is a reasonable assumption although site preparation costs would proceed during the development of the site. In the case of wet disposal, it may be economically sound to construct the embankment in stages, even if the amount of material to be placed or the engineering estimate is higher for staged construction. This is due to the high cost of the dam or levee and the cost of money over the life of the project. As an example… wet disposal area was analyzed for all construction occurring in 1980 and by a staged construction sequence (3 stages). In this case, staged construction provided a 30 percent savings in the total cost of the system.*"
- The 1981 study used two cost methods. The "Present Worth" (aka present value PV) cost method findings (page 62) indicated the following comparative ranges in wet dry versus wet disposal costs:

Disposal method	1980$ cost ($/ton)	2009$ update ($/ton)[94]
Dry disposal	$2.19 to $4.50	$4.81 to $9.87
Wet disposal	$1.86 to $5.68	$4.08 to $12.46

[93] Source: 1981 TVA/EPA report at http://nepis.epa.gov/Exe/ZyNET.exe/20006ORT.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1981+Thru+1985&Docs=&Query=tva+wet+dry+disposal&Time=&EndTime=&SearchMethod=3&TocRestrict=n&Toc=&TocEntry=&QField=pubnumber%5E%22600781013%22&QFieldYear=&QFieldMonth=&QFieldDay=&UseQField=pubnumber&IntQFieldOp=1&ExtQFieldOp=1&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C81thru85%5CTxt%5C00000000%5C20006ORT.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=10&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=p%7Cf&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x

[94] 1980$ costs from the 1981 TVA/EPA study updated by EPA ORCR to 2009$ using the GDP calculator at http://cost.jsc.nasa.gov/inflateGDP.html

- Using the EPA ORCR 2009$ updated unit cost midpoints displayed above yields the following rough cost estimate for the 158 electric utility plants with CCR impoundments:
  - Capital cost: (22.4 million tons per year wet CCR disposal for conversion at 158 plants) x ($4.81 to $9.87 per ton dry disposal unitized present value cost) x (40.6% capital cost fraction) x (50 years period-of-analysis for this RIA) = $2,187 million to $4,488 million present value capital cost
    Annualized capital cost: ($2,187 million to $4,488 million) x (0.07246 capital recovery factor @7% & 50-years) = $158.5 million to $325.2 million per year
  - O&M cost[95]: (22.4 million tons per year wet CCR disposal for conversion at 158 plants) x [(($4.81 to $9.87 per ton dry disposal unitized present value cost) x (59.4% dry O&M fraction)) – (($4.08 to $12.46 per ton wet disposal unitized present value cost) x (31.6% wet O&M fraction))] x (45 years dry disposal operational period 2017-2061 which assumed to begin 5 years after 2012 final rule promulgation) = $1,580.5 million to $1,941.4 million present value O&M
    Annualized O&M cost: ($1,580.5 million to $1,941.4 million) x (0.07246 capital recovery factor @7% & 50-years) = $114.5 million to $140.7 million per year
  - Total annualized cost (capital + O&M) = ($158.5 million to $325.2 million per year capital) + ($114.5 million to $140.7 million per year O&M) = $273 million to $466 million per year

- **Study #2 of 3: 1985 EPA**

- EPA's Air and Energy Engineering Research Laboratory (Research Triangle Park NC) published cost estimates for both wet and dry CCR disposal at coal-fired electric utility plants in the report "Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants", document nr. EPA/600/S7-85/028, August 1985, 12 pages.[96]
- This is a 3-year study of waste characterization, environmental data, engineering, and cost evaluations associated with disposal of coal ash and FGD waste by six coal-fired electricity plants ranging in nameplate capacity between 310 to 1,786 megawatts and located in FL, IL, MN, NC, PA, and WY. EPA used this study to assist preparation of EPA's 1988 "Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants" (report no. EPA530-SW-88-002, Feb 1988).
- This study developed "generic" capital and annual O&M costs for both wet CCR pond disposal and dry CCR landfill disposal methods involving fly ash, bottom ash, and FGD, based on specific costs for the six sites combined with cost estimates from other studies by TVA,

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[95] O&M cost extrapolation calculation in this RIA for the 1981 study applies two different O&M cost percentages based on the study's 59.4% dry disposal O&M cost percentage derived from page B-10, and on the study's 31.6% wet disposal O&M cost percentage derived from page C-11.
[96] Source: 1985 EPA AEERL report at http://nepis.epa.gov/Exe/ZyNET.exe/2000TNFC.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1981+Thru+1985&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=pubnumber%5E%22600S785028%22&QFieldYear=&QFieldMonth=&QFieldDay=&UseQField=pubnumber&IntQFieldOp=1&ExtQFieldOp=1&XmlQuery=&File=D%3A%5Czyfiles%5CIndex%20Data%5C81thru85%5CTxt%5C00000010%5C2000TNFC.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=10&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=p%7Cf&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x

EPRI, and other organizations. **Exhibit 4C** below displays the unitized capital costs and **Exhibit 4D** below displays the unitized O&M costs from the study updated for this RIA to 2009 price level.

- Using the 2009-updated mean unit capital and O&M cost estimates displayed in **Exhibit 4C** and **Exhibit 4D**, provides the following cost estimates for conversion to dry disposal, based on extrapolation to 22.4 million tons per year baseline wet CCR (i.e., wet fly ash, wet bottom ash, wet FGD, wet gypsum, wet other CCR) disposal in impoundments at 158 of the 495 electric utility plants which have a subtotal of 180,901 MW nameplate total capacity:
  - Capital cost: (180,901,000 kilowatt capacity for 158 electric utility plants with surface impoundments) x ($37.60 dry conversion capital cost per kilowatt capacity from **Exhibit 4C**) = $6,810 million capital cost
    Annual equivalent cost: ($6,810 million) x (0.07246 capital recovery factor @7% & 50-years) = $494 million/year
  - O&M cost: (22.4 million tons per year wet CCR disposed in impoundments) x (-$17.40 cost savings per ton to manage for dry disposal from **Exhibit 4D**) = -$389 million per year O&M cost savings.
  - Total average annualized cost (capital + O&M) = ($494 million/year capital cost) – ($389 million/year O&M cost savings) = $105 million per year dry conversion cost.

Exhibit 4C
Comparison of Unitized Capital Costs for Wet and Dry CCR Disposal (Source: 1985 EPA Study; $/kW)

Item	Disposal Operation	Wet or Dry CCR	Plant Size Categories (MW = megawatts) 250 Min	250 Max	500 Min	500 Max	1000 Min	1000 Max	2000 Min	2000 Max	Row Summary Across Four Size Categories Min	Max	Midpnt	Mean
1A	Fly ash handling/processing	Wet	$2.3	$6.8	$1.9	$5.5	$1.5	$6.4	$1.3	$3.6	$1.3	$6.8	$4.1	$3.7
1B		Dry	$2.2	$4.1	$1.8	$3.3	$1.4	$2.7	$1.2	$2.2	$1.2	$4.1	$2.7	$2.4
2	Fly ash storage	Dry	$4.7	$8.8	$4.2	$7.7	$3.7	$6.8	$3.2	$5.9	$3.2	$8.8	$6.0	$5.6
3A	Fly ash transport	Wet	$3.5	$6.4	$2.7	$5.1	$2.2	$4.0	$1.7	$3.2	$1.7	$6.4	$4.1	$3.6
3B		Dry	$0.3	$0.5	$0.3	$0.6	$0.3	$0.5	$0.2	$0.5	$0.2	$0.6	$0.4	$0.4
4A	Fly ash placement/disposal	Wet	$15.1	$27.8	$12.9	$23.9	$11.0	$20.5	$9.4	$17.5	$9.4	$27.8	$18.6	$17.3
4B		Dry	$4.3	$8.1	$3.3	$6.1	$2.5	$4.7	$1.9	$3.6	$1.9	$8.1	$5.0	$4.3
5	Bottom ash handling/processing	Wet/Dry	$2.2	$4.6	$1.7	$3.7	$1.3	$3.0	$1.0	$2.4	$1.0	$4.6	$2.8	$2.5
6A	Bottom ash transport	Wet	$3.0	$5.6	$2.4	$4.5	$1.9	$3.6	$1.5	$2.8	$1.5	$5.6	$3.6	$3.2
6B		Dry	$0.2	$0.4	$0.2	$0.3	$0.1	$0.2	$0.1	$0.2	$0.1	$0.4	$0.3	$0.2
7A	Bottom ash placement/disposal	Wet	$6.4	$11.8	$5.1	$9.6	$4.2	$7.7	$3.4	$6.2	$3.4	$11.8	$7.6	$6.8
7B		Dry	$1.3	$2.4	$1.1	$2.0	$0.9	$1.6	$0.7	$1.3	$0.7	$2.4	$1.6	$1.4
Summary:														
	Wet Subtotal (1A+3A+4A+5+6A+7A)	Wet (1982$)	$32.5	$63.0	$26.7	$52.3	$22.1	$45.2	$18.3	$35.7	$18.3	$63.0	$40.7	$37.0
	Dry Subtotal (1B+2+3B+4B+6B)	Dry (1982$)	$15.2	$28.9	$12.6	$23.7	$10.2	$19.5	$8.3	$16.1	$8.3	$29.0	$18.7	$16.8
	2009 Updated Wet Subtotal*	Wet (2009$)	$72.8	$141.1	$59.8	$117.1	$49.5	$101.2	$41.0	$79.9	$41.0	$141.1	$91.0	$82.8
	2009 Updated Dry Subtotal*	Dry (2009$)	$34.0	$64.7	$28.2	$53.1	$22.8	$43.7	$18.6	$36.0	$18.6	$64.9	$41.8	**$37.6**

* Note: 2009 price update multiplier (source: ENR Construction Cost Index ratio 2009:to:1982 = 8564/3825) = 2.239

Exhibit 4D

Comparison of Annual O&M Costs for Wet and Dry CCR Disposal (Source: 1985 EPA Study; $/dry metric ton)

			Plant Size Categories (MW = megawatts)								Row Summary Across Four Size Categories			
		Wet or Dry	250		500		1000		2000					
Item	Disposal Operation	CCR	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Midpnt	Mean
Fly Ash:														
1A	Fly ash handling/processing	Wet	$2.5	$6.8	$1.0	$5.4	$1.6	$4.3	$1.3	$3.6	$1.0	$6.8	$3.9	$3.3
1B		Dry	$2.5	$4.7	$2.1	$3.9	$1.7	$3.2	$1.5	$2.7	$1.5	$4.7	$3.1	$2.8
2	Fly ash storage	Dry	$3.3	$6.1	$3.0	$5.6	$2.8	$5.2	$2.5	$4.7	$2.5	$6.1	$4.3	$4.2
3A	Fly ash transport	Wet	$4.2	$7.6	$3.2	$5.9	$2.5	$4.7	$2.0	$3.7	$2.0	$7.6	$4.8	$4.2
3B		Dry	$1.7	$3.1	$1.5	$2.8	$1.3	$2.5	$1.2	$2.2	$1.2	$3.1	$2.2	$2.0
4A	Fly ash placement/disposal	Wet	$11.5	$21.3	$9.1	$16.8	$7.2	$13.5	$5.7	$10.5	$5.7	$21.3	$13.5	$12.0
4B		Dry	$7.0	$13.0	$5.6	$10.5	$4.6	$8.5	$3.7	$6.9	$3.7	$13.0	$8.4	$7.5
	Subtotal fly ash	Wet (1982$)	$18.2	$35.7	$13.3	$28.1	$11.3	$22.5	$9.0	$17.8	$8.7	$35.7	$22.2	$19.5
		Dry (1982$)	$11.2	$20.8	$9.2	$17.2	$7.6	$14.2	$6.4	$11.8	$6.4	$20.8	$13.6	$12.3
Bottom Ash:														
5	Bottom ash handling/processing	Wet/Dry	$11.3	$22.8	$9.0	$19.1	$6.9	$15.7	$5.3	$12.8	$5.3	$22.8	$14.1	$12.9
6A	Bottom ash transport	Wet	$9.2	$17.1	$7.3	$13.5	$5.6	$10.3	$4.3	$7.9	$4.3	$17.1	$10.7	$9.4
6B		Dry	$3.4	$6.3	$2.8	$5.2	$2.2	$4.1	$1.8	$3.3	$1.8	$6.3	$4.1	$3.6
7A	Bottom ash placement/disposal	Wet	$9.2	$17.1	$7.9	$14.6	$6.5	$12.1	$5.4	$10.0	$5.4	$17.1	$11.3	$10.4
7B		Dry	$5.4	$10.0	$4.7	$8.8	$4.1	$7.6	$3.5	$6.5	$3.5	$10.0	$6.8	$6.3
	Subtotal bottom ash	Wet (1982$)	$29.7	$57.0	$24.2	$47.2	$19.0	$38.1	$15.0	$30.7	$15.0	$57.0	$36.0	$32.6
		Dry (1982$)	$20.1	$39.1	$16.5	$33.1	$13.2	$27.4	$10.6	$22.6	$10.6	$39.1	$24.9	$22.8
Summary (Fly Ash & Bottom Ash):														
	Weighted average*	Wet (1982$)	$20.7	$40.4	$15.7	$32.3	$13.0	$25.9	$10.3	$20.6	$10.1	$40.4	$25.2	$22.4
		Dry (1982$)	$13.2	$24.8	$10.8	$20.7	$8.8	$17.1	$7.3	$14.2	$7.3	$24.8	$16.1	$14.6
	2009 updated weighted average**	Wet (2009$)	$46.4	$90.4	$35.2	$72.3	$29.1	$58.1	$23.1	$46.2	$22.6	$90.4	$56.5	$50.1
		Dry (2009$)	$29.5	$55.6	$24.2	$46.4	$19.8	$38.3	$16.4	$31.8	$16.4	$55.6	$36.0	$32.7
											Incremental cost from conversion to dry disposal =			**-$17.4**

Notes:

* Fly:to:ash weighted average based on 2005 relative annual tonnages evaluated in the RIA: Fly ash tons/year = 15,200,000; Bottom ash tons/year = 4,300,000

** 2009 price update multiplier (source: ENR Construction Cost Index ratio 2009:to:1982 = 8564/3825) = 2.239

- **Study #3 of 3: 2009 USWAG**

- On 11 June 2009 the Utility Solid Waste Action Group (Jim Roewer, Executive Director) provided to EPA a 14-page cost study USWAG sponsored by the EOP Group Inc., containing an estimate of $39,000 million present value (PV) for conversion to dry disposal: "Cost Estimates for Closure of Ash Ponds at Fossil Fuel Power Generation Facilities", prepared in 2009 by EOP Group Inc. USWAG/EOP's $39,000 million PV estimate uses a 3% discount rate over 20 years with a 10-year implementation period, and consists of:
  - $12,900 million PV (33%) for fly ash and bottom ash conversion to dry disposal
  - $2,500 million PV (6%) for foregone sunk cost in ponds
  - $23,700 million PV (61%) for construction of new wastewater plants for other non-ash ancillary wastewaters (e.g., stormwater) which are currently co-mingled with the wet ash.
- For purpose of comparing this estimate with the other two cost studies above, the following rough calculations extend the O&M costs from the 20-year period from the USWAG/EOP study, to the 50-year period applied in this RIA:
  - Dry management O&M cost = ($2.00 per ton higher cost than wet management) x (20.6 million tons per year in impoundments) x (40-years after 10-year impoundment phase-out) = $1,648 million (undiscounted).
    PV discounted @7% over 50-years = $279 million PV present value
  - Waste water treatment plant (WWTP) O&M cost = ($525 million per year) x (40-years after 10-year impoundment phase-out) = $21,000 million (undiscounted).

  PV discounted @7% over 50-years = $3,558 million PV present value
- Substituting these 50-year based PV O&M cost estimates for the 20-year based PV O&M cost estimates into the USWAG/EOP $39,000 million 20-year PV total cost estimate produces the following 50-year based average annualized cost:
  - <u>Capital cost</u>:($39,000 million PV total cost) – ($400 million 20-year PV dry management O&M) – ($5,200 million 20-year PV WWTP O&M) = $33,400 million PV capital cost

  Annual equivalent capital cost: ($33,400 million PV) x (0.07246 capital recovery factor @7% & 50-years) = $2,420 million per year annualized capital cost
  - <u>O&M cost</u>: ($279 million 50-year PV dry management O&M) + ($3,558 million 50-year PV WWTP O&M) = $3,837 million PV present value O&M

  Annualized O&M cost: ($3,837 million PV) x (0.07246 capital recovery factor @7% & 50-years) = $278 million per year O&M
  - <u>Total annualized cost</u> (capital + O&M) = $2,698 million per year

Exhibit 4E below presents a summary of the extrapolated cost estimates based on the per-plant cost findings from these three alternative cost studies, compared to the cost estimate based on the 2005 TVA cost study applied in this RIA.

Exhibit 4E Summary of Wet Conversion Cost Estimates Based on Four Alternative Studies 1981, 1985, 2005, 2009 ($millions updated to 2009$)					
	A	B	C	D	E (A to D)
Type of Dry Conversion Cost Element	**Cost Study #1** EPA 1981	**Cost Study #2** EPA 1985	**Selected for Basis of the Estimate Applied in this RIA Cost Study #3** TVA 2005	**Cost Study #4** USWAG/EOP 2009	Implied Range
1. Capital cost:					
1a. Present value (PV) =	$2,187 to $4,488	$6,810	$22,984	$33,400	$2,187 to $33,400
1b. Annualized equivalent* =	$158 to $325	$494	$1,665	$2,420	$158 to $2,420
2. Average annual O&M cost	$115 to $141	-$389 savings	$11	$278	-$389 savings to $278
3. Total annualized cost (1b+2)	$273 to $466	$105	**$1,676 (PV** = $23,137)**	$2,698	$105 to $2,698
Row 3 implied uncertainty range compared to estimate based on 2005 TVA study =					**-94% to +61%**
Notes: * Annualized over a 50-year period @7% discount rate. ** Present value computed by multiplying the annualized value by a 13.801 present value multiplier, which represents 7% discount over 50-years.					

- **Update of Cost Estimate for Converting from Wet to Dry CCR Disposal**
    - **Purpose of Dry Conversion Cost Estimate Update**

The purpose of this section is to update the initial estimate above in this RIA, of the cost of converting CCR disposal impoundments to dry disposal (i.e., landfills). The initial **$23.137 billion** estimate (present value discounted at 7% over 50-years) presented in above in this section of the RIA is based on the 2005 universe of 158 coal-fired electric utility plants (classified in NAICS code 22) with active CCR impoundments addressed in EPA's October 2009 draft RIA for the proposed rule. **Exhibit 4F** below provides a summary of this initial cost estimate.[97] As of February 2010, the 2005 universe is the latest available data from the U.S. Department of Energy's Energy Information Administration (EIA) Form 767 database, because the EIA temporarily suspended its electric utility industry data collection survey questionnaire to revise it.

[97] EPA's 2009 draft RIA cost estimate was based on an extrapolation of a cost estimate developed in 2005 by the Tennessee Valley Authority (TVA) for converting its Kingston TN coal-fired electric plant to dry disposal of fly ash and bottom ash. In the RIA, EPA (a) unitized TVA's cost estimate on a cost-per-ton basis for both the capital cost and annual O&M cost components, and then (b) extrapolated the unit costs to the 2005 national universe of 22.4 million tons wet disposed CCR associated with the 158 electric utility plants with active CCR impoundments as of 2005. **Exhibit 4F** below displays how the draft RIA timed the capital and O&M costs over the 50-year period of analysis applied in the RIA (2012 to 2061), and the result of discounting the 50-year cost stream at a 7% annual rate.

Exhibit 4F

PROPOSED RULE OCT 2009 RIA "OPTION 1" (RCRA Subtile C 3004x)				
All Impoundments Must Convert to Dry Ash System in 5-Years				
Capital cost for conversion to dry (non-discounted lump-sum) =				$22,984,000,000
Added annual O&M for dry compared to wet (non-discounted) =				$15,800,000
			A	**B**
				5-Year phase-out
			Count of existing	08 Oct 2009 draft RIA
			electric utility	simple estimate if
			plants with	lump-sum capital cost
	Row	Year	impoundments	in 1st year of final rule
	1	**2012**	158	$22,984,000,000
	2	2013	158	$0
	3	2014	158	$0
	4	2015	158	$0
	5	2016	158	$0
	6	2017	158	$15,800,000
	7	2018	158	$15,800,000
	8	2019	158	$15,800,000
	9	2020	158	$15,800,000
	10	2021	158	$15,800,000
	11	2022	158	$15,800,000
	12	2023	158	$15,800,000
	13	2024	158	$15,800,000
	14	2025	158	$15,800,000
	15	2026	158	$15,800,000
	16	2027	158	$15,800,000
	17	2028	158	$15,800,000
	18	2029	158	$15,800,000
	19	2030	158	$15,800,000
	20	2031	158	$15,800,000
	21	2032	158	$15,800,000
	22	2033	158	$15,800,000
	23	2034	158	$15,800,000
	24	2035	158	$15,800,000
	25	2036	158	$15,800,000
	26	2037	158	$15,800,000
	27	2038	158	$15,800,000
	28	2039	158	$15,800,000
	29	2040	158	$15,800,000
	30	2041	158	$15,800,000
	31	2042	158	$15,800,000
	32	2043	158	$15,800,000
	33	2044	158	$15,800,000
	34	2045	158	$15,800,000
	35	2046	158	$15,800,000
	36	2047	158	$15,800,000
	37	2048	158	$15,800,000
	38	2049	158	$15,800,000
	39	2050	158	$15,800,000
	40	2051	158	$22,984,000,000
	41	2052	158	$15,800,000
	42	2053	158	$15,800,000
	43	2054	158	$15,800,000
	44	2055	158	$15,800,000
	45	2056	158	$15,800,000
	46	2057	158	$15,800,000
	47	2058	158	$15,800,000
	48	2059	158	$15,800,000
	49	2060	158	$15,800,000
	50	2061	158	$15,800,000
Non-discounted total cost =				$46,663,000,000
Non-discounted average cost =				$933,000,000
Present value cost (@ 7% disc.rate) =				**$23,167,000,000**
Average annualized cost (@ 7% disc.rate) =				**$1,679,000,000**
Discount rate =		**7%**		
nnual engineering + ancillary costs for RIA "Option 1" Subtitle C =				$595,000,000
Total annualized cost for RIA "Option 1" Subtitle C =				**$2,274,000,000**
		Present value cost (@ 7% disc.rate) =		**$31,383,000,000**

PROPOSED RULE OCT 2009 RIA "OPTION 1" (RCRA Subtile C 3004x)				
All Impoundments Must Convert to Dry Ash System in 5-Years				
Capital cost for conversion to dry (non-discounted lump-sum) =				$22,984,000,000
Added annual O&M for dry compared to wet (non-discounted) =				$15,800,000
			A	**B**
				5-Year phase-out
			Count of existing	08 Oct 2009 draft RIA
			electric utility	simple estimate if
			plants with	lump-sum capital cost
	Row	Year	impoundments	in 1st year of final rule
	1	**2012**	158	$22,984,000,000
	2	2013	158	$0
	3	2014	158	$0
	4	2015	158	$0
	5	2016	158	$0
	6	2017	158	$15,800,000
	7	2018	158	$15,800,000
	8	2019	158	$15,800,000
	9	2020	158	$15,800,000
	10	2021	158	$15,800,000
	11	2022	158	$15,800,000
	12	2023	158	$15,800,000
	13	2024	158	$15,800,000
	14	2025	158	$15,800,000
	15	2026	158	$15,800,000
	16	2027	158	$15,800,000
	17	2028	158	$15,800,000
	18	2029	158	$15,800,000
	19	2030	158	$15,800,000
	20	2031	158	$15,800,000
	21	2032	158	$15,800,000
	22	2033	158	$15,800,000
	23	2034	158	$15,800,000
	24	2035	158	$15,800,000
	25	2036	158	$15,800,000
	26	2037	158	$15,800,000
	27	2038	158	$15,800,000
	28	2039	158	$15,800,000
	29	2040	158	$15,800,000
	30	2041	158	$15,800,000
	31	2042	158	$15,800,000
	32	2043	158	$15,800,000
	33	2044	158	$15,800,000
	34	2045	158	$15,800,000
	35	2046	158	$15,800,000
	36	2047	158	$15,800,000
	37	2048	158	$15,800,000
	38	2049	158	$15,800,000
	39	2050	158	$15,800,000
	40	2051	158	$22,984,000,000
	41	2052	158	$15,800,000
	42	2053	158	$15,800,000
	43	2054	158	$15,800,000
	44	2055	158	$15,800,000
	45	2056	158	$15,800,000
	46	2057	158	$15,800,000
	47	2058	158	$15,800,000
	48	2059	158	$15,800,000
	49	2060	158	$15,800,000
	50	2061	158	$15,800,000
Non-discounted total cost =				$46,663,000,000
Non-discounted average cost =				$933,000,000
Present value cost (@ 7% disc.rate) =				**$23,167,000,000**
Average annualized cost (@ 7% disc.rate) =				**$1,679,000,000**
Discount rate =		**7%**		
nnual engineering + ancillary costs for RIA "Option 1" Subtitle C =				$595,000,000
Total annualized cost for RIA "Option 1" Subtitle C =				**$2,274,000,000**
		Present value cost (@ 7% disc.rate) =		**$31,383,000,000**

o Recent Trend in CCR Impoundment Phase-Outs

Since formulating the initial cost estimate above, EPA obtained new information which indicates that many electric utility plants have already closed or are planning to close CCR impoundments and convert to dry disposal (i.e., landfill disposal and/or sell and transport dry CCR offsite for beneficial use by other industries) for reasons independent of the CCR proposed rule. As displayed below in **Exhibit 4G**, EIA's historical data[98] for the electric utility industry indicate that between 1996 and 2005, the tonnage of CCR disposed in impoundments has decreased by 10% from 25.2 to 22.5 million tons despite total CCR generation at electric utility plants increasing 24% over that same period from 102.0 million tons (1996) to 126.3 million tons (2005). This represents an average annual CCR impoundment **phase-out rate of 1.1% per year**.

	1996	2005	10-year decrease
Tonnage wet disposal	25.188 million	22.537 million	10%
Percentage of generation	25% of CCR	18% of CCR	7%

Exhibit 4G
Documentation of Recent Trend (1996-2005) In Switching From Wet to Dry CCR Disposal in the US Electric Utility Industry

Coal Ash, FGD Waste - EIA Data

Thousand Short Tons

	1996							2005						
	Utility Landfill (Dry)	Utility Disposal Ponds (Wet)	On Site Use and Storage	Sold	Off Site Disposal	Total	%	Utility Landfill (Dry)	Utility Disposal Ponds (Wet)	On Site Use and Storage	Sold	Off Site Disposal	Total	%
Fly Ash	21,450	15,710	2,446	12,091	8,110	59,806	59%	22,557	15,322	4,645	21,211	10,626	74,360	59%
Bottom Ash	5,340	4,973	1,968	4,322	2,537	19,140	19%	6,109	4,374	3,553	5,767	2,177	21,981	17%
Sludge	12,938	3,484	1,011	236	987	18,655	18%	9,592	1,886	467	409	2,507	14,861	12%
Gypsum	502	987	379	1,190	88	3,146	3%	55	872	372	8,513	783	10,595	8%
Other	171	35	0	691	305	1,202	1%	227	83	116	3,749	315	4,490	4%
Total	40,401	25,188	5,804	18,529	12,028	101,950	100%	38,539	22,537	9,153	39,650	16,407	126,286	100%

% Share of Total

	1996							2005						
	Utility Landfill (Dry)	Utility Disposal Ponds (Wet)	On Site Use and Storage	Sold	Off Site Disposal	Total		Utility Landfill (Dry)	Utility Disposal Ponds (Wet)	On Site Use and Storage	Sold	Off Site Disposal	Total	
Fly Ash	36%	26%	4%	20%	14%	100%		30%	21%	6%	29%	14%	100%	
Bottom Ash	28%	26%	10%	23%	13%	100%		28%	20%	16%	26%	10%	100%	
Sludge	69%	19%	5%	1%	5%	100%		65%	13%	3%	3%	17%	100%	
Gypsum	16%	31%	12%	38%	3%	100%		1%	8%	4%	80%	7%	100%	
Other	14%	3%	0%	57%	25%	100%		5%	2%	3%	84%	7%	100%	
Total	40%	25%	6%	18%	12%	100%		31%	18%	7%	31%	13%	100%	

[98] Source: US Department of Energy EIA F767_PLANT database at: http://www.eia.doe.gov/cneaf/electricity/page/eia767.html

One important reason for this change is that dry systems allow plants more flexibility in the type of coal they use as fuel. For example, as plants switched from bituminous to sub-bituminous coal, they also converted to dry fly ash handling systems because the ash from some sub-bituminous coals has cementitious properties that can cause plugging and high maintenance costs for some wet ash disposal systems, thus necessitating dry ash systems. Also, some types of sub-bituminous coal fly ash are in economic demand by the cement industry because of their low carbon content and need to be stored dry for transport. EIA's historical data for coal-fired electric plant fly ash disposal confirms this same trend away from wet disposal to dry disposal (and to beneficial reuse). In 1996, 26% of fly ash was disposed of in ponds (aka "impoundments"). This fly ash disposal method dropped to 21% in 2005.

- **Possible Factors Behind this CCR Dry Disposal Conversion Trend**

In the next few years, there will be a number of factors that may affect the way coal-fired plants in the electric utility industry operate that may further encourage CCR dry disposal rather than wet disposal. Five example factors are:

1. Federal regulations: EPA plans to issue a number of regulations that will affect electric utility plants under the Clean Air Act and the Clean Water Act. For example anticipated Clean Air Act regulations will likely lead to increased use of SO2 controls on existing electric utility plants that will increase the tonnage of flue gas desulfurization (FGD) solids that must be processed (i.e., beneficially used or disposed) and is some cases add calcium derivatives to the existing fly ash (through use of dry scrubbers). While the incremental costs of handling such additional materials are site specific, there are a number of factors that are likely to drive electric utility companies to give more consideration to dry CCR disposal. While wet disposal was common on earlier generations of wet scrubbers, in recent cases, some electric utility companies have focused much more strongly on options to reduce costs by finding beneficial uses for CCR. Furthermore, given the magnitude of the upcoming projects and growing public interest in how CCR are handled and disposed, expediting approval of the project may also drive towards consideration of dry disposal methods.
2. State regulations: A number of state governments are considering programs that may affect their respective state-wide economic demand for electricity.
3. Technology: New technologies for generation, transmission, and use of electricity are being introduced into the market.
4. Fuel cost: Spot markets for coal make it easy for plants to fuel switch or mix coal fuel types. This means, among other things that wet CCR disposal systems, because they limit the types of coal that these plants can use, are likely to be further reduced.
5. Plant property: As land availability constraints becomes more important to electric utility plants (e.g., some electric utility plants are located in riparian settings), on-site wet disposal areas become less important in favor of smaller footprint on-site dry disposal landfills and sending CCR off-site for disposal or beneficial use.

As electric utility companies face this myriad of changes, they are likely to be reconsidering at a very detailed level how they are operating their plants. In fact, this is evident in the fact that some electric utility companies have already announced actual or planned closures of a number of coal-fired electric generator units, while other companies have announced plans to switch some units or plants from coal to other fuels such as natural gas. This consideration of the way electric utility plants will operate is likely to include a reconsideration of how the plants will handle and disposal CCR. Furthermore, since future air pollution regulations are likely to cause more reassessment at electricity plants with older and less efficient air emission particulate control devices and air pollution scrubbers, air regulations themselves are likely to provide further inducement to reconsider CCR disposal practices at plants that are currently using wet disposal. These actions in the near future also mean that the market and regulatory environment in which these plants operate will continue to be in flux and the ability to operate in a way that will make them able to respond quickly to changes will be important.

Corroborating continuation of this historical phase-out trend are recent (2009) announcements by five electric utility companies (i.e., Tennessee Valley Authority (TVA), Duke Energy Company, Hoosier Energy REC Inc, Vectren Southern Indiana Gas & Electric Company, and Westar Energy Company)[99] that they plan to convert all or a significant portion of their CCR impoundments to dry management within the next 10 years corroborates continuation of this recent impoundment phase-out trend. These 18 plants alone comprise 17% of the annual 22.4 million tons CCR disposed annually in impoundments (as of 2005). In addition, three companies have announced planned coal-fired electricity plant closures or planned switching from coal to other fuels. These three plants comprise 3% of the annual CCR impoundment disposal tonnage. See **Exhibit 4H** below for a list of these companies, their plant names, and associated CCR impoundment disposal annual tonnages. Future developments in the electric utility industry, including compliance with upcoming Clean Air Act and Clean Water Act regulations under development at EPA, will increase the dry disposal conversion trend. It is inappropriate to assign the costs of these conversions to the CCR proposed rule, because they would happen anyway, in absence of the rule.

[99] TVA's 20 August 2009 news release "TVA Coal Combustion Products Remediation Plan Proposed" announced that TVA plans "to convert all TVA wet ash and gypsum storage to dry…over eight to 10 years." . Recent plans to convert from wet CCR impoundment disposal to dry landfill disposal for electric utility plants operated by the Duke Energy Company, the Hoosier Electric Cooperative, and Vectren Southern Indiana Gas & Electric Company were reported 24 October 2009 by Mark Wilson of the Courier Press "Coal Ash Disposal Varies From Company to Company" at http://btop.courierpress.com/news/2009/oct/24/coal-ash-disposal-varies-from-company-to-company/?print=1
Westar Energy apparently converted to dry fly ash management by December 2006 according to "Coal Plant O&M: Retrofit Flyash-Handling System Pays Dividends," Douglas J. Smith, Contributing Editor, Coal Power magazine, 01 Nov 2007: http://www.coalpowermag.com/transportation/Coal-Plant-O-and-M-Retrofit-Flyash-Handling-System-Pays-Dividends_79.html

Exhibit 4H
Lists of Coal-Fired Electric Utility Plants With Active CCR Impoundments (as of 2005)
Which are Either Voluntarily Planning to Convert to Dry Disposal
or Voluntarily Planning to Close or Switch Away from Coal to Another Fuel Source (e.g., Natural Gas)

Plants With CCR Impoundments Soon Converting to Dry Disposal*				Coal-Fired Electric Utility Plants Closing or Switching Away From Coal Fuel with CCR Impoundments**			
A Company Name	B Plant Name	C State	D 2005 CCR Pond Tons (1,000s)***	E Company Name	F Plant Name	G State	H 2005 CCR Pond Tons (1,000s)***
1. PSI Energy Inc (Duke Energy)	Cayuga	IN	210.9	1. Progress Energy	Cape Fear	NC	101.3
2. PSI Energy Inc (Duke Energy)	Edwardsport	IN	11.5	2. Progress Energy	Lee	NC	106.1
3. PSI Energy Inc (Duke Energy)	R Gallagher	IN	125.6	3. Progress Energy	L V Sutton	NC	166.0
4. PSI Energy Inc (Duke Energy)	Wabash River	IN	192.1	4. Progress Energy	W H Weatherspoon	NC	47.0
5. PSI Energy Inc (Duke Energy)	Gibson	IN	897.8	5. Duke Energy Company	Buck	NC	121.9
6. Tennessee Valley Authority	Colbert	TN	29.2	6. Duke Energy Company	Dan River	NC	28.5
7. Tennessee Valley Authority	Widows Creek	TN	852.8	7. Northern States (Xcel Energy)	High Bridge	MN	0.01
8. Tennessee Valley Authority	Paradise	TN	517.9	8. Northern States (Xcel Energy)	Riverside	MN	6.7
9. Tennessee Valley Authority	Shawnee	TN	61.1				
10. Tennessee Valley Authority	Bull Run	TN	22.4				
11. Tennessee Valley Authority	Gallatin	TN	180.5				
12. Tennessee Valley Authority	John Sevier	TN	10.0				
13. Tennessee Valley Authority	Johnsonville	TN	53.7				
14. Tennessee Valley Authority	Kingston	TN	325.9				
15. Southern Indiana Gas & Electric Company (Vectren)	F B Culley	IN	35.6				
16. Southern Indiana Gas & Electric Company (Vectren)	A B Brown	IN	165.8				
17. Hoosier Energy R E C Inc	Frank E Ratts	IN	39.8				
18. Westar Energy	Jeffrey Energy Center	KS	184.1				
Subtotal impoundment tons for 18 plants listed above =			3,916.7	Subtotal for 8 plants listed above =			577.51
% of 22.4 million tons 2005 wet disposal tonnage by 158 plants =			**17%**	% of 22.4 million tons 2005 wet disposal tonnage by 158 plants =			**3%**

Notes:
* EPA-ORCR identified the 18 plants with recent plans to convert from wet to dry CCR landfill disposal for electric utility plants operated by the Duke Energy Company, the Vectren Company, and the Hoosier Electric Cooperative, from the 24 October 2009 news report by Mark Wilson of the Courier Press "Coal Ash Disposal Varies From Company to Company." . The Westar Energy plant was identified by an EPA-ORCR staff person based on knowledge of that specific plant or company.
** EPA identified the 8 plants switching from coal from SourceWatch websites: http://www.sourcewatch.org/index.php?title=Coal_plant_conversion_projects and http://www.sourcewatch.org/index.php?title=Existing_U.S._Coal_Plants
*** Source: Based on the 2005 DOE-EIA data.

- **Result of Dry Conversion Cost Update**

The result of this dry conversion cost update is displayed below in comparison to the initial conversion cost estimate. The adjusted cost incorporates the **average annual 1.1% decrease** in CCR impoundment disposal tonnage calculated based on the 1996-2005 EIA data trend as presented in **Exhibit 4G** above, relative to the 2005 base year impoundment disposal tonnage of 22.4 million tons over the same 50-year period (i.e., 2012 to 2061) applied in the RIA. This adjustment provides a declining future CCR impoundment tonnage trend which would be impacted by the CCR proposed rule when it is implemented, rather than simply assigning to the rule a dry conversion cost for the entire 2005 impoundment tonnage (i.e., 22.4 million tons) as was done in the initial cost estimate. The cost adjustment using this trend involved two steps:

> Step 1: Assign a dry conversion cost to the extrapolation phase-out trend (i.e., 2006 to 2061) representing what the electric utility industry could be expected to incur in the future in absence of the CCR rule. The results of this 1st step are displayed in columns A1 to A4 of **Exhibit 4I** below.
>
> Step 2: Re-estimate the phase-out cost under this same industry trend but by adding the requirement under the CCR rule that all remaining CCR impoundment tonnage that is not projected to be voluntarily phased-out within 5-years of the final rule's adoption must be phased-out. This step incorporates three assumptions: (a) EPA promulgates the final rule at the start of 2012, (b) state governments adopt the final rule 2-years later at end of 2013, and (c) the final rule allows a 5-year phase-out period which spans 2014 to 2018. The results of this 2nd step are displayed in columns B1 to B4 of **Exhibit 4I** below.

Exhibit 4I

Adjustment of Dry Conversion Cost Estimate to Account for Utility Industry's Voluntary Impoundment Phase-Out Trend

			A1	A2	A3	A4	B1	B2	B3	B4
			A. Cost of Dry Conversion Trend Without CCR Rule				**B. Dry Conversion Cost if Mandated by CCR Rule**			
Projected trendline year count	RIA 50-year period of analysis	End of year	Regression trendline wet disposal phaseout (million tons/year)	Year-by-year incremental conversion to dry (million tons/year)	Incremental added cost year-by-year ---- regression trendline dry conversion cost projection without CCR rule	Regression trendline dry conversion cumulative cost without CCR rule	Mandatory wet phaseout within 5-years of rule	Mandatory year-by-year incremental conversion to dry (million tons/year)	Incremental added cost year-by-year ---- mandatory dry conversion cost projection with CCR rule	Mandatory dry conversion cumulative cost with CCR rule
1		**2005**	**22.5**	**Base year**	**Base year**	**Base year**	**22.5**	**Base year**	**Base year**	**Base year**
2		2006	22.2	0.3	$22,122,377	$22,122,377	22.2	0.3	$22,122,377	$22,122,377
3		2007	21.9	0.3	$22,122,377	$44,244,754	21.9	0.3	$22,122,377	$44,244,754
4		2008	21.7	0.3	$22,122,377	$66,367,131	21.7	0.3	$22,122,377	$66,367,131
5		2009	21.4	0.3	$22,122,377	$88,489,508	21.4	0.3	$22,122,377	$88,489,508
6		2010	21.1	0.3	$22,122,377	$110,611,885	21.1	0.3	$22,122,377	$110,611,885
7		2011	20.8	0.3	$22,122,377	$132,734,262	20.8	0.3	$22,122,377	$132,734,262
8	1	**2012**	20.5	0.3	$22,122,377	$154,856,640	20.5	0.3	$22,122,377	$154,856,640
9	2	2013	20.2	0.3	$22,122,377	$176,979,017	20.2	0.3	$22,122,377	$176,979,017
10	3	2014	19.9	0.3	$22,122,377	$199,101,394	19.9	4.0	$298,704,663	$475,683,680
11	4	2015	19.6	0.3	$22,122,377	$221,223,771	19.6	4.0	$298,704,663	$774,388,344
12	5	2016	19.3	0.3	$22,122,377	$243,346,148	19.3	4.0	$298,704,663	$1,073,093,007
13	6	2017	19.0	0.3	$22,122,377	$265,468,525	19.0	4.0	$298,704,663	$1,371,797,671
14	7	2018	18.7	0.3	$22,122,377	$287,590,902	18.7	4.0	$298,704,663	$1,670,502,334
15	8	**2019**	**18.4**	0.3	$22,122,377	$309,713,279	0	0	$0	$1,670,502,334
16	9	2020	18.1	0.3	$22,122,377	$331,835,656	0	0	$0	$1,670,502,334
17	10	2021	17.8	0.3	$22,122,377	$353,958,033	0	0	$0	$1,670,502,334
18	11	2022	17.5	0.3	$22,122,377	$376,080,410	0	0	$0	$1,670,502,334
19	12	2023	17.2	0.3	$22,122,377	$398,202,787	0	0	$0	$1,670,502,334
20	13	2024	16.9	0.3	$22,122,377	$420,325,164	0	0	$0	$1,670,502,334
21	14	2025	16.6	0.3	$22,122,377	$442,447,541	0	0	$0	$1,670,502,334
22	15	2026	16.4	0.3	$22,122,377	$464,569,919	0	0	$0	$1,670,502,334
23	16	2027	16.1	0.3	$22,122,377	$486,692,296	0	0	$0	$1,670,502,334
24	17	2028	15.8	0.3	$22,122,377	$508,814,673	0	0	$0	$1,670,502,334
25	18	2029	15.5	0.3	$22,122,377	$530,937,050	0	0	$0	$1,670,502,334
26	19	2030	15.2	0.3	$22,122,377	$553,059,427	0	0	$0	$1,670,502,334
27	20	2031	14.9	0.3	$22,122,377	$575,181,804	0	0	$0	$1,670,502,334
28	21	2032	14.6	0.3	$22,122,377	$597,304,181	0	0	$0	$1,670,502,334
29	22	2033	14.3	0.3	$22,122,377	$619,426,558	0	0	$0	$1,670,502,334
30	23	2034	14.0	0.3	$22,122,377	$641,548,935	0	0	$0	$1,670,502,334
31	24	2035	13.7	0.3	$22,122,377	$663,671,312	0	0	$0	$1,670,502,334
32	25	2036	13.4	0.3	$22,122,377	$685,793,689	0	0	$0	$1,670,502,334
33	26	2037	13.1	0.3	$22,122,377	$707,916,066	0	0	$0	$1,670,502,334
34	27	2038	12.8	0.3	$22,122,377	$730,038,443	0	0	$0	$1,670,502,334
35	28	2039	12.5	0.3	$22,122,377	$752,160,821	0	0	$0	$1,670,502,334
36	29	2040	12.2	0.3	$22,122,377	$774,283,198	0	0	$0	$1,670,502,334
37	30	2041	11.9	0.3	$22,122,377	$796,405,575	0	0	$0	$1,670,502,334
38	31	2042	11.6	0.3	$22,122,377	$818,527,952	0	0	$0	$1,670,502,334
39	32	2043	11.3	0.3	$22,122,377	$840,650,329	0	0	$0	$1,670,502,334
40	33	2044	11.0	0.3	$22,122,377	$862,772,706	0	0	$0	$1,670,502,334
41	34	2045	10.8	0.3	$22,122,377	$884,895,083	0	0	$0	$1,670,502,334
42	35	2046	10.5	0.3	$22,122,377	$907,017,460	0	0	$0	$1,670,502,334
43	36	2047	10.2	0.3	$22,122,377	$929,139,837	0	0	$0	$1,670,502,334
44	37	2048	9.9	0.3	$22,122,377	$951,262,214	0	0	$0	$1,670,502,334
45	38	2049	9.6	0.3	$22,122,377	$973,384,591	0	0	$0	$1,670,502,334
46	39	2050	9.3	0.3	$22,122,377	$995,506,968	0	0	$0	$1,670,502,334
47	40	2051	9.0	0.3	$22,122,377	$1,017,629,345	0	0	$0	$1,670,502,334
48	41	2052	8.7	0.3	$22,122,377	$1,039,751,722	0	0	$0	$1,670,502,334
49	42	2053	8.4	0.3	$22,122,377	$1,061,874,100	0	0	$0	$1,670,502,334
50	43	2054	8.1	0.3	$22,122,377	$1,083,996,477	0	0	$0	$1,670,502,334
51	44	2055	7.8	0.3	$22,122,377	$1,106,118,854	0	0	$0	$1,670,502,334
52	45	2056	7.5	0.3	$22,122,377	$1,128,241,231	0	0	$0	$1,670,502,334
53	46	2057	7.2	0.3	$22,122,377	$1,150,363,608	0	0	$0	$1,670,502,334
54	47	2058	6.9	0.3	$22,122,377	$1,172,485,985	0	0	$0	$1,670,502,334
55	48	2059	6.6	0.3	$22,122,377	$1,194,608,362	0	0	$0	$1,670,502,334
56	49	2060	6.3	0.3	$22,122,377	$1,216,730,739	0	0	$0	$1,670,502,334
57	50	2061	6.0	0.3	$22,122,377	$1,238,853,116	0	0	$0	$1,670,502,334
Summary Relative to 2005			Column total =	16.5	$1,238,853,116	$35,307,313,810		22.2	$1,670,502,334	$77,993,470,971
(56 years after base year)			Average annual =			$630,487,747				$1,392,740,553
			Present value (PV) =			$4,321,186,852				$12,375,281,254
			Annualized PV value =			$309,483,860				$886,318,954
Summary Relative to 2010			Column total =	15.3	$1,150,363,608	$35,086,090,039		21.1	$1,582,012,826	$77,772,247,201
(52 years after update)			Average annual =			$674,732,501				$1,495,620,138
			Present value (PV) =			$5,426,935,463				$15,984,210,270
			Annualized PV value =			$391,493,777				$1,153,085,179
Summary Relative to 2012			Column total =	14.7	$1,106,118,854	$34,842,743,891		20.5	$1,537,768,072	$77,528,901,053
(50 years same as RIA)			Average annual =			$696,854,878				$1,550,578,021
			Present value (PV) =			**$5,962,000,000**				**$18,049,000,000**
			Annualized PV value =			$432,005,623				$1,307,827,824
Discount rate =		7%	**Added Cost for Conversion to Dry Disposal Under the CCR Proposed Rule Compared to Conversion Trend Without Rule:**							
									Present value (PV) =	**$12,087,000,000**
									Annualized PV value =	$875,822,201
					Percent reduction compared to October 2009 draft RIA dry conversion cost estimate:					
									October 2009 draft RIA cost estimate =	$23,200,000,000
									Reduction in cost estimate compared to RIA =	**-48%**

As summarized below in comparison to the initial cost estimate, the updated conversion cost is the difference in the step-1 cost to the electric utility industry for continuation of the phase-out trend without the CCR rule, compared to the step-2 cost for mandatory phase-out with the rule.

Dry conversion cost:	Initial cost estimate	Updated cost estimate	
Average annualized cost	$1.676 billion/year	$0.876 billion/year	(48% reduction)
Present value (PV) cost	$23.2 billion PV	$12.1 billion PV	(48% reduction)

The updated cost is also presented below after integrating the updated dry conversion cost back into the overall cost of the CCR proposed rule which contains two other cost categories as estimated for the Subtitle C option (i.e., $491 million/year for engineering control costs + $107 million/year for ancillary regulatory costs).

Rule total cost: (i.e., updated dry conversion cost + engineering control cost + ancillary cost)

	Initial cost estimate	Updated estimate	
Average annualized cost	$2.27 billion/year	$1.47 billion/year	(35% reduction)
Present value (PV) cost	$31.4 billion PV	$20.3 billion PV	(35% reduction)

As shown above, the composite effect of the two cost update factors is they reduce the initial dry conversion cost estimate by **48%**, and reduce by **35%** the overall compliance cost estimate (i.e., dry conversion cost plus engineering control costs plus ancillary costs).

- **Factors Which May Accelerate the CCR Impoundment Phase-Out Trend**

For the reasons described above, it is clear that there is a significant past and continuing trend toward CCR impoundment phase-out at electric utility plants, regardless of the CCR rule, and that this trend will continue. Described below, EPA has identified **seven factors** which corroborate continuation of this impoundment phase-out trend, some of which have been quantified in the cost adjustment:

1. Industry conversions to dry CCR disposal: This factor corroborates the phase-out trend applied in the cost update. As discussed above, there is a documented over **two-decade long trend 1996 to 2019** away from wet CCR disposal in the electric utility industry. This trend consists of two parts: (a) the 1996-2005 historical data period, plus (b) the more recent (2009) announcements of actual conversions which occurred between 2005 and 2009, and planned conversions to occur within the next 10 years (i.e., by 2019). According to one company (United Conveyor Corporation) who has been supplying dry disposal equipment and conversion services to the electric utility industry, the main historical drivers for this voluntary shift have been (1) generating dry fly ash as a saleable co-product to other industries for beneficial uses, and (2) decreasing the volume of fly ash going to impoundments to provide greater capacity for bottom ash. Since then, concern over possible future environmental release liabilities associated with CCR impoundments, and pressure from individual state governments, has led electric utility companies to consider dry conversion. TVA is the most prominent example of this trend which publicly announced[100] in 2009 it plans to convert its wet fly ash and wet bottom ash systems to

[100] TVA's 20 August 2009 news release is at http://www.tva.gov/news/releases/julsep09/ccprp_other.htm

dry disposal within the next eight to 10 years (i.e. by 2019). Conversions of this sort are a current trend, and they will definitely continue, even in the absence of the CCR proposed rule. As summarized in **Exhibit 4H** above (columns A to D), EPA identified 18 such plants constituting **17%** of the industry-wide wet CCR disposal tonnage as of 2005. It is inappropriate to attribute the wet disposal phase-out cost of the CCR proposed rule to plants independently moving to dry CCR disposal. At this point, EPA expects that most plants will choose to move to dry disposal given the additional factors presented below.

2. Plants switching to other fuels: EPA assumes this factor is reflected in the phase-out trend applied to the cost update. Some coal-fired electricity plants have since 2005 switched, or are planning to switch, some or all of their coal-fired boilers at certain plants, from coal to other fuels (e.g. natural gas) for reasons unrelated to the CCR proposed rule. In such cases, the cost of closure of their CCR disposal impoundments should not be attributed to the cost of the proposed rule. This factor decreases the estimated cost of the rule, and particularly EPA's estimated future cost of phasing-out wet disposal attributable to the proposed rule. For example, based on EPA's recent internet search, as also displayed in **Exhibit 4H** above (columns E to H), EPA identified 8 coal-fired electric utility plants using impoundments (as of 2005) representing **3%** of wet CCR disposal by the 158 plants, which have or plan to switch fuels at one or more of their coal-fired electricity generation boilers within one or more plants, or to close one or more of their coal-fired boilers or entire coal-fired plants.

3. Lifespan expiration of existing CCR impoundments: This factor suggests a faster future phase-out trend than applied in the cost update, but is not applied in the cost update. Another factor which corroborates the future continuation of the electric utility industry's voluntary phase-out of CCR impoundments, is the fact that existing (i.e., active, operational) CCR impoundments have distinct operational lifespans. When an impoundment reaches its end-of-lifespan, the electric utility plant must in that future year either add new impoundment capacity by installing another impoundment, or convert to dry disposal by installing a landfill (or providing their annual CCR for beneficial uses). For purpose of estimating the "engineering cost" component (in **Chapter 4** of this RIA), EPA assigned impoundment lifespan start years (i.e., year in which impoundment construction was completed and began receiving CCR), and future expected impoundment operational lifespan closure years, to each of the 158 coal-fired plants with operational CCR impoundments (as of 2005) identified in this RIA. For the most part, the impoundment start years were based on actual industry-reported data from the references cited in this RIA. However, expected closure years were provided by industry for 78 of the 158 plants; thus, EPA assigned expected closure years to the remainder 80 plants assuming a 40-year lifespan. **Exhibit 4J** below presents a summary of the expected future closure years in relation to the remaining lifespan years and associated impoundment tonnages which are expected to reach end of operational lifespan in absence of the CCR rule. This summary indicates that all existing CCR impoundments could be expected to reach end-of-lifespan by year 2051, and that **20%** of impoundments will have reached end-of-lifespan by year 2018. According to the cost update assumptions discussed in the 2nd update steps of prior section above, year 2018 represents the 5th year of the CCR final rule's assumed 5-year phase-out period spanning 2014 to 2018, which also assumes the CCR final rule is promulgated by EPA at the start of 2012 and that state governments will adopt the rule 2-years later by the end of 2013. This lifespan expiration trend corroborates the assumed continuation of the phase-out trend depicted in **Exhibit 4I** (column A1) which indicates that **17%** of CCR impoundment tonnage may be expected to have phased-out by year 2018 (i.e., 18.7 million tons remaining by 2018 compared to 22.5 million tons in the analysis base year 2005) in absence of the CCR rule. In fact, given that end-of-lifespan provides companies with a low-cost opportunity to convert to dry disposal, the higher 20% end-of-lifespan percentage compared to the

17% phase-out trend suggest the future phase-out trend may be accelerated compared to the 1.1% annual phase-out assumed based on the 1996-2005 trend. For example, this result suggests that by 2018 the annual phase-out rate in that year could be **1.3%** (i.e., (20%/17%) x 1.1%)).

4. EPA's Clean Air Act emissions standards: This factor is not quantified in the cost update. Where existing coal-fired electric utility plants put in new air emission scrubbing systems, EPA believes they will overwhelmingly rely on CCR management systems that do not require wet disposal impoundments. Two of EPA's upcoming Clean Air Act (CAA) air pollution regulations may lead some coal plants to begin using large amounts of reagent to capture SO2 from boiler flue gas:

- EPA's Clean Air Mercury Rule (CAMR) which was vacated by the DC Circuit Court in 2007 compels EPA under the CAA Section 112 to issue maximum achievable control technology (MACT) regulations for coal- and oil-fired electric utility units: http://www.epa.gov/ttn/atw/utility/utilitypg.html
- EPA's remanded Clean Air Interstate Rule (CAIR) was also vacated by the DC Circuit Court in 2007 but was later reinstated and remanded back to the Agency for further review/clarification: http://www.epa.gov/cair

Such plants would likely experience a significant increase in the amount of fly ash or wet FGD waste tonnage to be disposed, because the reactants are either captured with the fly ash or with the wet FGD waste. If these plants currently dispose of bottom ash, fly ash, or wet FGD waste in wet impoundments, the likelihood of significantly increased future disposal tonnages may prompt them to consider a switch to dry disposal. Therefore, new CCR generated as a result of new Clean Air Act emissions requirements are very likely to cause plants to switch away from wet disposal independent from the CCR proposed rule. EPA has not quantified this factor for purpose of updating the 2009 RIA regulatory cost estimate in this RIA.

5. EPA's Clean Water Act effluent standards: This factor is not quantified in the cost update. EPA is currently developing new industrial wastewater effluent regulations for coal-fired electricity plants. These new regulations are likely to tighten significantly existing effluent limits. These new regulations will be one more factor likely to influence plants to switch to dry disposal systems.

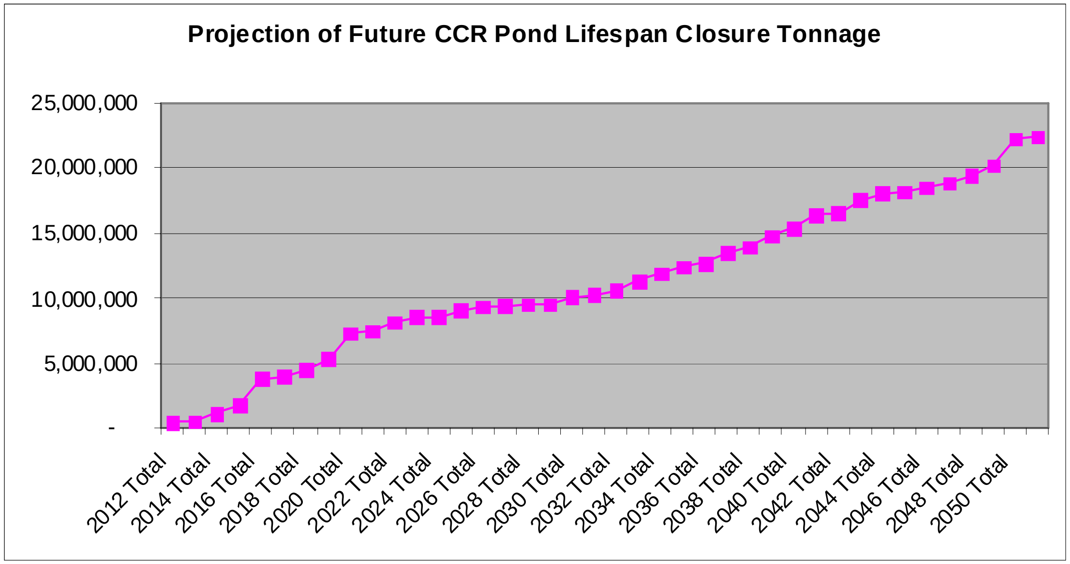
6. State government implementation of rule: This factor is quantified in the cost update. It recognizes that states require two years for their state legislatures or environmental regulatory programs to adopt new RCRA regulations such as the CCR final rule, which is necessary for the rule to become federally enforceable. In the initial cost estimate, EPA assumed that the CCR final rule would become effective (i.e., adopted by states) in year 2012 and that dry conversion capital costs would all be incurred in that single year. In contrast to that simple cost estimation framework, this cost update factor pushes the dry conversion cost 2-years out into the future beginning in 2014. The 5-year allowed dry conversion (i.e., impoundment phase-out) period is thus 2014 to 2018. In reality, there is a further distinction to be made. For states which operate EPA-authorized RCRA regulatory programs (as of 2005, EPA-authorized states comprise 97% of the 22.4 million tons annual CCR impoundment disposal tonnage), they could have 2-years adoption period. However, in non-authorized states (i.e., AK, IA), territories, and Indian country, the CCR rule becomes effective in 2012 by fact that EPA will implement it directly. According to the 2005 EIA data, in this 2nd group there are four plants with impoundments in IA plus one plant with impoundment(s) on tribal land totaling 3% of the 22.4 million tons impoundment disposal in 2005.[101] Because this 2nd group only comprises a very small 3% fraction of the annual CCR impoundment disposal tonnage, and to avoid adding another layer of complexity to the cost update which would only result in a very small (i.e., <5%) difference in updated estimate, the cost update does not separately calculate costs for both groups addressing under this factor, but applies implementation year to the entire 22.4 million tonnage. This 2-year final rule adoption cost-timing adjustment factor is highlighted in **Exhibit 4I** above.

7. 5-year impoundment phase-out period: This factor is quantified in the cost update. It recognizes that electric utility plants are likely to incur dry conversion capital costs spread across each of the years in the CCR rule's 5-year mandated phase-out period, rather than incurring all dry conversion capital cost in one year as was simply assumed in the initial cost estimate. This cost-timing adjustment factor is highlighted in **Exhibit 4I** above.

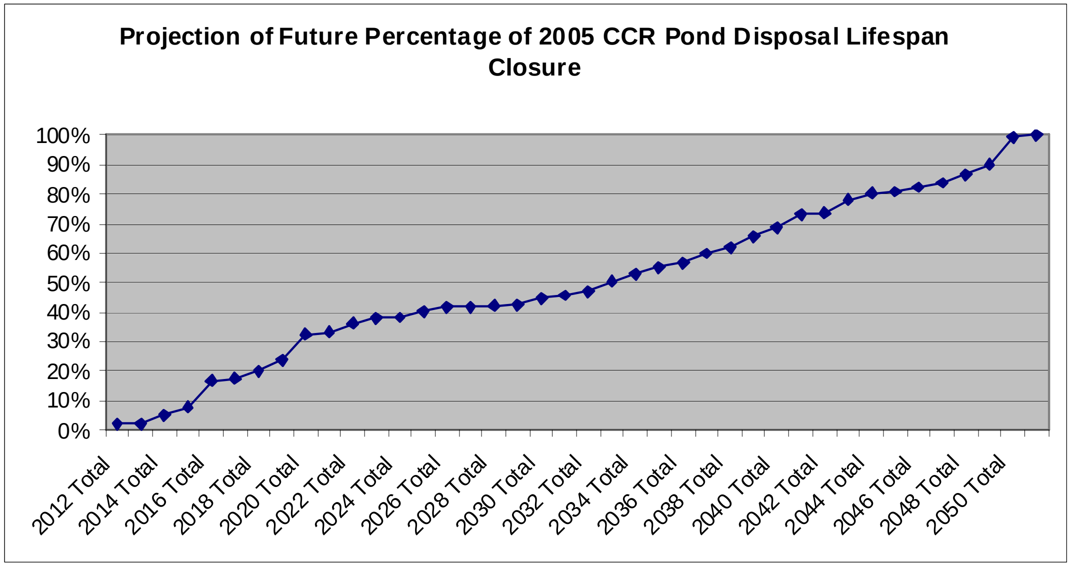
[101] As of 2005, the four IA plants are the George Neal North plant (50,200 tons/year CCR impoundment disposal), the Lansing plant (24,000 tons/year), the Louisa plant (23,000 tons/year), and the Walter Scott Jr Energy Center plant (104,000 tons/year). The one plant located on tribal land is the Four Corners plant in NM (501,400 tons/year).

Exhibit 4J

RIA 50-year period	Actual company planned or EPA estimated pond closure year	CCR pond end of lifespan (tons/year)	Cumulative pond lifespan end (tons/year)	% pond tonnage phaseout
	2009 Total	0	0	0%
	2010 Total	0	0	0%
	2011 Total	0	0	0%
1	**2012 Total**	481,300	481,300	2.1%
2	2013 Total	40,400	521,700	2.3%
3	2014 Total	634,700	1,156,400	5.2%
4	2015 Total	599,450	1,755,850	7.8%
5	2016 Total	2,021,700	3,777,550	16.9%
6	2017 Total	189,300	3,966,850	17.7%
7	**2018 Total**	513,400	4,480,250	**20%**
8	2019 Total	838,400	5,318,650	23.7%
9	2020 Total	1,969,160	7,287,810	32.5%
10	2021 Total	183,100	7,470,910	33.4%
11	2022 Total	661,700	8,132,610	36.3%
12	2023 Total	410,800	8,543,410	38.1%
13	2024 Total	39,000	8,582,410	38.3%
14	2025 Total	477,700	9,060,110	40.4%
15	2026 Total	280,900	9,341,010	41.7%
16	2027 Total	27,600	9,368,610	41.8%
17	2028 Total	134,000	9,502,610	42.4%
18	2029 Total	36,200	9,538,810	42.6%
19	2030 Total	527,100	10,065,910	44.9%
20	2031 Total	170,350	10,236,260	45.7%
21	2032 Total	327,400	10,563,660	47.2%
22	2033 Total	746,500	11,310,160	50.5%
23	2034 Total	594,100	11,904,260	53.1%
24	2035 Total	473,000	12,377,260	55.3%
25	2036 Total	322,000	12,699,260	56.7%
26	2037 Total	742,800	13,442,060	60.0%
27	2038 Total	476,100	13,918,160	62.1%
28	2039 Total	825,900	14,744,060	65.8%
29	2040 Total	642,050	15,386,110	68.7%
30	2041 Total	1,009,100	16,395,210	73.2%
31	2042 Total	141,600	16,536,810	73.8%
32	2043 Total	992,010	17,528,820	78.3%
33	2044 Total	505,700	18,034,520	80.5%
34	2045 Total	104,400	18,138,920	81.0%
35	2046 Total	338,000	18,476,920	82.5%
36	2047 Total	326,800	18,803,720	83.9%
37	2048 Total	575,800	19,379,520	86.5%
38	2049 Total	788,300	20,167,820	90.0%
39	2050 Total	2,075,700	22,243,520	99.3%
40	2051 Total	121,900	**22,400,000**	100.0%
Column total (2005 base) =		**22,400,000**		



Projection of Future CCR Pond Lifespan Closure Tonnage



Projection of Future Percentage of 2005 CCR Pond Disposal Lifespan Closure

Exhibit 4K below summarizes the above regulatory cost estimates on an incremental basis (i.e., without including the "Baseline Costs" estimated in **Chapter 3** of this RIA). **Appendix J** presents regulatory costs estimates for each of the 495 electric utility plants.

Exhibit 4K
Summary of Cost Estimates for the October 2009 Draft RIA Regulatory Options
($millions in 2009 price level; average annual amortized @7% discount rate over 50-year period 2012 to 2061)

RCRA Regulatory Cost Element	Subtitle C Hazardous waste	Subtitle D (version 1)	Hybrid C&D
A. Engineering Controls (onsite):	**$491**	**$491**	**$491**
1. Groundwater monitoring	$13	$13	$13
2. Bottom liners	$95	$95	$95
3. Leachate collection	$8	$8	$8
4. Fugitive dust controls	$5	$5	$5
5. Water runon/runoff controls	$2	$2	$2
6. Financial assurance	$30	$30	$30
7. Disposal unit location restrictions	$76	$76	$76
8. Closure capping to cover unit	$255	$255	$255
9. Post-closure groundwater monitoring	$2	$2	$2
10. Storage design & operating standards	Not estimated in this RIA	Not estimated in this RIA	Not estimated in this RIA
B. Other Ancillary Costs:	**$107**	**$1**	**$9**
11. For offsite disposal (11a+11b+11c) = 11a. RCRA manifest cost 11b. Added operation for hazmat truck 11c. Offsite LF RCRA Subtitle C permit	$77 $66 $8 $3	$0 Not relevant Not relevant Not relevant	$0 (offsite applies only to LFs so no incremental cost over baseline)
12. Structural integrity inspections	$1	$1	$1
13. RCRA facility-wide investigation	$7.6	Not relevant	$2.4
14. RCRA facility-wide corrective action	Not estimated in this RIA; historical average = $5.4 million per case	Not relevant	Not estimated in this RIA; historical average = $5.4 million per case
15. RCRA TSDF haz waste disposal permit	$7	Not relevant	$2
16. RCRA enforcement inspection	$0.06	$0	$0.02
17. Future added cleanup cost as "hazardous waste"	Not estimated in this RIA: case studies indicate possible $18 to $376 million per case	Not relevant	Not estimated in this RIA; case studies indicate possible $18 to $376 million per case
18. EPA paperwork reporting/recordkeeping	$13	Not relevant	$4
C. Land Disposal Restriction Dewatering Treatment	**$876 (updated)**	**$876 (updated)**	**$876 (updated)**
TOTAL ANNUALIZED COSTS (A+B+C) = Average cost per-ton (94.2 million tons disposed) = Average cost per-plant (467 disposing plants) =	**$1,474 per year (updated)** ($15.65 per ton) ($3.16 million per plant)	**$1,368 per year (updated)** ($14.52 per ton) ($2.93 million per plant)	**$1,376 per year (updated)** ($14.61 per ton) ($2.95 million per plant)

Note: **Chapter 6** of this RIA scales these cost estimates based on the October 2009 draft RIA options, to the 2010 regulatory options.

4C. State-by-State Distribution of Incremental CCR Regulatory Costs

Exhibit 4L below summarizes the distribution of estimated regulatory costs on a state-by-state basis and by option. This state-by-state summary is based on apportionment of nationwide average annualized cost estimated for each regulatory option, according to state-by-state annual CCR tonnage generated by the 495 coal-fired electric utility plants.

Exhibit 4L
State-by-State Distribution of Estimated Incremental Costs for the October 2009 Draft RIA Regulatory Options
($million average annualized cost in 2009$ over 50-year period of analysis 2012 to 2061)

A	B	C	D	E	F	G	H
Item	State	# of coal-fired electricity plants	2005 CCR generation by coal-fired electric utility plants (tons/year)	State % of nationwide CCR generation (based on Column D)	Subtitle C Hazardous waste	Subtitle D (version 1)	Hybrid C&D: Subtitle C impoundments Subtitle D landfills
1	AK	2	46,179	0.03%	$0.4	$0.4	$0.4
2	AL	16	3,210,337	2.27%	$33.5	$31.1	$31.2
3	AR	4	744,267	0.53%	$7.8	$7.3	$7.3
4	AZ	8	3,334,030	2.36%	$34.8	$32.3	$32.5
5	CA	6	159,927	0.11%	$1.6	$1.5	$1.5
6	CO	12	1,704,433	1.21%	$17.8	$16.6	$16.6
7	CT	0	172,280	0.12%	$1.8	$1.6	$1.7
8	DC	0	0	0.00%	$0.0	$0.0	$0.0
9	DE	2	251,205	0.18%	$2.7	$2.5	$2.5
10	FL	15	6,132,345	4.34%	$64.0	$59.4	$59.7
11	GA	13	6,077,700	4.30%	$63.4	$58.9	$59.2
12	HI	1	58,968	0.04%	$0.6	$0.5	$0.6
13	IA	15	1,136,289	0.80%	$11.8	$11.0	$11.0
14	ID	0	0	0.00%	$0.0	$0.0	$0.0
15	IL	17	3,856,748	2.73%	$40.2	$37.4	$37.6
16	IN	33	8,798,845	6.23%	$91.8	$85.3	$85.7
17	KS	8	1,495,099	1.06%	$15.6	$14.5	$14.6
18	KY	31	9,197,567	6.51%	$96.0	$89.1	$89.6
19	LA	3	1,614,800	1.14%	$16.8	$15.6	$15.7
20	MA	0	363,150	0.26%	$3.8	$3.6	$3.6
21	MD	4	1,932,740	1.37%	$20.2	$18.8	$18.9
22	ME	1	48,000	0.03%	$0.4	$0.4	$0.4
23	MI	24	2,369,673	1.68%	$24.8	$23.0	$23.1
24	MN	20	1,525,979	1.08%	$15.9	$14.8	$14.9
25	MO	20	2,679,742	1.90%	$28.0	$26.0	$26.1
26	MS	6	1,229,400	0.87%	$12.8	$11.9	$12.0

Exhibit 4L State-by-State Distribution of Estimated Incremental Costs for the October 2009 Draft RIA Regulatory Options ($million average annualized cost in 2009$ over 50-year period of analysis 2012 to 2061)							
A	B	C	D	E	F	G	H
Item	State	# of coal-fired electricity plants	2005 CCR generation by coal-fired electric utility plants (tons/year)	State % of nationwide CCR generation (based on Column D)	Subtitle C Hazardous waste	Subtitle D (version 1)	Hybrid C&D: Subtitle C impoundments Subtitle D landfills
27	MT	5	1,830,624	1.30%	$19.2	$17.8	$17.9
28	NC	27	5,504,531	3.90%	$57.5	$53.4	$53.7
29	ND	9	3,038,100	2.15%	$31.7	$29.4	$29.6
30	NE	6	614,473	0.44%	$6.5	$6.0	$6.1
31	NH	1	176,900	0.13%	$1.9	$1.8	$1.8
32	NJ	2	735,214	0.52%	$7.7	$7.1	$7.2
33	NM	4	3,983,300	2.82%	$41.6	$38.6	$38.8
34	NV	2	391,500	0.28%	$4.1	$3.8	$3.9
35	NY	11	1,479,792	1.05%	$15.5	$14.4	$14.4
36	OH	24	10,429,446	7.39%	$108.9	$101.2	$101.7
37	OK	3	1,490,800	1.06%	$15.6	$14.5	$14.6
38	OR	1	99,900	0.07%	$1.0	$1.0	$1.0
39	PA	28	15,359,680	10.88%	$160.4	$148.9	$149.7
40	RI	0	0	0.00%	$0.0	$0.0	$0.0
41	SC	14	2,178,360	1.54%	$22.7	$21.1	$21.2
42	SD	2	103,753	0.07%	$1.0	$1.0	$1.0
43	TN	12	3,240,120	2.29%	$33.8	$31.4	$31.5
44	TX	18	13,165,728	9.32%	$137.4	$127.6	$128.2
45	UT	7	2,582,144	1.83%	$27.0	$25.1	$25.2
46	VA	13	2,388,526	1.69%	$24.9	$23.1	$23.3
47	VT	0	0	0.00%	$0.0	$0.0	$0.0
48	WA	1	1,405,220	1.00%	$14.7	$13.7	$13.8
49	WI	12	1,412,534	1.00%	$14.7	$13.7	$13.8
50	WV	20	9,231,718	6.54%	$96.4	$89.5	$90.0
51	WY	12	2,224,848	1.58%	$23.3	$21.6	$21.7
	Totals =	**495**	**141.2 million**	100%	**$1,474/year**	**$1,368/year**	**$1,376/year**

4D. Cost Estimation Uncertainty

This section addresses OMB's 2003 Circular A-4 "Regulatory Analysis" guidance (page 40) requirement for RIAs involving rules with expected annual economic effects of $1 billion or more, to present a formal quantitative analysis of the uncertainties about benefit and cost estimates. This section only addresses uncertainties with respect to cost estimates for both baseline cost and incremental costs for the regulatory options. This section first presents **three specific examples** of data quality uncertainty factors in this RIA, followed by an **overall uncertainty factor** to represent all such specific data quality uncertainty factors combined (the three factors below are not additive across their low- and high-end percentage range endpoints because such simple addition would represent unlikely compounding of these factors):

- **Specific Examples of Data Quality Uncertainty Factors in This RIA**

1. CCR tonnage data: The baseline and regulatory cost estimates in this RIA are based on the annual CCR disposal and beneficial use tonnages reported by electric utility plants to the 2005 DOE-EIA Form 767 database. However, the DOE-EIA 767 data reporting form[102] does not provide respondents with a definition for the "tons" collected in Schedule 3 of the data reporting form. Because there are three numerical definitions of "ton" commonly used in the US (i.e., short-ton = 2,000 pounds, long-ton = 2,200 pounds; and metric ton = 2,205 pounds), this factor potentially introduces **-20% to +20%** uncertainty range. For purpose of consistency with the use of short-tons in most EPA RCRA program reports,[103] this RIA interprets CCR "tons" as short-tons.
2. Data sources: Also with respect to CCR tonnage data, this RIA cites multiple possible sources of data based on different published sources. For example, as displayed in **Exhibit 4D** of this RIA, one source (American Coal Ash Association) provides an industry survey-based estimate of CCR generation by electric utility plants in 2005 of 123.1 million tons. Whereas this RIA estimates 141.2 million tons CCR generation in 2005 based on data from the 2005 DOE-EIA Form 767 database for plants >100 MW in size and based on supplemental estimates made in this RIA for <100 MW size plants. This data source inconsistency factor represents **-13% to +15%** uncertainty range.
3. Data years: Information and data used to evaluate and estimate the cost of baseline CCR disposal practices are from various published sources dated 1995, 1996, and 2006. Furthermore, unit costs for CCR disposal unit engineering controls applied in this RIA are from different published data years such as 2000, 2004, and 2007. This RIA updated historical data to 2009 price levels using various indexes, some of which were specific to a particular type of unit cost, and other indexes were general (e.g., GDP Price Deflator). The uncertainty in accuracy of unit costs introduced by use of historical data is **not quantified**.

- **Overall Data Quality Uncertainty Range**

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[102] Instructions to the 2005 DOE-EIA Form 767 data reporting questionnaire (24 pages) are available at http://www.eia.doe.gov/cneaf/electricity/forms/eia767/eia767instr.pdf
A copy of the 2005 DOE-EIA 767 data reporting questionnaire (16 pages) is available at http://www.eia.doe.gov/cneaf/electricity/forms/eia767/eia767.pdf
[103] One example of the standardized use of "short-tons" in EPA RCRA program reports is the RCRA Biennial Hazardous Waste Reports which are archived at http://www.epa.gov/waste/inforesources/data/biennialreport/index.htm

The method applied to characterize the overall level of quantitative uncertainty in the cost estimates of this RIA, is based on the 02 February 2005 "Recommended Practice No. 18R-97: Cost Estimate Classification System as Applied in Engineering, Procurement, and Construction for the Process Industries"[104]. This method is specifically applicable to cost estimates developed for mechanical and chemical process equipment used for engineering, procurement and construction across a wide variety of industries including the electric utility industry sector (i.e., NAICS code 22). As summarized in **Exhibit 4M** below, this cost estimate classification system involves five estimation categories (i.e., Class 1, Class 2, Class 3, Class 4, Class 5) reflecting different relative (a) levels of cost definition, (b) purposes and uses of cost estimates, (c) cost estimation methodologies, (d) expected accuracy ranges, and (e) degrees of cost estimate preparation effort.

Exhibit 4M
Summary of Cost Estimation Classification System for Characterizing Data Quality Uncertainty in this RIA

Estimate Category	Level of Detail (Quantity of Input Information & Data)	Level of Effort (Time Required to Complete the Cost Estimate)	Expected Accuracy Range
Class 5	Very limited information (e.g., little more than proposed project type, location, and capacity).	Very limited amount of time and with little effort, sometimes requiring less than one hour FTE to prepare the cost estimate.	-50% to +100%
Class 4	1% to 5% complete, limited information (e.g., preliminary engineered process and equipment lists) for purpose of alternatives analysis, screening analysis, or demonstration of economic feasibility.	Sometimes requiring up to two months FTE for preparing the cost estimate.	-30% to +50%
Data quality uncertainty range applied in this RIA (i.e., between Class 3 and Class 4) =			**-25% to +40%**
Class 3	10% to 40% complete, semi-detailed information (e.g., process flow diagrams, equipment diagrams, layout drawings, engineered process and equipment lists).	May require up to nine months FTE to prepare the cost estimate.	-20% to +30%
Class 2	30% to 70% complete, detailed information	May require up to 1.5 years FTE to prepare the cost estimate.	-15% to +20%
Class 1	50% to 100% complete and full project definition (e.g., virtually all engineering and design documentation/plans)	May require up to or over three years FTE to prepare the cost estimate.	-10% to +15%

Because the bulk of the data collection and analysis presented in this RIA was executed in a relatively short time (i.e., five months) using semi-detailed information for baseline CCR disposal conditions, disposal unit costs, and engineering control and ancillary costs for the regulatory options, the level of numerical uncertainty for the baseline cost and incremental costs for each of the regulatory options estimated in this RIA may be classified between a Class 3 and Class 4 type of estimate (i.e., -25% to +40%), as displayed below in **Exhibit 4N.** These uncertainty ranges represent a probability distribution about the cost estimates, and may be interpreted as the expected values (i.e., best estimates) and low-end and high-end ranges about each cost estimate. Such quantitative indicators of uncertainty are identified in OMB's Circular A-4 (pages 40, 41) as acceptable for characterizing probability distributions for cost estimates involving major rules with possible annual economic effects of $1 billion or more for one or more regulatory options.

[104] Recommended Practice No. 18R-97 (10 pages) published by the Association for the Advancement of Cost Engineering at: http://www.aacei.org/technical/rps/18r-97.pdf

Exhibit 4N Cost Estimation Uncertainty with Overall Data Quality Uncertainty Factor Applied to the October 2009 Draft RIA Options ($millions in 2009$)			
Cost Estimate Uncertainty Indicator	Subtitle C Hazardous waste	Subtitle D (version 1)	Hybrid C&D: Subtitle C for impoundments Subtitle D for landfills
Best estimate (w/updated LDR cost):	**$1,474/year (updated) $20,343 PV**	**$1,368/year (updated) $18,880 PV**	**$1,376/year (updated) $18,990 PV**
-25% uncertainty low-end	$1,106/year $15,264 PV	$1,026/year $14,160 PV	$1,032/year $14,243 PV
+40% uncertainty high-end	$2,064/year $28,485 PV	$1,915/year $26,429 PV	$1,926/year $26,581 PV
Note: PV = present value of average annualized cost over 50-years @7% discount rate, calculated by multiplying the average annualized cost by the present value factor = 13.801.			

Note: **Chapter 6** of this RIA scales these estimated costs based on the October 2009 draft RIA, to the 2010 regulatory options.

Chapter 5
Potential Benefits of RCRA Regulation of CCR Disposal in the Electric Utility Industry

Exhibit 5A below displays social benefits associated with EPA's RCRA regulatory program, a few or many of which may be associated with any particular RCRA regulation. To a lesser or greater degree, a range of these benefit elements may be associated with future benefits from RCRA regulation of CCR disposal, according to the unique physical and environmental attributes at any particular CCR disposal site.

Exhibit 5A
Human Health, Environmental, & Economic Benefits of the EPA RCRA Regulatory Program*

Benefit Category (n = 6)	Benefit Sub-Element Examples (n = 36)	
1. Human Health Protection Benefits	1A. Mortality Reduction-Examples 1) Reduced risk of cancer fatality 2) Reduced risk of acute fatality	1B. Morbidity reduction-Examples 1) Reduced risk of cancer 2) Reduced risk of morbidity (e.g., asthma, nausea)
2. Ecological Protection Benefits	2A. Market Ecological Values: 1) Commercial fisheries 2) Market recreational benefits (e.g., involving fees) 3) Food	4) Fuel 5) Fiber 6) Timber 7) Fur/leather
	2B. Non-Market Ecological Values & Amenities (examples): 1) Non-market recreational benefits (e.g., w/out fees)	2) Non-use values: existence, bequest, and quasi-option values
3. Indirect Ecosystem & Resource Conservation Benefits	1) Climate moderation 2) Flood moderation 3) Groundwater recharge 4) Sediment trapping 5) Soil retention 6) Nutrient cycling	7) Pollination by wild species 8) Biodiversity 9) Water filtration 10) Soil fertilization 11) Pest control 12) Reduced pressure on endangered species 13) Avoided habitat destruction
4. Avoided Economic Costs	1) Avoided costs of providing government mandated alternate drinking water supplies	2) Avoided costs associated with government mandated cleanups of industrial waste accidents or spills
5. Avoided Materials Damages, Improved Aesthetics, & Historical Preservation	1) Aesthetic pleasure 2) Improved taste, order, visibility	3) Protection of resources with cultural and historic value 4) Protection of constructed resources (e.g., buildings, infrastructure)
6. Potential Long-Term Benefits (Sustainability)	1) Avoided increases in damages related to changes in affected populations 2) Benefits associated with resource conservation	3) Benefits associated with the precautionary principle, protection from unforeseen issues 4) Benefits from long-term increases in the value of environmental quality

* Source: Exhibit 1-1 of EPA Office of Solid Waste, "Approaches to Assessing the Benefits, Costs, and Impacts of the RCRA Subtitle C Program," prepared by Industrial Economics Inc., October 2000,

In contrast to the **Exhibit 5A** list of RCRA regulatory program benefits, because of time, data, and methodological limitations, the regulatory benefits estimated in this RIA do not represent a complete list of expected benefits of the CCR proposed rule. For example, the benefits analysis in this Chapter of the RIA does not estimate benefits of (a) reducing cancer risks associated with preventing direct effluent discharges of CCR to surface waters, (b) ecological and ecosystem benefits, (c) off-site CCR disposal regulatory benefits, or (d) non-cancer human health protection benefits. In contrast to this large number of possible benefit elements, this RIA monetizes only three benefit categories consisting of five sub-elements.

1. Groundwater Protection Benefits at CCR Disposal Sites
    a. Human health protection benefits (i.e., benefit of preventing cancer from arsenic exposure)
    b. Groundwater remediation costs avoided
2. CCR Impoundment Catastrophic Failure Benefits
    a. Future cleanup costs avoided
3. Benefits from Increase in Future CCR Beneficial Uses
    a. Direct market benefits (economic benefits)
    b. Lifecycle social benefits (economic + environmental benefits)

These monetized benefits are based on EPA's initial analysis using existing information and analytical techniques. EPA requests public comment on all data sources and analytical approaches used in estimating the benefits presented in this Chapter.

5A. Groundwater Protection Benefits (Avoided Future Cancer Risks & Groundwater Remediation Costs)

This section estimates the potential future benefits of reduced human cancer risks and avoided groundwater contamination remediation costs associated with controlling arsenic from onsite CCR landfills and surface impoundments. The estimates are based on EPA's risk assessment, which predicts leaching behavior using SPLP and TCLP data. Recent research and damage cases indicate that these leaching tests under-estimate risks from dry disposal.[105] Human cancer risks avoided are based on the individual "excess" lifetime cancer probabilities estimated below. This estimation follows an 8-step method which begins by characterizing the cancer risks and expected number of future cancer risks from arsenic releases to groundwater from CCR landfills and surface impoundments in the absence of EPA or state action. It then proceeds to monetize these cancers using accepted economic practices. Next, a baseline is established for the operation of state regulatory and remedial

[105] Recent EPA research demonstrates that CCR can leach significantly more aggressively under different pH conditions potentially present in disposal units. In a 2009 EPA study of 34 electric utility plants, CCR from 19 facilities exceeded at least one of the 40 CFR Toxicity Characteristic regulatory values for at least one type of CCR (e.g., fly ash or FGD residue) at the self-generated pH of the material (source: EPA Office of Research & Development, "Characterization of Coal Combustion Residues from Electric Utilities – Leaching and Characterization Data," EPA-600/R-09/151. Office of Research and Development, Air Pollution Control Division. Research Triangle Park, NC. December 2009). This behavior likely explains the rapid migration of chemical constituents from CCR disposal sites like Chesapeake, VA and Gambrills, MD. See also EPA "Characterization of Mercury-Enriched Coal Combustion Residues from Electric Utilities Using Enhanced Sorbents for Mercury Control," EPA 600/R-06/008. Office of Research and Development. Research Triangle Park, NC. January 2006; and EPA "Characterization of Coal Combustion Residues from Electric Utilities Using Wet Scrubbers for Multi-Pollutant Control," EPA/600/R-08/077. Office of Research and Development, Air Pollution Control Division. Research Triangle Park, NC. July 2008.

programs. Groundwater remediation costs and cancer costs under the baseline and each regulatory option are then estimated. Finally, the aggregate benefits from each regulatory option (incremental to the baseline) are estimated.

Step 1. Categorize CCR Disposal Units by Type

This step begins with the baseline data on CCR disposal (i.e., disposal unit liner types, annual CCR disposal tonnages) contained in **Appendix F** of this RIA for the 495 coal-fired electric utility plants. A subtotal 84 of the 495 plants dispose CCR offsite only, and thus, no liner type is assigned to these facilities in this benefits analysis.[106] Some of the plants have multiple data entries because they were known to have multiple CCR disposal units on-site. This estimation step assigned only the riskiest disposal unit type and liner type combinations of those listed for each such plant, which resulted in the six combinations displayed below in **Exhibit 5A-1**.[107] This hierarchy was based on the 90th percentile, trivalent arsenic cancer risks in the EPA-ORCR 2009 CCR risk report as follows, with those units posing the greatest risk appearing first. **Appendix K1** presents further information on CCR disposal unit liner types and associated data.

These plants were then further divided by the type of waste disposed in the units; CCR only or co-managed wastes. The ratio of facilities that only dispose CCR compared to facilities that co-manage CCR with coal refuse is displayed below in **Exhibit 5A-1**. These ratios allowed EPA to model a single number of potential cancer cases as a best estimate. The data used in the 2009 risk assessment[108] were from a 1995 EPRI survey. Thus, there is some uncertainty regarding the current accuracy of these ratios. To account for this uncertainty, EPA also calculated a bounding range of cancers based on the assumption that all facilities would dispose of CCR only, and that all facilities would co-manage CCR with coal refuse only.

Exhibit 5A-1
Categorization of CCR Disposal Unit Types

CCR Disposal Unit Type	CCR Only	Co-managed
1. Unlined Landfill	66%	34%
2. Clay-Lined Landfill	74%	26%
3. Composite-Lined Landfill	53%	47%
4. Unlined Surface Impoundment	32%	68%
5. Clay-Lined Surface Impoundment	48%	52%
6. Composite-Lined Surface Impoundment	71%	29%

[106] Note: 83 facilities in Exhibits E2 and E4 of the 2009 risk assessment are not assigned WMUs or liner types, 5 fewer than indicated in this RIA.
[107] Multiple CCR disposal units at a single industrial facility will all affect the same surrounding population. To avoid duplication of population risks, the analysis used the simplifying assumption that the human health risks will be driven by the riskiest single WMU, when multiple waste management units are present, but populations around all WMUs are accounted for in **Appendix K2** of this RIA.
[108] Source: EPA "Human and Ecological Risk Assessment of Coal Combustion Wastes," Office of Resource Conservation and Recovery, December 7, 2009.

Step 2. Determine Potentially Affected Populations of Groundwater Drinkers

With information on the universe of facilities, WMUs, and liners nearby groundwater-drinking populations were assigned. To accomplish this, EPA first assigned latitude and longitude coordinates to the 495 sites based on its 2007 eGRID database. Only a few sites were not in eGRID, and it is assumed that these sites were constructed since the 2007 eGRID data collection. Once latitude and longitude data were assigned, EPA used GIS data to ascertain the location of private groundwater wells within a one-mile radius from the latitude and longitude coordinates, and then the number of individuals drinking from those wells.[109,110] The data divide populations into adults (18 and older) and children, the same two populations examined in the 2009 risk assessment. Once these data were attached to specific sites, they were aggregated based on the liner/WMU categories above.

Aggregated data were then scaled to account for the missing population information and population growth. First, the data was scaled up to account for the missing population data in the sites not identified in eGRID. There were 5 unlined landfills, 1 clay-lined landfill, and 7 composite-lined landfills that had onsite disposal but no eGRID data from which to determine the population. All surface impoundments had the necessary eGRID data. To account for these individuals, EPA made the assumption that these plants had populations similar to the plants EPA had data for, since EPA had no data to suggest otherwise.[111] Thus, the population was scaled up by a scaling factor equal to the total number of plants divided by the number of plants for which EPA had population data as follows:

1) Unlined Landfills = 76/71 (~1.07)
2) Clay-Lined Landfills = 28/27 (~1.04)
3) Composite-Lined Landfills = 150/143 (~1.05)

The populations were then scaled up to current population levels based on Census data, resulting in a scaling factor of 1.093.

Once these preliminary population estimates were produced, it was also necessary to account for the size of the waste management unit. In the 2009 risk assessment, WMUs were assumed to be square as a requirement of the model. Using the same assumption here, the actual 1-mile radius around the square area of a WMU could be estimated by scaling the population density of the original 1-mile radius up to the area 1-mile around a square WMU of average size. This led to scaling factors of 1.81 and 2.56 for landfills and surface impoundments, respectively. Further discussion of this area-based scaling can be found in **Appendix K2**.

In addition to accounting for the increased area in the 1-mile radius, EPA assumed that half of the receptors would be up-gradient and half would be down-gradient of the WMU. For the purposes of this assessment, populations were assumed to be equally distributed within the

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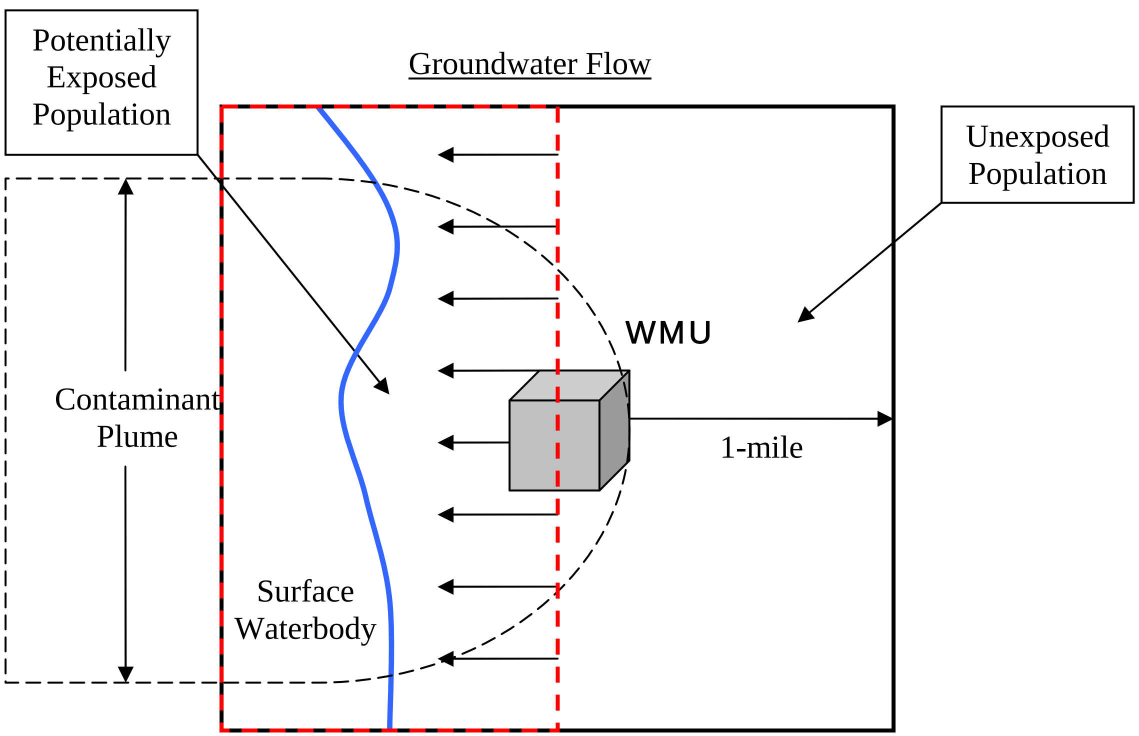
[109] This data was developed through the use of the 2000 census block data in combination with the 1990 census drinking water source data. For a further discussion of population development, see **Appendix K3** of this RIA.
[110] Municipal water systems using groundwater often rely on deeper aquifers, in which case they would be less susceptible to contamination from CCR releases. Therefore, these systems were not included in the 2009 Risk Assessment or in this analysis. However, exposure through this pathway is possible, which means that these population estimates could underestimate the population that is exposed to these wastes.
[111] EPA does not account for CCR disposed off-site as in the Gambrills MD and Chesapeake VA damage cases.

square whose center was the facility WMU. This is illustrated in **Exhibit 5A-2** below. It was also assumed that only down-gradient populations would be affected (red rectangle), and no up-gradient populations would be affected. This was accounted for by dividing the one-mile population by two. The issue of surface waterbodies is addressed below. **Appendix K3** provides a detailed explanation of the derivation of the exposed population by plant. Overall, 715,855 individuals are potentially exposed to CCR. Of this total, 34,533 use private drinking water wells.

Exhibit 5A-2
Conceptual Model for Exposed Well-Drinking Population



Step 3. Apply EPA-ORCR 2009 Arsenic Groundwater Risk Results

This step involved determining the most appropriate individual risk factors for use in estimating arsenic cancer population risk for the estimated populations residing near the CCR disposal sites. There are two sources of information on individual risks associated with arsenic exposure:

IRIS 1998: Based on skin cancer incidence, as data on skin cancer risks were available prior to the availability of quantitative data for internal cancers. Skin cancer is a health endpoint associated with lower fatality risk than the internal cancers induced by arsenic. The skin cancer based risk assessments no longer represent the current state of the science for health risk assessment for arsenic. This RIA presents these estimates below for informational purposes only. This source describes a distribution of risks to a hypothetical individual who drinks water from a well located at a randomly selected point one mile down-gradient from the waste management unit edge. The probabilistic risk estimates were "site-based" (that is, not site-specific, but based roughly on 181 actual coal-fired power plants that were operating in 1995). EPA has only the "peak" risks (i.e., those corresponding generally to the highest groundwater concentrations that are modeled to occur) available for analysis because computer modeling of peak risks contain gigabytes worth of information, and while EPA attempted to keep track of risks up to 10,000 years of the computer model run, the data in these large files became corrupted and are now unusable. However, below in this RIA EPA does extrapolate population risks in other years. These other years are the years between the cessation of operation of the landfill, or the years after the beginning of operation of the surface impoundment, leading up to the years in which the "peak" risks occur at half of the modeled facilities.

NRC 2001: The latest science on health risks associated with arsenic exposure is from the National Research Council (NRC) report "Arsenic in Drinking Water: 2001 Update"[112] which reviewed the available toxicological, epidemiological, and risk assessment literature on the health effects of inorganic arsenic, building upon the NRC's prior report, "Arsenic in Drinking Water" (1999). The 2001 report, developed by an eminent committee of scientists with expertise in arsenic toxicology and risk assessment provides a scientifically sound and transparent assessment of cancer risks from inorganic arsenic. EPA's Science Advisory Board endorses these estimates and the IRIS estimates are currently being updated to reflect this latest science. Therefore, while IRIS estimates exist, because the more recent NRC scientific information is available, this RIA relies on the NRC information for analysis of the cancer risks associated with CCR. **Appendix K4** provides more detailed information on how this NRC research was used.

For the purposes of initially estimating the expected number of cancers (i.e., cancer risks) in Steps 3 and 4, this RIA applied risk results obtained with the latest (i.e., 1998) IRIS value. However, in Step 5 below, the 2001 NRC research was used to update these cancer estimates. It should be noted that the 1998 IRIS skin cancer value does not examine bladder and lung cancer incidence, and therefore is not a substitute for the 2001 NRC cancer risk research in this area. To the extent that the skin cancers estimated by the IRIS value are not accounted for, this RIA may underestimate total cancer incidence.

[112] National Research Council, Arsenic in Drinking Water: 2001 Update, National Academy Press, 2001 at http://www.nap.edu/openbook.php?isbn=0309076293

This RIA extracted only those results from the EPA 2009 risk assessment to either represent (a) conventional CCR (i.e., fly ash, bottom ash, boiler slag, and flue gas desulphurization waste managed in the landfill or impoundment without mixing with other materials), or (b) CCR co-managed with coal refuse.[113] Of these results, only those for trivalent arsenic were used.[114] For the primary analysis, it was assumed that all arsenic was speciated in this manner. As noted in the EPA source data, arsenic III and arsenic V cancer risk results for unlined surface impoundments that co-dispose CCR with coal refuse were not statistically different at the 90th percentile, and these risks are likely to drive the population risk estimates. A sensitivity analysis was conducted where all arsenic was assumed to be speciated in the arsenic V state. This analysis is presented in **Appendix K5**. Finally, risks for both adult and child receptors were included so that each group would be accurately represented. Once all of these data were collected they were sorted by CCR disposal unit and liner type.

This analysis reflects possible groundwater and surface water interactions that could affect the population risk estimates. In situations in which the modeled distance to a surface water body was less than the modeled distance to a drinking water well EPA assumed that the groundwater plume is fully intercepted by a surface waterbody.[115] To this end, EPA extracted the model inputs for the distance to groundwater wells and the distance to surface waterbodies used in the EPA source, randomly selected from input distributions.[116] These two were then compared using a logical test in Microsoft Excel. This test returned a 0 if the surface waterbody was closer than the drinking water well and 1 if it was not. Thus, a 1 was a positive indication that the contaminant plume in that model run reached the groundwater well.

Finally, EPA extracted the exposure durations used in each model run from the EPA-ORCR 2009 CCR risk report to capture the fraction of the individual's lifetime risk that was experienced in a one-year period. EPA accomplished this by matching the probabilistic exposure duration inputs, to their corresponding age category. Then, each probabilistic run was sorted to return the exposure duration of the adult and child age category. These Monte Carlo data constituted a weighted approach for estimating individual human cancer risks. Population risk is typically calculated by multiplying risk results by the affected population. Since there were thousands of equally valid model iterations, this RIA assigned each of these risks an equal weight in its final population risks by using the average of these individual risks.

Individual risk estimation took into account the fact that the contaminant plumes might be intercepted by surface waterbodies by multiplying by either 0 or 1 as identified above. Each of these risks was then divided by exposure duration to estimate the yearly cancer risk.[117] Once all of these risks were calculated for a given WMU/liner type they were summed and divided by the number of iterations to give the average one year increment of risk for that WMU/liner type at the peak risk. Thus, the final equation that was used for calculating average risks can be stated as:

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[113] Fluidized Bed Combustion waste results were not deemed appropriate for use for the reasons discussed in EPA "Human and Ecological Risk Assessment of Coal Combustion Wastes," Office of Resource Conservation & Recovery, August 2009.
[114] A 1981 Oak Ridge National Laboratory study states "As (III) is likely to be the predominant arsenic species in ash pore water and groundwater." Source: Turner, Ralph R. "Oxidation State of Arsenic in Coal Ash Leachate," Environmental Science & Technology, Vol.15, Number 9, September 2001.
[115] Full interception will not occur in instances where the waterbody is shallow, the waterbody is man-made, or the facility is oriented perpendicular to the waterbody. This simplifying assumption serves to minimize the influence of the model runs in which interception may have occurred, but was not reflected in EPA "Human and Ecological Risk Assessment of Coal Combustion Wastes," Office of Resource Conservation & Recovery, August 2009.
[116] For further discussion of how these distributions were developed, see Appendix C of EPA "Human and Ecological Risk Assessment of Coal Combustion Wastes" Office of Resource Conservation and Recovery, Washington, DC, August 2009.
[117] For further discussion of cancer risks and exposure durations, see **Appendix K4** of this RIA.

$$iRISK = \frac{\sum \frac{RISKn \times WELLREACH}{EDn}}{N}$$

Where:

iRISK	=	Average increment of lifetime cancer risk from a 1-year exposure
RISKn	=	Risk result for the nth model run
WELLREACH	=	0 if plume is intercepted by a surface water body, 1 otherwise
EDn	=	Exposure duration for the nth model run
n	=	Iteration number
N	=	Number of iterations

The results are presented in **Exhibit 5A-3** below. For each, the results are presented for both adults and children under each of the WMU/liner scenarios. For full distributions of individual risks before averaging, see **Appendix K6 –** Distributions.

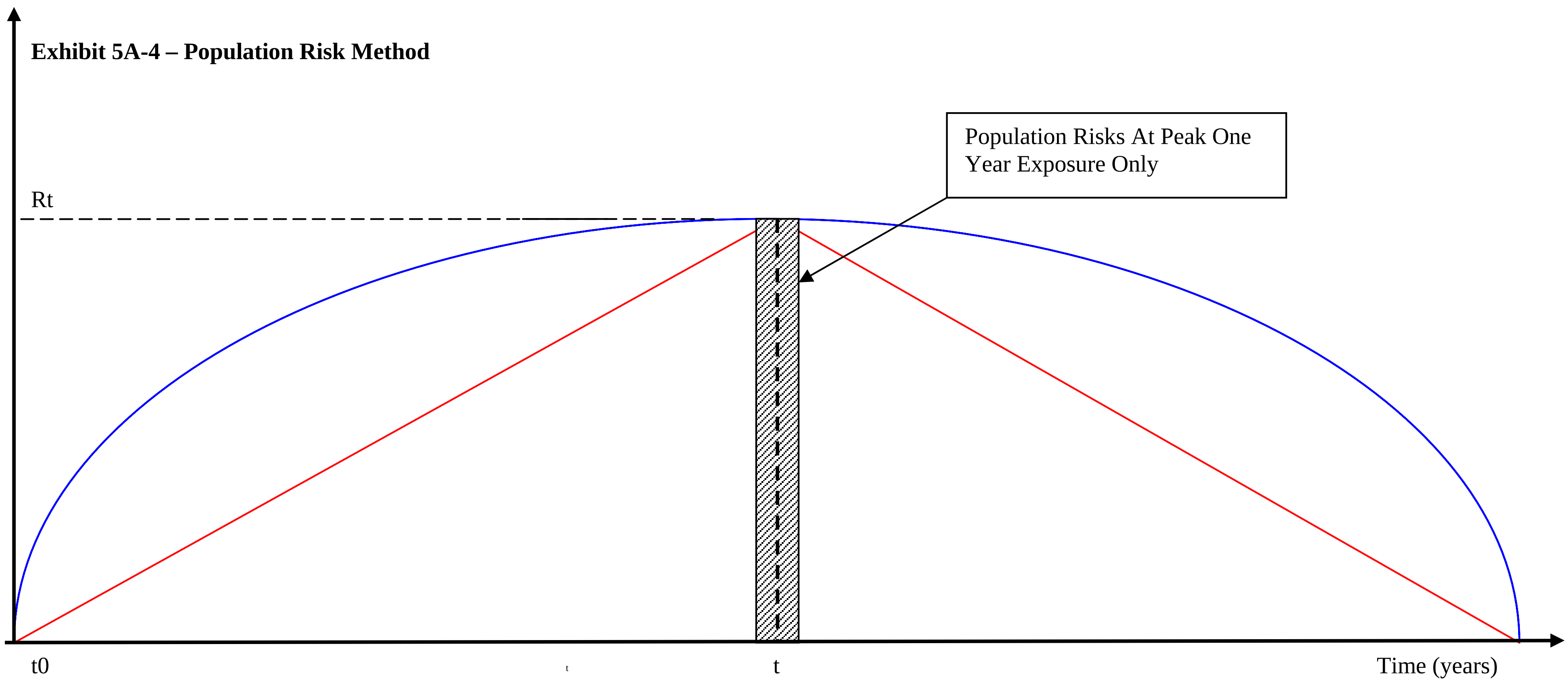
Exhibit 5A-3
Peak One Year Risks For CCR Cancer

	Conventional CCR		CCR Co-managed With Coal Refuse	
Liner - Receptor	Landfills	Impoundments	Landfills	Impoundments
Unlined - Adult	6E-06	4E-05	5E-06	2E-04
Unlined - Child	1E-05	1E-04	1E-05	4E-04
Clay-Lined - Adult	3E-06	3E-05	2E-06	1E-04
Clay-Lined - Child	7E-06	6E-05	4E-06	2E-04

Step 4. Extrapolate Annual Cancer Risks from Peak Cancer Risks

The peak risks that were calculated occur well after cancers can first materialize. Thus, constraining the benefits to only the peak population risks significantly underestimates total cancers avoided. To compensate for this shortfall, this RIA formulated an approach illustrated in **Exhibit 5A-4** below. The blue parabolic curve for population risk is based on the well concentrations over time in the results. While EPA cannot reconstruct the exact curve due to data availability issues, a parabolic curve represents groundwater contamination. From this shape it is clear that the peak population risks only capture a fraction of total population risks. Using an assumption of linear increases to the peak and linear decreases from the peak, produced the simplified risk profile seen as a red line in **Exhibit 5A-4**.

Exhibit 5A-4 – Population Risk Method



t0 = WMU built

t = time to peak risk

Rt = peak population risk

= Actual Risk Profile
= Simplified Risk Profile

The constant slope allowed estimation of the population risks from each year's exposure by assembling the model iteration times to peak.[118] Dividing peak risks (y-value) by the time to peak (x-value), the slope of the time line was determined for each WMU/liner type as displayed in **Exhibit 5A-5** below.

Exhibit 5A-5
Human Cancer Time Slope Factors For CCR

	Slopes For Conventional CCR		Slopes For CCR Co-managed With Coal Refuse	
Liner - Receptor	Landfills	Impoundments	Landfills	Impoundments
Unlined - Adult	1E-08	6E-07	8E-09	3E-06
Unlined - Child	2E-08	1E-06	2E-08	6E-06
Clay-Lined - Adult	5E-09	4E-07	3E-09	1E-06
Clay-Lined - Child	1E-08	7E-07	6E-09	3E-06

Multiplying this slope by the number of years elapsed yields the yearly increment of individual risk for that year. Multiplying this average incremental individual risk by the population exposed in each year[119] EPA estimated the number of cancers in each year. While this under-estimates cancer incidence by the difference between the blue and red profiles it is the best estimate based on currently available data.

As displayed in **Exhibit 5A-6** below, this approach results in an estimate between 45 and 196 potential cancer cases over 75 years[120] as a result of arsenic consumed through contaminated groundwater using EPA's 1995 cancer slope factor (1.5 mg/kg/d^{-1}) for arsenic based on skin cancers. Using the ratios of conventional CCR co-managed with coal refuse a best estimate within this range is **145 cancers**.

[118] Since these iterations were performed in later model runs they could not be tied to the specific model iterations used above. 67% of the model runs had the nearest groundwater well occurring beyond the nearest surface waterbody. Since the longer arrival times occur with longer travel distances, and these iterations tended to be the iterations that were intercepted, assumed that the 33% of model runs that were not intercepted are also the 33% of model runs with the shortest arrival times (i.e., shortest distances). Taking the midpoint of these arrival times yielded the 16.5th percentile.
[119] This RIA inflated the future population each year based on the future projections made by the US Census Bureau. From that point on, this RIA assumed a constant annual growth rate equal to the growth rate in year 2050.
[120] Seventy-five years were used for the analysis based on the 78 year time to peak period, less two years states are allowed to adopt the rule's provisions, and less an additional year for installing groundwater monitoring. Seventy-eight years are the time at which the risks for typical unlined and clay-lined surface impoundments that are not intercepted by surface water will peak. Cancers occurring after year 78, though potentially significant, are unlikely to play a significant role when monetized because under a 3% discount rate, benefits fall to ten percent of their value at year 78, and at a 7% discount rate, benefits fall to 0.5% of their value at year 78. These future cancers will be further reduced by state regulations, detection of contamination, and a general trend away from wet handling.

Exhibit 5A-6 Potential Future Human Cancer Cases from the Disposal of CCR Based on Arsenic Cancer-Slope Factor from EPA/IRIS						
	Disposal of Conventional CCR			Disposal of CCR Co-Managed with Coal Refuse		
WMU	Adult	Child	Totals	Adult	Child	Totals
Unlined Landfills	0.1	0.1	0.2	0.1	0.1	0.2
Clay-Lined Landfills	0.1	0.1	0.2	0.0	0.0	0.0
Unlined Surface Impoundments	20.1	16.3	36.4	98.1	67.6	166.7
Clay-Lined Surface Impoundments	4.8	3.5	8.3	17.6	12.6	309.2
Totals	25.1	20.0	**45**	115.8	80.3	**196**

Step 5. Estimate Arsenic Cancer Risks Using Recent NRC Science for Arsenic

Based on the NRC data source, lifetime exposure to 10 ug/L arsenic in drinking water would lead to 23 excess male bladder cancers and 14 excess male lung cancers per 10,000 people. Under the exposure factor assumptions used by the NRC the equivalent cancer slope factor (CSF) is 26 mg/kg/d^{-1}. For details of how this cancer slope factor was calculated, see **Appendix K4** – Cancer Calculations.[121] **Exhibit 5A-7** below displays the population risk estimates for CCR disposal base on the NRC source.[122] Using the NRC (2001) cancer slope factor one would expect between approximately 778 and 3,392 cancer cases over 75 years as a result of arsenic consumed through contaminated groundwater. Using the ratios of conventional CCR co-managed with coal refuse produces a best estimate within this range of **2,509 cancers**.

Exhibit 5A-7 Potential Future Human Cancer Cases from CCR Disposal Based on Arsenic Cancer-Slope Factor from NRC						
	Disposal of Conventional CCR			Disposal of CCR Co-Managed with Coal Refuse		
WMU	Adult	Child	Totals	Adult	Child	Totals
Unlined Landfills	2	2	4	1	1	2
Clay-Lined Landfills	1	1	2	1	1	2
Unlined Surface Impoundments	348	281	629	1,696	1,169	2,865
Clay-Lined Surface Impoundments	82	61	144	305	218	523
Totals	433	345	**778**	2,003	1,389	**3,392**

[121] EPA is currently in the process of revising the arsenic cancer slope factor in EPA's Integrated Risk Information System (IRIS).
[122] EPA also conducted a sensitivity analysis assuming the female cancer slope factor in **Appendix K5** of this RIA.

Step 6. Monetize Future Avoided Cancer Risk Benefits

Reflecting the best science available, EPA used a point estimate of cancer cases avoided to monetize cancer risks. **Appendix K4** provides further explanation as to why the NRC science is considered more appropriate than the older skin cancer research that the current IRIS value was derived from. Because EPA has greater confidence in the NRC estimates, it chose to use the 2,509 cancers calculated above as the best estimate. EPA also used the NRC ratio of 23 male bladder cancers to 14 male lung cancers to estimate how many of each type were likely to occur in each year. That is, 62%, or 1,556 cancers, are assumed to be bladder cancers and 38% or 953 are assumed to be lung cancers. **Appendix K7** shows the best estimate number of lung and bladder cancers in each year that was used in the remaining portions of this analysis.

Since cancers are not all fatal, the next step was to estimate the number of cancers that are fatal and non-fatal. This was done separately for each type of cancer using 5-year survival rates from the EPA-ORCR 2009 CCR risk report. The 5-year survival rate used for bladder cancer is 82% and the 5-year survival rate used for lung cancer is 14%. Thus, 1,276 (82%) of bladder cancers are non-fatal and 280 (18%) are fatal. For lung cancer, 133 (14%) are non-fatal and 820 (86%) are fatal. Again, these cancers are spread over the 75 years of the analysis. In order to monetize avoided cancer risks, this RIA applied the value of a statistical life (VSL) plus the cost of terminal cancer treatments displayed in **Exhibit 5A-8** below. To monetize avoided non-fatal cancer risks, this RIA used an estimate from Magat et al. (1996).[123] This study shows that a typical individual's assessment of a non-fatal lymphoma risk reduction was the equivalent of 58.3% of a fatal lymphoma risk reduction.[124] Therefore, this RIA assumed individuals value non-fatal bladder and lung cancer risk reduction in a similar manner.

Exhibit 5A-8
Unitized Monetary Values for Human Cancer Risks Applied in this RIA

Monetized Value	2008$
Fatal cancers: value of statistical life (VSL)*	$8,800,000
Non-fatal cancers: 58.3% of VSL*	$5,130,400
Medical costs associated with fatal bladder cancer**	$149,863
Medical costs associated with fatal lung cancer**	$87,703

Notes:
*Median VSL of $4.65 million (1997$) from Exhibit 7-3 (page 89) of EPA "Guidelines for Preparing Economic Analyses," EPA 240-R-00-003, Sept 2000; converted for this RIA to 2008 dollars using the Consumer Price Index. In addition, projections of benefits in future years are subject to income elasticity adjustments. These represent changes in valuation in relation to changes in real income. For example, if, for every 1% increase in real income, a particular consumer's willingness-to-pay for a particular item increases by 1%, this would be represented by an income elasticity of 1.0. For most items, income elasticity values are actually less than 1, indicating that valuation of most items does not increase as fast as real income levels. To do so, applied the change in Gross Domestic Product per-capita between the original dollar year of the estimates and 2008, and an income elasticity of 0.5 based on estimates from Viscusi, W. K. and Aldy, J. E. "The Value of a Statistical Life: A Critical Review of Market Estimates throughout the World," Journal of Risk and Uncertainty, Vol.27, 2003, pp. 15–76.
** These costs reflect the inpatient hospital stays, skilled nursing facility stays, home health agency charges, physicians' services, and outpatient and other medical services - in other words the treatment and maintenance costs. Costs are assumed to occur during initial

[123] Magat, Wesley A., V. Kip Viscusi and Joel Huber "A Reference Lottery Metric for Valuing Health," Management Science, Vol.42, Issue 8, 1996, pp.1118 - 1130.
[124] EPA acknowledges that alternative approaches to valuing non-fatal cancers are available. One such alternative is presented in **Appendix K5** of this RIA.

Exhibit 5A-8 Unitized Monetary Values for Human Cancer Risks Applied in this RIA
treatment, maintenance care between initial and terminal treatment and terminal treatment during the final six months prior to death: • Bladder cancer costs are based on survival and death rates each year for 20 years which captures most deaths from bladder cancer among those who are diagnosed with the disease. • Lung cancer costs are based on a 10 year time horizon during which most deaths are assumed to occur. The original figures in the 2001 EPA report are in 1996 dollars (source: EPA "The Cost of Illness Handbook," Office of Pollution Prevention & Toxics, October 2001). These costs are updated for this RIA to 2008 dollars using the Medical Care Component of the Consumer Price Index.

These values are further adjusted for cessation lag and income as described in **Appendix K8**. EPA used the cessation data of bladder cancers from arsenic in Chen and Gibb (2003)[125] to construct a Weibull curve approximating the lag time between reduced arsenic exposure and reduced cancer outcomes. Because this lag will reduce willingness to pay compared to an immediate risk reduction, the value of reduced statistical cancers are 83% and 67% of what they would be using an unadjusted VSL (at a 3% and 7% discount rate, respectively.) This is described in more detail in **Appendix K8**. For income, EPA projected per capita GDP, and used this combined with an income elasticity of 0.5 income elasticity of 0.5 from Viscusi and Aldy (2003) to estimate the growth in VSL until the exposure year. There has been economic debate over whether VSL should be adjusted to the year of exposure or the year of the cancer. However, typically, it is not possible to know when the exposure occurred. Because of the model used here, this RIA applied the VSL adjustment at the time of exposure. The full table of VSL adjustment factors, as well as their derivation, is presented in more detail in **Appendix K8**.

Applying these nominal dollar values to the number of fatal and non-fatal bladder and lung cancers in each year, a current year value for avoiding cancer risk was calculated for each of the 75 years. These values can be seen in **Appendix K7**. The present value (PV) of these values is approximately $4,696 million at a 3% discount rate and $885 million at a 7% discount rate. This would reflect the value of avoiding future cancer risks assuming that no steps were taken to prevent contamination and the resulting cancers. However, as discussed below, this is not realistic under baseline state regulatory controls.

Step 7. Account for Groundwater Remediation under the Baseline and Regulatory Options

The results above assume that arsenic is released from existing impoundments and landfills, without any controls (beyond the liners taken into account in the model). The benefits of regulatory options would be reflected by lower rates of cancer, resulting from the rule's controls (including ground-water monitoring, permitting, corrective action, phase-out of surface impoundments, financial assurance, etc.).[126] The rule will also have the benefits of reducing or eliminating groundwater remediation cost, because groundwater releases are eliminated through

[125] Source: Chen, C.W. & Gibb, H. "Procedures for Calculating Cessation Lag." Regulatory Toxicology and Pharmacology," Vol.38, Issue 2, 2003, pp.:157-65.

[126] The two Subtitle D Options evaluated were: (1) Subtitle D — regulation of landfills and surface impoundments, with liners required for existing and new surface impoundments, and new landfills and (2) Subtitle "D Prime" — regulation of landfills and surface impoundments, with liners required only for new surface impoundments and landfills.

controls like surface-impoundment phase-out, or reduced because releases are caught earlier. These benefits, and how they relate, are described in the section below.

First, even in the absence of federal regulations, CCR disposal units will not leach and cause cancers in all cases estimated through the evaluation above. Even without federal regulation, there will be facilities that discover contamination and clean the contamination up before cancers occur, either due to state regulations or good practice. Where exposures are identified, this RIA assumed that the pathway will be cut off (e.g., through provision of alternative water sources). Even facilities that fail to prevent contamination may detect that contamination and clean it up at a later time, although after exposure has occurred. This Step of the estimation attempted to account for these practices.

To estimate the different speed and cost of groundwater remediation likely under the baseline and under the three regulatory scenarios (i.e., Subtitle C, Subtitle D and Subtitle D Prime), this RIA began by examining the differences across states in groundwater monitoring requirements pertaining to CCR disposal units, and focused on groundwater monitoring requirements because adequate monitoring is needed to determine whether a release has occurred. This RIA assumes that, where releases of concern have been identified, and particularly where people may be at risk, drinking water pathways will be cut off and alternative drinking water will be provided. Then calculated the percentage of CCR disposed by each state, and noted which of three levels of groundwater monitoring were required:

1. No monitoring requirements
2. Monitoring requirements for only future newly constructed CCR disposal units
3. Monitoring requirements for both future new and existing CCR disposal units

Then EPA tracked the percentage of total waste that was discarded by facilities in states requiring each of these three monitoring scenarios. **Exhibit 5A-9** below presents these percentages for states requiring at least some monitoring (categories 2 and 3 above) and states requiring monitoring at exiting facilities (category 3 above). The first value in the table, 91%, is the percentage of CCR discarded in landfills that impose some form of monitoring requirements, whether for new landfills only, or for both new and existing landfills. 62% is the percent of CCR discarded in landfills that impose monitoring requirements on both new and existing CCR disposal units (a subset of the 91%).[127] Percentages are also provided for CCR that are managed in surface impoundments. **Appendix K9** provides these data for each individual state.

[127] Some states may require monitoring only for off-site units; however, in the absence of a specific breakdown, EPA made the assumption that on-site units would be monitored in all states that require monitoring.

Exhibit 5A-9 State Government Groundwater Monitoring Requirements Assumed in this RIA				
	Landfills		Surface Impoundments	
	Any Monitoring Requirements (categories 2&3)	Required at New and Existing Units (category 3)	Any Monitoring Requirements (categories 2&3)	Required at New and Existing Units (category 3)
Percent of Facilities	91%	62%	48%	12%

These percentages helped to determine when releases will be identified, and the likely cost of cleanups or other remedies, when releases are identified, under the baseline and three regulatory scenarios. Since all but 4 of the 2,509 cancers projected above result from surface impoundments, only surface impoundment monitoring data were used in the calculations.[128] For the baseline scenario, it was assumed that states with the highest level of monitoring requirements (those requiring groundwater monitoring at both new and existing units) would generally find groundwater contamination relatively early and would require preventive measures that would avoid cancers (e.g., intercept the plume and/or put residents on municipal or bottled water). Thus, 12% of contamination that could occur would have already been detected, and the resulting cancers prevented. To the extent that cleanups and/or alternative water are required, that was considered part of the baseline.

To model the Subtitle D option, EPA assumed that states with groundwater monitoring requirements at new units, or with some coverage of the units in question, would upgrade their existing programs to provide fuller coverage – because they already have a regulatory infrastructure – but other states with no program would not. While states that do not currently regulate units would not change their practices simply because EPA issued national rules, EPA recognizes that facilities in these latter states will to a certain extent comply, to avoid citizens' suits. However, EPA's and states' experience in implementing the RCRA program demonstrates that self-implementing ground-water monitoring programs are of limited reliability. Given these factors, the percentage of waste disposed of in states with some level of groundwater monitoring programs is a reasonable estimate of benefits for the subtitle D approach. Under these assumptions, contamination in states with monitoring requirements for only new units, as well as contamination in states with monitoring requirements for new and existing units would be detected promptly. This leads to 48% of surface impoundment groundwater contamination being detected before extensive damage has occurred, and therefore 48% of cancers being prevented.

Since the Subtitle "D Prime" option does not require the retrofitting of existing units, unlined surface impoundments would remain a continuing source of release. However, the presence of a new national rule accompanied by EPA support would lead at least some states to make such updates. Since the potential risks will fall somewhere between the Subtitle D option and the baseline, the midpoint between baseline and the Subtitle D option (30%) was chosen as a best estimate. This leads to 30% of contamination being immediately detected, and thus 30% of cancers being prevented.

[128] Note, however, that considerable evidence indicates that releases from dry disposal can present significant risk as well, as demonstrated by EPA research on CCR leach rates at different pHs and the damage cases.

Finally, for Subtitle C, there would be federal oversight of the groundwater monitoring requirement, and therefore this RIA assumes 100% of facilities would have contamination detected early. Looking forward, this would effectively prevent all cancers.[129] In addition, the technical standards of the subtitle C rule would largely prevent future releases because surface impoundments would be phased-out, and because new landfills would require composite liners. Similarly, closure requirements would largely prevent releases after closure of both types of units.

Where releases of arsenic from disposal units occur in the future, they will be detected promptly after they occur under the proposed option, as well as under the other options where good monitoring programs are in place. In these cases, there may be response costs, but no cancer risks. On the other hand, if facilities do not have adequate detection systems in place (and other adequate controls, e.g., liners, adequate closure, etc.), then detection will be delayed. This RIA assumes that releases will eventually be discovered, but that detection may be on a delayed basis. To quantify this assumed that contamination would be discovered consistently until it was all discovered. Since the rate of discovery is unpredictable, further assumed detection would be at a constant rate, reaching 100% detection by the final year of the analysis.[130] These discoveries were assumed not to start for six years because the first percentile of time duration until peak risks for unlined surface impoundments occurred. Restated, this profile assumes that facilities in states that require groundwater monitoring for existing units would generally find contamination in the future soon after it occurred, reducing response costs, and preventing cancer risks. But where monitoring and other controls were not adequate, releases would potentially go undetected for lengthy periods, causing cancers until the contamination was eventually detected and those residents switched to municipal or bottled drinking water. In addition, response costs would be significantly increased. The present value of avoiding all of the risks in the baseline case is the upper-bound on benefits, and this upper bound is reduced by detection and groundwater remediation as described in this section. The risk reduction benefit for each regulatory option is the difference between baseline risks and remaining risks under that option. These benefits, accounting for the detection and remediation, are presented in **Exhibit 5A-10** below. Baseline expected cancer risks are accounting for detection and remediation, compared to without taking these factor into account. Further discussion of the cancer profile can be found in **Appendix K7**.

This RIA projects a trend towards decreased management of CCR in surface impoundments. Facilities with surface impoundments have been slowly moving from wet handling in impoundments to dry handling in landfills or to beneficial uses. While this trend could affect the profile discussed above, it is unlikely to have a significant effect on risks for two reasons. First, surface impoundments, to the extent they are closed, are typically closed with waste in place. Thus, they are likely to continue to leach beyond the 75-year period modeled in the 2009 risk assessment; this is particularly true in situations where they are not lined (which are overwhelmingly the case) and where they are located in states without strong regulation. In the latter case, closures are likely to be inadequate, leading to continued infiltration. Second, the releases that occurred before the surface impoundments are closed will continue to migrate until they reach the groundwater wells or until they are intercepted by a surface waterbody (again particularly in states without strong programs). Given the relatively very large size of the CCR impoundments, and the presence of a hydraulic head at least before closure, these historic releases have the potential to be significant. Given these considerations, the closure of surface impoundments in states without regulations (e.g., corrective action, groundwater monitoring, etc.) would behave very similarly to active surface impoundments in terms of their risks to human health and the environment. For this reason, the regulatory oversight in the options above was not modified for closed CCR disposal units.

[129] Cancers from historic releases would not be affected, but the releases would be promptly identified and future exposures avoided.
[130] Some releases are likely to go entirely undetected in the absence of groundwater monitoring and other controls. However, to put a reasonable limit around the analysis, this RIA assumed 100% detection.

Exhibit 5A-10 **Present Value of Avoided Human Cancer Risks Associated with CCR Disposal** ($millions present value over 50-years)			
Discount rate	Subtitle C	Subtitle D	Subtitle D'
@ 3%	$1,825	$750	$375
@ 7%	$504	$207	$104

The other major cost associated with groundwater contamination is that of remediation or other response. To estimate that cost, EPA began by estimating the number of coal-fired electric utility plants that would require responses under various state environmental programs, based on the 2009 risk assessment. In any particular situation, a state could require remediation of a site involving potential drinking water to 10^{-4}, 10^{-5}, or 10^{-6} levels. In addition, states may choose to require groundwater remediation for groundwater that is not a likely drinking water source, because of ecological concerns. **Exhibit 5A-11** below shows the number of facilities potentially requiring cleanup. Since each estimate is equally acceptable under current state programs, the average is believed to be a best estimate for how many electric utility plants will ultimately need groundwater remediation so as not to overestimate the number of remediation events.

Exhibit 5A-11
Proportion of CCR Sites Requiring Remediation Based on State Cleanup Levels

State Cleanup Levels	Clean All Groundwater			Clean Only Drinkable Groundwater			Average
	10^{-4}	10^{-5}	10^{-6}	10^{-4}	10^{-5}	10^{-6}	
Total LF	22	50	72	7	16	24	32
Total SI	93	132	150	31	44	50	83

These plant counts are based on the probabilistic model iterations from the 2009 risk assessment which were used to estimate what fraction of sites would leach at above various clean up levels. Typically, solid waste cleanups can be conducted at either 10^{-4}, 10^{-5}, or 10^{-6} individual cancer risk levels. **Exhibit 5A-12** uses the PERCENTRANK function in Excel to estimate what percent of risk results fall at or below each clean up level. For example, in the first cell of **Exhibit 5A-12**, the 78% means that 10^{-4} is higher than 78% of the probabilistic results for unlined landfills with conventional ash.

UL = Unlined
CL = Clay-Lined
A = Conventionally Managed Ash
C = Co-managed Ash
LF = Landfill
SI = Surface Impoundment

Exhibit 5A-12 Percentile of Cleanup Levels in the EPA-ORCR 2009 CCR Risk Study								
Clean Up Level	UL A LF	CL A LF	UL C LF	CL C LF	UL A SI	CL A SI	UL C SI	CL C SI
1.00E-04	78%	83%	74%	85%	46%	59%	30%	43%
1.00E-05	55%	59%	42%	57%	15%	24%	12%	21%
1.00E-06	36%	35%	18%	28%	5%	7%	3%	8%

Model results equal to or above these percentiles would require a state or federal cleanup. In other words, the percentage of sites above the cleanup level displayed in **Exhibit 5A-13** can be derived by subtracting the percents in **Exhibit 5A-12** above from 100%. However, while states may require remediation of all groundwater, whether or not it is potable, they may also choose not to on a site by site basis. As discussed in the EPA-ORCR 2009 CCR risk report, it is estimated that two-thirds of sites are located closer to a surface waterbody than to the nearest groundwater well. Therefore, sites located on surface waterbodies may not be cleaned in some states. This 2/3 decrease is accounted for in the second set of values in **Exhibit 5A-13**.

Exhibit 5A-13 Percent of Electric Utility Plants Requiring Future Groundwater Remediation								
Clean Up Level	UL A LF	CL A LF	UL C LF	CL C LF	UL A SI	CL A SI	UL C SI	CL C SI
Assuming All Groundwater is Remediated								
1.00E-04	22%	17%	26%	15%	54%	41%	70%	58%
1.00E-05	45%	41%	58%	43%	85%	76%	89%	79%
1.00E-06	65%	65%	82%	72%	96%	93%	97%	93%
Assuming Only Potable Groundwater is Remediated								
1.00E-04	7%	6%	8%	5%	18%	13%	23%	19%
1.00E-05	15%	14%	19%	14%	28%	25%	29%	26%
1.00E-06	21%	21%	27%	24%	32%	31%	32%	31%

The number of utility plants with each type of CCR disposal, liner type, and management combination was calculated by taking the **Appendix F** plant data from this RIA and combining it with the conventional versus co-managed rates.

Exhibit 5A-14 Estimated Number of Electric Utility Plants by CCR Disposal Unit Type							
UL A LF	CL A LF	UL C LF	CL C LF	UL A SI	CL A SI	UL C SI	CL C SI
50	21	26	7	31	28	68	31

Multiplying the number of facilities in each category from **Exhibit 5A-14** above by the percent of facilities requiring remediation in **Exhibit 5A-13** above yields the estimated number of facilities that would lead to state or federal clean ups in **Exhibit 5A-15** below. These estimates of the number of facilities requiring cleanup does not account for any cleanups resulting from other constituents exceeding a hazard quotient of 1. Thus, this estimate may under-estimate the total number of cleanups.

Exhibit 5A-15 Number of Electric Utility Plants Requiring Future Groundwater Remediation								
Clean Up Level	UL A LF	CL A LF	UL C LF	CL C LF	UL A SI	CL A SI	UL C SI	CL C SI
Assuming All Groundwater Is Remediated								
1.00E-04	11	4	7	1	17	11	47	18
1.00E-05	23	9	15	3	26	21	60	24
1.00E-06	32	14	21	5	30	26	66	29
Assuming Only Potable Groundwater Is Remediated								
1.00E-04	4	1	2	0	6	4	16	6
1.00E-05	7	3	5	1	9	7	20	8
1.00E-06	11	5	7	2	10	9	22	9

With the number of units requiring remediation, EPA estimated the cost of groundwater remediation under the baseline and each regulatory option presented above. Groundwater remediation costs were estimated in two steps. First, EPA assumed contamination that might occur at sites in states with more stringent monitoring requirements, would be discovered promptly. This suggests that there is likely to be less remediation required than at the typical site. Thus, EPA assigned these sites the 25th percentile remediation costs displayed in **Exhibit 5A-16** below as the midpoint of the bottom half of costs. These future remediation events were spread evenly across all 75 years of the analysis.

Exhibit 5A-16 Per-Site Groundwater Contamination Remediation Costs*		
Cost element category	25th percentile "early costs"	75th percentile "later costs"
Capital Costs	$6,075,900	$21,195,000
Annual O&M	$98,910	$1,413,000
O&M at 3% discount rate**	$1,978,242	$28,260,605
O&M at 7% discount rate**	$1,239,522	$17,707,453
Total cost at 3%	$8,054,142	$49,455,605
Total cost at 7%	$7,315,422	$38,902,453

Notes:
*Cost data from Exhibits 3 and 4 in EPA "Cost Analyses for Selected Groundwater Cleanup Projects: Pump and Treat Systems and Permeable Reactive Barriers," Office of Solid Waste & Emergency Response, EPA-542-R-00-013. February 2001 at: http://www.epa.gov/tio/download/remed/542r00013.pdf
**O&M costs were capitalized over 30 years at both a 3% and 7% discount rate for use in the two estimates. This was done to simplify spreadsheet calculations.

For the remaining sites expected to require remediation, but lacking groundwater monitoring requirements, EPA assumed discovery of contamination would take longer. That is, CCR contamination would have migrated for some number of years, resulting in a larger groundwater plume to remediate, or more extensive remediation. EPA assigned these sites the 75th percentile remediation costs as the midpoint of the top half of costs. Since the first percentile time to peak results for unlined surface impoundments is six years, it is assumed that no discoveries and cleanups will be made in the first six years for these sites (three years once the two years for state adoption and one year for groundwater monitoring are considered). The costs are thus spread evenly over the remaining 72 years. The present value of these remediations, accounting for the slow, but continued discovery of contaminated sites, is presented in **Exhibit 5A-17** below. Further discussion of the discounted remediation costs for each year is presented in **Appendix K10**.

Exhibit 5A-17 Present Value of Future Groundwater Remediation Costs from CCR Contamination ($ millions present value over 50-years)				
Discount Rate	Subtitle C	Subtitle D	Subtitle D'	Baseline
@ 3%	$96	$1,016	$1,302	$1,587
@ 7%	$39	$336	$420	$504

Aggregate benefits from cancer risk reductions and avoided remediation costs are summarized in **Exhibit 5A-18** below. These benefits are calculated by subtracting the costs resulting under that option from the costs resulting under the baseline (i.e., cost avoided).

Exhibit 5A-18
Present Value of Future Avoided Human Cancer Risks
& Avoided Groundwater Remediation Cost Benefits
($millions present value over 50-years)

	Subtitle C	Subtitle D	Subtitle D'
@ 3% discount			
Groundwater Remediation Costs Avoided*	$1,491	$571	$286
Human Cancer Risks Avoided	$1,825	$750	$375
Total	$3,316	$1,321	$661
@ 7% discount			
Groundwater Remediation Costs Avoided*	$466	$168	$84
Human Cancer Risks Avoided	$504	$207	$104
Total	$970	$375	$188

Note:
* Calculated by subtracting the present value future groundwater remediation cost estimated in **Exhibit 5A-17** for each regulatory option, from the estimated baseline present value in that same Exhibit.

Step 8. Characterize Cancer Risk Estimation Uncertainties

There are a number of uncertainties associated with the annualized cancer estimates calculated in this RIA which are likely to under-estimate groundwater protection benefits:

- Estimates do not account for historic releases at operating plants. These releases could lead to further migration and future cancer risks without proper regulatory actions like groundwater monitoring.
- A linear slope for individual cancer risk was used to approximate the increase in cancer risks instead of the parabolic curve.
- Approximately 18% of plants dispose of CCR off-site only. Since these facilities were not accounted for, additional populations would be exposed to arsenic cancer risks from disposal as recently illustrated by the Gambrills, MD and Chesapeake, VA damage cases.
- Three new research studies[131] (2006, 2008, 2009) from EPA's Office of Research and Development, indicates that landfills may leach toxic metals much faster than originally believed. The damage cases at Gambrills MD and Chesapeake VA resulted in groundwater contamination much more quickly than would be expected, and are therefore consistent with this research.

[131] The three new EPA studies are:
1. "Characterization of Mercury-Enriched Coal Combustion Residues from Electric Utilities Using Enhanced Sorbents for Mercury Control," EPA 600/R-06/008. Office of Research and Development. Research Triangle Park, NC. January 2006.

- Multiple CCR disposal units at a single electric utility plant will all affect the same population. The risk estimates do not account for any additive risks from multiple units. However, the populations around these units are accounted for as described in **Appendix K2**.
- Multiple landfills could exist at some facilities. While the area of multiple surface impoundments was considered, the area of multiple landfills was not considered because EPA did not have survey results for dry handling even though some facilities are known to have more than one CCR landfill onsite.
- Residents on municipal water systems were not included in the 2009 risk assessment or in this analysis. However, exposure through this pathway is possible, which means this RIA likely under-estimated the human population that may be exposed to CCR.
- Populations that are farther than 1-mile that may be within the plume were not included.
- Some surface water bodies that this analysis assumes fully intercept the groundwater plume may in fact only partially intercept the plume, or not intercept it at all. This situation would be more likely to occur when surface water bodies are small or shallow with low flow rates, relative to the size of the aquifer underneath the CCR disposal unit, or are oriented such that they would not likely intercept the groundwater plume.
- Potential cancer cases resulting from consumption of recreationally-caught fish (contaminated by direct surface impoundment discharges and leaching from groundwater to surface water) are not included in the calculations.
- According to the EPA-ORCR 2009 CCR risk study, cancers can continue well after the analysis ends, but these cancers were not calculated in the population risk estimates.
- The use of a 5-year survival rate does not take into account those who may die from the cancer after year 5. Since some of the projected 5-year cancer survivors would have died in later years, they are undervalued in this assessment.
- The estimated number of cleanups is based only on modeled arsenic contamination. It does not account for cleanups based on hazard quotients over 1 for toxic constituents with non-cancer endpoints.

The following are some uncertainties that are likely to cause over-estimation of groundwater protection benefits:

- Cancer risk estimates might include some individuals who are down-gradient, but are outside the plume.
- All arsenic was assumed to be present in the arsenic III state. **Appendix K5** contains an analysis in which all arsenic was assumed to be speciated in the arsenic V state, and EPA concluded that even if some portion of arsenic was speciated in the arsenic V state, the final results would not significantly change.
- The male CSF estimate from NRC (2001) was used instead of the female CSF. **Appendix K5** contains an analysis in which this female CSF was applied.
- It is possible that some states would choose not to remediate CCR contamination above cleanup levels once local residents were placed on municipal or bottled water.

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2. "Characterization of Coal Combustion Residues from Electric Utilities Using Wet Scrubbers for Multi-Pollutant Control," EPA/600/R-08/077. Office of Research and Development, Air Pollution Control Division. Research Triangle Park, NC. July 2008.
3. "Characterization of Coal Combustion Residues from Electric Utilities – Leaching and Characterization Data," EPA-600/R-09/151. Office of Research and Development, Air Pollution Control Division. Research Triangle Park, NC. December 2009.

- Willingness to pay estimates for non-fatal cancers has been assigned lower values in some research. An alternative valuation for these cancers is presented in **Appendix K5**.
- Medical treatment costs for those dying of cancer would not occur until the cancer was first discovered.

The following are some uncertainties that have an unknown effect on the benefits:

- This RIA assumed an evenly distributed population for establishing up-gradient and down-gradient populations, as well as for adjusting population for the WMU area.
- The latitude and longitude data of the WMU are uncertain.
- State programs serve as a proxy for units managed well and units managed poorly. However, there could be some WMUs managed well in states without any program. Conversely, there could be some WMUs managed poorly in states with an existing program.
- State regulatory programs affecting CCR disposal may be different than summarized in **Appendix E** of this RIA.
- Remediation costs are very site-specific, and the 25th and 75th percentile costs used here may overestimate or underestimate the true remediation costs of any particular cleanup. For example, the cost of responses to new releases caught early will sometimes be below the estimated costs. In other cases, even if contamination is identified early, those costs can exceed the 75th percentile estimates above. Responses at Gambrills MD and Chesapeake VA, two sites where CCR contamination was identified relatively early, are examples of sites where actual groundwater remediation responses will far exceed the cost estimates.
- This RIA assumed that discovery of CCR groundwater contamination and the resulting remediation costs would be incurred evenly over the 75 year period for regulated facilities and evenly over the 72 years for unregulated facilities. However, experience under the municipal solid waste program indicates that the incorporation of lined units could reduce contamination over time.

5B. Benefit of Preventing Future CCR Impoundment Structural Failures (Avoided Cleanup Costs)

In December 2008, a failure of a CCR impoundment at the Tennessee Valley Authority (TVA) Kingston Fossil Fuel Plant TN resulted in the environmental release of 5.4 million cubic yards of CCR. This impoundment failure event illustrated the potential environmental damage severity of structural failures involving CCR impoundments. This section of the RIA estimates future avoided impoundment failure cleanup costs as a potential benefit of the CCR proposed rule, according to the following 5-step method.

Step 1. Characterize CCR Impoundment Release Data

EPA began by examining the CCR impoundment survey data collected in March and April 2009 by EPA under the authority of Section 104(e) of the Comprehensive Emergency Response, Compensation and Liability Act (CERCLA), from 162 individual electric utility plants and from 61 electric utility corporate headquarters offices. EPA obtained its list of facilities from a 2005 Department of Energy (DOE) Survey of coal burning electric utility facilities. EPA used DOE’s 2005 Energy Information Agency F767 database, which provides information on the disposition of coal ash from coal burning electricity producers. The database included "steam-electric plants with a generator nameplate rating of 10 or more megawatts." The term “generator,” means the actual electric generator, not the whole plant. A plant typically will have one or more generators. EPA also sent the letters to corporate offices of the electric utilities to make sure that all of their facilities were accounted for due to limitations in the DOE survey. Based on information received in response to the initial letter to the utility corporate headquarters offices, on April 27, 2009, EPA sent information request letters to an additional 48 plants that had been identified by the corporate offices.

Based EPA’s initial collation of the mail survey data, 42 CCR releases from impoundments were reported, all of which occurred within the last 15 years (1995-2009), in response to Question 8 of the survey questionnaire which asked for electric power plants to report all CCR impoundment releases which occurred within the last 10 years (i.e., 1999 to 2008). **Exhibit 5B-1** below presents a summary of these 42 CCR impoundments release cases. **Appendix K11** provides additional information about these 42 release cases.

Exhibit 5B-1

2009 EPA Mail Survey Data for 42 Historical Release Events Involving CCR Impoundments at Coal-Fired Electric Utility Plants

Item	Owner Company	Name of Coal-Fired Electric Plant	Name of CCR Impoundment	Capacity (acre feet)	Height (feet)	Year Installed	CCR Release (gallons)	Release year	Age at release
1	Allete Inc	Clay Boswell Power Station	Coal Pile Sump	1	20	1972	Unknown	2008	36
2	Ameren Energy Generating Co	Meredosia Power Station	Fly Ash Pond	650	24	1968	500	2006	38
3	American Electric Power	Cardinal Power Station	Fly Ash Reservoir 2	11350	237	1987	Unknown	2004	17
4	City of Springfield	Lakeside	Metal Cleaning Waste Basin		4	1982	Unknown	1998	16
5	City of Springfield	Lakeside	Metal Cleaning Waste Basin		4	1982	Unknown	2009	27
6	Dominion	Chesterfield Power Station	Lower (Old) Ash Pond	740	19	1964	Unknown	2005	41
7	Duke Energy Corp	Walter C. Beckjord Power Station	Ash Pond C	1400	50	1966	Unknown	1999	33
8	East Kentucky Power Coop Inc	Dale Power Station	Dale Ash Pond #4	112	26	1977	Unknown	2008	31
9	First Energy Generation Corp	Bruce Mansfield Power Station	Lakeside Ash Pond		20	1957	Unknown		
10	Georgia Power Co	Harllee Branch Power Station	C	1240	83	1971	Unknown	2000	29
11	Georgia Power Co	Bowen Power Station	Ash Pond	3719	45	1968	Unknown	2002	34
12	Georgia Power Co	Bowen Power Station	Ash Pond	3719	45	1968	Unknown	2008	40
13	Indianapolis Power & Light Co	Eagle Valley Generating Station	A/B/C Pond			1949	30,000,000	2007	58
14	Indianapolis Power & Light Co	Eagle Valley Generating Station	A/B/C Pond			1949	30,000,000	2008	59
15	Kansas City Power & Light Co	LaCygne Generating Station	Scrubber Sludge Ponds	6818	45	1971	Unknown	2007	36
16	Kansas City Power & Light Co	LaCygne Generating Station	Scrubber Sludge Ponds	6818	45	1971	Unknown	2007	36
17	Kansas City Power & Light Co	LaCygne Generating Station	Scrubber Sludge Ponds	6818	45	1971	Unknown	2009	38
18	MidAmerican Energy Co	Riverside Generating Station	South Surface Impoundment	109	10	1967	Unknown	2002	35
19	Northern Indiana Pub Serv Co	R. M. Schahfer Power Station	Little Blue Run Dam	84300	388	1975	Unknown		
20	Northern States Power Co	Sherburne County Power Station	Pond No. 2		57	1984	600	2007	23
21	PacifiCorp	Naughton Power Station	FGD Pond #2	382	25	1999	Unknown	2006	7
22	PacifiCorp	Naughton Power Station	North Ash Pond	2100	61	1973	11,100,000	2007	34
23	PacifiCorp	Dave Johnston Power Station	Blowdown Canal	1	0	1972	14,400	2009	37
24	PacifiCorp	Jim Bridger Power Station	FGD Pond #1	1340	32	1979	Unknown		
25	PacifiCorp	Jim Bridger Power Station	FGD Pond #2	11534	42	1990	Unknown		
26	PPL Generation, LLC	PPL Montour Power Station	Detention Basin	53	8	1968	Unknown	2004	36
27	PPL Generation, LLC	PPL Martins Creek Power Station	Ash Basin 4	40	43	1989	100,000,000	2005	16
28	PPL Generation, LLC	PPL Montour Power Station	Ash Basin No. 1		40	1968	Unknown	2007	39
29	PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 Stage Evaporation Ponds	4370	88	1992	100	1995	3
30	PPL Montana LLC	Colstrip Steam Electric Station	Units 3 & 4 Effluent Holding Pond	17000	138	1983	Unknown	1999	16
31	PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 Stage Evaporation Ponds	4370	88	1992	50	2000	8
32	PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 A Pond	245	25	1975	2,700	2003	28
33	PPL Montana LLC	Colstrip Steam Electric Station	Units 3 & 4 Effluent Holding Pond	17000	138	1983	Unknown	2004	21
34	PPL Montana LLC	Colstrip Steam Electric Station	Units 3 & 4 Effluent Holding Pond	17000	138	1983	Unknown	2005	22
35	PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 Stage Evaporation Ponds	4370	88	1992	2,000	2006	14
36	Progress Energy Carolinas Inc	W. H. Weatherspoon Power Station	1979 Pond		28	1979	Unknown	2001	22
37	Progress Energy Carolinas Inc	Roxboro Power Station	FGD Flush Pond		33	2008	Unknown	2008	0
38	Santee Cooper	Winyah Power Station	Unit 3 & 4 Slurry Pond	1190	30	1980	Unknown	2008	28
39	Tennessee Valley Authority	Kingston Power Station	Dredge Pond			1955	1,100,000,000	2008	53
40	Tennessee Valley Authority	Widows Creek Power Station	Gypsum Stack (Wet Stacking Area)	11157	75	1986	6,100,000	2009	23
41	Xcel Energy	PSCo Comanche Station	Polishing Pond (#4)	12	0	1972	3,000	2007	35
42	Xcel Energy	PSCo Valmont Station	West Ash Settling Pond	16	0	1964	5,050	2008	44
			Minimum =	1	0	1949	50	1995	0
			Maximum =	84,300	388	2008	1,100,000,000	2009	59
			Mean (average) =	6,874	59	1976	85,148,560	2005	29
			Median =	1,750	42	1974	5,050	2007	32
Column total (based on gallons released data for 15 of the 42 events) =							1.277 billion		

As displayed below in **Exhibit 5B-2**, EPA was able to collect cost data on three of the most significant and recent release cases (i.e., cases resulting in the most gallons released):

Exhibit 5B-2
Cleanup Costs for Three Recent Environmental Releases Involving CCR Impoundments

Item	Owner company name	Coal-fired electric utility Plant name & location	Impoundment release year	Release volume (gallons)	EPA-assigned cost for this RIA*
1	PPL Generation LLC	PPL Martins Creek Power Station PA ("Ash basin 4")	2005	100 million	$37 million
2	Tennessee Valley Authority (TVA)	Kingston TN ("Dredge cell dike")	2008	1.1 billion (5.4 million cubic yards)	$3.0 billion
3	Tennessee Valley Authority (TVA)	Widows Creek Power Station TN ("Gypsum stack")	2009	6.1 million	$9.2 million
			Column totals =	1.2061 billion	$3.0462 billion

* Data sources:

- Item 1: Page 29 of "Public Health Issues Surrounding Coal as an Energy Source," Brian Schwartz, MD, MS, Department of Environmental Health Sciences, February 2009 at http://www.jhsph.edu/bin/g/f/Coal_and_public_health_Mar_2009.pdf
- Item 2: $3.0 billion is EPA's initial "social cost" estimate assigned in this RIA to the December 2008 TVA Kingston TN impoundment release event. Social cost represents the opportunity costs incurred by society, not just the monetary costs for cleanup. OMB's 2003 "Circular A-4: Regulatory Analysis" (page 18) instructs Federal agencies to estimate "opportunity costs" for purpose of valuing benefits and costs in RIAs. This $3.0 billion social cost estimate is larger than TVA's $933 million to $1.2 billion cleanup cost estimate (i.e., TVA's estimate as of 03 Feb 2010), because EPA's social cost estimate consists of three other social cost elements in addition to TVA's cleanup cost estimate: (a) TVA cleanup cost, (b) response, oversight and ancillary costs associated with local, state, and other Federal agencies, (c) ecological damages, and (d) local (community) socio-economic damages. **Appendix Q** to this RIA provides EPA's documentation and calculation of these four cost elements, which total $3.0 billion in social cost. **Appendix Q** to this RIA also provides an alternative, lower estimate of social costs, based on different modeling assumptions for capturing such costs. This alternative analysis suggests that TVA's cleanup costs alone may be close to the social costs associated with the Kingston impoundment failure. EPA specifically requests comment on this social cost estimate, and will continue to develop this estimate for the final rule.
- Item 3: 25 January 2010 e-mail entitled "TVA Widow's Creek Clean Up Info" from Anda Ray, Sr. Vice President of TVA Environment & Technology and TVA Sustainablity Officer, to Jim Kohler, EPA-ORCR Environmental Engineer.

Given this limited data, this RIA attempted to quantify the likelihood and costs of future releases using a historical methodology. First, distinguished between three types of historical CCR impoundment structural failures (i.e., releases):

1. Catastrophic failures: Involving a billion gallons or more. These releases would have the potential to cause as much or more damage than occurred in December 2008 at TVA's Kingston TN plant.
2. Significant failures: Involving between a million and a billion gallons. These would be less than a complete failure, but still costly. TVA Widow's Creek (6,100,000 gallons) and PPL Martin's Creek (100,000,000 gallons) are the lowest and highest known releases in this category, respectively. As an approximation, EPA assumes their costs should also bracket the costs of other significant releases.[132] Thus, EPA estimates that the typical costs of a significant failure will be $23.1 million (the average of TVA Widow's Creek and PPL Martin's Creek).
3. Seepage failures: Involving releases below one million gallons. While these releases can still be significant and present risks to human health and the environment, this RIA does not include these in this analysis, which under-estimates total costs using this historical methodology. These smaller seeps are common to earthen dams and are not necessarily a problem unless the seepage volume is increasing or the seepage becomes cloudy - indicating the possible transport of CCR through the embankment.

Step 2. Fit a Distribution of Future Releases.

For the two categories consisting of catastrophic and significant releases, this RIA estimates not only the cleanup costs of these events, but also their frequency. Since relatively little data are available, this RIA applies a Poisson distribution. The Poisson distribution is used when rare discrete events, and not continuous functions, are being modeled. To be a Poisson process, the arrival of events must satisfy stationarity, non-multiplicity, and independence. Here, the events (releases) satisfy non-multiplicity because the probability of two or more events in a short period of time is very small. They also satisfy independence because releases occurring in one time period are independent of releases in any other time period. However, as these impoundments increase in age, it is quite likely that releases might increase over time, which would violate the stationarity requirement. This potential problem is dealt with in Step 4 below. For the present, it will be assumed that releases occur at a constant rate in the future. In general, a Poisson distribution can be represented by the equation:

$$\frac{(\lambda t)^k e^{-(\lambda t)}}{k!}$$

[132] This is a valid assumption if cleanup costs are closely correlated to tonnage released. Since cost modeling software typically requires an input of gallons released, the correlation is likely strong.

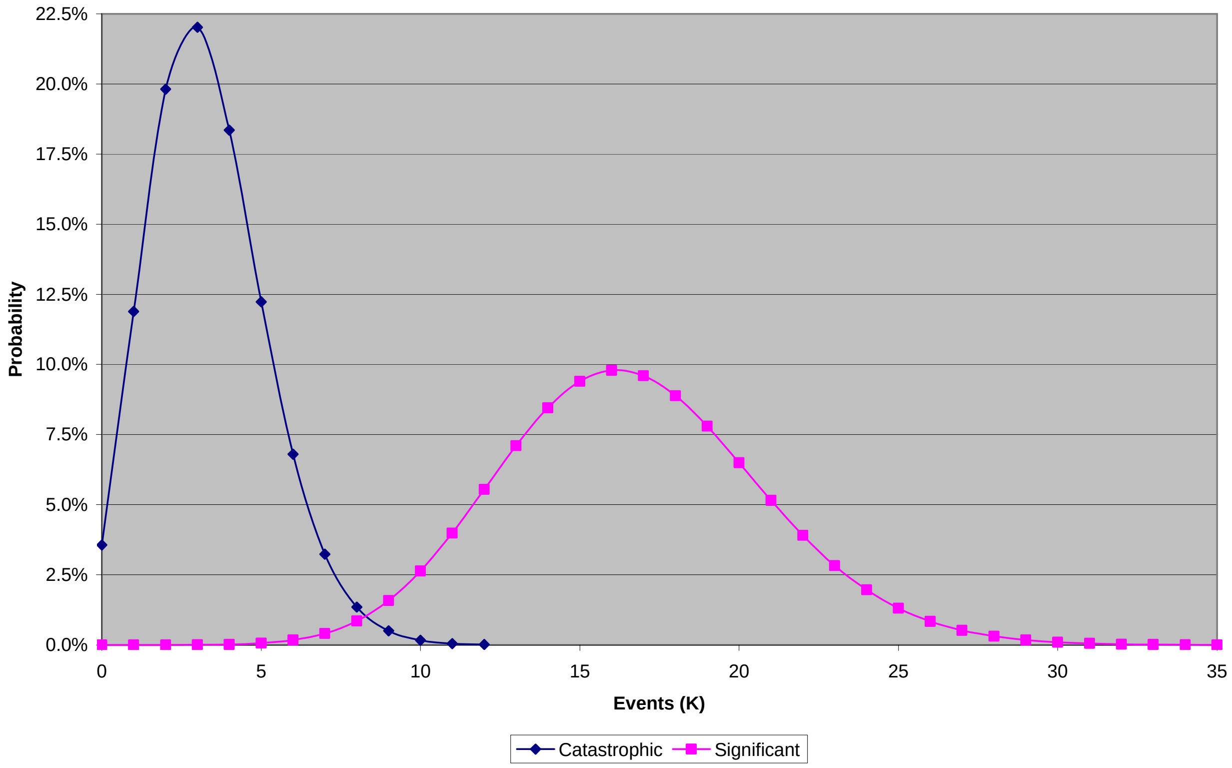
Where:

λ	=	Observed arrival rate (0.067 for catastrophic, 0.333 for significant);[133]
t	=	Time period being projected (50 years)
e	=	Constant (2.71828183)
k	=	Number of impoundment release events projected

The probabilities of a specific number of future CCR impoundment catastrophic or significant releases are illustrated in **Exhibit 5B-2** and **Exhibit 5B-3** (cumulative distribution) below.

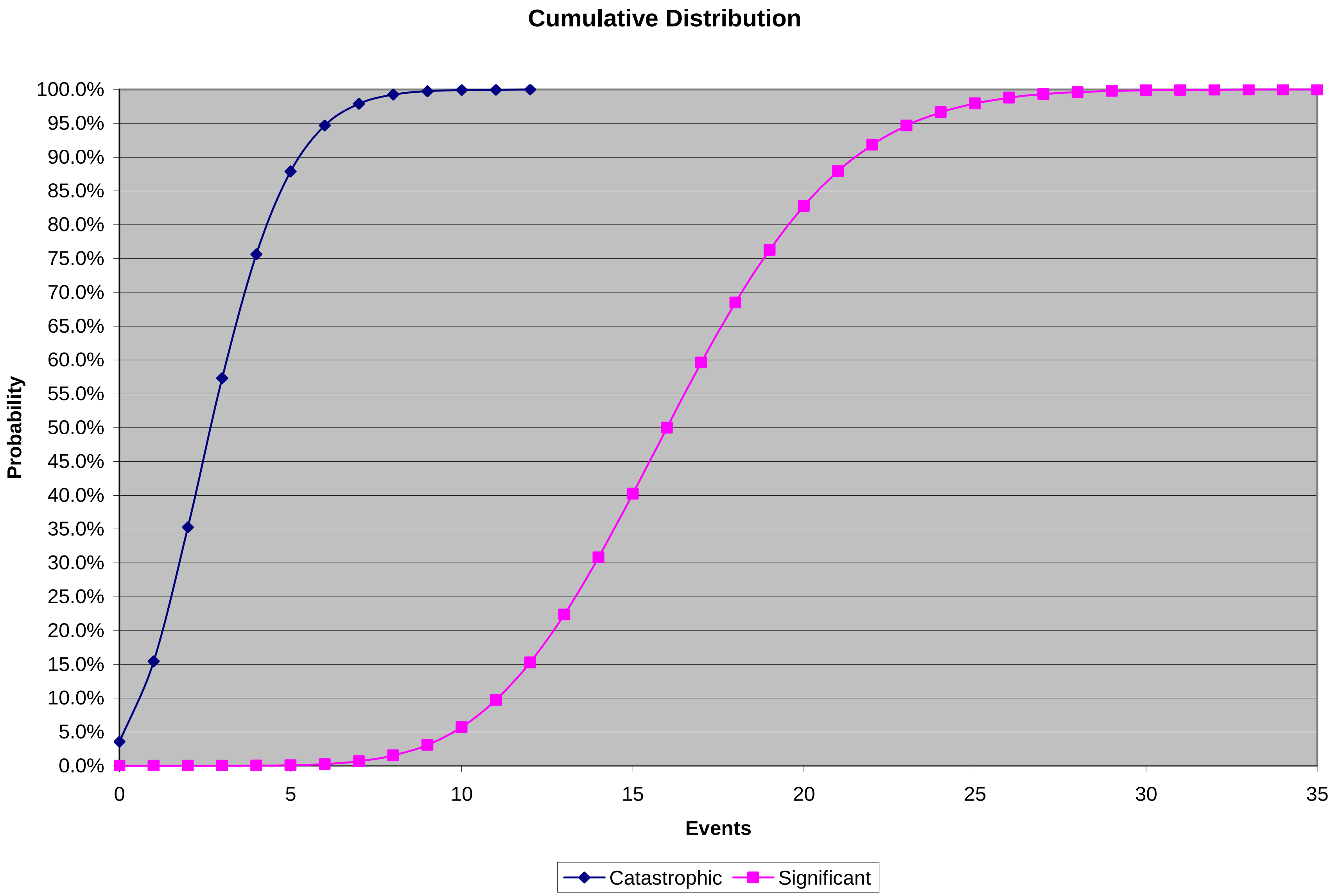
Exhibit 5B-2

Poisson Distribution (Lamda=0.067, T=50) (Lamda=0.333, T=50)



[133] λ was calculated by dividing the number of events observed between 1995 and 2009 by the 15-year time period.

Exhibit 5B-3


Cumulative Distribution
Probability
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
65.0%
60.0%
55.0%
50.0%
45.0%
40.0%
35.0%
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
0
5
10
15
20
25
30
35
Events
Catastrophic
Significant

Step 3. Calculate Future Impoundment Failure Avoided Cleanup Cost Benefits

After fitting a distribution of the number of releases likely to occur, EPA proceeded to combine these with the cost data presented in Step 1 above. This was done for the average case and three high-end cases (90^{th}, 95^{th}, and 99^{th} percentiles). For each case, the number of expected releases seen in **Exhibit 5B-4** below was divided by 50 to get the expected number of releases per year. These events were then multiplied by their respective costs, and the catastrophic and significant release values were summed in each year.

Exhibit 5B-4
Projected Future CCR Impoundment Releases
Based on 15-Year (1995-2009) Period of Historical CCR Impoundment Structural Failure Cases

Type of CCR Impoundment Release	Expected Number of Release Events				Assigned Cost Per Failure Event
	99^{th} %-ile	95^{th} %-ile	90^{th} %-ile	Average	
Catastrophic	8	7	6	3	$3.0 billion*
Significant	27	24	22	17	$23.1 million

* Note: $3.0 billion is EPA's initial "social cost" estimate assigned in this RIA to the December 2008 TVA Kingston TN impoundment release event. Social cost represents the opportunity costs incurred by society, not just the monetary costs for cleanup. OMB's 2003 "Circular A-4: Regulatory Analysis" (page 18) instructs Federal agencies to estimate "opportunity costs" for purpose of valuing benefits and costs in RIAs. This $3.0 billion social cost estimate is larger than TVA's $933 million to $1.2 billion cleanup cost estimate (i.e., TVA's estimate as of 03 Feb 2010), because EPA's social cost estimate consists of three other social cost elements in addition to TVA's cleanup cost estimate: (a) TVA cleanup cost, (b) response, oversight and ancillary costs associated with local, state, and other Federal agencies, (c) ecological damages, and (d) local (community) socio-economic damages. **Appendix Q** to this RIA provides EPA's documentation and calculation of these four cost elements, which total $3.0 billion in social cost. **Appendix Q** to this RIA also provides an alternative, lower estimate of social costs, based on different modeling assumptions for capturing such costs. This alternative analysis suggests that TVA's cleanup costs alone may be close to the social costs associated with the Kingston impoundment failure. EPA specifically requests comment on this social cost estimate, and will continue to develop this estimate for the final rule.

However, EIA data indicate that there is a current trend among coal-fired power plants to switch from wet handling to dry handling. As seen below in **Exhibit 5B-5**, this will lead to a decrease of approximately 300,000 tons being disposed of in surface impoundments per year, or approximately 1.3% of the initial 22.5 million tons in 2005. Since the tons disposed of (and similarly, the number of surface impoundments) likely relate to the number of releases, these decreases are accounted for by using 2005 wet tonnage as a benchmark and assuming the quantity of wet tonnage declines 300,000 tons per year. The cost for each year is multiplied by the remaining percent still handled wet.

Exhibit 5B-5 Decreasing CCR Wet Disposal Trend					
Year	% CCR Still Disposed Wet	Year	% CCR Still Disposed Wet	Year	% CCR Still Disposed Wet
2005	100.0%	2024	75.2%	2043	50.3%
2006	98.7%	2025	73.9%	2044	49.0%
2007	97.4%	2026	72.6%	2045	47.7%
2008	96.1%	2027	71.2%	2046	46.4%
2009	94.8%	2028	69.9%	2047	45.1%
2010	93.5%	2029	68.6%	2048	43.8%
2011	92.2%	2030	67.3%	2049	42.5%
2012	90.9%	2031	66.0%	2050	41.2%
2013	89.5%	2032	64.7%	2051	39.9%
2014	88.2%	2033	63.4%	2052	38.6%
2015	86.9%	2034	62.1%	2053	37.3%
2016	85.6%	2035	60.8%	2054	36.0%
2017	84.3%	2036	59.5%	2055	34.7%
2018	83.0%	2037	58.2%	2056	33.3%
2019	81.7%	2038	56.9%	2057	32.0%
2020	80.4%	2039	55.6%	2058	30.7%
2021	79.1%	2040	54.3%	2059	29.4%
2022	77.8%	2041	52.9%	2060	28.1%
2023	76.5%	2042	51.6%	2061	26.8%

The final step in the calculation was to take the adjusted costs in each year and discount them by 3% and 7% to calculate the present value (PV) as displayed in **Exhibit 5B-6** below. A full table of year-by-year costs can be found in **Appendix K11**. Approximately 97% of these costs result from catastrophic releases, and the remaining 3% result from significant releases. It is important to note that no costs are attributed to 2012-2014 as the rule will not be adopted and implemented until 2015. However, all costs beginning in 2015 are assumed to be avoided under subtitle C. Although facilities are given 5 years to phase out CCR impoundments under one of the proposed regulatory options, the other options require regular inspections of CCR impoundments to prevent catastrophic or significant releases.

For a subtitle D approach, expect delayed compliance with the requirement that surface impoundments be lined and that existing unlined surface impoundments be closed if they aren't lined when compared to compliance with the surface impoundment phaseout under subtitle C. Compliance will largely depend on the uncertainties of state regulations, the implementation of those regulations, and citizen suits. Also, since some facilities will line their surface impoundments instead of converting to dry handling, these facilities will continue to pose risks for catastrophic failure even though they may no longer require cleanup costs for groundwater contamination. The percent of states with at least some surface impoundment regulations, 48% as described in **Appendix K9**, is used as a proxy for the phase-out of existing impoundments. However, the 5.5% of those 48% that would retrofit with composite liners could still pose release risks. This results in 45% of the subtitle C benefits being realized in subtitle D.

For the subtitle D prime approach, existing impoundments will not need to be lined, but can continue to operate until they close. Third-party inspections of surface impoundments would be required under this option, but it is difficult to predict the extent to which these inspections would actually occur and would decrease catastrophic failures. In any case, the benefits of subtitle D prime would be less than those of subtitle D and greater than the baseline in terms of costs of catastrophic failures avoided. Thus, EPA used the midpoint as a best-estimate of the effectiveness that these inspections would have, which results in 23% of the subtitle C benefits being realized in a subtitle D prime approach.

Exhibit 5B-6
Estimate of Future CCR Impoundment Structural Failure Cleanup Costs Avoided As Benefits Under Three RCRA Regulatory Options
(present value in $millions)

Discount Rate	99th %-ile	95th %-ile	90th %-ile	Average
Subtitle C special waste				
3%	$7,407	$6,483	$5,567	$3,124
7%	$4,177	$3,656	$3,140	$1,762
Subtitle D (version 2)				
3%	$3,333	$2,917	$2,505	$1,406
7%	$1,880	$1,645	$1,413	$793
Subtitle “D Prime”				
3%	$1,704	$1,491	$1,280	$719
7%	$961	$841	$722	$405

Step 4. Account for Increasing CCR Impoundment Release Trend

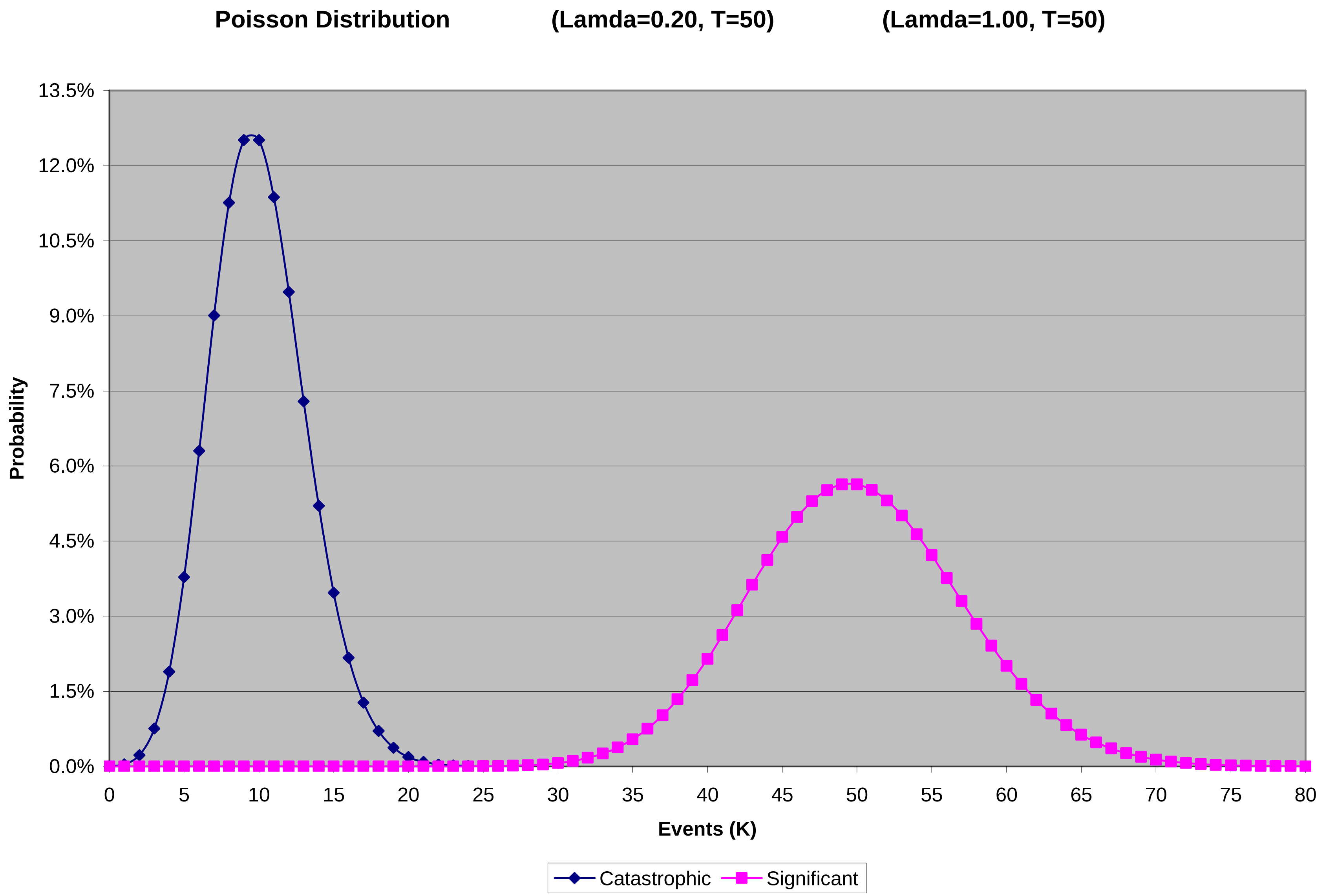
In Step 2 above, it was noted that the arrival rate of releases might violate the stationarity requirement for Poisson distributions. This is due to the trend of increasing release frequency based on the aging structure of the earthen impoundments. EPA attempted to discern whether a time trend was likely between releases and the average age of the surface impoundments. First, EPA limited the universe to the 38 releases that had reported release dates within the past 15 years. Next, the number of releases in 2009 was scaled up to account for the fact that the EPA mail survey questionnaires were returned by June of 2009. Thus, the four releases in 2009 were scaled up by 12 months/6 months, or a factor of 2. Using commission age and only those releases for which a release year was known, EPA constructed the profile of releases in the years ranging from 1995 to 2009 displayed in **Exhibit 5B-7** below.

Exhibit 5B-7
Summary of 15-Year (1995-2009) Period of Historical CCR Impoundment Structural Failures

Year	CCR impoundment average age	Count of impoundment release events	% of all CCR impoundments releasing
1995	21.1	1	0.20%
1996	21.5	0	0.00%
1997	22.5	0	0.00%
1998	23.5	1	0.19%
1999	24.5	2	0.38%
2000	25.3	2	0.38%
2001	26.1	1	0.19%
2002	27.0	2	0.37%
2003	27.9	1	0.19%
2004	28.7	3	0.55%
2005	29.7	3	0.55%
2006	30.5	3	0.55%
2007	31.3	7	1.27%
2008	32.3	8	1.45%
2009	33.0	8	1.44%

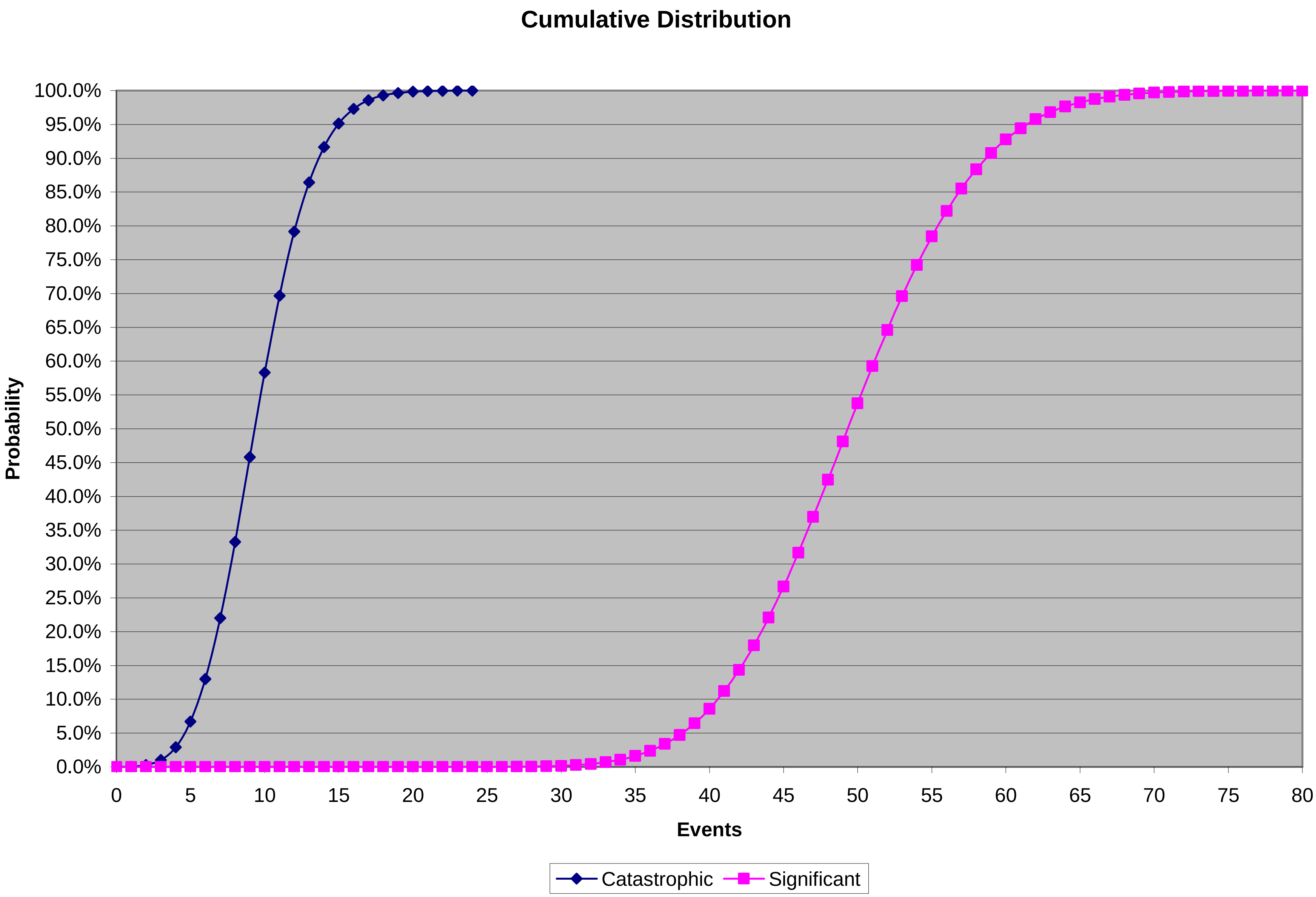
As can be seen in the table above, both the absolute number of releases and the percent of units with releases have increased over the past 15 years. All five significant releases and the catastrophic release at TVA Kingston TN have happened since 2005. To account for this potential lack of stationarity, EPA conducted a sensitivity analysis with alternate values of λ. Instead of looking at the last 15 years, EPA assumed that the previous 5-year period best reflects impoundment releases. Thus, in place of the earlier calculated lambda values (0.067 and 0.333) derived by dividing the number of catastrophic and significant failures between 1995 and 2009 by 15, EPA calculated higher lambdas (0.2 and 1) by dividing the catastrophic and significant failures between 2005 and 2009 by 5. Using these new lambda values, but keeping the same 50-year forecast period, EPA derived the Poisson distribution seen in the two figures below. The probability of a specific number of catastrophic or significant releases is illustrated in **Exhibit 5B-8** and **Exhibit 5B-9** (cumulative distribution) below.

Exhibit 5B-8



Poisson Distribution
(Lamda=0.20, T=50)
(Lamda=1.00, T=50)
Probability
13.5%
12.0%
10.5%
9.0%
7.5%
6.0%
4.5%
3.0%
1.5%
0.0%
0
5
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
Events (K)
Catastrophic
Significant

Exhibit 5B-9


Cumulative Distribution
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
65.0%
60.0%
55.0%
50.0%
45.0%
40.0%
35.0%
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
Probability
0
5
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
Events
Catastrophic
Significant

With these new distributions, EPA performed the same calculations as described in Step 3. The expected number of releases in **Exhibit 5B-10** below was divided by 50 to get releases per year; these releases were multiplied by the cost per release; an adjustment was made to account for voluntary switching to dry handling; and yearly values were discounted. A full exhibit of year-by-year costs can be found in **Appendix K11**.

Exhibit 5B-10
Projection of Future CCR Impoundment Releases
Based on 5-Year (2005-2009) Historical CCR Impoundment Release Cases

Type of CCR impoundment release event	Expected Number of Release Events				Cost per CCR impoundment release event
	99^{th} %-ile	95^{th} %-ile	90^{th} %-ile	Average	
Catastrophic	18	15	14	10	$3.0 billion*
Significant	67	62	59	50	$23.1 million

* Note: $3.0 billion is EPA's initial "social cost" estimate assigned in this RIA to the December 2008 TVA Kingston TN impoundment release event. Social cost represents the opportunity costs incurred by society, not just the monetary costs for cleanup. OMB's 2003 "Circular A-4: Regulatory Analysis" (page 18) instructs Federal agencies to estimate "opportunity costs" for purpose of valuing benefits and costs in RIAs. This $3.0 billion social cost estimate is larger than TVA's $933 million to $1.2 billion cleanup cost estimate (i.e., TVA's estimate as of 03 Feb 2010), because EPA's social cost estimate consists of three other social cost elements in addition to TVA's cleanup cost estimate: (a) TVA cleanup cost, (b) response, oversight and ancillary costs associated with local, state, and other Federal agencies, (c) ecological damages, and (d) local (community) socio-economic damages. **Appendix Q** to this RIA provides EPA's documentation and calculation of these four cost elements, which total $3.0 billion in social cost. **Appendix Q** to this RIA also provides an alternative, lower estimate of social costs, based on different modeling assumptions for capturing such costs. This alternative analysis suggests that TVA's cleanup costs alone may be close to the social costs associated with the Kingston impoundment failure. EPA specifically requests comment on this social cost estimate, and will continue to develop this estimate for the final rule.

EPA estimated subtitle C (special waste) costs avoided that were between two and three times the costs predicted in Step 3. This difference helps to explain how significant the assumption of lambda, and the potential non-stationarity of the data, can have on the final results. Sensitivity results were also calculated for subtitle D (version 2) and subtitle "D prime" approaches. As assumed above for the subtitle D (version 2) option, EPA expects delayed compliance with the requirement that surface impoundments be lined and that existing unlined surface impoundments be closed if they are not lined when compared to compliance with the surface impoundment phaseout under subtitle C. Compliance will largely depend on the uncertainties of state regulations, the implementation of those regulations, and citizen suits. Also, since some facilities will line their surface impoundments instead of converting to dry handling, these facilities will continue to pose risks for catastrophic failure even though they may no longer require cleanup costs for groundwater contamination. The percent of states with at least some surface impoundment regulations, 48% as described in **Appendix K9,** is used as a proxy for the phase-out of existing impoundments. However, the 5.5% of those 48% that would retrofit with composite liners could still pose release risks. This results in 45% of the subtitle C (special waste) benefits being realized in Subtitle D (version 2).

For the subtitle "D prime" approach, existing impoundments will not need to be lined, but can continue to operate until they close. Third-party inspections of surface impoundments would be required under this option, but it is difficult to predict the extent to which these inspections would actually occur and would decrease catastrophic failures. In any case, the benefits of subtitle "D prime" would be less than those of subtitle D (version 2) and greater than the baseline in terms of costs of catastrophic failures avoided. Thus, this RIA used the midpoint as a best-estimate of the effectiveness that these inspections would have. This results in 23% of the subtitle C (special waste) benefits being realized in a subtitle "D prime" approach. **Exhibit 5B-11** below presents the avoided cleanup cost estimates for the three regulatory options (i.e., Subtitle C special waste, Subtitle D version 2, and Subtitle "D prime").

Exhibit 5B-11
Future CCR Impoundment Structural Failure Cleanup Costs Avoided
($millions present value over 50-years)

Discount Rate	99th %-ile	95th %-ile	90th %-ile	Average
Subtitle C (special waste)				
3%	$16,708	$13,966	$13,043	$9,371
7%	$9,423	$7,876	$7,356	$5,285
Subtitle D (version 2)				
3%	$7,519	$6,285	$5,869	$4,217
7%	$4,240	$3,544	$3,310	$2,378
Subtitle "D Prime"				
3%	$3,843	$3,212	$3,000	$2,155
7%	$2,167	$1,811	$1,692	$1,216

Step 5. Estimate Future Avoided Cleanup Costs for Two Alternative Impoundment Failure Scenarios (Scenario #2 & #3)

Not all of these releases are likely to pose the type of catastrophic risks that were seen at TVA's Kingston, TN plant. Catastrophic releases are more likely where there is a high potential for impoundment materials to disperse over large areas. This is most likely to occur at tall impoundments. Thus, this RIA presents an alternative assumption that the Kinston-like catastrophic releases would only occur at these tall impoundments. In addition, as age appears to be a driving factor in releases, this analysis also assumed that Kingston-like catastrophic releases would occur at older impoundments. Particularly, 96 impoundments of the 584 covered in the 2009 EPA mail survey were at least 40 feet tall and at least 25 years old. The analysis below assumes that 10% - 20% of these impoundments could fail within the next 20 years. This is equivalent to the upper percentiles of failures predicted in Steps 3 and 4 above; however it moves the costs forward in time, to show the sensitivity of the benefits with respect to time.

Exhibit 5B-12 Scenario #2: Cleanup Cost Estimates for CCR Impoundment Catastrophic Failures @ 10% Failures						
% of Tons Baseline	Year	Costs @3% (in millions)	Costs @7% (in millions)	% of Tons Subtitle C	Costs @3% (in millions)	Costs @7% (in millions)
88.2%	2014	-	-	88.2%	-	-
86.9%	2015	$1,146	$1,022	70.6%	$930	$830
85.6%	2016	$1,095	$941	52.9%	$677	$582
84.3%	2017	$1,047	$866	35.3%	$438	$362
83.0%	2018	$1,001	$797	17.6%	$213	$169
81.7%	2019	$956	$733	0.0%	$0	$0
80.4%	2020	$914	$674			
79.1%	2021	$873	$619			
77.8%	2022	$833	$569			
76.5%	2023	$796	$523			
75.2%	2024	$759	$481			
73.9%	2025	$724	$441			
72.6%	2026	$691	$405			
71.2%	2027	$659	$372			
69.9%	2028	$628	$341			
68.6%	2029	$598	$313			
67.3%	2030	$569	$287			
66.0%	2031	$542	$263			
64.7%	2032	$516	$241			
63.4%	2033	$491	$221			
62.1%	2034	$467	$202			
Baseline Total		$15,305	$10,309	C Total	$2,259	$1,943

Given the costs above, the total benefits of a Subtitle C phase out over 5 years would be the difference between the potential catastrophic failure costs under C and the catastrophic failure costs under the baseline. For the 20% "Scenario #3", this figure is double, as displayed below in **Exhibit 5B-13**. For Subtitle D, it is assumed that the 48% of states (by tonnage, as described in **Appendix K9**) that have at least some regulatory oversight currently, would enforce the retrofitting requirement. However, since 5.5% of impoundments already have composite liners, these units would not be expected to close. Thus 94.5% times 48% leads to an approximately 45% of the Subtitle C benefits. For Subtitle D prime, the requirement of dam safety inspections would be likely to result in some amount catastrophic failure reduction between the baseline and the Subtitle D approach. This RIA uses the midpoint, a 23% reduction, as a best estimate. While these estimates are likely much higher than the actual benefits from preventing catastrophic failures, they do help to define the upper bound of what is possible under current practices of mismanagement.

Exhibit 5B-13 **Avoided Future CCR Impoundment Catastrophic Failure Cleanup Costs** ($millions present value)			
Scenarios	Subtitle C Special waste	Subtitle D (version 2)	Subtitle "D Prime"
Scenario #2: Assuming 10% of the 96 Impoundments Fail			
at 3%	$13,046	$5,918	$2,959
at 7%	$8,366	$3,795	$1,897
Scenario #3: Assuming 20% of the 96 Impoundments Fail			
at 3%	$26,092	$11,836	$5,918
at 7%	$16,732	$7,590	$3,795
Note: These future CCR impoundment failure cleanup costs avoided do not account for avoided costs from releases that are less than "catastrophic."			

5C. Induced Effect of RCRA Regulation on CCR Beneficial Use

This section assesses the potential effects of the different regulatory options for disposal of CCR on the future annual quantities of CCR beneficially used. It also estimates the values of social and economic impacts associated with baseline and different levels of beneficial use. It estimates the expected increase in beneficial use from increased cost of disposal of CCR and evaluates future changes in the beneficial use of coal combustion residuals (CCR) as a result of a potential "*stigma*" effect.

5C1. Baseline Environmental & Economic Benefits of CCR Beneficial Use by Other Industries

According to CCR beneficial use market data compiled for year 2005 as displayed below in **Exhibit 5C-1**, and extrapolated in this RIA to 2009 as displayed in **Exhibit 5C-2** below, 62 million tons of annual CCR generated by **272** of the 495 electric utility plants is not disposed, but is beneficially used as material substitutes in at least **14 industrial applications**. The purpose of this section is to provide estimates of two categories of baseline benefits associated with baseline CCR beneficial use, consisting of five sub-elements (i.e., 1a, 1b, 2a, 2b, 2c):

1. Economic benefits: Economic benefits estimated in this section are based on recent market prices and include:
   a. Annual cost savings to over 14 CCR beneficial use industries in the form of reduced industrial raw and intermediate materials purchase prices relative to purchasing higher-priced substitute materials, compared to paying electric utility plants lower prices for buying and using CCR as an industrial material.
   b. Cost savings to electric utility plants for avoiding the cost of disposing CCR which is beneficially used.

2. Lifecycle benefits: Lifecycle benefits as quantified in this RIA are based on market or social values assigned to the relative physical consequences of using CCR compared to substitute industrial materials, through the entire "materials flow" chain of the national economy which consists of five basic stages (1. raw materials extraction, 2. materials processing, 3. industrial manufacturing, 4. product use, 5. product end-of-lifespan disposal/recycling). Three lifecycle physical consequences are quantified in this RIA but not all monetized:
   a. Lifecycle resource consumption savings (water & energy consumption)
   b. Lifecycle air pollution emissions (GHG, CO, NOx, SOx, PM, Hg, Pb)
   c. Lifecycle wastes (wastewaters and solid wastes)

   Lifecycle benefits in this RIA are only based on three categories of CCR beneficial uses (i.e., concrete, cement, and wallboard representing a sub-total of 58% of all CCR beneficial uses) which were addressed in the prior 2008 study[134] used as a reference for this section of the RIA.

[134] Source: EPA Office of Solid Waste "Waste and Materials-Flow Benchmark Sector Report: Beneficial Use of Secondary Materials – Coal Combustion Products," Final Report, EPA report nr. 530-R-08-003, prepared by Industrial Economics Inc., 95 pages, 12 Feb 2008 at: http://www.epa.gov/osw/partnerships/c2p2/pubs/benuse07.pdf. The beneficial use market data cited in this source is summarized from the American Coal Ash Association (ACAA) 2005 national survey of the electric utility industry.

Lifecycle benefits encompass economic benefits so these two categories are not additive but duplicative. Lifecycle benefits in this RIA are based on "lifecycle analysis" (LCA), a method which involves estimating both internalized (e.g., market priced) and externalized (e.g., costs not captured in market prices) material flow consequences:

> "*Life cycle analysis depicts the production of materials in a system of complex physical outcomes, and can predict the incremental physical consequences of a change in material inputs, technology, waste management practices, or price incentives. In LCA, as in reality, one change in the physical system, such as the substitution of fly ash for virgin Portland cement, leads to a corresponding cascade of economy-wide impacts and shifts. As inputs are substituted, technologies, physical outputs, and exposure pathways change. Using a range of modeling platforms and life cycle inventories to calculate the outputs associated with each incremental change, LCA calculates the net result of all of these interactions, capturing the total incremental effect of a change in operations on physical environmental impacts such as air emissions, and energy and water use.*"

- **Economic Benefits of CCR Beneficial Use**

As estimated in **Exhibit 5C-1** below (Column F), CCR used for beneficial use applications has an estimated annual US market value of **$177 million** per-year based on annual CCR sales revenue data supplied by 233 electric utility plants to the 2005 EIA-767 database, updated in this RIA to 2009. Based on comparison with the average higher prices for substitute industrial materials, using lower-priced CCR provides the US national economy with **$2,300 million** in annual net cost savings compared to the higher $2,477 million annual cost of substitute materials in these 14 industrial applications (see Column I of **Exhibit 5C-1**).

Exhibit 5C-1

Estimate of Annual Materials Cost Savings Benefit of CCR Generated by the Electric Utility Industry for Beneficial Use in Industrial Applications

A Item	B Industry Application	C 2005 CCR beneficial use (million tons)	D % of CCR beneficial use market	E 2005 average market price paid electric plants* ($/ton)	F (C x E) Implied annual CCR sales revenues to electric utility plants	G 2005 avg price for substitute material ($/ton)	H (C x G) 2005 implied annual alternative materials cost	I (H – F) Implied annual US national cost savings w/CCR beneficial uses
1	Construction concrete ingredient NAICS code 3273	See 1A + 1B	See 1A + 1B	See 1A + 1B	See 1A + 1B	See 1A + 1B	See 1A + 1B	See 1A + 1B
1A	Direct ingredient: substitute for portion of Portland cement ingredient in concrete mfg NAICS code 3273	16.35	33.0%	$0 to $45	$0 to $735.8 million	$80	$1,308 million	$572.2 to $1,308 million
1B	Indirect ingredient: raw feed blended with limestone or shale to make cement clinker to be ground into cement for concrete mfg NAICS code 3273	4.22	8.5%	$0 to $45	$0 to $189.9 million	$80	$337.6 million	$147.7 to $337.6 million
2	Construction structural fill for building foundations and embankments NAICS code 238910	8.35	16.8%	$1	$8.35 million	$3	$25.05 million	$16.7 million
3	Construction wall board NAICS code 327420	8.18	16.5%	$0 to $8	$0 to $65.4 million	$4.5 to $12	$36.8 to $98.2 million	$32.8 to $36.8 million
4	Waste stabilization (substitute for lime) NAICS code 5622	2.84	5.7%	$15 to $25	$42.6 to $71.0 million	$66	$187.4 million	$116.4 to $144.8 million
5	Blasting grit NAICS code 212322	1.63	3.3%	Not reported	Not reported	Not reported	Not estimated	Not estimated
6	Roofing granules NAICS code 324122	Included with grit (row 5)	Included with grit (row 5)	Not reported	Not estimated	Not reported	Not estimated	Not estimated
7	Minor uses (n=7)**	8.04	16.2%	$3 to $20	$24.1 to $160.8 million	$5 to $83	$40.2 to $667.3 million	$16.1 to $506.5 million
	Column totals (2005) =	49.61	100%	Implied average (F/C) = $3	$75 to $1,231 million (best estimate**** = $149 million)	Implied average (H/C) = $40	$1,935 to $2,624 million (best est.**** = $1,979 million)	$1,830
	2008 updated estimates =	**62*** **			**$177 million**		$2,477 million	**$2,300 million ($37 per ton)**

Explanatory notes:

Source: Data in columns C, E, and G are from "Waste and Materials-Flow Benchmark Sector Report: Beneficial Use of Secondary Materials – Coal Combustion Products," EPA report nr. 530-R-08-003, prepared by Industrial Economics Inc., 95 pages, 12 Feb 2008 at http://www.epa.gov/osw/partnerships/c2p2/pubs/benuse07.pdf

* Average price includes "free on board" (FOB) shipping and insurance costs paid by the supplier from the point of manufacture to a specified destination.

** Minor uses include: (1) agricultural soil amendment for flue gas desulfurization gypsum, (2) road base foundation layer underlying pavements for bottom ash, (3) mine reclamation material as substitute for soil, (4) mineral filler in asphalt, (5) soil stabilizer, (6) snow and ice control substitute for sand, and (7) mining.

*** 2009 update estimated tonnage (Column C above) derived in **Exhibit 5C-2** of this RIA; 2009:to2005 multiplier = 62.09/49.61 = 1.25.

**** "Best estimate" in Column F based on sum of coal-fired electric plant CCR "byproduct sales revenues" from the DOE-EIA F767_PLANT database for 233 plants.
"Best estimate" in Columns H and I derived by numerical interpolation of the ranges displayed based on the proportionate best estimate and range of Column F.

Exhibit 5C-2

2001-2008 Historical Trend in CCR Beneficial Use Quantity (Short Tons*)

A. Actual Data:	Year	CCR Beneficial Use** (tons per year)	% change	% Use	Linear Regression Output	
Actual =	2001	37,119,321			R-Squared	0.943
Actual =	2002	45,523,256	+22.6%	35%	Standard Error	1,859,123
Actual =	2003	46,384,405	+1.9%	38%	Observations	8
Actual =	2004	49,089,818	+5.8%	40%		*Coefficients*
Actual =	2005	49,612,541	+1.1%	40%	Intercept	39,784,058
Actual =	2006	54,203,170	+9.3%	43%	X Variable	2,867,597
Actual =	2007	56,039,005	+3.4%	43%		
Actual =	2008	60,593,660	+8.1%	46%		

Notes:

* Tons source: Amer. Coal Ash Assoc http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=3

** "Beneficial use" data in this Exhibit correspond to the 15 categories defined in the ACAA dataset which do not match the definition (examples) of CCR beneficial uses in EPA-ORCR's CCR proposed rule.

B. Trendline:	Year	Regression best fit	% change
Trendline =	2001	39,784,100	
Trendline =	2002	42,651,700	7.2%
Trendline =	2003	45,519,300	6.7%
Trendline =	2004	48,386,800	6.3%
Trendline =	2005	51,254,400	5.9%
Trendline =	2006	54,122,000	5.6%
Trendline =	2007	56,989,600	5.3%
Trendline =	2008	59,857,200	5.0%
Projection =	2009	62,724,800	4.8%
	Annual average growth rate =		5.2%

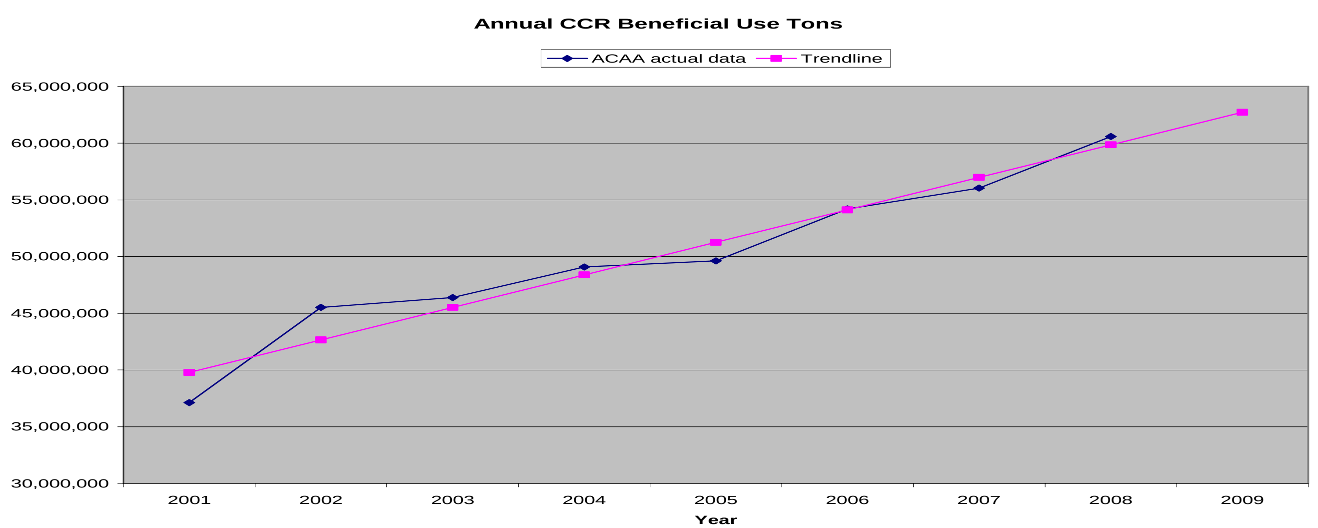


Exhibit 5C-3 below presents a 2004 state-by-state summary of annual quantity of CCR beneficially used.

Exhibit 5C-3
State-by-State Summary of CCR Beneficial Use (2004*)

A	B	C	D	E
Item	State	2004 CCR generation (short tons)	2004 CCR beneficial use (short tons)	% CCR used beneficially
1	AK	43,000	Not reported	NR
2	AL	3,408,000	663,000	19%
3	AR	688,000	324,000	47%
4	AZ	2,764,000	1,161,000	42%
5	CA	50,000	0	0%
6	CO	1,548,000	252,000	16%
7	CT	181,000	0	0%
8	DC	0	0	NA
9	DE	121,000	24,000	20%
10	FL	5,092,000	3,171,000	62%
11	GA	3,141,000	1,022,000	33%
12	HI	48,000	0	0%
13	IA	1,260,000	750,000	60%
14	1D	0	0	0%
15	IL	4,419,000	1,968,000	45%
16	IN	9,549,000	3,023,000	32%
17	KS	1,399,000	575,000	41%
18	KY	14,537,000	2,521,000	17%
19	LA	1,588,000	716,000	45%
20	MA	310,000	130,000	42%
21	MD	1,983,000	646,000	33%
22	ME	36,000	0	0%
23	MI	2,145,000	614,000	29%
24	MN	1,561,000	387,000	25%
25	MO	2,348,000	1,070,000	46%
26	MS	1,758,000	681,000	39%
27	MT	952,000	51,000	5%
28	NC	3,545,000	1,641,000	46%
29	ND	2,757,000	731,000	27%
30	NE	469,000	299,000	64%

A	B	C	D	E
Item	State	2004 CCR generation (short tons)	2004 CCR beneficial use (short tons)	% CCR used beneficially
31	NH	141,000	57,000	40%
32	NJ	600,000	112,000	19%
33	NM	3,668,000	864,000	24%
34	NV	825,000	314,000	38%
35	NY	1,379,000	368,000	27%
36	OH	6,980,000	2,290,000	33%
37	OK	1,277,000	625,000	49%
38	OR	95,000	81,000	85%
39	PA	9,545,000	2,941,000	31%
40	RI	0	0	NA
41	SC	2,172,000	1,169,000	54%
42	SD	105,000	28,000	27%
43	TN	3,803,000	2,163,000	57%
44	TX	12,943,000	4,395,000	34%
45	UT	2,341,000	812,000	35%
46	VA	2,442,000	203,000	8%
47	VT	0	0	NA
48	WA	2,301,000	1,683,000	73%
49	WI	1,437,000	1,219,000	85%
50	WV	7,220,000	2,401,000	33%
51	WY	2,106,000	508,000	24%
	Totals =	129,001,000	44,653,000	35%

Notes:
* Source: DOE & EPA, "Coal Combustion Waste Management at Landfills and Surface Impoundments 1994-2004," DOE/PI-0004, Aug 2006, page 5 (Table 1) at: http://www.ead.anl.gov/pub/doc/coal_waste_report.pdf
In comparison, the ACAA reports that a 5% smaller amount of 122,465,119 tons CCR was generated in 2004

- **Lifecycle Benefits Associated with CCR Beneficial Use**

The baseline (2005) material cost savings estimate displayed in **Exhibit 5C-1** above is adjusted below to exclude the mining applications use, because mine-filling is not covered in the proposed rule.[135] As displayed in **Exhibit 5C-4** below, subtracting 2.3% of the mining applications beneficial use category decreased the baseline CCR beneficial use from 49.6 million tons to 48.5 million tons (relative to 2005).

Exhibit 5C-4
Subtraction of Mining Application Minor Use from the Minor Use Category of the Material Cost Savings for CCR Beneficial Use

CCR Beneficial Use Category (Minor Uses)	CCR beneficial use tons (2005)	% of all CCR uses	Materials price cost savings (million 2009$)
1. Flowable fill	259,907	0.5%	$10.7
2. Road base/sub-base	1,461,992	2.9%	$60.0
3. Soil modification/stabilization	1,139,640	2.3%	$46.8
4. Mineral filler in asphalt	140,838	0.3%	$5.8
5. Snow & ice control	547,541	1.1%	$22.5
6. Mining applications	1,132,945	2.3%	$46.5
7. Agriculture	415,741	0.8%	$17.1
8. Aggregate	872,776	1.8%	$35.8
9. Miscellaneous minor uses	2,071,157	4.2%	$85.1
Sub-total Minor Uses =	8,042,537	16.2%	$330.3
Total All Uses (Major + Minor) =	49,612,541	100.0%	$1,830
Total Excluding Mining =	48,479,596	97.7%	**$1,783.5 ($37 per ton)**

From a materials lifecycle analysis perspective, CCR beneficial use generates net environmental benefits. Based on a 2008 life cycle study[136] of two of the 14 CCR beneficial use industrial applications (i.e., concrete and wallboard) there are 12 environmental benefit categories with the annual magnitudes estimated below in **Exhibit 5C-5**. This estimate of environmental benefits is based on only 47% (i.e., 23.2 million tons) of the 49.62 million tons for the 2005 CCR beneficial use market as reported in that 2008 study. Thus, these estimates may understate annual environmental benefits of CCR beneficial uses. These net benefits are not additive to the economic benefits, but encompass them.

[135] As noted in the Federal Register notice of EPA's proposed CCR rule, minefilling will be addressed in an alternate rulemaking.
[136] Source: Exhibit 5-3 of "Waste and Materials-Flow Benchmark Sector Report: Beneficial Use of Secondary Materials – Coal Combustion Products," prepared by Industrial Economics Inc for the EPA Office of Solid Waste, 12 Feb 2008, 95 pages at http://www.epa.gov/osw/partnerships/c2p2/pubs/benuse07.pdf

To avoid double-counting of economic and social benefits, EPA evaluated the monetization of the energy, water, and air pollution-related impacts for any such double counting. Based on this evaluation, this RIA concludes that each of the individual monetized estimates for these impacts are fully additive and do not double count benefits, with one exception regarding partial overlap between energy cost savings and the value of avoided SOx air emissions. For SOx, where there exists a cap and trade permit program, firms must pay to emit SOx. A portion of the SOx emissions avoided from beneficially using CCR is from the energy sector. Under the presumption that the marginal costs of abatement equal the value of marginal damages, the value of the portion of SOx emissions from the energy sector will be reflected in the energy cost savings. The portion of avoided SOx emissions that comes from sectors other than energy is not reflected in energy cost savings and thus should be retained. However, separately adding a value for reduced SOx emissions likely represents some amount of double counting.

Unlike the SOx permit program, most regulation of NOx and particulate matter (PM) does not require firms to purchase permits to pollute. Thus there is little to no overlap between the external costs of these air pollutants and energy costs. In addition, aside from limited state programs, GHG damages are not currently regulated and would not be reflected in the market price for energy. Thus, the benefits from NOx, particulates and GHG reductions are fully additive to private energy cost savings. Furthermore, for water use, the only benefits included are the direct cost savings, and because the water savings in these cases are not associated with energy production, these savings are not being captured elsewhere. Reduced water use in the production process is a real cost savings that should be a component of total benefits.

Therefore, this RIA concludes that there is only a partial double counting between energy cost savings and the savings associated with reduced SOx emissions. No other beneficial use benefits categories are affected by this double counting issue. Thus, **Exhibit 5C-5** below has subtracted the $1,491 million benefits attributable to SOx reductions from the environmental benefits estimate, resulting in an environmental estimate of **$22,980 million per year**, or **$474 per ton** average lifecycle benefit, assigning zero values to tonnage other than concrete and wallboard. In addition to baseline lifecycle benefits, there are an estimated **$2,927 million per year** in baseline avoided disposal cost benefits to the electric utility industry (i.e., (49.61 million tons CCR beneficial use in 2005) x ($59 per ton average baseline disposal cost estimated in **Exhibit 3L** of this RIA)), which constitutes a total of **$25,907 million per year** (relative to 2005 CCR beneficial use tonnage), which is an average of **$533 per ton** nationwide baseline social benefits from CCR beneficial use.

Exhibit 5C-5
Estimate of Annual Baseline Lifecycle Benefits from CCR Beneficial Use
(Based on 2005 CCR beneficial use tonnage)

Benefit category	Physical quantity of environmental benefits for 48.5 million tons annual CCR beneficial use w/out mining application*	Unit monetization values (2009$)**	Estimated benefits ($millions per year)
A. Resource Consumption Savings			
1. Energy consumption	158 trillion BTU energy savings	$0.00003093 per BTU	$4,888
2. Water consumption	32.1 billion gallons water savings	$0.0025259 per gallon	$81
		Subtotal (1+2) =	$4,969
B. Air Pollution Savings			
3. GHG - greenhouse gases	11.5 million metric tons CO2 equivalent emissions avoided	$20.76 per metric ton	$239
4. CO – carbon monoxide	9,200 metric tons emissions avoided	Not estimated	Not estimated
5. NOx – nitrous oxides	30,400 metric tons emissions avoided	$10,255 per metric ton	$312

Exhibit 5C-5 **Estimate of Annual Baseline Lifecycle Benefits from CCR Beneficial Use** (Based on 2005 CCR beneficial use tonnage)			
Benefit category	Physical quantity of environmental benefits for 48.5 million tons annual CCR beneficial use w/out mining application*	Unit monetization values (2009$)**	Estimated benefits ($millions per year)
6. SOx – sulfur oxides	*23,900 metric tons emissions avoided*	*$62,375 per metric ton*	*$1,491*
7. PM – particulate matter	9,704 metric tons emissions avoided	$486,312 per metric ton	$4,719
8. Particles non-specified	26,200 metric tons emissions avoided	$486,312 per metric ton	$12,741
9. Hg - mercury	0.584 metric tons emissions avoided	Not estimated	Not estimated
10. Pb - lead	0.656 metric tons emissions avoided	Not estimated	Not estimated
		Subtotal (3 to 10) =	$19,502
		Subtotal air pollution savings excluding SOx & excluding mine-filling use =	$18,011
C. Other Environmental Savings			
11. Waterborne wastes	2,446 short tons waste generation avoided (SM + BOD + COD + Cu + Hg + Pb + Se)	Not estimated	Not estimated
12. Solid waste	27,991 short tons waste generation avoided	Not estimated	Not estimated
		Total (1 to 12) =	$24,471
		Total annual lifecycle benefits (excluding SOx & excluding mine-filling use) =	**$22,980 ($474/ton)**

Notes:

* Physical quantity of environmental benefits are based on only two of the 14 beneficial use industrial applications (i.e., 15.0 million tons per year fly ash CCR used in concrete, plus 8.2 million tons per year FGD CCR used in wallboard). These estimates are from Exhibit 5-3 (page 5-6) of "Waste and Materials-Flow Benchmark Sector Report: Beneficial Use of Secondary Materials – Coal Combustion Products," prepared by Industrial Economics Inc for the EPA Office of Solid Waste, 12 Feb 2008; available at http://www.epa.gov/osw/partnerships/c2p2/pubs/benuse07.pdf. This 2008 reference report does not provide environmental impact estimates for the other 12 beneficial use industrial applications.

** Unit monetary values applied for monetization are from the following sources:

- Row 1 & Row 2: 2007 values from Exhibit 5-3 (page 5-6) of the Industrial Economics Inc reference report. Unit values updated for this RIA from 2007 to 2009 using NASA's Gross Domestic Product Deflator Inflation Calculator at http://cost.jsc.nasa.gov/inflateGDP.html
- Row 3: Based on the September 2009 interim social cost of carbon (i.e., interim SCC) from Table III.H.6-3, page 29617 of the joint EPA and DOT-NHTSA "Proposed Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards," Federal Register, Volume 74, No. 186, 28 Sept 2009. The value applied in this RIA is the $19.50 per ton median value from the $5 to $56 per ton range displayed in the 2007 column in that source. Furthermore, this RIA updated the 2007$ median value from 2007 to 2009 dollars using the NASA Gross Domestic Product Deflator Inflation Calculator at http://cost.jsc.nasa.gov/inflateGDP.html. EPA is aware that final SCC values were published on March 9, 2010 in conjunction with a Department of Energy final rule. EPA intends to use the final SCC values for the CCR final rule RIA. The final SCC values are published in the Department of Energy, Energy Efficiency & Renewable Energy Building Technologies Program, "Small Electric Motors Final Rule Technical Support Document: Chapter 16 - Regulatory Impact Analysis", March 9, 2010 at http://www1.eere.energy.gov/buildings/appliance_standards/commercial/sem_finalrule_tsd.html).
- Rows 4-10: Unit values from the report "The Influence of Location, Source, and Emission Type in Estimates of the Human Health Benefits of Reducing a Ton of Air Pollution" by Neal Fann, Charles Fulcher and Bryan Hubbell, in Air Quality, Atmosphere & Health, Volume 2, No.3, Sept 2009, pages 169-176. The dollar values from this report were updated from 2006 to 2009 using NASA's Gross Domestic Product Deflator Inflation Calculator at http://cost.jsc.nasa.gov/inflateGDP.html
- Rows 12-13: Waterborne waste and solid waste generation avoided benefits were not monetized in the 2008 Industrial Economics Inc. reference study cited above.

5C2. Potential Effect of RCRA Regulation of CCR Disposal on CCR Beneficial Use

Under the proposed regulation, the Bevill exemption still applies to quantities of CCR directed to certain beneficial uses so that these quantities do not face increased disposal costs associated with Subtitle C or D regulation of disposed CCR. The increased costs of disposal of CCR as a result of their regulation under RCRA subtitle C will create a strong economic and regulatory incentive for increased beneficial uses of CCR. In fact, EPA concludes that the increased costs of disposal of CCR under subtitle C of RCRA, but not the beneficial use of CCR, will actually increase their usage in non-regulated beneficial uses, simply as a result of the economics of supply and demand. The economic driver - availability of a low-cost, functionally equivalent or often superior substitute for other raw materials - will continue to make CCR an increasingly desirable product. Furthermore, it has been EPA's experience in the RCRA hazardous waste regulations and elsewhere that material inevitably flows to less regulated applications.

On the other hand, industry and state government stakeholders have asserted in letters to EPA, that regulation of CCR as a RCRA "hazardous waste" will impose a "stigma" on CCR beneficial use which will significantly curtail these uses. In their view, even an action that regulates only the disposal of CCR in landfills or surface impoundments as hazardous waste, but retains the Bevill exemption for beneficial uses, would have this effect. Also, the states particularly have argued that, by operation of state law, the beneficial use of CCR would be prohibited under many states' beneficial use programs, if EPA were to designate CCR as a hazardous waste when disposed.

The purpose of this section of the RIA is to quantify both possibilities – i.e., an induced increase (Scenario #1) and an induced decrease (Scenario #2) -- in future CCR beneficial use, and to explain the basis for this RIA selecting the former (Scenario #1) as the "base case."

- **Examples of Hazardous Waste Recycling Success Not "*Stigma*"**

EPA's past experiences with the impacts of RCRA regulation, and with how RCRA industrial hazardous wastes and other hazardous materials are used and recycled, suggests that a "hazardous waste" designation of industrial secondary materials and wastes, does not impose a significant barrier to its beneficial use (e.g., recycling), and that non-regulated uses generally increase as the costs of regulated disposal increase. As summarized below, EPA's experience has shown that the economic incentive of a high disposal cost has outweighed any hypothetical stigma effect in case after case of hazardous waste recycling. Six examples listed below illustrate the point that a RCRA "hazardous waste" designation does not stand in the way of a material's (or waste's) subsequent industrial recycling or reuse as a raw or intermediate material:

1. <u>Electric arc furnace dust:</u> RCRA hazardous waste (waste code = K061), and yet it is a highly recycled material. Specifically, between 2001 and 2007, approximately 42% to 51% of K061 was recycled as evidenced by Biennial Reporting System (BRS) data. Both currently and historically, K061 has been used as an ingredient in fertilizer, an input in making steel, and in the production of zinc products, including pharmaceutical materials. Slag from the smelting of K061 is in high demand for use in road construction. The use of slag is regulated under Pennsylvania's beneficial use program, despite the fact that it is derived from a listed hazardous waste. In fact, there is little doubt that, without its regulation as a hazardous waste, a significantly greater amount of K061 would be diverted from recycling to disposal in non-hazardous landfills.

2. Electroplating wastewater sludge: Listed hazardous waste (F006) that is recycled for its copper, zinc, and nickel content for use in the commercial market. In 2007, approximately 35% of F006 material was recycled according to BRS data. These materials are clearly in no way stigmatized in the marketplace.
3. Chat: Superfund cleanup waste with lead contamination is used in road construction in Oklahoma and the surrounding areas. In this case, the very waste that has triggered an expensive Superfund cleanup is successfully offered in the marketplace as a raw material in road building. The alternative costs of disposal in this case are a significant driver in the beneficial use of this material, and the Superfund origin of the material has not prevented its use.
4. Used oil: Frequently a hazardous waste if disposed of, and is regulated under the RCRA subtitle C standards. While used oil that is recycled is subject to a separate set of standards under subtitle C (and is not identified as a hazardous waste), "stigma" does not prevent home do-it-yourselfers from collecting used oil, or automotive shops from accepting it and sending it on for recovery. Collected used oil may be re-refined, reused, or used as a fuel in boilers, often at the site where it is collected. One large commercial used oil handler reports managing 500 million gallons of used oil a year.
5. Spent etchants: Directly used as ingredients in the production of a copper micronutrient for livestock.
6. Spent solvents: Generated from metals parts washing are directly used in the production of roofing shingles.

And in all such cases, these materials are generally RCRA hazardous wastes before reclamation. Many materials widely used in homes today can be classified as "hazardous" materials, and many come with warning labels. For example, motor oil comes with warning labels. Gasoline would be a characteristic hazardous waste if disposed of, as would many common drain cleaners and household cleaners. Cathode ray tube monitors for TVs and computers, as well as many fluorescent lamps are all hazardous wastes if disposed of. Fluorescent lamps (and CFLs) are potentially hazardous when disposed of because of mercury. Mercury is an indispensable resource, and virtually all of the mercury used for lamps and other uses in the U.S. is derived from discarded mercury or mercury products – that is, from hazardous waste. Even products as unlikely as nicotine gum or dental amalgam would be a hazardous waste when disposed of. Consumers are generally comfortable with these products, and their regulatory status does not discourage their use.

- **Differing Views About Prospect of Future "*Stigma*"**

Stakeholders have also expressed the concern that standards-setting organizations might prohibit the use of CCR in specific products or materials in their voluntary standards. Recently, the American Standards and Testing Materials (ASTM) International Committee C09, and its subcommittee, C09.24, in a December 23, 2009 letter to EPA indicated that ASTM would remove fly ash from the project specifications in its concrete standard if EPA determined that CCR were a hazardous waste. However, ASTM standards are developed through an open consensus process, and current standards cover the use of numerous hazardous materials in construction and other activities. For example, ASTM provides specifications for the reuse of solvents and thus, by implication, does not appear to take issue with the use of these recycled wastes, despite their classification as hazardous wastes.[137]

[137] For example, see ASTM Volume 15.05, Engine Coolants, Halogenated Organic Solvents and Fire Extinguishing Agents; Industrial and Specialty Chemicals, at or ASTM D5396 - 04 Standard Specification for Reclaimed Perchloroethylene.

Others take a different view on how standard-setting organizations will react. Most notably, a US Green Building Council representative has been quoted in the New York Times as saying that LEED incentives for using fly ash in concrete would remain in place, even under an EPA hazardous determination. If the Green Building Council (along with EPA) continues to recognize fly ash as an environmentally beneficial substitute for Portland cement, EPA believes that the use of this material is unlikely to decrease solely because of "stigma" concerns.

In addition, Congress directed government agencies to increase their purchase of recycled-content products. Specifically, section 6002 of RCRA requires EPA to designate products that can be made with recovered materials and to recommend practices for buying these products. Once a product is designated, "procuring agencies" [138] are required to purchase it with the highest recovered material content level practicable if they spend more than $10,000 a year on that item. EPA's federal Comprehensive Procurement Guidelines (CPG), requiring the use of fly ash in cement for federally funded projects, would remain in place. Thus, any federal, state, or local agency carrying out federally funded construction projects would continue to be required to give a preference to fly ash as a Portland cement replacement.

Finally, many state governments have argued that their statutes or regulations prohibit the use of hazardous wastes in their state beneficial use programs, and therefore that, if EPA lists CCR as a hazardous waste (even if only for disposal), their use would be precluded in those states. EPA has reviewed the regulations of 10 states with the highest consumption of fly ash and/or cement and concluded that while these states do not allow the use of hazardous waste in their beneficial use programs, CCR that are beneficially reused will remain Bevill-exempt solid wastes, or in some cases, would not be considered wastes at all and thus, the continued use of CCR under these programs should not be affected by the proposed CCR rule. For EPA's summary of 10 state government CCR beneficial use regulations, see **Appendix K12**. For the above reasons, this RIA presents the increased future CCR beneficial use (Scenario #1) as the "base case." However, this RIA monetizes both scenarios (i.e., induced increase and induced "stigma" decrease) using the following 10-step method.

Step 1. Project Future Annual Tonnage CCR Generation

To estimate the levels of CCR beneficial use, the first task was to project the future annual tonnage of CCR generated by the electric utility industry. The amount of CCR is likely to increase proportionally, as utilities comply with new Clean Air Act requirements. Not reflecting this proportional increase, this RIA relied on the EIA future forecast for coal burned by the electric utility industry.[139] As displayed in **Exhibit 5C-6** below, the EIA data extends out to the year 2035. However, to remain consistent with the other cost and benefit estimates, this RIA extended this trend out to the year 2061 based on regression-fit extrapolation using the following first-order regression of coal burned as dependent variable against year as independent variable:

[138] Procuring agencies include all federal agencies, and any state or local agency or government contractor that uses appropriated federal funds.

[139] Source: Based on 2007 to 2035 annual short tons coal consumption by electric power sector forecast data from the Energy Information Administration (EIA), "Year-by-Year Reference Case Tables (2008-2035): Table 15 Coal Supply, Disposition, and Prices" from the report "Annual Energy Outlook 2010 Early Release," December 14, 2009 at http://www.eia.doe.gov/oiaf/aeo. The EIA report presents a midterm projection and analysis of US energy supply, demand, and prices through 2035, based on the EIA's National Energy Modeling System. Further information on the EIA's projections is available at

$$y = \beta_0 + \beta_1 x$$

Where:

y	=	Tons coal burned at time = x
β_0	=	Tons coal burned at time = 0
β_1	=	Additional tons coal burned each year, on average
x	=	Time elapsed (years)

Running the regression, calculated a β_0 (or intercept) of 1,001,902,312; a β_1 (or slope) of 6,082,277; and an R-squared (or fit) of 87%. This regression was used to extrapolate the EIA projection out to the year 2061 as displayed in **Exhibit 5C-7** and as graphed in **Exhibit 5C-8** below.

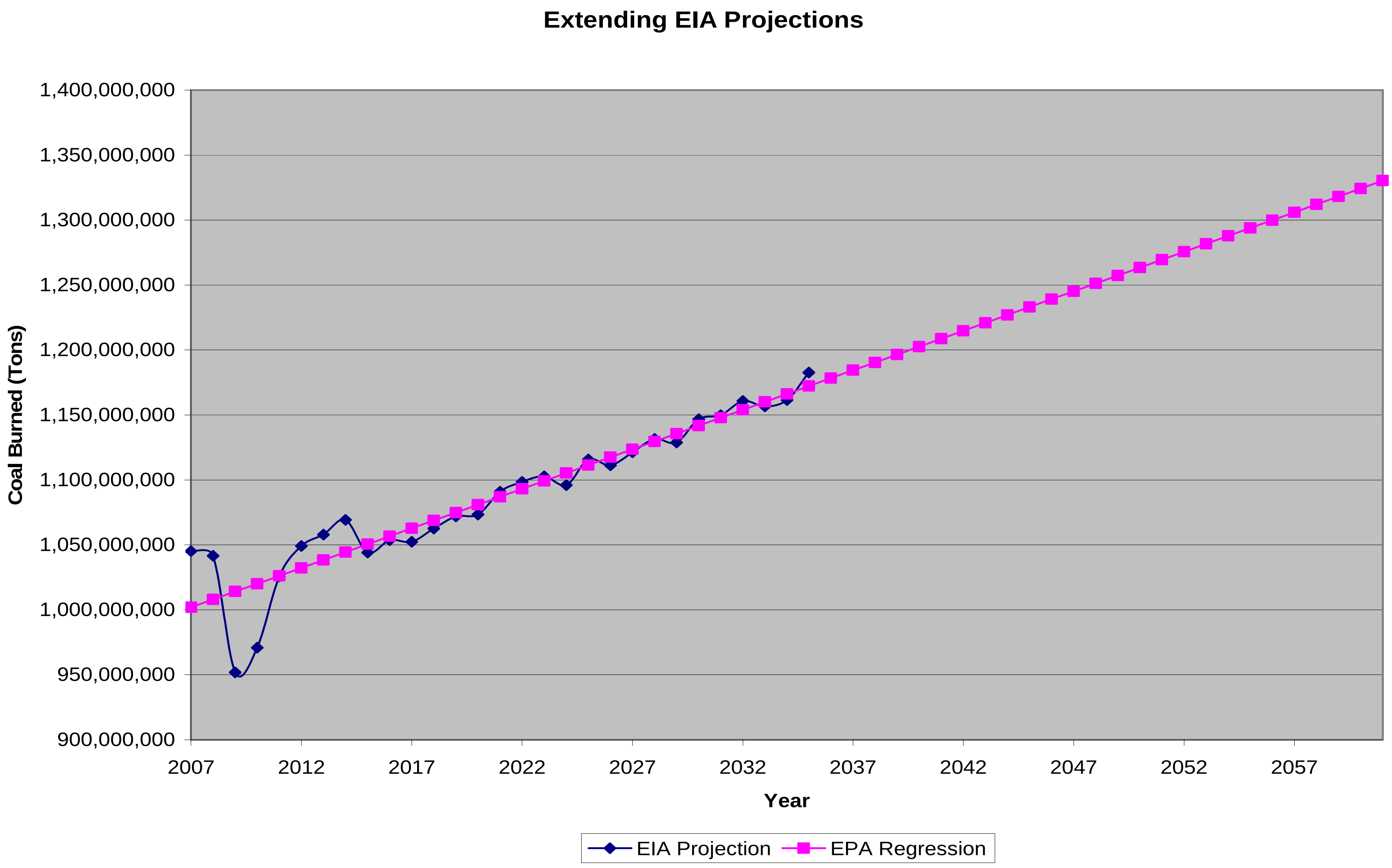
Table 5C-6
Coal Burned Forecast Data From EIA

Year	X = Time Elapsed	Y = EIA Projection (Tons Coal Burned)
2007	0	1,045,140,137
2008	1	1,041,599,976
2009	2	951,846,252
2010	3	970,887,207
2011	4	1,025,782,227
2012	5	1,049,056,519
2013	6	1,057,912,842
2014	7	1,069,233,154
2015	8	1,044,051,880
2016	9	1,053,579,224
2017	10	1,052,420,654
2018	11	1,062,561,646
2019	12	1,071,914,062
2020	13	1,073,440,308
2021	14	1,090,903,931
2022	15	1,098,539,673
2023	16	1,102,742,065
2024	17	1,096,057,129
2025	18	1,115,724,243
2026	19	1,111,202,026
2027	20	1,121,313,477
2028	21	1,131,518,677
2029	22	1,128,823,120
2030	23	1,146,826,782
2031	24	1,149,894,043
2032	25	1,160,750,977
2033	26	1,156,721,802
2034	27	1,161,479,736
2035	28	1,182,647,705

Exhibit 5C-7 EPA Extrapolation of EIA Projection to 2061			
Year	Tons Burned	Year	Tons Burned
2007	1,001,902,312	2035	1,172,206,065
2008	1,007,984,589	2036	1,178,288,342
2009	1,014,066,866	2037	1,184,370,619
2010	1,020,149,143	2038	1,190,452,896
2011	1,026,231,420	2039	1,196,535,173
2012	1,032,313,697	2040	1,202,617,450
2013	1,038,395,974	2041	1,208,699,727
2014	1,044,478,251	2042	1,214,782,003
2015	1,050,560,527	2043	1,220,864,280
2016	1,056,642,804	2044	1,226,946,557
2017	1,062,725,081	2045	1,233,028,834
2018	1,068,807,358	2046	1,239,111,111
2019	1,074,889,635	2047	1,245,193,388
2020	1,080,971,912	2048	1,251,275,665

Exhibit 5C-7 EPA Extrapolation of EIA Projection to 2061			
Year	Tons Burned	Year	Tons Burned
2021	1,087,054,189	2049	1,257,357,942
2022	1,093,136,466	2050	1,263,440,219
2023	1,099,218,743	2051	1,269,522,495
2024	1,105,301,019	2052	1,275,604,772
2025	1,111,383,296	2053	1,281,687,049
2026	1,117,465,573	2054	1,287,769,326
2027	1,123,547,850	2055	1,293,851,603
2028	1,129,630,127	2056	1,299,933,880
2029	1,135,712,404	2057	1,306,016,157
2030	1,141,794,681	2058	1,312,098,434
2031	1,147,876,958	2059	1,318,180,710
2032	1,153,959,235	2060	1,324,262,987
2033	1,160,041,511	2061	1,330,345,264
2034	1,166,123,788	Total	64,136,808,356

Exhibit 5C-8



Extending EIA Projections
1,400,000,000
1,350,000,000
1,300,000,000
1,250,000,000
1,200,000,000
1,150,000,000
1,100,000,000
1,050,000,000
1,000,000,000
950,000,000
900,000,000
Coal Burned (Tons)
2007
2012
2017
2022
2027
2032
2037
2042
2047
2052
2057
Year
EIA Projection
EPA Regression

Based on the most recent CCR beneficial use data from ACAA, EPA estimated the average tons of CCR generated for every ton of coal burned by electric utility plants. For this calculation, this RIA only used the most recent data year (2008) to estimate a conversion rate because over time, the quantities of CCR generated per ton of coal combusted has steadily increased. Thus an average of recent years would not reflect this trend. The steady increase over time is due to tightening of industrial air pollution regulations. This trend would likely continue in the future as further facilities undergo new source review, or implement new Clean Air Act requirements under upcoming EPA rules like the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). Thus, the future annual tonnages of CCR estimated in this RIA are likely under-estimates. Dividing the 2008 tons of CCR generated (136 million tons) by the 2008 tons of coal burned by the electric power sector (1,042 million tons), EPA produced a CCR-to-coal relationship factor of 0.131. Applying this factor to the extrapolated coal consumption projection produced the future CCR generation scenario displayed below in **Exhibit 5C-9**.

Exhibit 5C-9
Projected Future Annual CCR Generation by the Electric Utility Industry:
Scenario Based on Extrapolation of EIA's Projection of Electric Power Sector Coal Burned 2007-2035
(Short Tons)

Year	CCR	Year	CCR	Year	CCR	Year	CCR
2012	134,764,862	2025	145,087,115	2038	155,409,369	2051	165,731,622
2013	135,558,881	2026	145,881,135	2039	156,203,388	2052	166,525,642
2014	136,352,901	2027	146,675,154	2040	156,997,408	2053	167,319,661
2015	137,146,920	2028	147,469,174	2041	157,791,427	2054	168,113,681
2016	137,940,940	2029	148,263,193	2042	158,585,447	2055	168,907,700
2017	138,734,959	2030	149,057,213	2043	159,379,466	2056	169,701,720
2018	139,528,979	2031	149,851,232	2044	160,173,486	2057	170,495,739
2019	140,322,998	2032	150,645,252	2045	160,967,505	2058	171,289,759
2020	141,117,018	2033	151,439,271	2046	161,761,525	2059	172,083,778
2021	141,911,037	2034	152,233,291	2047	162,555,544	2060	172,877,798
2022	142,705,057	2035	153,027,310	2048	163,349,564	2061	173,671,817
2023	143,499,076	2036	153,821,330	2049	164,143,583		
2024	144,293,096	2037	154,615,349	2050	164,937,603		

Appendix K5 to this RIA presents alternative estimates of future CCR generation. These estimates take into account the recent increasing trend in the ratio of tons CCR generated to the tons coal combustion. For example, in year 2035 the constant ratio projection above yields a value of 153 million tons CCR generated whereas the increasing ratio projection in **Appendix K5** yields a value of 191 million tons of CCR generated. While the exact magnitude of such an increase is uncertain, there would be at least some increase as a result of increased air pollution controls. These include future changes due to EPA's New Source Review (NSR), EPA's Clean Air Interstate Rule (CAIR), and EPA's Clean Air Mercury Rule (CAMR).

Step 2. Project Future Baseline Annual Tonnage CCR Beneficial Use (Without RCRA Regulation)

This step involves projecting the extent to which CCR would be beneficially used in the absence of the proposed RCRA regulation of CCR disposal (i.e., future baseline CCR beneficial use). **Exhibit 5C-10** below displays the recent (i.e., 2001 to 2008) trend in annual tonnage of CCR beneficial use, and as a percentage relative to annual CCR generation by the electric utility industry.

Exhibit 5C-10
Recent CCR Beneficial Use Trend (2001-2008)

Year	CCR Generation (short tons)	CCR Beneficial Use (short tons)	Fraction
2001	117,930,542	37,119,321	31.5%
2002	128,703,572	45,523,256	35.4%
2003	121,744,571	46,384,405	38.1%
2004	122,465,119	49,089,818	40.1%
2005	123,126,093	49,612,541	40.3%
2006	124,795,124	54,203,170	43.4%
2007	131,127,693	56,039,005	42.7%
2008	136,073,107	60,593,660	44.5%

Source: American Coal Ash Association (ACAA) at http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=3

If the recent trends in CCR generation and CCR beneficial use continued in a linear fashion, more than 100% of CCR would be beneficially used before year 2061. Furthermore, a linear extrapolation for beneficial use would not be appropriate because as more and more CCR is used, it would likely become increasingly difficult to use the remaining CCR due to saturation of local markets, competition between CCR generators, and other factors, depending on overall macro-economic factors. Thus, for purpose of extrapolation to the 50-year period-of-analysis (2012 to 2061), this RIA instead modeled the recent trend data as an asymptotic, exponential function of the form:

$$Y = 1 - \frac{1}{B^{C*(X+D)}}$$

Where:

Y	=	Percent of CCR beneficially used
X	=	Time elapsed relative to 2001
B	=	1.021
C	=	1.369
D	=	13.99

Beneficial uses of CCR have been consistently growing in the recent past. Since the percent of CCR beneficially used has been growing, EPA sought to characterize that trend so that the future percent beneficially used could be applied to the future tons of CCR. The ACAA data from 2001 to 2008 indicate that this trend was increasing. After running several regressions, EPA disposed of the typical trend fits for various reasons. A first-order (linear) trend line was abandoned because it would have led to beneficial use above 100% well within the time-frame of the analysis. Higher order regressions led to oddities where beneficial use would trend away from 100% at some point in time. Once typical fits were ruled out, EPA assumed that CCR beneficial use would not exceed 100% of CCR generated.[140] Instead, it would potentially become more and more difficult to use CCR as a higher percent went to beneficial uses, because of market limitations. Thus, it made sense to use an exponential curve that approached, but never crossed an asymptote of 100% beneficial use.

To fit an exponential curve to the 2001 to 2008 CCR beneficial use data, a spreadsheet calculation solver was programmed to minimize the residual sum of squares between the actual and projected percent of CCR beneficial use by changing the regression equation variables B, C, and D. From solver result, B was set to 1.021, C was set to 1.369, and D was set to 13.99. Using these values, the future CCR beneficial use projection as measured on a percentage basis relative to CCR generation were estimated, as displayed in **Exhibit 5C-11** and **Exhibit 5C-12** below. The percentage of CCR beneficially used under the baseline (i.e., without RCRA regulation) is expected to gradually approach, but never reach 100% of CCR generation. By 2061 at the end of the 50-year period-of-analysis, 88% of CCR would be beneficially used under this projection. While this is a relatively high number, current experiences in at least one US state and in at least 16 other countries (i.e., 15 European countries + Japan), already demonstrate that very high CCR beneficial use rates of 90% and above are achievable:

1. <u>Wisconsin</u>: Several companies are developing technologies to convert CCR into bricks used in construction, and one such technology was recently commercialized in Wisconsin.[141] Some of these technologies have the potential for using **100%** CCR (fly ash) in brick production, as opposed to the conventional 30%-50% limit for replacing Portland cement in concrete.
2. <u>Europe</u>: As of 2007, 15 European countries reported a CCR beneficial use rate of **89%** (i.e., 55.449 million metric tons beneficially used in 2007 in 24 industrial applications, out of the 62.094 million metric tons generated in 2007).[142]
3. <u>Japan</u>: As of 2006, Japan reported a CCR beneficial use rate of **97%** (i.e., 10.657 million tons used in Japan in 2006 for 3 cement applications, 6 civil engineering applications, 3 construction applications, 2 agriculture/forestry/fisheries applications, and at least three other miscellaneous applications, out of the 10.969 million tons CCR generated in Japan in 2006).[143]

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[140] The fact that some electric utility plants currently excavate previously disposed CCR for supplying to beneficial use markets suggests this may be a limiting assumption which could underestimate future potential growth of CCR beneficial use. For example, one electric utility company reported a 106% CCR beneficial use rate in 2006 for its four electricity plants because it recovered CCR that it had previously disposed.

[141] Source: "CalStar Gives Sneak Peek of Low-Carbon Brick Factory," Cleantech Group, 27 Oct 2009 at http://cleantech.com/news/5217/calstar-flyash-low-carbon-brick

[142] Source: Europe's 2007 CCR beneficial use rate is reported by ECOBA (European Coal Combustion Products Association) which was founded in 1990 by European energy producers to deal with matters related to the usage of construction raw materials from coal. As of 2009, membership in ECOBA consists of 24 companies and associations from 15 countries in Europe, all generators of electricity and heat. ECOBA members represent over 86 % of total CCR generation by the 27 total European countries. ECOBA's 15 member countries are Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Netherlands, Poland, Portugal, Romania, Russia, Spain, and United Kingdom. ECOBA's 2007 CCR beneficial use rate is reported in "Production and Utilisation of CCPs in 2007 in Europe (EU 15)" at: http://www.ecoba.com/evjm,media/statistics/ECOBA_Stat_2007_EU15.pdf

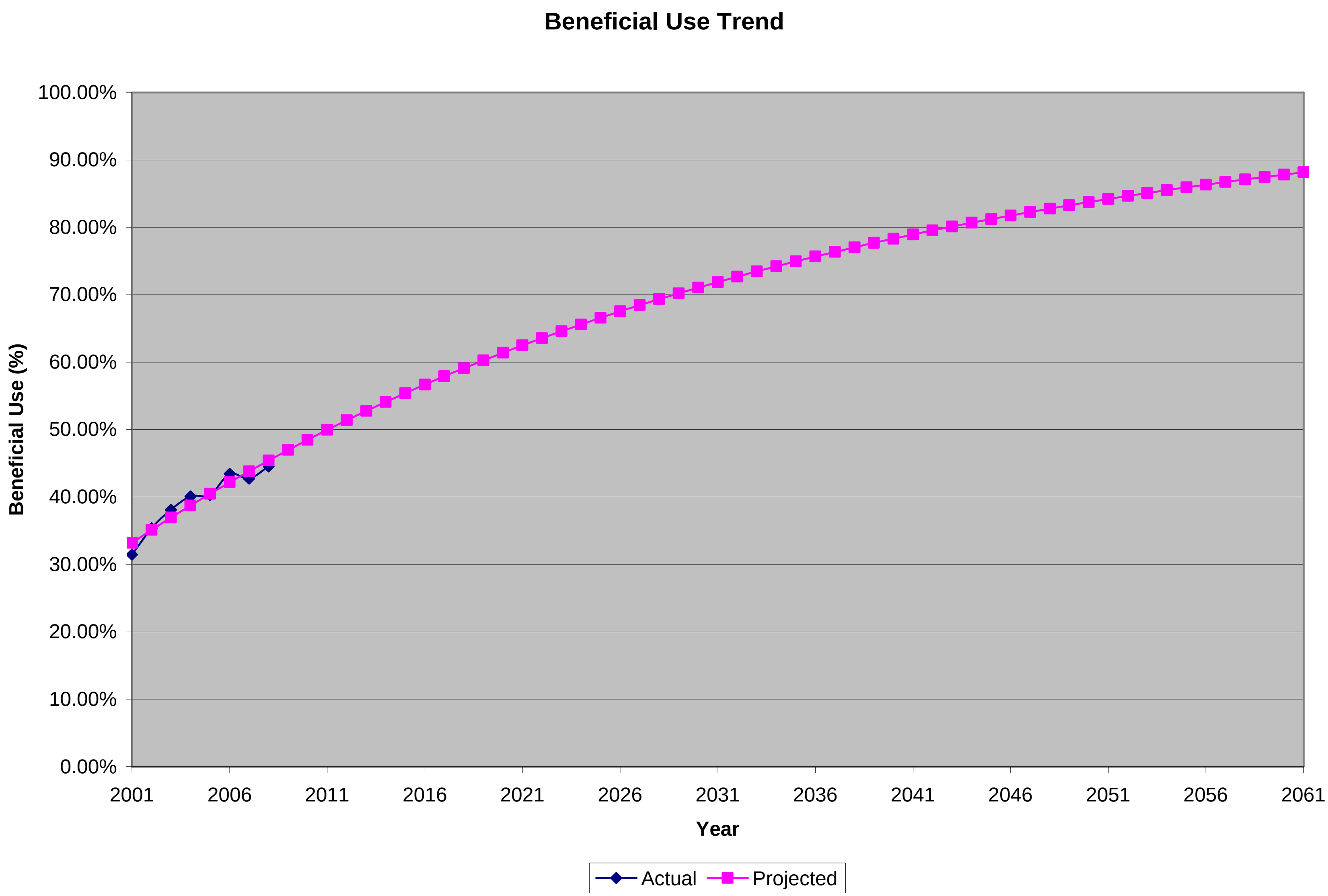
[143] Source: Japan's 2006 CCR beneficial use rate is reported by the Japan Coal Energy Center (JCOAL) in Table 3-1 of "Status of Coal Ash Production" at: http://www.jcoal.or.jp/coaltech_en/coalash/ash01e.html

Exhibit 5C-11
Projected Future Baseline CCR Beneficial Use Measured as Percentage of CCR Generation

Year	% Beneficial Use	Year	% Beneficial Use	Year	% Beneficial Use	Year	% Beneficial Use
2001	33.22%	2016	56.67%	2031	71.89%	2046	81.76%
2002	35.11%	2017	57.91%	2032	72.69%	2047	82.28%
2003	36.96%	2018	59.10%	2033	73.47%	2048	82.79%
2004	38.75%	2019	60.27%	2034	74.22%	2049	83.28%
2005	40.49%	2020	61.39%	2035	74.95%	2050	83.75%
2006	42.19%	2021	62.49%	2036	75.67%	2051	84.21%
2007	43.83%	2022	63.56%	2037	76.36%	2052	84.66%
2008	45.43%	2023	64.60%	2038	77.03%	2053	85.10%
2009	46.98%	2024	65.60%	2039	77.68%	2054	85.52%
2010	48.49%	2025	66.58%	2040	78.32%	2055	85.93%
2011	49.95%	2026	67.53%	2041	78.94%	2056	86.33%
2012	51.37%	2027	68.45%	2042	79.53%	2057	86.72%
2013	52.76%	2028	69.35%	2043	80.12%	2058	87.10%
2014	54.10%	2029	70.22%	2044	80.68%	2059	87.47%
2015	55.41%	2030	71.07%	2045	81.23%	2060	87.82%
						2061	88.17%

Japan's 17 types of CCR beneficial use applications are listed for year 2003 in Table 1 "Breakdown of Fields for the Effective Use of Coal Ash" from "Part 2 CCT Overview Environmental Protection Technologies (Technologies to Effectively Use Coal Ash): 5C1. Coal Ash Generation Process and Application Fields" at http://www.brain-c-jcoal.info/cctinjapan-files/english/2_5C1.pdf

Exhibit 5C-12



Applying the percent of CCR beneficially used in each year to the quantities of CCR shown above, the following future annual tons of beneficially used CCR may be expected as displayed below in **Exhibit 5C-13**. The monetized value of this future baseline projection is:

	PV @3% discount	PV @7% discount
Economic value:	$102,290 million PV	$51,170 million PV
Lifecycle social value:	$1,554,323 million PV	$777,541 million PV

Exhibit 5C-13
Baseline Projected Future CCR Beneficial Use
(Short Tons)

Year	CCR Beneficial Use	Year	CCR Beneficial Use	Year	CCR Beneficial Use	Year	CCR Beneficial Use
2012	69,234,181	2025	96,599,301	2038	119,713,602	2051	139,569,037
2013	71,516,427	2026	98,514,244	2039	121,345,430	2052	140,985,202
2014	73,767,022	2027	100,404,645	2040	122,958,473	2053	142,387,139
2015	75,986,563	2028	102,270,993	2041	124,553,122	2054	143,775,155
2016	78,175,638	2029	104,113,770	2042	126,129,762	2055	145,149,549
2017	80,334,827	2030	105,933,448	2043	127,688,769	2056	146,510,616
2018	82,464,703	2031	107,730,494	2044	129,230,513	2057	147,858,644
2019	84,565,827	2032	109,505,366	2045	130,755,358	2058	149,193,918
2020	86,638,755	2033	111,258,513	2046	132,263,659	2059	150,516,713
2021	88,684,034	2034	112,990,378	2047	133,755,767	2060	151,827,302
2022	90,702,202	2035	114,701,396	2048	135,232,025	2061	153,125,952
2023	92,693,789	2036	116,391,994	2049	136,692,770		
2024	94,659,318	2037	118,062,592	2050	138,138,332		

Step 3. Estimate Potential Induced Effect of RCRA Regulation on CCR Beneficial Use

After establishing a future baseline of CCR beneficial use annual tonnage, this step involved formulating three alternative scenarios whereby future CCR beneficial use under RCRA regulation of CCR disposal could either:

- Scenario #1: Increase in beneficial use
- Scenario #2: Decrease
- Scenario #3: Remain unchanged from baseline

Increases due to increased disposal costs were estimated first and constitute the "base case" of this RIA. By increasing disposal costs, electric utility plants face an "*avoided disposal cost incentive*" to ship their CCR farther for beneficial uses by other industries; that is, utilities would be willing to pay more transportation costs to avoid the higher disposal costs. Thus, RCRA regulation of CCR disposal would likely open new markets at farther transport distances, or increase purchases by existing markets. The effect of this stimulus would be to increase CCR beneficial use. The concept of "*avoided disposal cost incentive*" is recognized and defined by the American Coal Ash Association (ACAA) on its website as follows:

> "*If a [coal-fired electric utility] plant markets its [CCR] into commercial applications, then disposal of this [CCR] is not required. Not only is a revenue stream created for the [coal-fired electricity plant] but also the need to dispose of the [CCR] is avoided. As discussed above, disposal is not just the transportation and placement of [CCR] in a disposal site. The need for future space is a concern. If [CCR is] marketed, then the need to develop future [CCR disposal] sites (including land acquisition, permitting, design and construction costs) is avoided …. It is not uncommon for a company to help offset the costs of transportation or placement at construction sites by providing the contractor or trucking firm a payment of some sort. For example, if the cost of disposal at a plant is normally four dollars a ton, then the company may arrange a payment of four dollars or less to the contractors to cover transportation and placement costs. The difference between the amount of this payment and the cost of disposal is also referred to as "avoided disposal costs.*" Source: ACAA Frequently Asked Question nr. 14 webpage at: http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=5#Q14

On the other hand, some stakeholders have claimed that a Subtitle C "hazardous waste" approach would have a "stigma" effect on CCR, reducing their use. That is, due to the label of "hazardous waste," some purchasers of CCR might opt to turn down the CCR for more expensive substitutes in fear that the CCR might either harm their sales or create liability, and generators might be reluctant to provide the material to users because of liability concerns. The final alternative, that beneficial use quantities remain the same, results in no net costs or benefits for the Subtitle C approach because it is assumed that the baseline trend plays out the same as it would absent a rule. Thus, no further analysis of this option was necessary.

The two alternative Scenario analyses (i.e., Scenario #1, Scenario #2) in this section build upon the ACAA's historical CCR beneficial use data.[144] ACAA data on the beneficial use was modified to remove the use of CCR in minefilling applications because the proposed rule does not address minefilling operations. Excluding 100% of the ACAA reported quantity of CCR used in minefilling results in a reduction of 1.13 million tons per year in the amount beneficially used. As a result, the 2005 quantity of beneficial use relied upon for our analyses is 48.5 million tons per year of CCR, rather than the original 49.6 million tons per year reported by ACAA.

[144] Source: Historical CCR beneficial use data from the American Coal Ash Association (ACAA) "Coal Combustion Products -- Production & Use Statistics" webpage at: http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=3

Step 4: Estimate Potential Induced Increase in Future CCR Beneficial Use (Scenario #1)

Under the assumptions and numerical framework described below, this RIA estimates that the Subtitle C option would initially induce an increase of 28% in CCR beneficial uses. This growth estimate is a generalized, aggregate estimate across all 15 existing CCR beneficial use markets. Due to a lack of available data (i.e., market location, elasticity, cross-elasticity, etc.), this estimate does not take into account unique economic supply or economic demand conditions in any single market or for any particular beneficial use, relative to the generalized aggregate estimate. However, key uses, such as use of fly ash as a Portland cement replacement, have great opportunity for increased use, far above 28% in the initial year. For example, if fly ash use in concrete increased to a 30% replacement rate for Portland cement (a very reasonable replacement rate, consistent with current specifications), fly ash usage could increase by more than 100% from the 14 million tons used annually at current replacement rates of 10% to 12%. One of the main barriers to this increase usage is transportation costs. Because EPA did not have specific data on this market, this RIA does not specifically quantify it; however, it is exactly the type of use that increased disposal costs could foster.

The method presented below may be characterized as a "*Raw Material Cost Method*" which represents the 1st stage of the generalized 4-stage materials flow lifecycle (MFL) through the economy. This 4-stage MFL conceptual framework has been integrated into existing cost modeling software systems[145] used by government agencies and the private sector, and consists of the following four material flow cradle-to-grave or cradle-to-cradle stages:

1st MFL stage: Raw materials acquisition
2nd MFL stage: Product manufacturing
3rd MFL stage: Product use, re-use, maintenance
4th MFL stage: Recycling, waste management

This method evaluates the difference in raw material acquisition cost under two alternative conditions. The first condition (Baseline) represents current conditions without RCRA regulation of CCR disposal. The second condition (Subtitle C) represents future conditions with RCRA regulation for CCR disposed by electric utilities.

The economic mechanism in this estimation method, which affects different raw material acquisition costs under the two alternative conditions, is the "*avoided disposal cost incentive*" described above. In other words, it is the avoided disposal cost under RCRA regulation compared to the industry's baseline disposal cost. This difference in cost is an incremental cost relative to baseline. From an economic standpoint, this represents an incremental economic incentive to electric utility plants to reduce or eliminate CCR disposal, thereby reducing or avoiding new regulatory compliance costs by increasing their future annual supply of CCR to beneficial use markets. This "*avoided disposal cost incentive*" induced by RCRA regulation has already been anticipated in 2009 by at least one CCR beneficial use industry (***bold face*** added for emphasis):

[145] Example cost modeling/estimation software systems using this 4-stage framework are 1. FAST, 2. EE Energy/ Environment Life-Cycle Assessments, 3. EPA Enviro Accounting Method, and 4. TEAM (Tools for Environmental Analysis and Mangement); source: "Table 3-1. Overview of Life-Cycle Stages and Costs Considered by Software Systems and Tools" at http://www.p2pays.org/ref/01/00047/00047e.htm

> "*Using [coal] fly ash in building materials is nothing new, as it's already incorporated in products including Portland cement and asphalt concrete. However, it's estimated that 65 percent of fly ash from coal-fired power plants worldwide goes to landfills, with the U.S. reporting a slightly lower 57 percent, according to the American Coal Ash Association. Kane said the key to CalStar's products is that they offer the same performance as aesthetics as traditional bricks, but without the energy use. Currently, the cost to buy a ton of fly ash in the U.S. ranges from about $5 to $30, but* ***that could change as fly ash disposal faces tighter government restrictions, he said. "The cost to send fly ash to landfills will go up, and utilities will be faced with finding the most beneficial use,*** *" Kane said.*"[146]

The baseline average "*raw material acquisition cost*" is $94.50/ton, consisting of CCR price, CCR disposal cost, and CCR transportation cost:

1. <u>CCR price:</u> Price paid to electric utility plants by beneficial use industries for the purchase of CCR. ACAA identifies 15 industrial beneficial use markets involving the beneficial use of CCR, many of which involve the construction industry.[147] The average price paid by these industries to electric utility plants is $3.00 per ton, across a reported range of $0 to $45 per ton.[148]
2. <u>CCR disposal cost:</u> Cost to the electric utility industry for disposing CCR. This factor also represents the "*avoided disposal cost incentive*" in the sense that this is an "*avoided cost*" to the electric utility industry for CCR tonnages beneficially used by other industries. A unitized "total cost" ($ per ton) for CCR disposal consisting of both a 50-year amortized capital cost for CCR disposal units plus a 50-year amortized O&M costs for CCR disposal is used to monetize this cost factor.[149] The average baseline CCR disposal cost is $59/ton (source: **Exhibit 3L**). This is additive to the "CCR price" element because it represents a subsidy by electricity plants.
3. <u>CCR transport cost:</u> Average one-way CCR transport distance between electric utility plants and their CCR beneficial use customer industries. This method does not explicitly distinguish whether the transport cost is paid by the electric utility plants or by the beneficial use industries.[150] Average CCR transport cost from electric utility plants to beneficial use sites is estimated at ($0.26/mile/ton)[151] x (125 miles)[152] = $32.50/ton.

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[146] Source: Cleantech Group, "CalStar Gives Sneak Peek of Low-Carbon Brick Factory," 29 Oct 2009 at http://cleantech.com/news/5217/calstar-flyash-low-carbon-brick
[147] ACAA lists 15 beneficial use markets: concrete, cement, flowable fill, structural fill/embankments, road base/sub-base, soil modification, mineral filler in asphalt, snow/ice control, blasting grit/roofing granules, mining applications, gypsum panel products, waste stabilization/solidification, agriculture, construction aggregate, and miscellaneous uses.
[148] $3 per-ton CCR price is from Column E of **Exhibit 5C-1**; this price represents the tonnage-weighted average across a reported price range of $0 to $45 per ton CCR.
[149] Although in the short-run (< 3 years), marginal business decisions may be made relative to short-term O&M costs, long-term (> 3 years) business decisions usually consider both amortized capital costs and O&M costs.
[150] The CCR price data used to monetize the CCR price factor above are reportedly based on "FOB" prices which may include some portion of transport cost (e.g., transport vehicle loading to a trans-shipment location).
[151] $0.26 per-ton-per-mile is the midpoint of the $0.15 to $0.37 per-ton-per-mile range reported in "Estimation of the Marginal Greenhouse Gas Abatement Curve for the Beneficial Use of Fly Ash as a Substitute for Portland Cement in Ready-Mix Concrete Production," EPA Office of Resource Conservation and Recovery (ORCR), 19 June 2009, page 11.
[152] 125 miles is the midpoint of the 100 to 150 mile range reported in footnote 74 on page 4-8 of EPA's 03 June 2008 "Report to Congress: Study on Increasing the Usage of Recovered Mineral Components in Federal Funded Projects Involving Procurement of Cement or Concrete to Address the Safe, Accountable, Flexible, Efficient Transportation, Equity Act: A Legacy for Uses by the EPA, the Department of Transportation (DOT) and the Department of Energy (DOE)," report nr. EPA530-R-08-007, available at http://www.epa.gov/waste/conserve/tools/cpg/products/cement2.htm.

In comparison to these baseline "*raw materials acquisition cost*" elements, CCR disposal costs are estimated to be $83/ton for the Subtitle C option (source: **Exhibit 4K**). While this represents a 44% increase ($26/ton) over the baseline disposal cost of $59/ton, this ignores the CCR price and the transportation cost elements. Factoring these components in, the $26/ton increase represents a 28% increase above the total baseline raw material cost of $94.50/ton. This RIA applies this 28% growth factor to represent demand elasticity[153] assumptions of:

+0.64 with respect to the CCR "*avoided disposal cost incentive*" factor (i.e., +28%/+44%).
+1.00 with respect to total "*raw material acquisition cost*" consisting of all three cost factors included (i.e., +28%/+28%).

This RIA applies the elasticity estimate of 1.0 in reference to the "*raw material acquisition cost*" to represent the potential increase in CCR beneficial use by 28% over the baseline under the Subtitle C option. The other regulatory options are proportionately adjusted below. In comparison to historical annual percentage changes in CCR beneficial use tonnages, this 28% increase is a reasonable assumption as it falls between the -22.6% decrease and +55.2% increase min-max range (annual mean = +8.2% increase) over the 43 year period 1966 to 2008,[154] as displayed in **Exhibit 5C-14** below.

Exhibit 5C-14
Historical Annual Percentage Change in CCR Beneficial Use (1966-2008)

A	B	C	D	E	F (E/C)	G
Item	Year	CCR generation (tons)	CCR disposal (tons)	CCR beneficial use (tons)	Percent CCR beneficial use	Annual % change in CCR beneficial use tons
1	1966	26,000,000	22,000,000	4,000,000	15%	
2	1967	28,000,000	23,000,000	5,000,000	18%	25.0%
3	1968	30,000,000	24,000,000	6,000,000	20%	20.0%
4	1969	31,500,000	26,000,000	5,500,000	17%	-8.3%
5	1970	39,000,000	33,200,000	5,800,000	15%	5.5%
6	1971	41,500,000	32,500,000	9,000,000	22%	55.2%
7	1972	46,000,000	38,000,000	8,000,000	17%	-11.1%
8	1973	50,000,000	41,500,000	8,500,000	17%	6.3%
9	1974	59,000,000	50,000,000	9,000,000	15%	5.9%
10	1975	60,000,000	50,000,000	10,000,000	17%	11.1%
11	1976	62,000,000	50,000,000	12,000,000	19%	20.0%
12	1977	67,000,000	53,000,000	14,000,000	21%	16.7%
13	1978	68,000,000	52,000,000	16,000,000	24%	14.3%
14	1979	75,500,000	60,000,000	15,500,000	21%	-3.1%
15	1980	66,000,000	54,000,000	12,000,000	18%	-22.6%
16	1981	68,000,000	51,500,000	16,500,000	24%	37.5%

[153] In economics, the elasticity of supply indicates the responsiveness of the quantity of a product or service supplied to the market relative to a change in its price (i.e., (% change in quantity supplied) / (% change in its price)). Similarly, the elasticity of demand indicates the responsiveness of the quantity of market demand for a product or service relative to a change in its price (i.e., (% change in quantity demanded) / (% change in its price)).
[154] Historical CCR beneficial use data for 1966-2008 from ACAA at http://www.acaa-usa.org/associations/8003/files/Revised_1966_2007_CCP_Prod_v_Use_Chart.pdf

Exhibit 5C-14 Historical Annual Percentage Change in CCR Beneficial Use (1966-2008)						
A	B	C	D	E	F (E/C)	G
Item	Year	CCR generation (tons)	CCR disposal (tons)	CCR beneficial use (tons)	Percent CCR beneficial use	Annual % change in CCR beneficial use tons
17	1982	65,000,000	51,000,000	14,000,000	22%	-15.2%
18	1983	64,000,000	51,000,000	13,000,000	20%	-7.1%
19	1984	69,000,000	53,000,000	16,000,000	23%	23.1%
20	1985	66,000,000	48,000,000	18,000,000	27%	12.5%
21	1986	67,500,000	53,000,000	14,500,000	21%	-19.4%
22	1987	82,000,000	63,000,000	19,000,000	23%	31.0%
23	1988	83,000,000	62,500,000	20,500,000	25%	7.9%
24	1989	87,000,000	69,500,000	17,500,000	20%	-14.6%
25	1990	86,000,000	64,000,000	22,000,000	26%	25.7%
26	1991	88,000,000	65,500,000	22,500,000	26%	2.3%
27	1992	82,000,000	62,000,000	20,000,000	24%	-11.1%
28	1993	88,000,000	69,000,000	19,000,000	22%	-5.0%
29	1994	89,000,000	66,000,000	23,000,000	26%	21.1%
30	1995	92,000,000	68,000,000	24,000,000	26%	4.3%
31	1996	102,000,000	76,000,000	26,000,000	25%	8.3%
32	1997	104,000,000	74,500,000	29,500,000	28%	13.5%
33	1998	108,000,000	77,000,000	31,000,000	29%	5.1%
34	1999	107,000,000	74,000,000	33,000,000	31%	6.5%
35	2000	108,500,000	76,500,000	32,000,000	29%	-3.0%
36	2001	117,930,542	80,811,221	37,119,321	31%	16.0%
37	2002	128,703,572	83,180,316	45,523,256	35%	22.6%
38	2003	121,744,571	75,360,166	46,384,405	38%	1.9%
39	2004	122,465,119	73,375,301	49,089,818	40%	5.8%
40	2005	123,126,093	73,513,552	49,612,541	40%	1.1%
41	2006	124,795,124	70,591,954	54,203,170	43%	9.3%
42	2007	131,127,693	75,088,688	56,039,005	43%	3.4%
43	2008	136,073,107	75,479,447	60,593,660	45%	8.1%
Minimum annual %=						-22.6%
Maximum annual % =						55.2%
Median annual % =						6.4%
Mean annual % =						8.2%
Overall percent growth =						1414.8%
Average annual compound growth =						6.5%

This is a limiting analysis because it does not include other developments that may be expected increasingly to push CCR to beneficial use:

1. Aspects of the proposed CCR rule: This analysis does not take into account that some RCRA regulatory options for CCR disposal require electricity plants to move to dry management of CCR, either through changes to air pollution control strategies or through drying of CCR after they have been generated. This will make the material more amenable to beneficial uses.
2. The analysis is based on current market conditions: It does not take into account new technologies and products now being developed, for example, involving the use of CCR in brick construction.[155] An increased "*avoided disposal cost incentive*" could be a great boon to such new beneficial use technologies, applications, and products.

- **Comparison of "*Raw Materials Acquisition Cost Method*" to "*Travel Cost Method*"**

The method applied above involved three cost components of the "*raw material acquisition cost*," not just in relation to the transportation cost component, which is relatively narrower approach that can be called a "*Transportation Cost Method*." Compared to this other method, the raw material acquisition cost method provides a smaller estimate of effect because the incremental cost is evaluated relative to a broader set of costs thereby translating numerically into a smaller percentage change, rather than relative to only one cost factor which would translate into a relatively larger percentage change. This methodological difference may be illustrated by using the calculation numbers applied above, to only the transportation cost factor. Using a simplistic transportation distance model which uses the CCR disposal unit cost ($ per ton) to determine the average circular radius of a CCR transportation market between electricity utility plant suppliers of CCR and their beneficial users customers, the increase in transport distance would be calculated as follows (relative to the 2005 49.6 million tons CCR beneficially used as reported by the ACAA):

- Baseline transportation cost (without CCR rule)
  ($0.26/mile/ton) x (125 miles one-way average CCR transport distance) x (49.6 million tons/year beneficial use in 2005) = $1,612 million/year transport cost
- Hypothetical new transportation cost (with rule)
  Transport subsidy equivalency = ($85/ton avoided disposal cost under rule) – ($59/ton avoided disposal cost without rule) = $26/ton subsidy equivalency
  (49.6 million tons/year beneficial use) x ($26/ton subsidy equivalency) = $1,290 million per year subsidy equivalency
- Hypothetical new transport distance:
  [($1,612 million/year) + ($1,290 million/year)] / (49.6 million tons per year beneficial use) / ($0.26/mile/ton) = 225 miles
  Percentage increase in transport distance:
  [(225 miles) – (125 miles)] / (125 miles) = 80% increase in radial transport distance

[155] Several companies are developing technologies to convert CCR into bricks used in construction, and one such technology was recently commercialized at a power plant in Wisconsin. Some of these technologies have the potential for using 100% CCR (fly ash) in brick production, as opposed to the conventional 30%-50% limit for replacing Portland cement in concrete.

- Hypothetical expansion of CCR customer delivery area:
  Baseline customer area @125 miles radial transport distance = (3.1415 x (125 miles)^2) = 49,100 square miles
  Expanded customer area @225 miles radial transport distance = (3.1415 x (225 miles)^2) = 159,000 square miles
  Incremental increase in customer area = (159,000 – 49,100 sq. miles) / (49,100 sq.miles) = 124% increase in delivery area

Step 5: Estimate Hypothetical "*Stigma*" Decrease in Future CCR Beneficial Use (Scenario #2)

A number of industry and state government stakeholders have asserted to the EPA, that designating CCR as a hazardous waste (even if the designation is only applicable to those CCR that are disposed of) would create a "stigma" that would reduce or curtail or eliminate the beneficial use of CCR. This RIA presents an alternative stigma effect scenario in an effort to evaluate what countervailing impact that "stigma" may have on the increased beneficial use of CCR estimated in this RIA above. This potential reduction scenario assumes different potential impacts in three categories of beneficial CCR usage (uses covered in the CPGs, consolidated uses, and unconsolidated uses). For documentation of the calculations discussed in this section, see **Appendix K13**.

- **"*Stigma*" on CCR in Consolidated Uses Specified in Comprehensive Procurement Guidelines**

First, some uses for CCR involve the production of specific products that are expressly covered by the federal Comprehensive Procurement Guidelines (CPGs), which require procuring agencies that spend more than $10,000 a year on an item to buy products containing recovered materials. Procuring agencies are federal, state, and local agencies, and their contractors, that use appropriated federal funds. For example, if a county agency spends more than $10,000 a year on an EPA-designated item and part of that money is from appropriated federal funds, then the agency must purchase that item made from recovered materials.[156] As such, if there were any impacts due to stigma, EPA believes that the markets for these uses are less likely to be affected by a hazardous waste label for CCR. CCR categories currently covered under the CPGs include concrete/concrete products/grout, flowable fill, and blasting grit/roofing granules.

According to U.S. Census data, the public portion of total construction spending equaled 20.7% in 2005, 21.4% in 2006, 24.6% in 2007, and had swelled to 35.4% by Nov. 2009 (likely in direct relationship to the current state of the economy and current federal stimulus spending). Similarly, U.S. EPA (2008d) estimates that for concrete projects, the cement demand attributable to federal concrete projects reflects approximately 20% of the annual total demand. EPA then apportioned the amounts of CCR usage into a public construction vs. a private construction split. Based on the Census Bureau and EPA data,[157] EPA established a 25% / 75% split of the totals for these products, such that 25% of the total usage is recognized as accruing to public construction and 75 % to private construction.

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[156] Agencies may elect not to purchase designated items when the cost is unreasonable; inadequate competition exists; items are not available within a reasonable period of time; or items do not meet the agency's reasonable performance specifications.
[157] Source: EPA "Report to Congress: Study on Increasing the Usage of Recovered Mineral Components in Federal Funded Projects Involving Procurement of Cement or Concrete to Address the Safe, Accountable, Flexible, Efficient Transportation, Equity Act: A Legacy for Uses by the EPA, the Department of Transportation (DOT) and the Department of Energy (DOE)," EPA530-R-08-007, June 3, 2008 at: http://www.epa.gov/waste/conserve/tools/cpg/products/cement2.htm

Given that the public procurement of these products should continue because of their CPG designation, this RIA assumed that there will be no negative impact on the public portion of CCR usage. That is, the demand for CPG products made from CCR will be the same as it currently is for the public portion of the construction market. However, this RIA assumes a 50% reduction of total private uses.[158] This results in an estimated 6.8 million tons per year reduction in CCR use for this category of beneficial uses.

- **"*Stigma*" for CCR in Other Consolidated Uses**

Not all consolidated uses of CCR are covered under federal CPGs. Thus, this scenario also estimated the potential impacts on the use of CCR in non-CPG, consolidated uses. These CCR categories include blended cement/raw feed for clinker, mineral filler in asphalt, gypsum panel products, waste stabilization/solidification, and miscellaneous/other. In the case of CCR used in blended cement, mineral filler – asphalt, gypsum for wallboard, and miscellaneous/other applications, this RIA assumed that 50% of these uses will be reduced. Thus, the potential reductions in this category will total 6.8 million tons per year.

For the use of CCR in waste stabilization/solidification applications, this RIA assumed that stigma will not have a negative impact. For this use, the CCR are already being used in a waste management context. The CCR are used in secure landfills to immobilize wastes typically more hazardous than the CCR themselves. Therefore, this RIA projects no reduction in the future annual tonnage of CCR used for this purpose.

- **"*Stigma*" for Unconsolidated Uses**

In addition to the consolidated uses of CCR discussed above, CCR can be employed in unconsolidated uses. For some of these uses, the CCR products may be more similar to the disposed material proposed to be regulated. In addition, they have typically not been chemically fixed within a product. As a result, stigma concerns may be more plausible. Markets that involve unconsolidated uses of CCR include structural fill/embankments, road base/sub-base, soil modification/stabilization, snow/ice control, aggregate, agriculture, and miscellaneous/other. For purpose of the sensitivity analysis, this RIA assumed a potential reduction of 80%.[159] This results in an additional 11.1 million tons per year reduction of beneficially used CCR. By adding the 6.8 million tons from CPG consolidated uses, to the 6.8 million tons from non-CPG consolidated uses, plus the 11.1 million tons from unconsolidated uses, this RIA estimates that a severe stigma effect would lead to a 51% reduction of beneficial use.

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[158] The 50% reduction is considered a worst-case assumption because these materials provide significant value at competitive costs – for example, concrete that includes fly ash typically performs better than non-CCR concrete, and is likely to retain favorable treatment under Leadership in Energy and Environmental Design (LEED). In addition, academic studies of "stigma" associated with products rarely leads to decreased usage to this extent.

[159] EPA has assumed this high "stigma" effect because a number of the uses may appear close to the disposal scenario, e.g., structural fills. Also, it is widely recognized that CCR in unconsolidated uses may present risks, if used in the wrong conditions. (Indeed, EPA takes comment on unconsolidated uses in the preamble to the CCR proposed rule due to the increased potential for risks.) Some of these uses are likely to be particularly sensitive to public concerns and liability concerns. These include agricultural uses and dispersive uses, like use of bottom ash or boiler slag for ice and snow control. Therefore, if stigma does have a role to play, EPA believes it is reasonable to assume it will be significant for unconsolidated uses. Even for the purposes of a worst-case sensitivity analysis, however, EPA believes that, given the success of many of these uses in states with rigorous beneficial use programs, "stigma" will not completely eliminate such uses; therefore, it has estimated a decrease of 80%.

Step 6: Apply Estimated Induced Effect Scenarios to Baseline CCR Beneficial Use

Applying the first effect (increase in the sale of CCR due to a decrease in price), EPA noted that a 28% increase with an elasticity of 1.0 would makes sense when there is ample room for growth. But as the market becomes more and more saturated, it is less and less likely that unit elasticity would apply. Instead, the elasticity is likely to decrease with increasing saturation. To account for this, the beneficial use increase was set to 28% of either the existing beneficial use tonnage, or to 28% of the remaining CCR tonnage, whichever was less. In other words, once beneficial use was greater than 50% of total CCR, the increase would be constrained to 28% of what was left over after beneficial use was accounted for. EPA also accounted for the fact that the price change would not fully affect the market until the rule (and therefore the costs) had been phased in. Full implementation was assumed to occur by 2019. However, industry would undoubtedly likely attempt to prepare for these increased costs as soon as a final rule was passed, and therefore the beneficial use increases were assumed to linearly approach 28% by 2019. The projected tons of beneficial use under Subtitle C are shown in Exhibit 28 below.

As seen below, subtitle C in EPA's analysis would drive more CCR toward beneficial use due to the increased costs of disposal. However, as discussed in Step 4 above, there is also the possibility that there would be a stigma associated with the "hazardous waste" designation. Here the beneficial use of CCR would be 49% of the baseline due to stigma. Since the maximum CCR beneficially used is less than 50% of all CCR, the constraint imposed on the straight 28% increase would not be necessary. Thus, once the full 51% decrease and 28% increase are accounted for, the future CCR beneficial use annual tonnages are calculated as displayed below in **Exhibit 5C-15**.

Exhibit 5C-15
Two Alternative Scenarios of Projected Future CCR Beneficial Use 2012-2061
(Short Tons)

Year	Scenario #1: w/out Stigma	Scenario #2: w/Stigma	Year	Scenario #1: w/out Stigma	Scenario #2: w/Stigma
2012	71,527,755	33,924,749	2037	128,297,364	82,753,160
2013	75,999,399	36,206,995	2038	129,708,417	84,404,170
2014	80,338,539	38,457,590	2039	131,105,658	86,035,997
2015	84,549,013	40,677,131	2040	132,489,375	87,649,041
2016	88,634,566	42,866,206	2041	133,859,848	89,243,690
2017	92,598,855	45,025,395	2042	135,217,354	90,820,330
2018	96,445,450	47,155,270	2043	136,562,164	92,379,337
2019	100,177,835	49,256,395	2044	137,894,545	93,921,081
2020	101,892,669	51,329,323	2045	139,214,759	95,445,925
2021	103,587,595	53,374,602	2046	140,523,061	96,954,227
2022	105,263,001	55,392,770	2047	141,819,704	98,446,334
2023	106,919,270	57,384,357	2048	143,104,936	99,922,592
2024	108,556,775	59,349,885	2049	144,378,997	101,383,338
2025	110,175,889	61,289,868	2050	145,642,128	102,828,900
2026	111,776,973	63,204,812	2051	146,894,561	104,259,605
2027	113,360,387	65,095,213	2052	148,136,525	105,675,770
2028	114,926,484	66,961,561	2053	149,368,245	107,077,707
2029	116,475,608	68,804,337	2054	150,589,942	108,465,723
2030	118,008,102	70,624,016	2055	151,801,831	109,840,117
2031	119,524,301	72,421,062	2056	153,004,125	111,201,184
2032	121,024,534	74,195,934	2057	154,197,031	112,549,212
2033	122,509,126	75,949,081	2058	155,380,753	113,884,485
2034	123,978,394	77,680,946	2059	156,555,491	115,207,281
2035	125,432,652	79,391,964	2060	157,721,441	116,517,870
2036	126,872,208	81,082,562	2061	158,878,794	117,816,520

Step 7: Estimate Potential Induced Effects on Future Annual Tonnages of CCR Beneficial Use

Exhibit 5C-16 below shows beneficial use projected under Subtitle C. Beneficial use under the increasing disposal cost scenario would lead to an increase of 28% above the baseline estimate. However, as the market becomes more and more saturated, it will likely become harder to increase beneficial use. Thus, the increase is constrained to 28% of the remaining unused CCR. The elasticity column represents the effective percent change in quantity for each percent change in price once this constraint has been accounted for. While the elasticity is assumed to initially be 1.0, the effect of market saturation drives that elasticity towards zero over time as seen below.

Exhibit 5C-16
Scenario #1: Increase in Future CCR Beneficial Use Under the Subtitle C Option

Year	CCR generation (tons)	% beneficial use	Beneficial use (tons)	% increase	Increased beneficial use (tons)	Increase w/o mine filling (tons)	Implied elasticity
2012	134,764,862	53.08%	71,527,755	3.31%	2,293,574	2,241,198	0.95
2013	135,558,881	56.06%	75,999,399	6.27%	4,482,972	4,380,599	0.90
2014	136,352,901	58.92%	80,338,539	8.91%	6,571,517	6,421,451	0.85
2015	137,146,920	61.65%	84,549,013	11.27%	8,562,450	8,366,919	0.80
2016	137,940,940	64.26%	88,634,566	13.38%	10,458,928	10,220,089	0.76
2017	138,734,959	66.75%	92,598,855	15.27%	12,264,028	11,983,968	0.73
2018	139,528,979	69.12%	96,445,450	16.95%	13,980,748	13,661,485	0.69
2019	140,322,998	71.39%	100,177,835	18.46%	15,612,008	15,255,494	0.66
2020	141,117,018	72.20%	101,892,669	17.61%	15,253,914	14,905,577	0.63
2021	141,911,037	72.99%	103,587,595	16.81%	14,903,561	14,563,225	0.60
2022	142,705,057	73.76%	105,263,001	16.05%	14,560,799	14,228,291	0.57
2023	143,499,076	74.51%	106,919,270	15.35%	14,225,480	13,900,629	0.55
2024	144,293,096	75.23%	108,556,775	14.68%	13,897,458	13,580,097	0.52
2025	145,087,115	75.94%	110,175,889	14.05%	13,576,588	13,266,555	0.50
2026	145,881,135	76.62%	111,776,973	13.46%	13,262,729	12,959,864	0.48
2027	146,675,154	77.29%	113,360,387	12.90%	12,955,743	12,659,887	0.46
2028	147,469,174	77.93%	114,926,484	12.37%	12,655,491	12,366,492	0.44
2029	148,263,193	78.56%	116,475,608	11.87%	12,361,839	12,079,545	0.42
2030	149,057,213	79.17%	118,008,102	11.40%	12,074,654	11,798,919	0.41
2031	149,851,232	79.76%	119,524,301	10.95%	11,793,807	11,524,485	0.39
2032	150,645,252	80.34%	121,024,534	10.52%	11,519,168	11,256,118	0.38
2033	151,439,271	80.90%	122,509,126	10.11%	11,250,612	10,993,695	0.36
2034	152,233,291	81.44%	123,978,394	9.72%	10,988,015	10,737,095	0.35
2035	153,027,310	81.97%	125,432,652	9.36%	10,731,256	10,486,198	0.33
2036	153,821,330	82.48%	126,872,208	9.00%	10,480,214	10,240,889	0.32
2037	154,615,349	82.98%	128,297,364	8.67%	10,234,772	10,001,052	0.31
2038	155,409,369	83.46%	129,708,417	8.35%	9,994,815	9,766,574	0.30
2039	156,203,388	83.93%	131,105,658	8.04%	9,760,228	9,537,345	0.29
2040	156,997,408	84.39%	132,489,375	7.75%	9,530,902	9,313,255	0.28
2041	157,791,427	84.83%	133,859,848	7.47%	9,306,725	9,094,198	0.27
2042	158,585,447	85.26%	135,217,354	7.20%	9,087,592	8,880,069	0.26
2043	159,379,466	85.68%	136,562,164	6.95%	8,873,395	8,670,764	0.25
2044	160,173,486	86.09%	137,894,545	6.70%	8,664,032	8,466,182	0.24
2045	160,967,505	86.49%	139,214,759	6.47%	8,459,401	8,266,224	0.23
2046	161,761,525	86.87%	140,523,061	6.24%	8,259,402	8,070,792	0.22
2047	162,555,544	87.24%	141,819,704	6.03%	8,063,938	7,879,791	0.22
2048	163,349,564	87.61%	143,104,936	5.82%	7,872,911	7,693,126	0.21
2049	164,143,583	87.96%	144,378,997	5.62%	7,686,228	7,510,706	0.20

Exhibit 5C-16 Scenario #1: Increase in Future CCR Beneficial Use Under the Subtitle C Option							
Year	CCR generation (tons)	% beneficial use	Beneficial use (tons)	% increase	Increased beneficial use (tons)	Increase w/o mine filling (tons)	Implied elasticity
2050	164,937,603	88.30%	145,642,128	5.43%	7,503,796	7,332,440	0.19
2051	165,731,622	88.63%	146,894,561	5.25%	7,325,524	7,158,239	0.19
2052	166,525,642	88.96%	148,136,525	5.07%	7,151,323	6,988,016	0.18
2053	167,319,661	89.27%	149,368,245	4.90%	6,981,106	6,821,687	0.18
2054	168,113,681	89.58%	150,589,942	4.74%	6,814,787	6,659,166	0.17
2055	168,907,700	89.87%	151,801,831	4.58%	6,652,282	6,500,372	0.16
2056	169,701,720	90.16%	153,004,125	4.43%	6,493,509	6,345,224	0.16
2057	170,495,739	90.44%	154,197,031	4.29%	6,338,387	6,193,644	0.15
2058	171,289,759	90.71%	155,380,753	4.15%	6,186,835	6,045,554	0.15
2059	172,083,778	90.98%	156,555,491	4.01%	6,038,778	5,900,878	0.14
2060	172,877,798	91.23%	157,721,441	3.88%	5,894,139	5,759,541	0.14
2061	173,671,817	91.48%	158,878,794	3.76%	5,752,842	5,621,471	0.13

Exhibit 5C-17 below shows beneficial use projected under Subtitle C with a worst-case stigma assumption. Increased beneficial use under the increasing disposal costs of a Subtitle C rule are not accounted for. However, as soon as the rule becomes effective in 2012, the Scenario #2 of this RIA simulates a stigma effect which decreases the tons beneficially used by 51%. Once the disposal cost effect is fully captured by 2019, and the market has adjusted to stigma, beneficial use is assumed to grow at the same rate it would have otherwise.

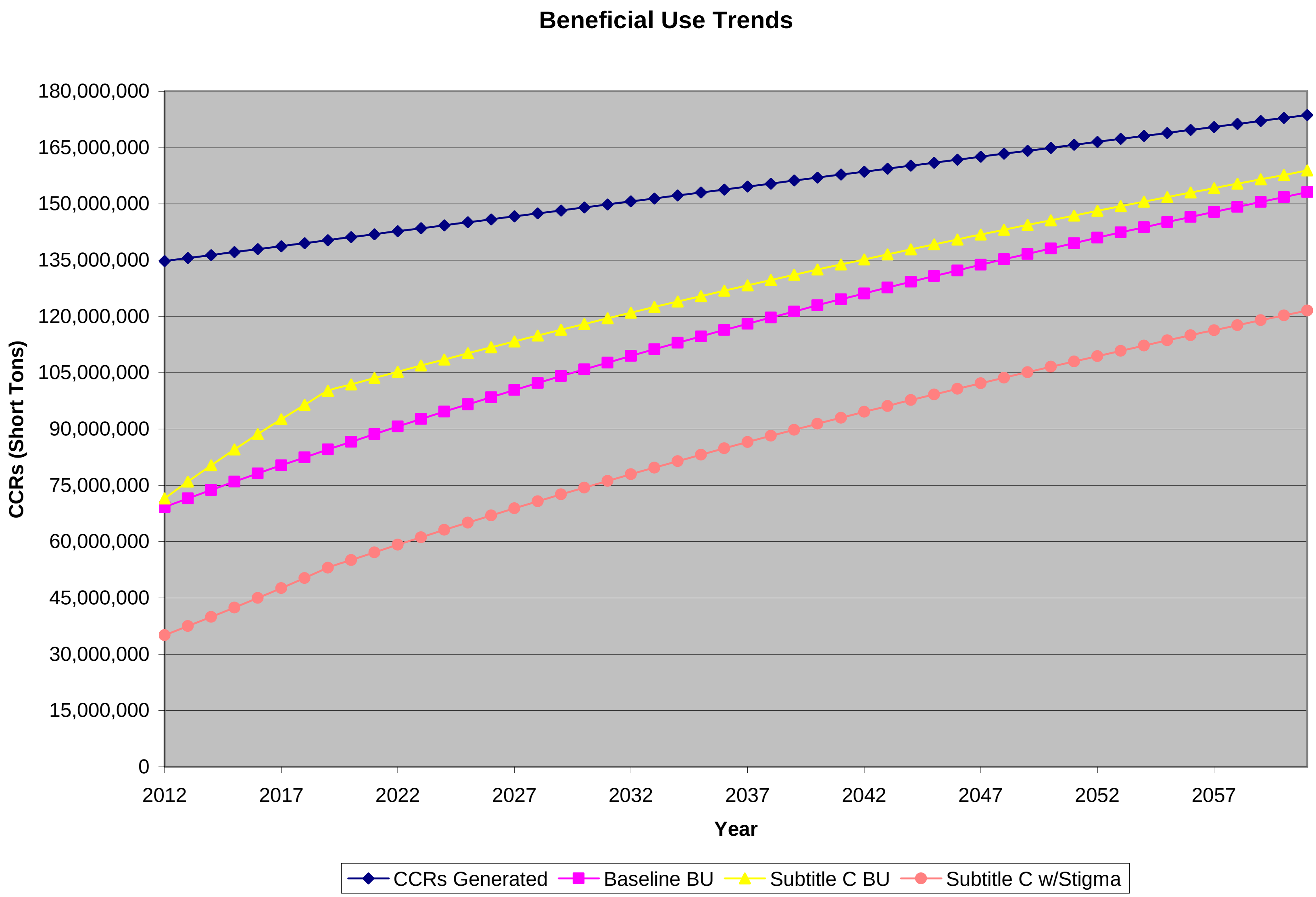
Exhibit 5C-17 Scenario #2: Decrease in Future CCR Beneficial Use Because of Stigma Under Subtitle C Option						
Year	CCR generation tons	% beneficial use	Beneficial use tons	% Decrease	Decrease tons	Decrease w/out mine filling tons
2012	134,764,862	25.17%	33,924,749	-51.00%	-35,309,432	-33,342,859
2013	135,558,881	26.71%	36,206,995	-49.37%	-35,309,432	-33,342,859
2014	136,352,901	28.20%	38,457,590	-47.87%	-35,309,432	-33,342,859
2015	137,146,920	29.66%	40,677,131	-46.47%	-35,309,432	-33,342,859
2016	137,940,940	31.08%	42,866,206	-45.17%	-35,309,432	-33,342,859
2017	138,734,959	32.45%	45,025,395	-43.95%	-35,309,432	-33,342,859
2018	139,528,979	33.80%	47,155,270	-42.82%	-35,309,432	-33,342,859
2019	140,322,998	35.10%	49,256,395	-41.75%	-35,309,432	-33,342,859
2020	141,117,018	36.37%	51,329,323	-40.75%	-35,309,432	-33,342,859
2021	141,911,037	37.61%	53,374,602	-39.81%	-35,309,432	-33,342,859
2022	142,705,057	38.82%	55,392,770	-38.93%	-35,309,432	-33,342,859
2023	143,499,076	39.99%	57,384,357	-38.09%	-35,309,432	-33,342,859
2024	144,293,096	41.13%	59,349,885	-37.30%	-35,309,432	-33,342,859
2025	145,087,115	42.24%	61,289,868	-36.55%	-35,309,432	-33,342,859

Exhibit 5C-17
Scenario #2: Decrease in Future CCR Beneficial Use Because of Stigma Under Subtitle C Option

Year	CCR generation tons	% beneficial use	Beneficial use tons	% Decrease	Decrease tons	Decrease w/out mine filling tons
2026	145,881,135	43.33%	63,204,812	-35.84%	-35,309,432	-33,342,859
2027	146,675,154	44.38%	65,095,213	-35.17%	-35,309,432	-33,342,859
2028	147,469,174	45.41%	66,961,561	-34.53%	-35,309,432	-33,342,859
2029	148,263,193	46.41%	68,804,337	-33.91%	-35,309,432	-33,342,859
2030	149,057,213	47.38%	70,624,016	-33.33%	-35,309,432	-33,342,859
2031	149,851,232	48.33%	72,421,062	-32.78%	-35,309,432	-33,342,859
2032	150,645,252	49.25%	74,195,934	-32.24%	-35,309,432	-33,342,859
2033	151,439,271	50.15%	75,949,081	-31.74%	-35,309,432	-33,342,859
2034	152,233,291	51.03%	77,680,946	-31.25%	-35,309,432	-33,342,859
2035	153,027,310	51.88%	79,391,964	-30.78%	-35,309,432	-33,342,859
2036	153,821,330	52.71%	81,082,562	-30.34%	-35,309,432	-33,342,859
2037	154,615,349	53.52%	82,753,160	-29.91%	-35,309,432	-33,342,859
2038	155,409,369	54.31%	84,404,170	-29.49%	-35,309,432	-33,342,859
2039	156,203,388	55.08%	86,035,997	-29.10%	-35,309,432	-33,342,859
2040	156,997,408	55.83%	87,649,041	-28.72%	-35,309,432	-33,342,859
2041	157,791,427	56.56%	89,243,690	-28.35%	-35,309,432	-33,342,859
2042	158,585,447	57.27%	90,820,330	-27.99%	-35,309,432	-33,342,859
2043	159,379,466	57.96%	92,379,337	-27.65%	-35,309,432	-33,342,859
2044	160,173,486	58.64%	93,921,081	-27.32%	-35,309,432	-33,342,859
2045	160,967,505	59.30%	95,445,925	-27.00%	-35,309,432	-33,342,859
2046	161,761,525	59.94%	96,954,227	-26.70%	-35,309,432	-33,342,859
2047	162,555,544	60.56%	98,446,334	-26.40%	-35,309,432	-33,342,859
2048	163,349,564	61.17%	99,922,592	-26.11%	-35,309,432	-33,342,859
2049	164,143,583	61.77%	101,383,338	-25.83%	-35,309,432	-33,342,859
2050	164,937,603	62.34%	102,828,900	-25.56%	-35,309,432	-33,342,859
2051	165,731,622	62.91%	104,259,605	-25.30%	-35,309,432	-33,342,859
2052	166,525,642	63.46%	105,675,770	-25.04%	-35,309,432	-33,342,859
2053	167,319,661	64.00%	107,077,707	-24.80%	-35,309,432	-33,342,859
2054	168,113,681	64.52%	108,465,723	-24.56%	-35,309,432	-33,342,859
2055	168,907,700	65.03%	109,840,117	-24.33%	-35,309,432	-33,342,859
2056	169,701,720	65.53%	111,201,184	-24.10%	-35,309,432	-33,342,859
2057	170,495,739	66.01%	112,549,212	-23.88%	-35,309,432	-33,342,859
2058	171,289,759	66.49%	113,884,485	-23.67%	-35,309,432	-33,342,859
2059	172,083,778	66.95%	115,207,281	-23.46%	-35,309,432	-33,342,859
2060	172,877,798	67.40%	116,517,870	-23.26%	-35,309,432	-33,342,859
2061	173,671,817	67.84%	117,816,520	-23.06%	-35,309,432	-33,342,859

Exhibit 5C-18 below shows the projected future annual CCR generation and three trends in beneficial use (i.e., scenario #1 increase without stigma, scenario #2 decrease with stigma, and scenario #3 no change in relation to the increasing baseline trend). Scenario #1 assumes that the increased cost of disposal from regulation will induce the electric utility industry to seek out additional CCR beneficial use markets thereby increasing future annual beneficial use of CCR above the increasing baseline trend. Experiences with the EPA RCRA Subtitle C hazardous waste program indicate that industry often increases annual recycling and materials recovery rates after RCRA regulation (e.g., after EPA has listed certain types and sources of secondary industrial materials as RCRA "hazardous wastes"). Thus, EPA regards the increased beneficial use Scenario #1 as the most likely outcome. A second curve in the Exhibit below displays the Scenario #2 decreased CCR beneficial use stigma effect under the Subtitle C regulatory option (this RIA does not apply scenario #2 under the Subtitle D options). The Exhibit also presents Scenario #3 in which future annual CCR beneficial use is projected to continue on its recent upwardly increasing trendline without any induced future change as a result of the CCR rule. The future annual beneficial use tonnages for both scenario #1 and scenario #2 are estimated in this RIA incrementally relative to the scenario #3 baseline trend.

Exhibit 5C-18



Step 8: Monetize Potential Induced Effects on Future CCR Beneficial Use

Based on multiplying a unitized average monetized social benefit value of **$559 per ton** consisting of (a) the $474 per ton unitized lifecycle benefit value, plus the (b) $85 per ton average avoided disposal cost estimated for the subtitle C option, to the 50-year (i.e., 2012 to 2061) projected future baseline tonnage displayed in **Exhibit 5C-18** above, produces an estimated future baseline social benefit value from CCR beneficial use of:

	PV @3% discount	PV @7% discount
Future baseline economic value:	$102,290 million PV	$51,170 million PV
Future baseline lifecycle social value*:	$1,554,323 million PV	$777,541 million PV

(* Includes avoided CCR disposal cost to electric utility industry)

- **Monetization of Scenario #1 (Induced Increase in CCR Beneficial Use)**

Exhibit 5C-19 below provides an estimate of the potential increase in future annual tonnage and economic and social benefits associated with CCR beneficial uses (not including minefilling) that could occur as a result of the CCR proposed rule. This quantity is incrementally calculated each year as the quantity projected under the Subtitle C option (without stigma), less the quantity projected under the baseline.

Exhibit 5C-19
Scenario #1: Benefit from Future Increase in CCR Beneficial User Under Subtitle C "Special Waste"

Year	CCR Beneficial Use Increase (tons)	Nominal Benefits (Millions)		Discounted Benefits @ 3% (Millions)		Discounted Benefits @ 7% (Millions)	
		Econ	Social	Econ	Social	Econ	Social
2012	2,241,198	$82	$1,253	$82	$1,253	$82	$1,253
2013	4,380,599	$161	$2,449	$156	$2,377	$151	$2,289
2014	6,421,451	$236	$3,590	$223	$3,384	$206	$3,135
2015	8,366,919	$308	$4,677	$282	$4,280	$251	$3,818
2016	10,220,089	$376	$5,713	$334	$5,076	$287	$4,359
2017	11,983,968	$441	$6,699	$380	$5,779	$314	$4,776
2018	13,661,485	$503	$7,637	$421	$6,396	$335	$5,089
2019	15,255,494	$561	$8,528	$456	$6,934	$350	$5,311
2020	14,905,577	$548	$8,332	$433	$6,578	$319	$4,850
2021	14,563,225	$536	$8,141	$411	$6,239	$291	$4,428
2022	14,228,291	$523	$7,954	$389	$5,918	$266	$4,043
2023	13,900,629	$511	$7,771	$369	$5,614	$243	$3,692
2024	13,580,097	$500	$7,591	$350	$5,324	$222	$3,371
2025	13,266,555	$488	$7,416	$332	$5,050	$203	$3,077

Exhibit 5C-19
Scenario #1: Benefit from Future Increase in CCR Beneficial User Under Subtitle C "Special Waste"

Year	CCR Beneficial Use Increase (tons)	Nominal Benefits (Millions)		Discounted Benefits @ 3% (Millions)		Discounted Benefits @ 7% (Millions)	
		Econ	Social	Econ	Social	Econ	Social
2026	12,959,864	$477	$7,245	$315	$4,790	$185	$2,810
2027	12,659,887	$466	$7,077	$299	$4,542	$169	$2,565
2028	12,366,492	$455	$6,913	$284	$4,308	$154	$2,342
2029	12,079,545	$444	$6,753	$269	$4,085	$141	$2,138
2030	11,798,919	$434	$6,596	$255	$3,874	$128	$1,951
2031	11,524,485	$424	$6,442	$242	$3,674	$117	$1,781
2032	11,256,118	$414	$6,292	$229	$3,484	$107	$1,626
2033	10,993,695	$404	$6,146	$217	$3,304	$98	$1,484
2034	10,737,095	$395	$6,002	$206	$3,132	$89	$1,355
2035	10,486,198	$386	$5,862	$195	$2,970	$81	$1,237
2036	10,240,889	$377	$5,725	$185	$2,816	$74	$1,129
2037	10,001,052	$368	$5,591	$176	$2,670	$68	$1,030
2038	9,766,574	$359	$5,460	$167	$2,532	$62	$940
2039	9,537,345	$351	$5,331	$158	$2,400	$56	$858
2040	9,313,255	$343	$5,206	$150	$2,276	$52	$783
2041	9,094,198	$335	$5,084	$142	$2,157	$47	$715
2042	8,880,069	$327	$4,964	$135	$2,045	$43	$652
2043	8,670,764	$319	$4,847	$128	$1,939	$39	$595
2044	8,466,182	$311	$4,733	$121	$1,838	$36	$543
2045	8,266,224	$304	$4,621	$115	$1,742	$33	$496
2046	8,070,792	$297	$4,512	$109	$1,651	$30	$452
2047	7,879,791	$290	$4,405	$103	$1,565	$27	$413
2048	7,693,126	$283	$4,301	$98	$1,484	$25	$376
2049	7,510,706	$276	$4,199	$93	$1,406	$23	$343
2050	7,332,440	$270	$4,099	$88	$1,333	$21	$313
2051	7,158,239	$263	$4,002	$83	$1,263	$19	$286
2052	6,988,016	$257	$3,906	$79	$1,198	$17	$261
2053	6,821,687	$251	$3,813	$75	$1,135	$16	$238
2054	6,659,166	$245	$3,723	$71	$1,076	$14	$217
2055	6,500,372	$239	$3,634	$67	$1,019	$13	$198
2056	6,345,224	$233	$3,547	$64	$966	$12	$181
2057	6,193,644	$228	$3,462	$60	$916	$11	$165
2058	6,045,554	$222	$3,380	$57	$868	$10	$150
2059	5,900,878	$217	$3,299	$54	$822	$9	$137
2060	5,759,541	$212	$3,220	$51	$779	$8	$125
2061	5,621,471	$207	$3,142	$49	$738	$8	$114
			Present Value	$9,806	$149,001	$5,560	$84,489

- **Monetization of Potential "*Stigma*" Decrease in CCR Beneficial Use (Scenario #2)**

The **$559 per ton** social benefit value estimated above is the proper estimate for increased beneficial use because this RIA assumes that all beneficial uses will increase in equal proportions. However, it would not be appropriate to apply this same dollar estimate to decreased beneficial use from stigma because different uses decrease by different amounts, and therefore the decrease in benefits would not necessarily equal the 51% decrease in tons. Based on the breakdown of beneficial uses displayed below in **Exhibit 5C-20**, these individual use category losses were summed to create a weighted average benefit reduction of 42%. However, on a tonnage basis 51% of beneficial use tons are reduced. Dividing the weighted value by the unweighted value for each ton lost, the benefits decreased by only 82% of the average $559/ton, or $458/ton. This average unitized social benefits value is used to monetize the estimated tons lost from the stigma Scenario #2.

Exhibit 5C-20
Calculation of the "*Stigma*" Adjustment Factor for the CCR Beneficial Use Reduction Scenario #2

Beneficial Use Industrial Category	CCR Beneficial Use (2005 tons)	Disposal Cost Savings (millions)	Life Cycle Benefits (millions)	Total Benefits (millions)	Percent Lost From Stigma	Benefits Lost (millions)
1. Concrete/concrete products/grout	16,353,331	$1,390	$17,593	$18,983	37.5%	$7,118.6
2. Blended cement/raw feed for clinker	4,215,234	$358	Not estimated	$358	50%	$179.0
3. Flowable fill	259,907	$22	Not estimated	$22	37.5%	$8.3
4. Structural fill/embankments	8,349,999	$710	Not estimated	$710	80%	$568.0
5. Road base/sub-base	1,461,992	$124	Not estimated	$124	80%	$99.2
6. Soil modification/stabilization	1,139,640	$97	Not estimated	$97	80%	$77.6
7. Mineral filler in asphalt	140,838	$12	Not estimated	$12	50%	$6.0
8. Snow & ice control	547,541	$47	Not estimated	$47	80%	$37.6
9. Blasting grit/roofing granules	1,633,407	$139	Not estimated	$139	37.5%	$52.1
10. Gypsum panel products (wallboard)	8,178,079	$695	$5,387	$6,082	50%	$3,041.0
11. Waste stabilization/solidification	2,839,954	$241	Not estimated	$241	0%	$0.0
12. Agriculture	415,741	$35	Not estimated	$35	80%	$28.0
13. Aggregate	872,776	$74	Not estimated	$74	80%	$59.2
14. Miscellaneous other	2,071,157	$176	Not estimated	$176	65%	$114.4
Weighted Total =	48,479,596	$4,120	$22,980	$27,100	42%	$11,382
Unweighted Total =	48,479,596	$4,120	$22,980	$27,100	51%	$13,821
					Adjustment Factor =	**0.82**

Exhibit 5C-21 below provides an estimate of the beneficial use decrease scenario. This quantity is calculated each year as the quantity projected under subtitle C (with stigma) less the quantity projected under the baseline.

Exhibit 5C-21 Scenario #2: Cost of Potential Future Reduction in CCR Beneficial Use Under Subtitle C with "*Stigma*"							
Year	CCR Beneficial Use Decrease (Short Tons)	Nominal Costs (Millions)		Discounted Costs @ 3% (Millions)		Discounted Costs @ 7% (Millions)	
		Economic	Social	Economic	Social	Economic	Social
2012	-33,342,859	-$1,269	-$15,816	-$1,269	-$15,816	-$1,269	-$15,816
2013	-33,342,859	-$1,269	-$15,816	-$1,232	-$15,355	-$1,186	-$14,781
2014	-33,342,859	-$1,269	-$15,816	-$1,196	-$14,908	-$1,109	-$13,814
2015	-33,342,859	-$1,269	-$15,816	-$1,162	-$14,474	-$1,036	-$12,910
2016	-33,342,859	-$1,269	-$15,816	-$1,128	-$14,052	-$968	-$12,066
2017	-33,342,859	-$1,269	-$15,816	-$1,095	-$13,643	-$905	-$11,276
2018	-33,342,859	-$1,269	-$15,816	-$1,063	-$13,245	-$846	-$10,539
2019	-33,342,859	-$1,269	-$15,816	-$1,032	-$12,860	-$790	-$9,849
2020	-33,342,859	-$1,269	-$15,816	-$1,002	-$12,485	-$739	-$9,205
2021	-33,342,859	-$1,269	-$15,816	-$973	-$12,122	-$690	-$8,603
2022	-33,342,859	-$1,269	-$15,816	-$944	-$11,768	-$645	-$8,040
2023	-33,342,859	-$1,269	-$15,816	-$917	-$11,426	-$603	-$7,514
2024	-33,342,859	-$1,269	-$15,816	-$890	-$11,093	-$564	-$7,022
2025	-33,342,859	-$1,269	-$15,816	-$864	-$10,770	-$527	-$6,563
2026	-33,342,859	-$1,269	-$15,816	-$839	-$10,456	-$492	-$6,134
2027	-33,342,859	-$1,269	-$15,816	-$815	-$10,152	-$460	-$5,732
2028	-33,342,859	-$1,269	-$15,816	-$791	-$9,856	-$430	-$5,357
2029	-33,342,859	-$1,269	-$15,816	-$768	-$9,569	-$402	-$5,007
2030	-33,342,859	-$1,269	-$15,816	-$746	-$9,290	-$376	-$4,679
2031	-33,342,859	-$1,269	-$15,816	-$724	-$9,020	-$351	-$4,373
2032	-33,342,859	-$1,269	-$15,816	-$703	-$8,757	-$328	-$4,087
2033	-33,342,859	-$1,269	-$15,816	-$682	-$8,502	-$307	-$3,820
2034	-33,342,859	-$1,269	-$15,816	-$662	-$8,254	-$287	-$3,570
2035	-33,342,859	-$1,269	-$15,816	-$643	-$8,014	-$268	-$3,336
2036	-33,342,859	-$1,269	-$15,816	-$624	-$7,780	-$250	-$3,118
2037	-33,342,859	-$1,269	-$15,816	-$606	-$7,554	-$234	-$2,914
2038	-33,342,859	-$1,269	-$15,816	-$589	-$7,334	-$219	-$2,723
2039	-33,342,859	-$1,269	-$15,816	-$571	-$7,120	-$204	-$2,545
2040	-33,342,859	-$1,269	-$15,816	-$555	-$6,913	-$191	-$2,379
2041	-33,342,859	-$1,269	-$15,816	-$539	-$6,711	-$178	-$2,223
2042	-33,342,859	-$1,269	-$15,816	-$523	-$6,516	-$167	-$2,078
2043	-33,342,859	-$1,269	-$15,816	-$508	-$6,326	-$156	-$1,942
2044	-33,342,859	-$1,269	-$15,816	-$493	-$6,142	-$146	-$1,815
2045	-33,342,859	-$1,269	-$15,816	-$479	-$5,963	-$136	-$1,696
2046	-33,342,859	-$1,269	-$15,816	-$465	-$5,789	-$127	-$1,585
2047	-33,342,859	-$1,269	-$15,816	-$451	-$5,621	-$119	-$1,481
2048	-33,342,859	-$1,269	-$15,816	-$438	-$5,457	-$111	-$1,384
2049	-33,342,859	-$1,269	-$15,816	-$425	-$5,298	-$104	-$1,294

Exhibit 5C-21 Scenario #2: Cost of Potential Future Reduction in CCR Beneficial Use Under Subtitle C with "*Stigma*"								
Year	CCR Beneficial Use Decrease (Short Tons)	Nominal Costs (Millions)		Discounted Costs @ 3% (Millions)		Discounted Costs @ 7% (Millions)		
		Economic	Social	Economic	Social	Economic	Social	
2050	-33,342,859	-$1,269	-$15,816	-$413	-$5,144	-$97	-$1,209	
2051	-33,342,859	-$1,269	-$15,816	-$401	-$4,994	-$91	-$1,130	
2052	-33,342,859	-$1,269	-$15,816	-$389	-$4,848	-$85	-$1,056	
2053	-33,342,859	-$1,269	-$15,816	-$378	-$4,707	-$79	-$987	
2054	-33,342,859	-$1,269	-$15,816	-$367	-$4,570	-$74	-$923	
2055	-33,342,859	-$1,269	-$15,816	-$356	-$4,437	-$69	-$862	
2056	-33,342,859	-$1,269	-$15,816	-$346	-$4,308	-$65	-$806	
2057	-33,342,859	-$1,269	-$15,816	-$336	-$4,182	-$60	-$753	
2058	-33,342,859	-$1,269	-$15,816	-$326	-$4,060	-$56	-$704	
2059	-33,342,859	-$1,269	-$15,816	-$316	-$3,942	-$53	-$658	
2060	-33,342,859	-$1,269	-$15,816	-$307	-$3,827	-$49	-$615	
2061	-33,342,859	-$1,269	-$15,816	-$298	-$3,716	-$46	-$574	
			Present Value	-$33,639	-$419,145	-$18,744	-$233,549	

Step 9: Estimate Potential Induced Effect on CCR Beneficial Use of the Other RCRA Regulatory Options

The analysis above demonstrates the valuation of beneficial use effects using only the subtitle C option. However, the results may be extrapolated to the other regulatory options. **Exhibit 5C-22** below displays the beneficial use effect scenarios linearly extrapolated in relation to the result of subtitle C based on the potential increase in CCR disposal cost. In other words, the ratio of the disposal cost estimated under those other scenarios to the subtitle C disposal cost can be applied to the beneficial use benefits under those alternative options.

Exhibit 5C-22 Potential Induced Effect of RCRA Regulation on Future CCR Beneficial Use: 2 Scenarios ($millions present value @7%)			
Component	Subtitle C Special waste	Subtitle D (version 2)	Subtitle "D prime"
Assumed scaling ratios relative to C value =	100%	40%	16%
Scenario #1: Increase in Beneficial Use (Base Case)			
Percentage increase relative to baseline =	+11%	+4%	+2%
Economic market value	+$5,560	+$2,224	+$890
Lifecycle social value	+$84,489	+$33,796	+$13,518
Scenario #2: Decrease in Beneficial Use			
Percentage increase relative to baseline =	-18%	N/A	N/A
Economic market value	-$18,744	N/A	N/A
Lifecycle social value	-$233,549	N/A	N/A

Step 10: Quantify Potential Capacity Impacts on Commercial Subtitle C Waste Landfills (Under Scenario #2)

For Scenario #2 estimated above involving a potential future reduction in annual CCR beneficial use, such loss would require additional disposal of 33.3 million tons CCR annually (source: **Exhibit 5C-16**) which will likely create four future industrial waste disposal problems:

1. Annual disposal rate exceedance: Relative to the 33.3 million lost beneficial use annnual tonnages, there is a much smaller quantity of 2 million tons per year of RCRA-regulated hazardous waste which is currently disposed in RCRA Subtitle C permitted onsite (captive) and offsite (commercial) landfills in the US.[160] This implies a potential 1,665% annual increase (i.e., 16.65 times larger) in demand for hazardous waste landfill capacity.
2. Limited geographic availability: There are currently 19 to 24 commercial hazardous waste landfills operating in 15 to 17 states.[161] However, the CCR which is currently beneficially used is generated by 272 electric utility plants located in 41 states.[162] Thus disposal at commercial hazardous waste landfills would require out-of-state shipment involving at least 24 to 26 states which do not have commercial hazardous waste landfills.
3. Remaining disposal capacity exceedance: The 19 to 24 commercial hazardous waste landfills have an available total remaining capacity of 21.7 million to 25.4 million tons hazardous waste.[163] The additional 33.3 million tons per year of CCR beneficial use needing disposal under the Scenario #2 will consume this entire remaining total capacity within less than one year.
4. Increase landfill prices: In addition, such a large increase in nationwide economic demand for commercial hazardous waste landfills could drive-up landfill tipping fees which recently (2004) ranged between $61 and $139 per ton nationwide ($90 per ton national average).[164] As verification of this potential effect on landfill prices, a recent (August 2009) market study[165] of the US commercial

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[160] Source: 2 million tons per year is based on the annual average of landfill tonnages reported for years 2001 (2.09 million tons), 2003 (1.68 million tons), 2005 (2.04 million tons), and 2007 (1.94 million tons) in EPA's "RCRA National Analysis Biennial Hazardous Waste Report" at http://www.epa.gov/waste/inforesources/data/biennialreport/index.htm

[161] Source: These two ranges (i.e., 19 to 24 commercial haz waste landfill counts and 15 to 17 states) are from two alternative data sources:

- Source #1 of 2: 24 commercial RCRA-permitted hazardous waste landfill count and 17 state identities as listed in the Hazardous Waste Consultant "2007 Directory of US Commercial Hazardous Waste Management Facilities," Vol.25, Issue 1, 2007, pp.4.1 to 4.44. The 17 states are AL, AR, CA, CO, ID, IL, IN, LA, MI, NV, NJ, NY, OH, OK, OR, TX, UT.
- Source #2 of 2: As compiled 02 Oct 2009 by EPA OSWER-ORCR staff (Cpan Lee, Environmental Scientist), this available remaining capacity estimate is based on three sources: (a) actual capacity estimates provided to OSWER-ORCR by facilities in April-Sept 2009, (b) information provided to OSWER-ORCR by EPA Regions and States in April/May 2009, and (c) capacity estimates developed by OSWER-ORCR using 1995-2007 RCRA Biennial Report data. The 15 States are AL, CA, CO, ID, IL, IN, LA, MI, NV, NY, OH, OK, OR, TX, and UT.

[162] The 41 states are AL, AR, AZ, CO, DE, FL, GA, IA, IL, IN, KS, KY, LA, MA, MD, MI, MN, MO, MS, MT, NC, ND, NE, NH, NJ, NM, NV, NY, ,OH, OK, OR, SC, SD, TN, TX, UT, VA, WA, WI, WV, WY.

[163] Source: 02 Oct 2009 estimates by EPA OSWER-ORCR staff (Cpan Lee, Environmental Scientist) cited in a prior footnote in this section of the RIA.

[164] Source: US commercial hazardous waste landfill prices for bulk hazardous waste without treatment reported by the Environmental Technology Council (ETC) "May 2004 Incinerator and Landfill Cost Data" website at http://www.etc.org/costsurvey8.cfm

[165] Source: Page 10 of "Hazardous Waste Industry Review 2008-2009," Joan Berkowitz and Robert Crisp, Farkas Berkowitz & Company, August 2009; http://www.farkasberkowitz.com/marketresearch.htm

hazardous waste industry, provides the following empirical evidence of price increases by commercial hazardous waste landfills in response to annual increases in landfill disposal tonnage:

> "*On average, the number of surveyed landfill firms that increased prices exceeds the number that received higher volumes in 2008. Volumes increased for 50 percent of respondents and decreased for 42 percent, but 67 percent raised prices and 33 percent left prices unchanged. The survey did not ask how much, if any, of the reported price increase was due to fuel surcharges. The survey did determine that 92 percent of respondents applied fuel surcharges, but fuel surcharges cannot account for all of the price increases because the surcharges cover increased costs, and 77 percent of respondents reported increased [profit] margins.*"

Chapter 6
Comparison of Regulatory Benefits to Costs

Section 6A of this Chapter presents a series of exhibits which summarize and compare the results of the cost and benefit estimates presented in **Chapter 4** and **Chapter 5**, respectively, scaled to the three 2010 regulatory options. Section 6B of this Chapter provides explanation of the scaling method and factors applied.

6A. Comparison of Regulatory Benefits to Costs Based on Alternative Discount Rates

The series of six **Exhibits 6A to 6F** below summarize cost and benefits according to the three alternative beneficial use scenarios (i.e., induced increase, induced decrease, and no change), and according to the two OMB-prescribed alternative discount rates of 7% and 3% for use in RIAs:

7% discount rate: The 7% discount rate as a "base case" to represent the financial opportunity cost (i.e., borrowing cost) to affected businesses, which is consistent with OMB's 2003 Circular A-4 guidance[166] (page 33), and with OMB's 1992 Circular A-94 guidance[167] (page 8) which indicate that a 7% discount rate "base case" should be used for regulatory analyses when regulation is expected to primarily and directly affect businesses and industries.

3% discount rate: This is a second mandatory discount rate specified in OMB's 2003 Circular A-4 guidance (page 34).

In these six summary exhibits below, the comparison of regulatory benefits to costs involves two numerical comparisons:

1. Net benefits (i.e., benefits minus costs)
2. Benefit/cost ratios (i.e., benefits divided by costs)

	Two alternative discount rates:	
	7% discount rate	3% discount rate
Three alternative CCR beneficial use impact scenarios:	(base case in this RIA)	
Scenario #1: Induced increase (base case)	**Exhibit 6A**	**Exhibit 6B**
Scenario #2: Induced decrease	**Exhibit 6C**	**Exhibit 6D**
Scenario #3: No change	**Exhibit 6E**	**Exhibit 6F**

[166] OMB's 17 Sept 2003 Circular A-4 "Regulatory Analysis" guidance is available at: http://www.whitehouse.gov/omb/circulars_a004_a-4/
[167] OMB's 29 Oct 1992 Circular A-94 "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs," is available at http://www.whitehouse.gov/omb/rewrite/circulars/a094/a094.html

Exhibit 6A
Comparison of Regulatory Benefits to Costs Under Scenario #1 – Induced Beneficial Use Increase @7% Discount Rate – Detailed Summary
($Millions in 50-Year Present Values @2009$ Prices)

Costs	Subtitle C "Special Waste"		Subtitle D (version 2)		Subtitle "D prime"	
1. Engineering Controls	$6,780		$3,254		$3,254	
2. Ancillary Costs	$1,480		$5		$5	
3. Dry Conversion	$12,089		4,836		$0	
Total Costs (1+2+3) =	$20,349		$8,095		$3,259	
Benefits						
4. Groundwater Protection Benefits*	$970		$375		$188	
Count of Human Cancer Risks Avoided**	726		296		148	
Monetized Value of Human Cancer Risks Avoided	$504		$207		$104	
Groundwater Remediation Costs Avoided	$466		$168		$84	
5. Induced Impact on CCR Beneficial Use	Econ. benefits	Social benefits	Econ. benefits	Social benefits	Econ. Benefits	Social benefits
Scenario #1 @7% discount rate =	$5,560	$84,489	$2,224	$33,796	$890	$13,518
6. CCR Impoundment Failure Costs Avoided						
If Based on Extrapolated Recent Failure Cases	$1,762		$793		$405	
If Based on 10% Future Failures	$8,366		$3,795		$1,897	
If Based on 20% Future Failures	$16,732		$7,590		$3,795	
7. Non-quantified Benefits***	Q		R		S	
Total Benefits (4+5+6):						
Total Benefits w/Extrapolated Recent Failure Cases =	$8,292	$87,221	$3,392	$34,964	$1,483	$14,111
Total Benefits @10% Future Failures =	$14,896	$93,825	$6,394	$37,966	$2,975	$15,603
Total Benefits @20% Future Failures =	$23,262	$102,191	$10,189	$41,761	$4,873	$17,501
Net Benefits (Total Benefits minus Total Costs)						
Net Benefits w/Extrapolated Recent Failure Cases =	($12,057)	$66,872	($4,703)	$26,869	($1,776)	$10,852
Net Benefits @10% Future Failures =	($5,453)	$73,476	($1,701)	$29,871	($284)	$12,344
Net Benefits @20% Future Failures =	$2,913	$81,842	$2,094	$33,666	$1,614	$14,242
Benefit/Cost Ratio (BCR)						
BCR w/Extrapolated Recent Failure Cases =	0.407	4.286	0.419	4.319	0.455	4.330
BCR @10% Future Failures =	0.732	4.611	0.790	4.690	0.913	4.788
BCR @20% Future Failures =	1.143	5.022	1.259	5.159	1.495	5.370

Notes:
* Cancer risk reflects the arsenic groundwater pathway only and does not include other human health mortality or morbidity risks from non-carcinogens, nor do they reflect ecological and socio-economic damages that could occur. Thus, the benefits are underestimated in this RIA.
** Cancer risks avoided are based on National Academy of Science (2001) data, which represents recent scientific information.
*** Q>R>S; For example, non-quantified ecological benefits could add 159%, and socio-economic benefits could add 24%, compared to avoided cleanup cost benefit.

Exhibit 6B Comparison of Regulatory Benefits to Costs Under Scenario #1 – Induced Beneficial Use Increase @3% Discount Rate ($Millions in 50-Year Present Values @2009$ Prices)						
Costs	**Subtitle C "Special Waste"**		**Subtitle D (version 2)**		**Subtitle "D prime"**	
1. Engineering Controls	$12,640		$6,067		$6,067	
2. Ancillary Costs	$2,759		$9		$9	
3. Dry Conversion	$22,538		$9,016		$0	
Total Costs (1+2+3) =	$37,938		$15,092		$6,076	
Benefits						
4. Groundwater Protection Benefits*	$3,316		$1,321		$661	
Count of Human Cancer Risks Avoided**	726		296		148	
Monetized Value of Human Cancer Risks Avoided	$1,825		$750		$375	
Groundwater Remediation Costs Avoided	$1,491		$571		$286	
5. Induced Impact on CCR Beneficial Use	Econ. benefits	Social benefits	Econ. benefits	Social benefits	Econ. Benefits	Social benefits
Scenario #1 @3% discount rate =	$9,806	$149,001	$3,922	$59,600	$1,569	$23,840
6. CCR Impoundment Failure Costs Avoided						
If Based on Extrapolated Recent Failure Cases	$3,124		$1,406		$719	
If Based on @ 10% Future Failures	$13,046		$5,918		$2,959	
If Based on @ 20% Future Failures	$26,092		$11,836		$5,918	
7. Non-quantified Benefits***	Q		R		S	
Total Benefits (4+5+6):						
Total Benefits w/Extrapolated Recent Failure Cases =	$16,246	$155,441	$6,649	$62,327	$2,949	25,220
Total Benefits @10% Future Failures =	$26,168	$165,363	$11,161	$66,839	$5,189	$27,460
Total Benefits @20% Future Failures =	$39,214	$178,409	$17,079	$72,757	$8,148	$30,419
Net Benefits (Total Benefits minus Total Costs)						
Net Benefits w/Extrapolated Recent Failure Cases =	($21,692)	$117,503	($8,443)	$47,235	($3,127)	$19,144
Net Benefits @10% Future Failures =	($11,770)	$127,425	($3,931)	$51,747	($887)	$21,384
Net Benefits @20% Future Failures =	$1,276	$140,471	$1,987	$57,665	$2,072	$24,343
Benefit/Cost Ratio (BCR)						
BCR w/Extrapolated Recent Failure Cases =	0.428	4.097	0.441	4.130	0.485	4.151
BCR @10% Future Failures =	0.690	4.359	0.740	4.429	0.854	4.519
BCR @20% Future Failures =	1.034	4.703	1.132	4.821	1.341	5.006

Notes:
* Cancer risk reflects the arsenic groundwater pathway only and does not include other human health mortality or morbidity risks from non-carcinogens, nor do they reflect ecological and socio-economic damages that could occur. Thus, the benefits are underestimated in this RIA.
** Cancer risks avoided are based on National Academy of Science (2001) data, which represents recent scientific information.
*** Q>R>S.

Exhibit 6C
Comparison of Regulatory Benefits to Costs Under Scenario #2 – Induced Beneficial Use Decrease @7% Discount Rate
($Millions in 50-Year Present Values @2009$ Prices)

Costs	Subtitle C "Special Waste"		Subtitle D (version 2)		Subtitle "D prime"	
1. Engineering Controls	$6,780		$3,254		$3,254	
2. Ancillary Costs	$1,480		$5		$5	
3. Dry Conversion	$12,089		4,836		$0	
Total Costs (1+2+3) =	$20,349		$8,095		$3,259	
Benefits						
4. Groundwater Protection Benefits*	$970		$375		$188	
Count of Human Cancer Risks Avoided**	726		296		148	
Monetized Value of Human Cancer Risks Avoided	$504		$207		$104	
Groundwater Remediation Costs Avoided	$466		$168		$84	
5. Induced Impact on CCR Beneficial Use	Econ. benefits	Social benefits	Econ. benefits	Social benefits	Econ. Benefits	Social benefits
Scenario #2 @7% discount rate =	($18,744)	($233,549)	$0 (no impact)	$0 (no impact)	$0 (no impact)	$0 (no impact)
6. CCR Impoundment Failure Costs Avoided						
If Based on Extrapolated Recent Failure Cases	$1,762		$793		$405	
If Based on 10% Future Failures	$8,366		$3,795		$1,897	
If Based on 20% Future Failures	$16,732		$7,590		$3,795	
7. Non-quantified Benefits***	Q		R		S	
Total Benefits (4+5+6):						
Total Benefits w/Extrapolated Recent Failure Cases =	($16,012)	($230,817)	$1,168	$1,168	$593	$593
Total Benefits @10% Future Failures =	($9,408)	($224,213)	$4,170	$4,170	$2,085	$2,085
Total Benefits @20% Future Failures =	($1,042)	($215,847)	$7,965	$7,965	$3,983	$3,983
Net Benefits (Total Benefits minus Total Costs)						
Net Benefits w/Extrapolated Recent Failure Cases =	($36,361)	($251,166)	($6,927)	($6,927)	($2,666)	($2,666)
Net Benefits @10% Future Failures =	($29,757)	($244,562)	($3,925)	($3,925)	($1,174)	($1,174)
Net Benefits @20% Future Failures =	($21,391)	($236,196)	($130)	($130)	$724	$724
Benefit/Cost Ratio (BCR)						
BCR w/Extrapolated Recent Failure Cases =	(0.787)	(11.343)	0.144	0.144	0.182	0.182
BCR @10% Future Failures =	(0.462)	(11.018)	0.515	0.515	0.640	0.640
BCR @20% Future Failures =	(0.051)	(10.607)	0.984	0.984	1.222	1.222

Notes:
* Cancer risk reflects the arsenic groundwater pathway only and does not include other human health mortality or morbidity risks from non-carcinogens, nor do they reflect ecological and socio-economic damages that could occur. Thus, the benefits are underestimated in this RIA.
** Cancer risks avoided are based on National Academy of Science (2001) data, which represents recent scientific information.
*** Q>R>S.

Exhibit 6D
Comparison of Regulatory Benefits to Costs Under Scenario #2 – Induced Beneficial Use Decrease @3% Discount Rate
($Millions in 50-Year Present Values @2009$ Prices)

Costs	Subtitle C "Special Waste"		Subtitle D (version 2)		Subtitle "D prime"	
1. Engineering Controls	$12,640		$6,067		$6,067	
2. Ancillary Costs	$2,759		$9		$9	
3. Dry Conversion	$22,538		$9,016		$0	
Total Costs (1+2+3) =	$37,938		$15,092		$6,076	
Benefits						
4. Groundwater Protection Benefits*	$3,316		$1,321		$661	
Count of Human Cancer Risks Avoided**	726		296		148	
Monetized Value of Human Cancer Risks Avoided	$1,825		$750		$375	
Groundwater Remediation Costs Avoided	$1,491		$571		$286	
5. Induced Impact on CCR Beneficial Use	Econ. benefits	Social benefits	Econ. benefits	Social benefits	Econ. Benefits	Social benefits
Scenario #2 @3% discount rate =	($34,946)	($435,419)	$0 (no impact)	$0 (no impact)	$0 (no impact)	$0 (no impact)
6. CCR Impoundment Failure Costs Avoided						
If Based on Extrapolated Recent Failure Cases	$3,124		$1,406		$719	
If Based on 10% Future Failures	$13,046		$5,918		$2,959	
If Based on 20% Future Failures	$26,092		$11,836		$5,918	
7. Non-quantified Benefits***	Q		R		S	
Total Benefits (4+5+6):						
Total Benefits w/Extrapolated Recent Failure Cases =	($28,506)	($428,979)	$2,727	$2,727	$1,380	$1,380
Total Benefits @10% Future Failures =	($18,584)	($419,057)	$7,239	$7,239	$3,620	$3,620
Total Benefits @20% Future Failures =	($5,538)	($406,011)	$13,157	$13,157	$6,579	$6,579
Net Benefits (Total Benefits minus Total Costs)						
Net Benefits w/Extrapolated Recent Failure Cases =	($66,443)	($466,917)	($12,365)	($12,365)	($4,696)	($4,696)
Net Benefits @10% Future Failures =	($56,521)	($456,995)	($7,853)	($7,853)	($2,456)	($2,456)
Net Benefits @20% Future Failures =	($43,475)	($443,949)	($1,935)	($1,935)	$503	$503
Benefit/Cost Ratio (BCR)						
BCR w/Extrapolated Recent Failure Cases =	(0.751)	(11.307)	0.181	0.181	0.227	0.227
BCR @10% Future Failures =	(0.490)	(11.046)	0.480	0.480	0.596	0.596
BCR @20% Future Failures =	(0.146)	(10.702)	0.872	0.872	1.083	1.083

Notes:
* Cancer risk reflects the arsenic groundwater pathway only and does not include other human health mortality or morbidity risks from non-carcinogens, nor do they reflect ecological and socio-economic damages that could occur. Thus, the benefits are underestimated in this RIA.
** Cancer risks avoided are based on National Academy of Science (2001) data, which represents recent scientific information.
*** Q>R>S.

Exhibit 6E
Comparison of Regulatory Benefits to Costs Under Scenario #3 – No Change to Beneficial Use @ 7% Discount Rate
($Millions in 50-Year Present Values @2009$ Prices)

Costs	**Subtitle C "Special Waste"**		**Subtitle D (version 2)**		**Subtitle "D prime"**	
1. Engineering Controls	$6,780		$3,254		$3,254	
2. Ancillary Costs	$1,480		$5		$5	
3. Dry Conversion	$12,089		4,836		$0	
Total Costs (1+2+3) =	$20,349		$8,095		$3,259	
Benefits						
4. Groundwater Protection Benefits*	$970		$375		$188	
Count of Human Cancer Risks Avoided**	726		296		148	
Monetized Value of Human Cancer Risks Avoided	$504		$207		$104	
Groundwater Remediation Costs Avoided	$466		$168		$84	
5. Induced Impact on CCR Beneficial Use	Econ. benefits	Social benefits	Econ. benefits	Social benefits	Econ. Benefits	Social benefits
Scenario #3 @7% discount rate =	$0 (no change)	$0 (no change)	$0 (no change)	$0 (no change)	$0 (no change)	$0 (no change)
6. CCR Impoundment Failure Costs Avoided						
If Based on Extrapolated Recent Failure Cases	$1,762		$793		$405	
If Based on 10% Future Failures	$8,366		$3,795		$1,897	
If Based on 20% Future Failures	$16,732		$7,590		$3,795	
7. Non-quantified Benefits***	Q		R		S	
Total Benefits (4+5+6):						
Total Benefits w/Extrapolated Recent Failure Cases =	$2,732	$2,732	$1,168	$1,168	$593	$593
Total Benefits @10% Future Failures =	$9,336	$9,336	$4,170	$4,170	$2,085	$2,085
Total Benefits @20% Future Failures =	$17,702	$17,702	$7,965	$7,965	$3,983	$3,983
Net Benefits (Total Benefits minus Total Costs)						
Net Benefits w/Extrapolated Recent Failure Cases =	($17,617)	($17,617)	($6,927)	($6,927)	($2,666)	($2,666)
Net Benefits @10% Future Failures =	($11,013)	($11,013)	($3,925)	($3,925)	($1,174)	($1,174)
Net Benefits @20% Future Failures =	($2,647)	($2,647)	($130)	($130)	$724	$724
Benefit/Cost Ratio (BCR)						
BCR w/Extrapolated Recent Failure Cases =	0.134	0.134	0.144	0.144	0.182	0.182
BCR @10% Future Failures =	0.459	0.459	0.515	0.515	0.640	0.640
BCR @20% Future Failures =	0.870	0.870	0.984	0.984	1.222	1.222

Notes:
* Cancer risk reflects the arsenic groundwater pathway only and does not include other human health mortality or morbidity risks from non-carcinogens, nor do they reflect ecological and socio-economic damages that could occur. Thus, the benefits are underestimated in this RIA.
** Cancer risks avoided are based on National Academy of Science (2001) data, which represents recent scientific information.
*** Q>R>S.

Exhibit 6F
Comparison of Regulatory Benefits to Costs Under Scenario #3 – No Change to Beneficial Use @ 3% Discount Rate
($Millions in 50-Year Present Values @2009$ Prices)

Costs	Subtitle C "Special Waste"		Subtitle D (version 2)		Subtitle "D prime"	
1. Engineering Controls	$12,640		$6,067		$6,067	
2. Ancillary Costs	$2,759		$9		$9	
3. Dry Conversion	$22,538		$9,016		$0	
Total Costs (1+2+3) =	$37,938		$15,092		$6,076	
Benefits						
4. Groundwater Protection Benefits*	$3,316		$1,321		$661	
Count of Human Cancer Risks Avoided**	726		296		148	
Monetized Value of Human Cancer Risks Avoided	$1,825		$750		$375	
Groundwater Remediation Costs Avoided	$1,491		$571		$286	
5. Induced Impact on CCR Beneficial Use	Econ. benefits	Social benefits	Econ. benefits	Social benefits	Econ. Benefits	Social benefits
Scenario #3 @3% discount rate =	$0 (no change)	$0 (no change)	$0 (no change)	$0 (no change)	$0 (no change)	$0 (no change)
6. CCR Impoundment Failure Costs Avoided						
If Based on Extrapolated Recent Failure Cases	$3,124		$1,406		$719	
If Based on 10% Future Failures	$13,046		$5,918		$2,959	
If Based on 20% Future Failures	$26,092		$11,836		$5,918	
7. Non-quantified Benefits***	Q		R		S	
Total Benefits (4+5+6):						
Total Benefits w/Extrapolated Recent Failure Cases =	$6,440	$6,440	$2,727	$2,727	$1,380	$1,380
Total Benefits @10% Future Failures =	$16,362	$16,362	$7,239	$7,239	$3,620	$3,620
Total Benefits @20% Future Failures =	$29,408	$29,408	$13,157	$13,157	$6,579	$6,579
Net Benefits (Total Benefits minus Total Costs)						
Net Benefits w/Extrapolated Recent Failure Cases =	($31,498)	($31,498)	($12,365)	($12,365)	($4,696)	($4,696)
Net Benefits @10% Future Failures =	($21,576)	($21,576)	($7,853)	($7,853)	($2,456)	($2,456)
Net Benefits @20% Future Failures =	($8,530)	($8,530)	($1,935)	($1,935)	$503	$503
Benefit/Cost Ratio (BCR)						
BCR w/Extrapolated Recent Failure Cases =	0.170	0.170	0.181	0.181	0.227	0.227
BCR @10% Future Failures =	0.431	0.431	0.480	0.480	0.596	0.596
BCR @20% Future Failures =	0.775	0.775	0.872	0.872	1.083	1.083

Notes:
* Cancer risk reflects the arsenic groundwater pathway only and does not include other human health mortality or morbidity risks from non-carcinogens, nor do they reflect ecological and socio-economic damages that could occur. Thus, the benefits are underestimated in this RIA.
** Cancer risks avoided are based on National Academy of Science (2001) data, which represents recent scientific information.
*** Q>R>S.

6B. Factors Applied for Scaling Benefits and Costs to the Three 2010 Regulatory Options

The regulatory compliance cost estimation presented in **Chapter 4** of this RIA was initially formulated with reference to the October 2009 draft RIA regulatory options. Furthermore, the regulatory benefits evaluation in **Chapter 5** of this RIA was based only on the 2010 regulatory options. To resolve this inconsistency in scope between the two different sets of regulatory options evaluated for costs and for benefits, respectively, this RIA applies the scaling factors (i.e., percentage extrapolation multipliers) displayed below in **Exhibit 6F**.

The cost analysis presented in **Chapter 4** of this RIA is built upon a detailed (i.e., plant-by-plant for all 495 coal-fired electric utility plants) engineering cost model which estimated "engineering control" costs associated with the RCRA 3004(x) custom-tailored technical standards of the 2009 regulatory options (i.e., Subtitle C "hazardous waste" option, Subtitle D non-hazardous waste option requiring composite liners for new CCR disposal units, and a "hybrid" C/D option). Although the engineering control costs were the same for each of the three October 2009 options, "ancillary costs" differed according to whether an option was formulated in reference to Subtitle C or to Subtitle D authority. For example, only the Subtitle C "hazardous waste" option and the Subtitle C component of the "Hybrid C/D" option required the cost associated with manifesting offsite shipments of CCR between coal-fired electric utility plants and offsite CCR disposal locations. The October 2009 draft RIA presented the "dry conversion cost" element as a separable "sub-option" for both the Subtitle C and Subtitle D options.

However, in 2010 EPA identified a different set of three regulatory options to describe in the proposed rule and evaluate in RIA (i.e., Subtitle C "special waste" option with wet disposal phase-out, Subtitle D option which in effect would phase-out wet CCR disposal by requiring retrofitting existing impoundments with composite liners, and a Subtitle "D prime" option requiring liners only for new disposal units). In order to meet EPA's end-of-March 2010 internal deadline for completing the 2nd draft of this RIA, EPA did not revised the **Chapter 4** cost analysis or the **Chapter 7** supplemental analyses, but applied scaling factors for bridging the cost estimates to the 2010 options. Numerically, the scaling factors represent alternative compliance rate assumptions in relation to the 2009 draft RIA's Subtitle C "hazardous waste" option as a reference case for both cost and benefit estimate scaling to the three 2010 regulatory options. The scaling factors assume less compliance under the non-Federally enforceable Subtitle D based options compared to the Federally-enforceable Subtitle C option. Section 6B of this RIA provides the numerical values assigned to the scaling factors on an itemized basis according to the separate cost element and benefit element categories, for each of the three 2010 regulatory options.

Exhibit 6F
Scaling Factors (Extrapolation Multipliers) Applied in this RIA to Estimate the Costs & Benefits of the 2010 Regulatory Options for CCR Disposal

Economic Impact Category	Subtitle C Special Waste	Subtitle D (version 2)	Subtitle "D prime"
Regulatory Compliance Costs:			
1. Engineering control costs	100%	48%	48%
2. Ancillary costs	100%	48%	48%
3. Dry conversion costs	100%	40%	0%
Regulatory Benefits:			

Exhibit 6F Scaling Factors (Extrapolation Multipliers) Applied in this RIA to Estimate the Costs & Benefits of the 2010 Regulatory Options for CCR Disposal			
Economic Impact Category	Subtitle C Special Waste	Subtitle D (version 2)	Subtitle "D prime"
1. Groundwater contamination prevention benefits:			
Groundwater remediation costs avoided	100%	48%	30%
Monetized value of human cancer risks avoided	100%	48%	30%
2. Impoundment structural failure cleanup costs avoided	100%	45%	23%
3. Induced impact on CCR beneficial use:			
Scenario #1: Induced increase	100%	40%	16%
Scenario #2: Induced decrease	100%	None (0%)	None (0%)
Scenario #3: No change	Not relevant	Not relevant	Not relevant

The following two sub-sections (6B.1 and 6B.2) provide explanation and documentation of the scaling factors displayed in **Exhibit 6F** above.

6B.1 Regulatory Cost Scaling Factors

- Engineering control costs: For both RCRA subtitle C and subtitle D, the engineering control costs would be identical under both options. However, state governments are not required to develop comparable programs under RCRA Subtitle D rules, and states cannot enforce Federal subtitle D rules. In addition, because of the nature of subtitle D authority, individual requirements (e.g., groundwater monitoring, impoundment closure) will be more generic, allowing industry great latitude in complying. Thus, actual costs under Subtitle D options will be lower than under Subtitle C, because facilities would not be expected to comply to the same extent. In estimating future annual tons of CCR that might be managed under new standards, and the extent to which they would be similar under the Subtitle C option, this RIA applies the percentage of tons of CCR disposed in states with groundwater monitoring requirements as a way to estimate the likely costs incurred by industry for the other options. Although the engineering control cost category consists of 10 cost elements as defined in this RIA, the percentage of states with groundwater monitoring programs is a reasonable surrogate indicator because states imposing groundwater monitoring requirements indicates which states will generally address specific units, and which are likely to upgrade their programs under subtitle D, if EPA were to issue a national subtitle D rule. In those states, management standards may significantly improve, although not to the level of subtitle C for the reasons discussed above. On the other hand, certainly some facilities in states without programs will choose to comply with the national regulation (taking full advantage of the more generic nature of the federal D standards). Taking these two factors together, using the percentage of CCR disposed in states with groundwater monitoring programs provides a reasonable estimate of the extent to which facilities will take steps to comply with the national standards, and therefore of the costs of compliance. For the federally-enforceable subtitle C option, the cost recognizes that all states (100%) will be required by the CCR rule to install groundwater monitoring (and all other engineering controls). For both the non-federally enforceable subtitle D and the "D prime" options, the cost estimates assume that the 48% of waste disposed of in states that currently require surface impoundments to have groundwater monitoring (either for new units only or for new and existing units) will generally upgrade their programs, improving compliance, and that a modest number of facilities in other states would independently make efforts to comply – giving an overall estimate of 48%. This 48% is applied as a scaling factor multiplier to estimate engineering control costs for both the Subtitle D and "D prime" in relation to the Subtitle C engineering cost estimate.

- Ancillary costs: The RIA separately estimated "ancillary" costs under both Subtitle C and Subtitle D assuming 100% nationwide adoption. For the Subtitle D or "D prime" options, the cost estimate only includes inspections of surface impoundments by qualified engineers. The same logic applies to this requirement as it does to the engineering controls, and therefore this RIA applied the same 48% scaling factor multiplier relative to the Subtitle D ancillary cost estimates.
- Dry conversion costs: For the dry conversion cost, 40% is only applied as a scaling multiplier under the Subtitle D option because the "D prime" option does not require dry conversion. The 40% value is calculated in **Exhibit 6G** below, which is based in part on assuming that the cost for retrofitting or building new impoundments is 63% of the cost of dry conversion under Subtitle C as calculated in **Exhibit 6H** below.

Exhibit 6G
Estimate of Subtitle D (version 2) Impoundment Liner Retrofit or Build New Lined Impoundment Cost

A	B	C	D	E	F	G (D x F x 63%**)
Row	Year	Count of existing electric utility plants with impoundments	**Subtitle C special waste**: Dry Conversion Cost	Percent existing CCR impoundments with composite liners*	Percent of CCR impoundments without composite liners	**Subtitle D (v.2)**: Must Retrofit or Build New Lined Impoundments
1	2012	158	$22,984,000,000	5.5%	94.5%	$13,709,900,000
2	2013	158	$0	5.5%	94.5%	$0
3	2014	158	$0	5.5%	94.5%	$0
4	2015	158	$0	5.5%	94.5%	$0
5	2016	158	$0	5.5%	94.5%	$0
6	2017	158	$15,800,000	5.5%	94.5%	$9,400,000
7	2018	158	$15,800,000	5.5%	94.5%	$9,400,000
8	2019	158	$15,800,000	5.5%	94.5%	$9,400,000
9	2020	158	$15,800,000	5.5%	94.5%	$9,400,000
10	2021	158	$15,800,000	5.5%	94.5%	$9,400,000
11	2022	158	$15,800,000	5.5%	94.5%	$9,400,000
12	2023	158	$15,800,000	5.5%	94.5%	$9,400,000
13	2024	158	$15,800,000	5.5%	94.5%	$9,400,000
14	2025	158	$15,800,000	5.5%	94.5%	$9,400,000
15	2026	158	$15,800,000	5.5%	94.5%	$9,400,000
16	2027	158	$15,800,000	5.5%	94.5%	$9,400,000
17	2028	158	$15,800,000	5.5%	94.5%	$9,400,000
18	2029	158	$15,800,000	5.5%	94.5%	$9,400,000
19	2030	158	$15,800,000	5.5%	94.5%	$9,400,000
20	2031	158	$15,800,000	5.5%	94.5%	$9,400,000

Exhibit 6G Estimate of Subtitle D (version 2) Impoundment Liner Retrofit or Build New Lined Impoundment Cost						
A	B	C	D	E	F	G (D x F x 63%**)
Row	Year	Count of existing electric utility plants with impoundments	**Subtitle C special waste**: Dry Conversion Cost	Percent existing CCR impoundments with composite liners*	Percent of CCR impoundments without composite liners	**Subtitle D (v.2)**: Must Retrofit or Build New Lined Impoundments
21	2032	158	$15,800,000	5.5%	94.5%	$9,400,000
22	2033	158	$15,800,000	5.5%	94.5%	$9,400,000
23	2034	158	$15,800,000	5.5%	94.5%	$9,400,000
24	2035	158	$15,800,000	5.5%	94.5%	$9,400,000
25	2036	158	$15,800,000	5.5%	94.5%	$9,400,000
26	2037	158	$15,800,000	5.5%	94.5%	$9,400,000
27	2038	158	$15,800,000	5.5%	94.5%	$9,400,000
28	2039	158	$15,800,000	5.5%	94.5%	$9,400,000
29	2040	158	$15,800,000	5.5%	94.5%	$9,400,000
30	2041	158	$15,800,000	5.5%	94.5%	$9,400,000
31	2042	158	$15,800,000	5.5%	94.5%	$9,400,000
32	2043	158	$15,800,000	5.5%	94.5%	$9,400,000
33	2044	158	$15,800,000	5.5%	94.5%	$9,400,000
34	2045	158	$15,800,000	5.5%	94.5%	$9,400,000
35	2046	158	$15,800,000	5.5%	94.5%	$9,400,000
36	2047	158	$15,800,000	5.5%	94.5%	$9,400,000
37	2048	158	$15,800,000	5.5%	94.5%	$9,400,000
38	2049	158	$15,800,000	5.5%	94.5%	$9,400,000
39	2050	158	$15,800,000	5.5%	94.5%	$9,400,000
40	2051	158	$22,984,000,000	5.5%	94.5%	$13,709,900,000
41	2052	158	$15,800,000	5.5%	94.5%	$9,400,000
42	2053	158	$15,800,000	5.5%	94.5%	$9,400,000
43	2054	158	$15,800,000	5.5%	94.5%	$9,400,000
44	2055	158	$15,800,000	5.5%	94.5%	$9,400,000
45	2056	158	$15,800,000	5.5%	94.5%	$9,400,000
46	2057	158	$15,800,000	5.5%	94.5%	$9,400,000
47	2058	158	$15,800,000	5.5%	94.5%	$9,400,000
48	2059	158	$15,800,000	5.5%	94.5%	$9,400,000
49	2060	158	$15,800,000	5.5%	94.5%	$9,400,000
50	2061	158	$15,800,000	5.5%	94.5%	$9,400,000
Non-discounted total cost =			$46,663,000,000			$27,833,000,000
Non-discounted average cost =			$933,000,000			$557,000,000
Present value cost (@7% disc.) =			$23,167,000,000			$13,819,000,000
Average annualized cost (@7%) =			$1,679,000,000			$1,001,000,000
Percent reduction in annualized cost compared to Subtitle C Option conversion cost =						**40%**
Notes:						

Exhibit 6G Estimate of Subtitle D (version 2) Impoundment Liner Retrofit or Build New Lined Impoundment Cost						
A	B	C	D	E	F	G (D x F x 63%**)
Row	Year	Count of existing electric utility plants with impoundments	**Subtitle C special waste**: Dry Conversion Cost	Percent existing CCR impoundments with composite liners*	Percent of CCR impoundments without composite liners	**Subtitle D (v.2)**: Must Retrofit or Build New Lined Impoundments
* 5.5% existing impoundments with composite liners based on EPA's 2000 CCR regulatory determination and on the August 2006 joint EPA-DOE survey report. ** EPA estimated the capital and annual O&M costs for the Subtitle D requirement for either retrofitting or building new CCR impoundments with composite liners, by assuming that the cost for those requirements are 63% of the $23.167 billion present value cost for dry conversion under the Subtitle C option. This 63% cost scaling factor is calculated in **Exhibit 6H** of this RIA.						

Exhibit 6H Reference Data for Calculation of "63% Cost Scaling Factor" Applied in Exhibit 6G								
		Capital cost	O&M cost	Row total	Percent	Capital cost	Percent	
Dry Coal Ash Management (35-year lifespan cost in 1980$)								
1	In-plant handling system	$19,500,000	$693,100,000	$712,600,000	76%	$19,500,000	23%	
2	Conveyance (transport)	$10,364,000	$116,996,000	$127,360,000	14%	$10,364,000	12%	
3	Disposal (lined landfill)	$53,952,000	$39,926,000	$93,878,000	10%	$53,952,000	64%	
	Total =	$83,816,000	$850,022,000	$933,838,000	100%	$83,816,000	100%	
Wet Coal Ash Management (35-year lifespan cost in 1980$)								
1	In-plant handling system	$8,500,000	$302,121,000	$310,621,000	69%	$8,500,000	9%	
2	Conveyance (transport)	$31,954,000	$42,140,000	$74,094,000	16%	$31,954,000	34%	
3	Disposal (lined impoundment)	$52,906,000	$14,448,000	$67,354,000	15%	$52,906,000	57%	**63%***
	Total =	$93,360,000	$358,709,000	$452,069,000	100%	$93,360,000	100%	
Source: Based on cost data for an example 2600 megawatt (MW) nameplate capacity electric utility plant from pages B-8 (dry) and C-9 (wet) of the EPA/TVA joint study "Economic Analysis of Wet Versus Dry Ash Disposal Systems: Interagency Energy/Environment R&D Program Report," report nr. EPA-600/7-81-013, January 1981: http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=20006ORT.txt * EPA estimated the capital and annual O&M costs for the Subtitle D requirement for either retrofitting or building new CCR impoundments with composite liners, by assuming that the cost for those requirements are 63% of the $23.167 billion present value cost for dry conversion under the Subtitle C option. This 63% cost scaling factor is calculated in this exhibit.								

6B.2 Regulatory Benefits Scaling Factors

- Groundwater contamination benefits: Percentages are based on an examination of state programs related to groundwater monitoring requirements as described in **Chapter 5** of this RIA. The percentages given in **Exhibit 6F** above refer only to the input values to the estimation of groundwater protection benefits presented in **Chapter 5** of this RIA. For the Subtitle C option, all states will be required by the rule to have groundwater monitoring in place so that 100% of facilities over the baseline would detect contamination early and thus human cancers would be prevented. For the Subtitle D option, 48% of CCR are placed in surface impoundments in states with groundwater monitoring in place for new units only (or for new and existing units). It is likely that these states with some level of attention to groundwater monitoring would increase their attention (e.g., because they already have a RCRA program infrastructure) to groundwater monitoring, providing for much more effective systems, while other states would tend not to (although some individual facilities within those states would upgrade groundwater monitoring to some extent). Thus, this RIA estimates that overall, the new regulation would result in 48% of facilities detecting contamination early and 48% of cancers would be prevented. For the Subtitle D prime option, retrofitting existing units would not be required, and therefore existing and future releases would continue to occur from unlined surfaced impoundments. Currently 12% of CCR are placed in surface impoundments in states with groundwater monitoring. Some of these states would certainly upgrade their regulations, but given that surface impoundments would remain a potential source of release in all states, the Subtitle D prime option is less protective of groundwater than the Subtitle D option. Since this fraction is likely to fall between 48% and 12%, the mid-point of 30% was chosen as a best estimate for the D prime option.

- <u>Impoundment structural failure cleanup costs avoided</u>: This factor is not based on estimates of percentages of states likely to implement the new requirements (which for subtitle D would require liners for existing surface impoundments); it is unlikely that many states will choose to implement this requirement. Instead, compliance will not be enforceable, and will be left up to self-imposed schedules of industry or citizens suits. While most impoundments may eventually close, it will be a lengthy process. As a general estimate, through delaying closures and lengthening the process, industry may be able to reduce costs by 50%. In addition, since 5.5% of surface impoundments have composite liners already, they would remain in place, and therefore would not incur costs. Taking these figures together, this RIA applies a 45% scaling factor for this benefit.
- <u>Induced impact on CCR beneficial uses</u>:
  - Under Scenario #1 induced increase in beneficial use, beneficial uses are assumed to be linear with respect to total costs because increases in usage are directly proportional to the cost of the regulatory options. Therefore, under the Subtitle D option, the net reduction in total costs compared to the Subtitle C option is 40%. Under the Subtitle “D prime” option, since the dry conversion costs are 0%, a net result of 16% was applied. This percentage was derived by dividing the Subtitle “D prime” option cost by the total cost of Subtitle C.
  - Under Scenario #2 induced decrease in beneficial use, for the reasons described in Section 5C of this RIA, this RIA assumes that potential induced future decrease on beneficial use only applies to the Subtitle C regulatory option, not to the Subtitle D-based options.
  - Under Scenario #3 no change in beneficial use (relative to baseline), there is no impacts under any of the regulatory options, so no scaling assumptions are applied.

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:
  - o 365 operating days per year
  - o 24 operating hours per day
  - o 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

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.

[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

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[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

[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

7C. Minority & Low-Income Population Statistics (Executive Order 12898)

Under the 1994 Executive Order (EO) 12898[183] it is the responsibility of Federal agencies to the greatest extent practicable and permitted by law, and consistent with the principles set forth in the report on the National Performance Review, each Federal agency shall make achieving environmental justice (EJ) part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on (a) **minority** populations and (b) **low-income** populations. Although not defined in EO 12898, for purpose of this RIA the following definitions are applied:

- Minority population: Numerically measured according to Census Bureau "non-white" statistics (does not include Hispanics).
- Low-income population: Numerically measured according to Census Bureau "individuals below poverty[184] level."

Furthermore, section 3-302(b) of EO 12898 provides a trigger which indicates that Federal agencies shall collect and evaluate EJ data for any facilities or sites expected to have "substantial environmental, human health, or economic effect" when such facilities or sites become subject to "substantial" Federal environmental action:

> "*In connection with the development and implementation of agency strategies in section 1-103 of this order, each Federal agency, whenever practicable and appropriate, shall collect, maintain and analyze information on the race, national origin, income level, and other readily accessible and appropriate information for areas surrounding facilities or sites expected to have* ***substantial*** *environmental, human health, or economic* ***effect*** *on the surrounding populations, when such facilities or sites become the subject of a substantial Federal environmental administrative or judicial action. Such information shall be made available to the public unless prohibited by law*."

The EO 12898 does not establish quantitative thresholds for "substantial effect" on the surrounding populations, nor does this RIA formulate a quantitative threshold. This RIA uses the (1) CCR disposal baseline environmental and human health hazards (e.g., damage cases), and (2) the environmental and human health protection objectives described in the CCR proposed rule, as indicators of "substantial effect". For that reason, this section of the RIA presents an EJ data collection and analysis involving a 5-step process to compare minority and low-income population data for each electric utility plant location, to respective statewide population data, to identify whether these two population sub-groups disproportionately reside in geographic areas where electric utility plants are located. In addition, this RIA identifies two other possible affects of the CCR proposed rule on (a) environmental justice populations surrounding offsite landfills which may receive CCR, and (b) environmental justice populations within electric utility plant customer service areas.

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[183] Source: 1994 Executive Order 12898 is available at: http://www.epa.gov/fedrgstr/eo/eo12898.htm

[184] The US Census Bureau defines "poverty" following the Office of Management and Budget's (OMB) Statistical Policy Directive 14. The Census Bureau uses a set of money income thresholds that vary by family size and composition to determine who is in poverty. If a family's total income is less than the family's threshold, then that family and every individual in it is considered in poverty. Poverty income thresholds are available at http://www.census.gov/hhes/www/poverty/threshld/thresh08.html

- **Collection of Minority & Low-Income Demographic Data**

Step 1: Plant address 5-digit "Zip Code Tabulation Areas" (ZCTAs) formed the geographic basis for this EJ population data collection. Because ZCTAs represent irregularly shaped geographic areas, this ZCTA based data collection may be considered a "screening level" analysis. The US Bureau of Census uses over 33,000 ZCTA for its Census counts of population and other demographic statistics based on the US Postal Service's over 42,000 nationwide ZCTAs.[185] Currently, there are no size restrictions limiting how large or small a ZCTA can be in terms of either a minimum/maximum number of housing units or geographic area. Any particular ZCTA may be as small as a few city blocks or may cover many square miles. Many ZCTAs are for villages, census-designated places, portions of cities, or other entities that are not municipalities. The nationwide average ZCTA population is about 7,200 persons (i.e., (306.6 million mid-2009 US population) / (42,500 ZCTAs)). The nationwide average ZCTA area is about 83 square miles (i.e., (3,536,278 square miles total US land and water area) / (42,500 ZCTAs)), which is a land area equivalent to a five-mile radial distance (i.e., ((83 square miles) / (3.1416))^0.5). In comparison, the radial area monitored for contamination in response to the December 2009 TVA Kingston TN electric plant CCR spill is reportedly four miles,[186]and this average four-mile ZCTA radial distance falls between the 1-mile to 15-mile radial distances used by EPA's Superfund "Hazard Ranking System" (HRS) to define affected populations of sites having either (a) soil contamination only (1-mile), (b) groundwater and/or airborne contamination (4-miles), or (c) surface water contamination (15-miles downstream). More information about EPA's HRS is available at http://www.epa.gov/superfund/programs/npl_hrs/hrsint.htm.

Using the Census search engine Factfinder (http:factfinder.census.gov/home/saff/main.html?_lang=en), EPA retrieved population statistics for 464 (94%) of the 495 electric utility plants. For 42 plants (8%) there was no ZCTA Census data because the plants did not have complete address data from DOE, or because the Census search engine did not have data for the ZCTA.

Step 2: EPA collected statewide percentage data for minority and low-income subgroups for purpose of benchmark comparison to the plant-by-plant sub-group population statistics.

- EPA collected low-income population statewide percentages (3-year averages for 1998 to 2000) from the following Census Bureau website: http://www.census.gov/hhes/www/poverty/poverty00/tabled.pdf
- EPA collected statewide percentages for white population sub-group (data year 2000) from the Census Bureau website: . EPA then subtracted the percentage of white population in each state from 100% to produce the respective minority percentage for each state. For data year 2000, the Census Bureau expanded the white population classification by collecting both data for people who claimed to be "white-only" and for people who claimed to be "mixed white". Since the purpose of the EJ analysis is to evaluate all minorities, this step involved collecting the "white-only" data in order to calculate the minority percentage which includes people who reported to be of mixed race. **Exhibit 7F** below displays the statewide Census data for low-income and minority sub-populations.

[185] Source: US Census Bureau ZIP Code Tabulation Area (ZCTA) Frequently Asked Questions at: Nationwide total ZCTA count is from the US Postal Service's FAQ website at: http://zip4.usps.com/zip4/welcome.jsp

[186] Source: 4 mile radial monitoring area reported by Waste & Recycling News, 13 Feb 2009; http://www.wasterecyclingnews.com/email.html?id=1234543579

Exhibit 7F
Statewide Benchmark Data on Low-Income and Minority Populations (2000)

Item	State	Low Income %	Minority %
1	AK	8.4%	30.7%
2	AL	14.7%	28.9%
3	AR	15.8%	20.0%
4	AZ	13.5%	24.5%
5	CA	14.0%	40.5%
6	CO	8.5%	17.2%
7	CT	7.7%	18.4%
8	DC	17.4%	69.2%
9	DE	9.9%	25.4%
10	FL	12.1%	22.0%
11	GA	12.5%	34.9%
12	HI	10.6%	75.7%
13	IA	7.9%	6.1%
14	ID	13.3%	9.0%
15	IL	10.5%	26.5%
16	IN	8.3%	12.5%
17	KS	10.5%	13.9%
18	KY	12.5%	9.9%
19	LA	18.5%	36.1%
20	MA	10.1%	15.5%
21	MD	7.3%	36.0%
22	ME	9.8%	3.1%
23	MI	10.2%	19.8%
24	MN	7.8%	10.6%
25	MO	9.8%	15.1%
26	MS	15.5%	38.6%
27	MT	16.%	9.4%
28	NC	13.2%	27.9%

Item	State	Low Income %	Minority %
29	ND	12.7%	7.6%
30	NE	10.7%	10.4%
31	NH	7.6%	4.0%
32	NJ	8.1%	27.4%
33	NM	19.3%	33.2%
34	NV	10.1%	24.8%
35	NY	14.7%	32.1%
36	OH	11.1%	15.0%
37	OK	14.1%	23.8%
38	OR	12.9%	13.4%
39	PA	9.8%	14.6%
40	RI	10.2%	15.0%
41	SC	12.0%	32.8%
42	SD	9.4%	11.3%
43	TN	13.4%	19.8%
44	TX	14.9%	29.0%
45	UT	8.1%	10.8%
46	VA	8.1%	27.7%
47	VT	10.3%	3.2%
48	WA	9.5%	18.2%
49	WI	9.0%	11.1%
50	WV	15.8%	5.0%
51	WY	11.1%	7.9%
	Min =	7.3% (MD)	3.1% (ME)
	Max =	19.3% (NM)	75.7% (HI)
	National =	**11.9%**	**24.9%**

- **Comparison of Minority & Low-Income Populations Surrounding Electric Utility Plants to Statewide Benchmarks**

Step 3, Step 4 and Step 5 of this evaluation described below involved three complementary levels of data comparisons. All three comparisons also involved two complementary numerical comparisons, one based on calculating numerical percentages and the other on numerical ratios:

1. Plant level: Plant-by-plant disaggregated data comparison to statewide benchmarks
2. State level: State-by-state aggregated plant data comparison to statewide benchmarks
3. Nationwide level: Nationwide aggregated plant data comparison to nationwide benchmarks

- **Calculation of Three Alternative Demographic Statistics Comparison Methods**

Step 3: On a plant-by-plant basis, EPA compared the plant ZCTA percentage minority and percentage low-income population data, to the respective statewide average percentages for each sub-group. This constituted the 1st level of data comparison.

Step 4: For purpose of summary, EPA aggregated the plant level population comparison data for each state as displayed in **Exhibit 7G** below. This constituted the 2nd level of data comparison. There are no data displayed for DC, ID, RI or VT because there are no coal-fired electric utility plants in those states. **Appendix N** of this RIA presents the plant-by-plant Census data on which this Exhibit is based. This step also involved aggregating the data across all 495 plants for comparison with the nationwide aggregate minority and low-income percentage benchmarks. This constituted the 3rd level of data comparison.

Exhibit 7G
Minority and Low-Income Population Data Aggregated on State-by-State Basis

A	B	C	D	E	F (E/D)	G (**Exh 7F**)	H (DxG)	I	J	K (DxJ)	L (**Exh 7F**)	M (DxL)	N
General Population Data				**Low Income Population Data (Below Poverty)**					**Minority Population Data**				
Item	State	ZCTA count	2000 population residing in electric utility plant ZCTA areas	Count of plant ZCTA residents below poverty level	% of plant ZCTA residents below poverty level	State % below poverty level	Expected count of residents below poverty based on state%	Count of plants with ZCTA% > state% poverty level	% of plant ZCTA residents that are minority	Count of plant ZCTA residents that are minority	State-wide % minority	Expected count of minority based on state%	Count of plants with ZCTA% > state% minority level
1	AK	2	18,552	2,284	12.31%	8.40%	1,558	1	31.95%	5,928	30.70%	5,695	1
2	AL	9	82,854	20,331	24.54%	14.70%	12,180	6	42.17%	34,942	28.90%	23,945	4
3	AR	3	11,786	1,214	10.30%	15.80%	1,862	0	7.74%	912	20.00%	2,357	0
4	AZ	6	34,941	7,433	21.27%	13.50%	4,717	5	43.70%	15,270	24.50%	8,561	3
5	CA	4	112,895	24,749	21.92%	14.00%	15,805	5	45.22%	51,049	40.50%	45,722	2
6	CO	15	214,095	29,395	13.73%	8.50%	18,198	10	17.88%	38,275	17.20%	36,824	8
7	CT	2	42,716	6,427	15.05%	7.70%	3,289	1	45.14%	19,284	18.40%	7,860	1
8	DC	ND											

Exhibit 7G
Minority and Low-Income Population Data Aggregated on State-by-State Basis

A	B	C	D	E	F (E/D)	G (**Exh 7F**)	H (DxG)	I	J	K (DxJ)	L (**Exh 7F**)	M (DxL)	N
General Population Data				**Low Income Population Data (Below Poverty)**					**Minority Population Data**				
Item	State	ZCTA count	2000 population residing in electric utility plant ZCTA areas	Count of plant ZCTA residents below poverty level	% of plant ZCTA residents below poverty level	State % below poverty level	Expected count of residents below poverty based on state%	Count of plants with ZCTA% > state% poverty level	% of plant ZCTA residents that are minority	Count of plant ZCTA residents that are minority	State-wide % minority	Expected count of minority based on state%	Count of plants with ZCTA% > state% minority level
9	DE	3	46,925	3,979	8.48%	9.90%	4,646	1	28.86%	13,543	25.40%	11,919	1
10	FL	13	224,502	23,866	10.63%	12.10%	27,165	5	20.76%	46,617	22.00%	49,390	3
11	GA	9	202,973	29,461	14.51%	12.50%	25,372	4	42.66%	86,581	34.90%	70,838	4
12	HI	1	25,054	1,150	4.59%	10.60%	2,656	0	78.17%	19,584	75.70%	18,966	1
13	IA	14	324,050	31,434	9.70%	7.90%	25,600	13	7.02%	22,744	6.10%	19,767	9
14	ID	ND											
15	IL	23	455,834	83,407	18.30%	10.50%	47,863	14	41.46%	188,970	26.50%	120,796	8
16	IN	17	323,323	25,460	7.87%	8.30%	26,836	10	6.96%	22,488	12.50%	40,415	2
17	KS	6	59,517	7,718	12.97%	10.50%	6,249	4	36.76%	21,881	13.90%	8,273	3
18	KY	17	255,033	32,497	12.74%	12.50%	31,879	7	8.48%	21,615	9.90%	25,248	2
19	LA	4	30,381	7,546	24.84%	18.50%	5,620	3	45.16%	13,721	36.10%	10,968	2
20	MA	3	95,798	14,420	15.05%	10.10%	9,676	1	20.69%	19,819	15.50%	14,849	1
21	MD	7	101,141	10,622	10.50%	7.30%	7,383	4	12.39%	12,527	36.00%	36,411	1
22	ME	1	6,748	1,037	15.37%	9.80%	661	1	1.30%	88	3.10%	209	0
23	MI	20	383,284	30,735	8.02%	10.20%	39,095	8	10.56%	40,477	19.80%	75,890	2
24	MN	15	187,012	20,910	11.18%	7.80%	14,587	10	10.78%	20,157	10.60%	19,823	3
25	MO	19	251,484	24,714	9.83%	9.80%	24,645	10	7.47%	18,794	15.10%	37,974	2
26	MS	4	69,209	17,675	25.54%	15.50%	10,727	3	51.63%	35,735	38.60%	26,715	2
27	MT	5	53,209	8,441	15.86%	16.00%	8,513	2	13.25%	7,050	9.40%	5,002	4
28	NC	16	238,874	37,388	15.65%	13.20%	31,531	9	34.49%	82,397	27.90%	66,646	12
29	ND	5	27,087	2,440	9.01%	12.70%	3,440	1	4.40%	1,193	7.60%	2,059	0
30	NE	6	79,313	8,992	11.34%	10.70%	8,486	2	11.38%	9,027	10.40%	8,249	2
31	NH	2	53,302	4,355	8.17%	7.60%	4,051	2	5.40%	2,877	4.00%	2,132	2
32	NJ	6	119,286	17,958	15.05%	8.10%	9,662	3	43.96%	52,438	27.40%	32,684	3
33	NM	4	17,491	4,638	26.52%	19.30%	3,376	3	55.72%	9,746	33.20%	5,807	3
34	NV	3	8,471	823	9.72%	10.10%	856	1	15.75%	1,334	24.80%	2,101	1
35	NY	13	226,416	29,187	12.89%	14.70%	33,283	3	17.42%	39,451	32.10%	72,680	3
36	OH	23	391,705	42,242	10.78%	11.10%	43,479	7	12.24%	47,953	15.00%	58,756	2
37	OK	6	30,357	6,117	20.15%	14.10%	4,280	4	38.84%	11,791	23.80%	7,225	1
38	OR	1	3,884	596	15.35%	12.90%	501	1	39.19%	1,522	13.40%	520	1
39	PA	28	167,254	15,499	9.27%	9.80%	16,391	15	6.61%	11,048	14.60%	24,419	3
40	RI	ND											
41	SC	12	222,414	28,746	12.92%	12.00%	26,690	8	31.40%	69,831	32.80%	72,952	6
42	SD	2	30,508	1,763	5.78%	9.40%	2,868	1	5.55%	1,694	11.30%	3,447	0

Exhibit 7G
Minority and Low-Income Population Data Aggregated on State-by-State Basis

A	B	C	D	E	F (E/D)	G (**Exh 7F**)	H (DxG)	I	J	K (DxJ)	L (**Exh 7F**)	M (DxL)	N
General Population Data				**Low Income Population Data (Below Poverty)**					**Minority Population Data**				
Item	State	ZCTA count	2000 population residing in electric utility plant ZCTA areas	Count of plant ZCTA residents below poverty level	% of plant ZCTA residents below poverty level	State % below poverty level	Expected count of residents below poverty based on state%	Count of plants with ZCTA% > state% poverty level	% of plant ZCTA residents that are minority	Count of plant ZCTA residents that are minority	State-wide % minority	Expected count of minority based on state%	Count of plants with ZCTA% > state% minority level
43	TN	8	158,267	26,572	16.79%	13.40%	21,208	4	37.38%	59,159	19.80%	31,337	1
44	TX	17	98,402	14,147	14.38%	14.90%	14,662	10	22.41%	22,052	29.00%	28,537	3
45	UT	6	34,209	3,885	11.36%	8.10%	2,771	6	5.22%	1,784	10.80%	3,695	0
46	VA	15	220,800	21,822	9.88%	8.10%	17,885	11	37.78%	83,411	27.70%	61,162	11
47	VT	ND											
48	WA	1	21,842	3,394	15.54%	9.50%	2,075	1	9.54%	2,083	18.20%	3,975	0
49	WI	13	178,705	23,577	13.19%	9.00%	16,083	8	12.00%	21,446	11.10%	19,836	4
50	WV	13	64,771	15,577	24.05%	15.80%	10,234	11	6.45%	4,179	5.00%	3,239	2
51	WY	8	69,736	6,439	9.23%	11.10%	7,741	1	4.92%	3,428	7.90%	5,509	0
Summary:													
Column totals		430	6,076,410	**783,062**	**12.9%**	11.9%	**658,336**	240	**21.7%**	**1,317,895**	24.9%	**1,241,382**	129
				18.9%								**-5.8%**	
				Min =	4.6%	7.3%			1.3%		3.1%		
				Max =	26.5%	19.3%			78.2%		75.7%		
							Extrapolated to 495 plants =	**256**					**138**

Step 5: Ratios: EPA compared the percentages of minority and low-income populations surrounding the plants to their respective statewide benchmark percentages and to the nationwide percentages of these populations as calculated in Step 4, by calculating numerical ratios between the plant ZCTA group populations compared to statewide and nationwide percentages of minority and low-income populations. The purpose of these ratios is to indicate the relative degree by which the percentages are below or above the statewide percentages. **Exhibit 7H** below displays the results.

Exhibit 7H
Comparison of Minority and Low-Income Populations Near Coal-Fired Electric Utility Plants to Statewide Percentages

A	B	C	D	E	F (D–E)	G (D/E)	H	I	J (H–I)	K (I/J)
			Low-Income Data Comparison				**Minority Data Comparison**			
Item	State	Count of plants	Percent Low-Income Population Surrounding Plants	Statewide Low-Income Percentage (**Exhibit 7F**)	Difference	Ratio	Percent Minority Population Surrounding Plants	Statewide Minority Percentage (**Exhibit 7F**)	Differenc e	Ratio
1	AK	2	12.3%	8.4%	3.9%	1.47	32.0%	30.7%	1.3%	1.04
2	AL	9	24.5%	14.7%	9.8%	1.67	42.2%	28.9%	13.3%	1.46
3	AR	3	10.3%	15.8%	-5.5%	0.65	7.7%	20.0%	-12.3%	0.39
4	AZ	6	21.3%	13.5%	7.8%	1.58	43.7%	24.5%	19.2%	1.78
5	CA	5	21.9%	14.0%	7.9%	1.57	45.2%	40.5%	4.7%	1.12
6	CO	15	13.7%	8.5%	5.2%	1.62	17.9%	17.2%	0.7%	1.04
7	CT	2	15.0%	7.7%	7.3%	1.95	45.1%	18.4%	26.7%	2.45
8	DC	NR	NA	NA	NA	NA	NA	NA	NA	NA
9	DE	3	8.5%	9.9%	-1.4%	0.86	28.9%	25.4%	3.5%	1.14
10	FL	14	10.6%	12.1%	-1.5%	0.88	20.8%	22.0%	-1.2%	0.94
11	GA	9	14.5%	12.5%	2.0%	1.16	42.7%	34.9%	7.8%	1.22
12	HI	1	4.6%	10.6%	-6.0%	0.43	78.2%	75.7%	2.5%	1.03
13	IA	17	9.7%	7.9%	1.8%	1.23	7.0%	6.1%	0.9%	1.15
14	ID	NR	NA	NA	NA	NA	NA	NA	NA	NA
15	IL	25	18.3%	10.5%	7.8%	1.74	41.5%	26.5%	15.0%	1.56
16	IN	19	7.9%	8.3%	-0.4%	0.95	7.0%	12.5%	-5.5%	0.56
17	KS	7	13.0%	10.5%	2.5%	1.24	36.8%	13.9%	22.9%	2.64
18	KY	19	12.7%	12.5%	0.2%	1.02	8.5%	9.9%	-1.4%	0.86
19	LA	4	24.8%	18.5%	6.3%	1.34	45.2%	36.1%	9.1%	1.25
20	MA	4	15.1%	10.1%	5.0%	1.49	20.7%	15.5%	5.2%	1.33
21	MD	8	10.5%	7.3%	3.2%	1.44	12.4%	36.0%	-23.6%	0.34
22	ME	1	15.4%	9.8%	5.6%	1.57	1.3%	3.1%	-1.8%	0.42
23	MI	23	8.0%	10.2%	-2.2%	0.79	10.6%	19.8%	-9.2%	0.53
24	MN	15	11.2%	7.8%	3.4%	1.43	10.8%	10.6%	0.2%	1.02
25	MO	19	9.8%	9.8%	0.0%	1.00	7.5%	15.1%	-7.6%	0.49
26	MS	4	25.5%	15.5%	10.0%	1.65	51.6%	38.6%	13.0%	1.34

Exhibit 7H
Comparison of Minority and Low-Income Populations Near Coal-Fired Electric Utility Plants to Statewide Percentages

A	B	C	D	E	F (D–E)	G (D/E)	H	I	J (H–I)	K (I/J)
			Low-Income Data Comparison				**Minority Data Comparison**			
Item	State	Count of plants	Percent Low-Income Population Surrounding Plants	Statewide Low-Income Percentage (**Exhibit 7F**)	Difference	Ratio	Percent Minority Population Surrounding Plants	Statewide Minority Percentage (**Exhibit 7F**)	Differenc e	Ratio
27	MT	6	15.9%	16.0%	-0.1%	0.99	13.2%	9.4%	3.8%	1.41
28	NC	19	15.7%	13.2%	2.5%	1.19	34.5%	27.9%	6.6%	1.24
29	ND	7	9.0%	12.7%	-3.7%	0.71	4.4%	7.6%	-3.2%	0.58
30	NE	6	11.3%	10.7%	0.6%	1.06	11.4%	10.4%	1.0%	1.09
31	NH	2	8.2%	7.6%	0.6%	1.08	5.4%	4.0%	1.4%	1.35
32	NJ	6	15.1%	8.1%	7.0%	1.86	44.0%	27.4%	16.6%	1.60
33	NM	4	26.5%	19.3%	7.2%	1.37	55.7%	33.2%	22.5%	1.68
34	NV	3	9.7%	10.1%	-0.4%	0.96	15.7%	24.8%	-9.1%	0.63
35	NY	13	12.9%	14.7%	-1.8%	0.88	17.4%	32.1%	-14.7%	0.54
36	OH	24	10.8%	11.1%	-0.3%	0.97	12.2%	15.0%	-2.8%	0.82
37	OK	6	20.2%	14.1%	6.1%	1.43	38.8%	23.8%	15.0%	1.63
38	OR	1	15.3%	12.9%	2.4%	1.19	39.2%	13.4%	25.8%	2.92
39	PA	31	9.3%	9.8%	-0.5%	0.95	6.6%	14.6%	-8.0%	0.45
40	RI	NR	NA	NA	NA	NA	NA	NA	NA	NA
41	SC	12	12.9%	12.0%	0.9%	1.08	31.4%	32.8%	-1.4%	0.96
42	SD	2	5.8%	9.4%	-3.6%	0.61	5.6%	11.3%	-5.7%	0.49
43	TN	8	16.8%	13.4%	3.4%	1.25	37.4%	19.8%	17.6%	1.89
44	TX	18	14.4%	14.9%	-0.5%	0.96	22.4%	29.0%	-6.6%	0.77
45	UT	6	11.4%	8.1%	3.3%	1.40	5.2%	10.8%	-5.6%	0.48
46	VA	16	9.9%	8.1%	1.8%	1.22	37.8%	27.7%	10.1%	1.36
47	VT	NR	NA	NA	NA	NA	NA	NA	NA	NA
48	WA	1	15.5%	9.5%	6.0%	1.64	9.5%	18.2%	-8.7%	0.52
49	WI	15	13.2%	9.0%	4.2%	1.47	12.0%	11.1%	0.9%	1.08
50	WV	16	24.0%	15.8%	8.2%	1.52	6.5%	5.0%	1.5%	1.29
51	WY	9	9.2%	11.1%	-1.9%	0.83	4.9%	7.9%	-3.0%	0.62
Summary:										
		Min =	4.6%	7.3%	-6.0%	0.43	4.4%	3.1%	-23.6%	0.34
		Max =	26.5%	19.3%	10.0%	1.95	78.2%	75.7%	26.7%	2.92
Nationwide =		464	12.9%	11.9%	1.0%	**1.08**	21.7%	24.9%	-3.2%	**0.87**

- **Minority & Low-Income Demographic Findings**

Below is a summary of the three alternative but complementary comparison approaches based on the same minority and low-income population data: (a) itemized plant-by-plant basis, (b) nationwide aggregation basis, and (c) state-by-state aggregation basis. For purpose of determining the relative degree by which either group living near the 495 plants may exceed their respective statewide population percentages, the percentages are compared as a numerical ratio whereby a ratio of 1.00 indicates that the group population percentage living near a plant is equal to the statewide average, a ratio greater than 1.00 indicates the group population percentage near the plant is higher than the statewide population, and a ratio less than 1.00 indicates the group population is less than the respective statewide average.

- General population findings:
  - 464 plants (i.e., 94% of the 495 universe) for which year 2000 Census plant address ZCTA data are available are located in 47 states.
  - The plant address ZCTA population surrounding the 464 plants with ZCTA data is **6.08 million**, which is an average of 13,091 surrounding population per plant.

- Low-income population findings:
  - **0.78 million** low-income population surrounding the 464 plants represents **12.9%** of the 6.08 million total surrounding populations; this is higher than the **11.9%** national percentage.
  - State-by-state low-income population percentages surrounding these plants range from 4.6% in HI to 26.5% in NM.
  - Extrapolated and aggregated across all 495 plants, 256 plants (**52%**) have surrounding populations which exceed their statewide benchmark percentage of low-income population.
  - The ratios of low-income population percentages surrounding these plants range from 0.43 to 1.95, and the average of the ratios compared to the national average ratio of the low-income population is 1.08.
  - Approximately 29 of the 47 states (62%) have higher percentages of low-income populations compared to their respective statewide benchmarks.
  - States with the largest difference in low-income populations surrounding the plants compared to their statewide benchmarks are:

    1. Mississippi (26% vs. 16%)
    2. Alabama (25% vs. 15%)
    3. Illinois (18% vs. 11%)
    4. New Jersey (15% vs. 8%)
    5. Connecticut (15% vs. 8%)

- Minority population findings:
  - **1.32 million** minority population surrounding the 464 plants represents **21.7%** of the 6.08 million total surrounding populations; this is lower than the **24.9%** national minority population.

- The state-by-state range of minority population percentages surrounding these plants ranges from 1.3% in ME to 78.2% in HI.
- Extrapolated and aggregated across all 495 plants, 138 plants (**28%**) have surrounding populations which exceed their statewide benchmark minority percentage of population.
- The ratio of minority population percentages surrounding these plants range from 0.34 to 2.92, and the average of the ratios compared to the national average ratio of the minority population is 0.87.
- Approximately 24 of the 47 states (51.1%) have disproportionately high percentages of minority populations within the plant address ZCTA area compared to the rest of the state.
- States with the largest difference in minority populations between the ZCTA where the plants are located compared to the rest of the state are as follows:

1. Connecticut (45% vs. 18%)
2. Arizona (44% vs. 25%)
3. Oregon (39% vs. 13%)
4. Tennessee (37% vs. 20%)
5. Kansas (37% vs. 14%)

- Plant level results:

Using the plant-by-plant (i.e., itemized ZCTA) basis, 138 plants (28%) have surrounding minority populations which exceed their statewide minority benchmark percentages, whereas 357 plants (72%) have minority populations below their statewide benchmarks, which represents a plant ZCTA ratio of 0.39 (i.e., 138/357). Because this ratio is 61% less than 1.00 (i.e., 1.00 minus 0.39), this finding indicates that only a relatively small count of plants have surrounding minority population percentages which disproportionately exceed their statewide benchmarks. Also on a plant-by-plant ZCTA basis, 256 plants (52%) have surrounding low-income populations which exceed their respective statewide benchmarks, whereas 239 plants (48%) have surrounding low-income populations below their statewide benchmarks, which represents a plant ZCTA ratio of 1.07 (i.e., 256/239). Because this ratio is only slightly (7%) above 1.00, it indicates that a slightly disproportionate count of plants have surrounding low-income population percentages which exceed their statewide benchmarks.

- State level results:

Using the state-by-state aggregation basis, the percentages of minority and low-income populations surrounding the plants were compared to their respective statewide population benchmarks. From this, state ratios revealed that 24 of the 47 states (51%) have higher minority percentages, and 29 of the 47 states (62%) have higher low-income percentages surrounding the 495 plants, suggesting a slightly disproportionate higher minority surrounding population and a relatively large disproportionate, higher low-income surrounding population. However, in comparison to the other two numerical comparisons, this state-by-state count approach does not include numerically-weighting of state plant counts or state surrounding populations, which explains why this comparison method yields a different numerical result. This method illustrates how population comparison results may be sensitive to the comparison method.

- Nationwide results:

Using the nationwide aggregation basis across all 495 plants in all 47 states where the plants are located, 6.08 million people live in ZCTA surrounding the plants, which include a sub-total of 1.32 million (21.7%) minority and a sub-total of 0.8 million (12.9%) low-income population groups. A comparison of these percentages to the national benchmark averages across all states of 24.9% minority and 11.9% low-income, represents a minority ratio of 0.87 (i.e., 21.7%/24.9%) and a low-income ratio of 1.08 (i.e., 12.9%/11.9%). These nationwide aggregate ratios indicate a slightly lower disproportionate minority population surrounding the 495 plants, and a slightly higher disproportionate low-income population surrounding the plants. Comparison of nationwide population sub-totals for all plants for each demographic group compared to the expected value based on statewide averages, reveals that:

- **+18.9%** additional low-income residents near the plants compared to the expected low-income population based on statewide averages (i.e., 783,062 low-income population for all 464 plants compared to 658,336 expected count if based on statewide averages.)
- **-5.8%** less minority residents near the plants compared to the expected minority population based on statewide averages (i.e., 1,317,896 minority population for all 464 plants compared to 1,241,382 expected count if based on statewide averages).

These three alternative comparisons indicate that the current (baseline) environmental and human health hazards and risks from electric utility CCR disposal units, and the expected future benefits of the regulatory options, may have a disproportionately lower effect on minority populations and may have a disproportionately higher effect on low-income populations.

- **Other Potentially Affected Minority & Low-Income Populations**

There are two other potential differential effects of the regulatory options on two other population groups: (a) populations surrounding offsite CCR landfills, and (b) populations within the customer service areas of the 495 electric utility plants.

- Offsite CCR Landfills

The potential effect on offsite landfills involves the RCRA Subtitle C based regulatory options whereby four different fractions of CCR generation may be required to be disposed in RCRA Subtitle C permitted landfills rather than in non-RCRA permitted waste landfills:

- CCR fraction #1: Electric utility plants may switch the management of CCR, in whole or in part, from current onsite disposal to offsite commercial RCRA-permitted hazardous waste landfills (56.8 million is disposed in onsite landfills, and 22.4 million is disposed in onsite impoundments, totaling 79.2 million tons disposed onsite).
- CCR fraction #2: Some or all of the CCR which is currently disposed in offsite landfills that do not have RCRA Subtitle C permits may also switch to RCRA-permitted commercial hazardous waste landfills if the current receiving landfills do not obtain RCRA Subtitle C permits (15.0 million tons is disposed offsite).

- CCR fraction #3: Annual CCR generation which is currently supplied for industrial beneficial use applications could also switch to offsite commercial RCRA Subtitle C permitted landfills if such use becomes curtailed in part or in whole from either state government regulations or from market stigma (47.0 million tons is beneficially used).
- CCR fraction #4: Future cleanup of CCR disposal unit failures (e.g., impoundment collapse) would require disposal in RCRA Subtitle-permitted waste landfills (the two CCR impoundment release case studies in **Exhibit 4A** of this RIA represent a range of 0.25 million to 3.3 million tons per failure event).

One or more of these four potential shifts of CCR disposal from current non-hazardous landfills to hazardous waste landfills, could have a disproportionate effect on populations surrounding these locations, and in particular, minority and low-income populations surrounding commercial hazardous waste facilities, if current landfills operated by electric utility plants do not obtain future Subtitle C permits (Option 1). A recent (2007) study determined that minority and low-income populations disproportionately live near commercial hazardous waste facilities, although the study included other types of commercial hazardous waste treatment and disposal facilities in addition to commercial hazardous waste landfills.[187] An example of such potential EJ concerns is a 2009 US national news item involving the decision made by the Tennessee Valley Authority (TVA) to train transport 3 million tons of the TVA's (Kingston TN electricity plant) December 2008 CCR impoundment collapse site cleanup waste, 350 miles away to a landfill in a rural Alabama county which reportedly has about 70% minority (African American) and 33% low-income residents.[188] However, this example serves to illustrate that EJ concerns are not necessarily conclusive or shared by all affected EJ populations, as evidenced by the following remarks made to news reporters by the Alabama county government officials and county residents:[189]

> "*To county leaders, the train's loads, which will total three million cubic yards of coal ash from a massive spill at a power plant in east Tennessee last December [2008], are a tremendous financial windfall. A per-ton "host fee" that the landfill operators pay the county will add more than $3 million to the county's budget of about $4.5 million. The ash has created more than 30 jobs for local residents in a county where the unemployment rate is 17 percent and a third of all households are below the poverty line. A sign on the door of the landfill's scale house says job applications are no longer being accepted — 1,000 were more than enough. But some residents worry that their leaders are taking a short-term view, and that their community has been too easily persuaded to take on a wealthier, whiter community's problem…. County leaders, who are mostly black, bristle at accusations of environmental injustice, saying that the ash is perfectly safe and that criticism has been fostered by outsiders, or even competitors who wanted the ash disposal contract for themselves….. Bob Deacy, vice president of clean strategies and*

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[187] Source: United Church of Christ, "Toxic Wastes and Race at Twenty 1987-2007", March 2007. . This study evaluated and made findings on minority and low-income population data within a 1.8-mile radius "host neighborhood" of 413 commercial hazardous waste facilities, compared to "non-host" areas. The study (page x) found that "Host neighborhoods of commercial hazardous waste facilities are 56% people of color whereas non-host areas are 30% of color… Poverty rates in the host neighborhoods are 1.5 times greater than non-host areas (18% vs. 12%)."

[188] Source: Shaila Dewan, "Clash in Alabama Over Tennessee Coal Ash," The New York Times, 30 Aug 2009 at http://www.nytimes.com/2009/08/30/us/30ash.html

[189] Source: At least two news organizations identically reported these remarks on 30 Aug 2009:
#1 of 2: New York Times, "Clash in Alabama Over Tennessee Coal Ash" at http://www.nytimes.com/2009/08/30/us/30ash.html
#2 of 2: Waste Business Journal, "Waste From TVA Spill Begins to Arrive at Alabama Landfill Amid Controversy" at http://www.wastebusinessjournal.com/news/wbj20090901D.htm

project development for the Tennessee Valley Authority, whose Kingston Fossil Plant was the site of the ash spill that covered almost 300 acres of land and waterways, said Arrowhead [Alabama landfill] was chosen because it was reachable by train instead of truck, because it underbid other sites and because, unlike closer landfills, it had the capacity to handle all the ash."

- Electricity Service Area Customers

A third potential effect of the regulatory options described in today's notice is the price of electricity supplied by some or all of the affected 495 electric utility plants could increase to cover the cost of regulatory compliance. Thus customers in electric utility service areas could experience price increases, although the RIA estimates that future potential price increases could be expected to be below 1% increase relative to the $0.0900 per kilowatt hour national average price (February 2009) for all four customer sectors (i.e., residential, commercial, industrial, and transportation). The RIA for today's action did not evaluate the customer service area populations for the 495 plants.

7D. Child Population Statistics (Executive Order 13045)

- **Purpose of Child Population Data Analysis**

Under Executive Order (EO) 13045 of 21 April 1997, Federal Agencies shall make it a high priority (a) to identify and assess environmental health and safety risks that may disproportionately affect children, and (b) shall ensure that its policies, programs, activities, and standards address disproportionate risks to children that result from environmental health or safety risks. Although the EO does not define children, the US Census Bureau defines "children" as follows[190]:

> *Children: The term "children"… are all persons under 18 years, excluding people who maintain households, families, or subfamilies as a reference person or spouse.*

The purpose of this section is not to evaluate children risks, but to evaluate whether disproportionate percentages of children live near electric utility plants. This analysis involves a 5-step process for comparing children population data for each electric utility plant location, to statewide children population data to identify whether children disproportionately reside in geographic areas where electric utility plants are located.

- **Collection of Child Demographic Data**

Step 1: Plant address 5-digit "Zip Code Tabulation Areas" (ZCTAs) formed the geographic basis for this child population data collection. Because ZCTAs represent irregularly shaped geographic areas, this ZCTA based data collection may be considered a "screening level" analysis. The US Bureau of Census uses over 33,000 ZCTAs for its Census counts of population and other demographic statistics based on the US Postal Service's over 42,000 nationwide ZCTAs.[191] Currently, there are no size restrictions limiting how large or small a ZCTA can be in terms of either a minimum/maximum number of housing units or geographic area. Any particular ZCTA may be as small as a few city blocks or may cover many square miles. Many ZCTAs are for villages, census-designated places, portions of cities, or other entities that are not municipalities. The nationwide average ZCTA population is about 7,200 persons (i.e., (306.6 million mid-2009 US population) / (42,500 ZCTAs)). The nationwide average ZCTA area is about 83 square miles (i.e., (3,536,278 square miles total US land and water area) / (42,500 ZCTAs)), which is a land area equivalent to a 5-mile radial distance (i.e., ((83 square miles) / (3.1416))^0.5). In comparison, the radial area monitored for contamination in response to the December 2009 TVA Kingston TN electric plant CCR spill is reportedly four miles,[192] and this average 5-mile ZCTA radial distance falls between the 1-mile to 15-mile radial distances used by EPA's Superfund "Hazard Ranking System" (HRS)[193] to define affected populations of sites having either (a) soil contamination only (1-mile), (b) groundwater and/or airborne contamination (4-miles), or (c) surface water contamination (15-miles

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[190] The US Census Bureau definition of "children" is from its "Current Population Survey (CPS) - Definitions and Explanations" website at: http://www.census.gov/population/www/cps/cpsdef.html
[191] Source: US Census Bureau ZIP Code Tabulation Area (ZCTA) Frequently Asked Questions.: Nationwide total ZCTA count is from the US Postal Service's FAQ website at: http://zip4.usps.com/zip4/welcome.jsp
[192] Source: 4 mile radial monitoring area reported by Waste & Recycling News, 13 Feb 2009; http://www.wasterecyclingnews.com/email.html?id=1234543579
[193] More background information about EPA's HRS is available at http://www.epa.gov/superfund/programs/npl_hrs/hrsint.htm.

downstream). Using the Census search engine Factfinder (http:factfinder.census.gov/home/saff/main.html?_lang=en), EPA retrieved total population and people 18 and over for 464 (94%) of the 495 electric utility plants. For 42 plants (8%) there was no ZCTA Census data because the plants did not have complete address data from DOE or because the Census search engine did not have data for the ZCTA.

Step 2: EPA collected 3-year (2005 to 2007) average statewide percentages for people 18 and older data as displayed in **Exhibit 7I** below.

Exhibit 7I
State-by-State Data on Child Populations (2005-2007 Average)

Row	State	% children in state
1	AK	27.0%
2	AL	24.4%
3	AR	24.8%
4	AZ	26.4%
5	CA	25.9%
6	CO	24.7%
7	CT	23.7%
8	DC	19.5%
9	DE	23.9%
10	FL	22.3%
11	GA	26.5%
12	HI	22.3%
13	IA	23.9%
14	ID	27.3%
15	IL	25.1%
16	IN	25.1%
17	KS	25.2%
18	KY	23.9%
19	LA	25.4%
20	MA	22.5%
21	MD	24.4%
22	ME	21.5%
23	MI	24.6%
24	MN	24.5%
25	MO	24.4%
26	MS	26.3%
27	MT	23.2%
28	NC	24.4%
29	ND	22.5%
30	NE	25.3%

Row	State	% children in state
31	NH	23.1%
32	NJ	24.0%
33	NM	25.6%
34	NV	25.8%
35	NY	23.2%
36	OH	24.2%
37	OK	24.9%
38	OR	23.2%
39	PA	22.6%
40	RI	22.3%
41	SC	24.2%
42	SD	24.8%
43	TN	24.1%
44	TX	27.7%
45	UT	30.9%
46	VA	23.9%
47	VT	21.6%
48	WA	23.9%
49	WI	23.8%
50	WV	21.5%
51	WY	24.0%
	Max (UT)	30.9%
	Min (DC)	19.5%
	Nationwide	**24.7%**

- **Comparison of Child Populations Living Near Electric Utility Plants to Statewide Benchmarks**

Step 3, Step 4 and Step 5 of this evaluation described below involved three complementary levels of data comparisons. All three comparisons also involved two complementary numerical comparisons, one based on calculating numerical percentages and the other based on calculating numerical ratios:

1. Plant level: Plant-by-plant disaggregated data comparison to statewide benchmarks
2. State level: State-by-state aggregated plant data comparison to statewide benchmarks
3. National level: National aggregated plant data comparison to statewide benchmarks

Step 3: On a plant-by-plant basis, EPA compared the plant ZCTA percentage children, to the respective statewide average percentage children.

Step 4: For purpose of summary, EPA aggregated the plant level children population comparison data for each state as displayed in **Exhibit 7J** below. There are no data displayed for DC, ID, RI or VT because there are no coal-fired electric utility plants in those states. **Appendix O** of this RIA presents the plant-by-plant Census data on which this Exhibit is based.

Exhibit 7J
State-by-State Child Population Data for Coal-Fired Electric Utility Plants

General Population Data					**Child Population Data**				
Item	Count of plant unique ZCTAds	State	Count of plant ZCTAs which have Census population data	2000 plant ZCTA resident population	Child population count (<18 years) in plant ZCTAs	Child population percentage in plant ZCTAs	Statewide percentage child population	Expected children count in plant ZCTAs if based on state %	If plant ZCTA child% > state children%
1	2	AK	2	18,552	5,188	27.96%	27.00%	5,009	2
2	9	AL	9	82,854	21,978	26.53%	24.40%	20,216	4
3	3	AR	3	11,786	3,359	28.50%	24.80%	2,923	3
4	6	AZ	6	34,941	11,526	32.99%	26.40%	9,224	5
5	5	CA	4	112,895	36,285	32.14%	25.90%	29,240	5
6	15	CO	15	214,095	49,190	22.98%	24.70%	52,881	11
7	2	CT	2	42,716	10,743	25.15%	23.70%	10,124	1
8	NA	DC							
9	3	DE	3	46,925	11,169	23.80%	23.90%	11,215	1
10	14	FL	13	224,502	55,025	24.51%	22.30%	50,064	11
11	9	GA	9	202,973	50,964	25.11%	26.50%	53,788	5
12	1	HI	1	25,054	8,158	32.56%	22.30%	5,587	1
13	17	IA	14	324,050	77,708	23.98%	23.90%	77,448	15
14	NA	ID							

Exhibit 7J State-by-State Child Population Data for Coal-Fired Electric Utility Plants									
General Population Data					Child Population Data				
Item	Count of plant unique ZCTAds	State	Count of plant ZCTAs which have Census population data	2000 plant ZCTA resident population	Child population count (<18 years) in plant ZCTAs	Child population percentage in plant ZCTAs	Statewide percentage child population	Expected children count in plant ZCTAs if based on state %	If plant ZCTA child% > state children%
15	25	IL	23	455,834	129,772	28.47%	25.10%	114,414	14
16	19	IN	17	323,323	83,594	25.85%	25.10%	81,154	14
17	7	KS	6	59,517	16,532	27.78%	25.20%	14,998	6
18	19	KY	17	255,033	63,012	24.71%	23.90%	60,953	15
19	4	LA	4	30,381	8,617	28.36%	25.40%	7,717	4
20	4	MA	3	95,798	23,078	24.09%	22.50%	21,555	1
21	8	MD	7	101,141	23,529	23.26%	24.40%	24,678	5
22	1	ME	1	6,748	1,561	23.13%	21.50%	1,451	1
23	23	MI	20	383,284	94,994	24.78%	24.60%	94,288	13
24	15	MN	15	187,012	46,208	24.71%	24.50%	45,818	5
25	19	MO	19	251,484	60,084	23.89%	24.40%	61,362	12
26	4	MS	4	69,209	19,867	28.71%	26.30%	18,202	4
27	6	MT	5	53,209	14,115	26.53%	23.20%	12,344	5
28	19	NC	16	238,874	57,728	24.17%	24.40%	58,285	6
29	7	ND	5	27,087	7,411	27.36%	22.50%	6,095	4
30	6	NE	6	79,313	20,853	26.29%	25.30%	20,066	4
31	2	NH	2	53,302	10,713	20.10%	23.10%	12,313	0
32	6	NJ	6	119,286	29,806	24.99%	24.00%	28,629	4
33	4	NM	4	17,491	5,656	32.34%	25.60%	4,478	3
34	2	NV	2	8,471	1,827	21.57%	25.80%	2,186	1
35	13	NY	13	226,416	57,612	25.45%	23.20%	52,529	9
36	24	OH	23	391,705	101,253	25.85%	24.20%	94,793	14
37	6	OK	6	30,357	8,513	28.04%	24.90%	7,559	6
38	1	OR	1	3,884	1,378	35.48%	23.20%	901	1
39	31	PA	28	167,254	36,581	21.87%	22.60%	37,799	13
40	NA	RI							
41	12	SC	12	222,414	60,391	27.15%	24.20%	53,824	10
42	2	SD	2	30,508	7,510	24.62%	24.80%	7,566	1
43	8	TN	8	158,267	40,682	25.70%	24.10%	38,142	4
44	18	TX	17	98,402	27,471	27.92%	27.70%	27,257	7
45	6	UT	6	34,209	11,769	34.40%	30.90%	10,571	4
46	16	VA	15	220,800	55,824	25.28%	23.90%	52,771	10
47	NA	VT							
48	1	WA	1	21,842	5,514	25.24%	23.90%	5,220	1
49	15	WI	13	178,705	36,428	20.38%	23.80%	42,532	10

Exhibit 7J State-by-State Child Population Data for Coal-Fired Electric Utility Plants									
General Population Data					**Child Population Data**				
Item	Count of plant unique ZCTAds	State	Count of plant ZCTAs which have Census population data	2000 plant ZCTA resident population	Child population count (<18 years) in plant ZCTAs	Child population percentage in plant ZCTAs	Statewide percentage child population	Expected children count in plant ZCTAs if based on state %	If plant ZCTA child% > state children%
50	16	WV	13	64,771	10,946	16.90%	21.50%	13,926	10
51	9	WY	8	69,736	19,732	28.30%	24.00%	16,737	6
Summary:									
Total	464		429	6,076,410	**1,541,854**	25.37%	24.70%	**1,480,831**	**291**
					4.1%				
					Min=	16.90%	21.50%		
					Max=	35.48%	30.90%		
					Extrapolated to 495 plants =				**310**

Step 5: The percentage of children population surrounding the plant ZCTAs were compared to overall state percentages and the nationwide percentage of this sub-group population, by calculating ratios between the plant ZCTA children populations compared to statewide and nationwide percentages of children population. **Exhibit 7K** below displays the results.

Exhibit 7K Comparison of Child Population Data on a State-by-State Basis						
Item	State	Plants	Percentage of ZCTA Population Under 18 Years Old	Statewide Percentage of Children (**Exhibit 7I**)	Difference	Ratio
1	AK	2	28.0%	27.0%	1.0%	1.04
2	AL	9	26.5%	24.4%	2.1%	1.09
3	AR	3	28.5%	24.8%	3.7%	1.15
4	AZ	6	33.0%	26.4%	6.6%	1.25
5	CA	5	32.1%	25.9%	6.2%	1.24
6	CO	15	23.0%	24.7%	-1.7%	0.93
7	CT	2	25.1%	23.7%	1.4%	1.06
8	DC	NR	NA	NA	NA	NA
9	DE	3	23.8%	23.9%	-0.1%	1.00
10	FL	14	24.5%	22.3%	2.2%	1.10
11	GA	9	25.1%	26.5%	-1.4%	0.95
12	HI	1	32.6%	22.3%	10.3%	1.46

Exhibit 7K Comparison of Child Population Data on a State-by-State Basis						
Item	State	Plants	Percentage of ZCTA Population Under 18 Years Old	Statewide Percentage of Children (**Exhibit 7I**)	Difference	Ratio
13	IA	17	24.0%	23.9%	0.1%	1.00
14	ID	NR	NA	NA	NA	NA
15	IL	25	28.5%	25.1%	3.4%	1.13
16	IN	19	25.9%	25.1%	0.8%	1.03
17	KS	7	27.8%	25.2%	2.6%	1.10
18	KY	19	24.7%	23.9%	0.8%	1.03
19	LA	4	28.4%	25.4%	3.0%	1.12
20	MA	4	24.1%	22.5%	1.6%	1.07
21	MD	8	23.3%	24.4%	-1.1%	0.95
22	ME	1	23.1%	21.5%	1.6%	1.08
23	MI	23	24.8%	24.6%	0.2%	1.01
24	MN	15	24.7%	24.5%	0.2%	1.01
25	MO	19	23.9%	24.4%	-0.5%	0.98
26	MS	4	28.7%	26.3%	2.4%	1.09
27	MT	6	26.5%	23.2%	3.3%	1.14
28	NC	19	24.2%	24.4%	-0.2%	0.99
29	ND	7	27.4%	22.5%	4.9%	1.22
30	NE	6	26.3%	25.3%	1.0%	1.04
31	NH	2	20.1%	23.1%	-3.0%	0.87
32	NJ	6	25.0%	24.0%	1.0%	1.04
33	NM	4	32.3%	25.6%	6.7%	1.26
34	NV	2	21.6%	25.8%	-4.2%	0.84
35	NY	13	25.4%	23.2%	2.2%	1.10
36	OH	24	25.8%	24.2%	1.6%	1.07
37	OK	6	28.0%	24.9%	3.1%	1.13
38	OR	1	35.5%	23.2%	12.3%	1.53
39	PA	31	21.9%	22.6%	-0.7%	0.97
40	RI	NR	NA	NA	NA	NA
41	SC	12	27.2%	24.2%	3.0%	1.12
42	SD	2	24.6%	24.8%	-0.2%	0.99
43	TN	8	25.7%	24.1%	1.6%	1.07
44	TX	18	27.9%	27.7%	0.2%	1.01
45	UT	6	34.4%	30.9%	3.5%	1.11
46	VA	16	25.3%	23.9%	1.4%	1.06
47	VT	NR	NA	NA	NA	NA
48	WA	1	25.2%	23.9%	1.3%	1.06

Exhibit 7K Comparison of Child Population Data on a State-by-State Basis						
Item	State	Plants	Percentage of ZCTA Population Under 18 Years Old	Statewide Percentage of Children (**Exhibit 7I**)	Difference	Ratio
49	WI	15	20.4%	23.8%	-3.4%	0.86
50	WV	16	16.9%	21.5%	-4.6%	0.79
51	WY	9	28.3%	24.0%	4.3%	1.18
		Min =	16.9%	19.5%	-4.6%	0.79
		Max =	35.5%	30.9%	12.3%	1.53
	Nationwide =	464	25.4%	24.7%	0.7%	**1.03**

- **Child Population Data Findings**

Below is a summary of the three alternative but complementary comparison approaches based on the same children population data: (a) plant-by-plant (i.e., itemized ZCTA) basis, (b) nationwide aggregation basis, and (c) state-by-state aggregation basis. For purpose of determining the relative degree by which children may exceed these statewide percentages, the percentages are compared as a numerical ratio whereby a ratio of 1.00 indicates that the child population percentage living near a plant is equal to the statewide average, a ratio greater than 1.00 indicates the child population percentage near the plant is higher than the statewide population, and a ratio less than 1.00 indicates the child population is less than the respective statewide average.

- General population findings
  - 464 plants (i.e., 94% of the 495 universe) for which Census plant address ZCTA data are located in 47 states.
  - The plant address ZCTA population surrounding these plants is 6.08 million, which is an average of 13,091 surrounding population per plant.

- Child population findings
  - The sub-total number of children surrounding these 464 plants is 1.54 million (i.e., 25.4% of 6.08 million). In comparison, the national average of the child population in the US is 24.7%.
  - The ratios of the children population percentages surrounding these plants range from 0.79 to 1.53, and the average of the ratios compared to the national average ratio of the low-income population is 1.03.
  - 27 of the 47 states (57%) have disproportionately high percentages of children within the plant address ZCTAs compared to the statewide percentages.
  - States with the largest difference in the children population between the ZCTAs where the plants are located compared to the statewide percentages are as follows:
    1. Oregon (36% vs. 23%)

2. Hawaii (33% vs. 22%)
3. New Mexico (32% vs. 26%)
4. Arizona (33% vs. 26%)
5. California (32% vs. 26%)

- A sub-total of 291 plants (63%) have surrounding children populations which exceed their respective statewide percentage.

- Plant level results:

Using the plant-by-plant (i.e. itemized ZCTA) basis, 310 plants (63%) have surrounding child populations which exceed their statewide children benchmark percentages, whereas 185 plants (37%) have children populations below their statewide benchmarks, which represents a plant ZCTA ratio of 1.68 (i.e., 310/185). Since this ratio is much greater than 1.00, this finding indicates that a highly disproportionate count of plants have surrounding child population percentages which exceed their statewide benchmark.

- State level results:

Using the state-by-state aggregation basis, the percentage of child populations surrounding the plants were compared to their respective statewide population benchmarks. The state-by-state ratios revealed that approximately 27 of the 47 states (57%) have disproportionate percentages of children within the plant address ZCTA compared to the rest of the state suggesting a disproportionate surrounding child population. However, in comparison to the other two numerical comparisons above, this state-by-state count approach does not include numerically-weighting of state plant counts or state surrounding populations, which explains why this comparison method yields a different numerical result. This method illustrates how population comparison results may be sensitive to the comparison method.

- Nationwide results:

Using the nationwide aggregation basis across all 495 plants in all 47 states where the plants are located, 6.08 million people live in ZCTAs surrounding the plants, which include a sub-total of 1.54 million children (25.4%). Comparison of this percentage to the national aggregate benchmark across all states of 24.7% children yields a ratio of 1.03 (i.e., 25.4%/24.7%). This ratio indicates a slightly higher disproportionate child population surrounding the 495 plants. Comparison of the nationwide child population sub-total for all plants reveals that **+4.1%** additional children reside near the plants, compared to the expected child population if based on state averages (i.e., 1,541,854 children living near the 464 plants compared to 1,480,831 expected children count).

These three alternative comparisons indicate that the current (baseline) environmental and human health hazards and risks from electric utility CCR disposal units, and the expected future benefits of the regulatory options, may have a disproportionately higher effect on child populations.

7E. Unfunded Mandates (UMRA) & Federalism Implications Analysis (Executive Order 13132)

- **UMRA**

Among its other purposes and Federal agency rulemaking requirements, Title II of the 1995 Unfunded Mandates Reform Act (UMRA; 2 U.S.C. 1531-1538), requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and tribal governments and on the private sector, to determine whether any proposed rulemaking:

> *"…is likely to result in promulgation of any rule that includes any Federal mandate that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more in any one year*."

Section 202 of UMRA requires Federal agencies which propose rules that are likely to exceed this $100 million expenditure threshold on either the private sector or on state/local/tribal governments, to prepare a "Written Statement" containing the following five components, and supply the Written Statement to OMB as well as summarize it in the Federal Register notice (aka "preamble") for the proposed rule:

1. Identification of the applicable authorizing Federal law
2. Qualitative and quantitative assessment of the anticipated costs and benefits of the rule including the costs and benefits to State, local, and tribal governments or the private sector, and an analysis of whether Federal resources may be available to pay these costs
3. Estimates of future compliance costs and any disproportionate budgetary effects
4. Estimates of effects on the national economy such as productivity, economic growth, employment, job creation, international competitiveness
5. Description and summary of agency's prior consultation with elected representatives of the affected State, local and tribal governments.

Section 202 of UMRA allows Federal agencies to prepare the "Written Statement "in conjunction with or as a part of any other statement or analysis. Accordingly, the purpose of this section of the RIA is to determine whether the regulatory options evaluated in this RIA exceed this UMRA direct cost threshold.

Findings: The private sector and the state/local government shares of direct compliance costs under each option are displayed below in **Exhibit 7L**, which indicates that:

- Private sector cost test: All of the regulatory options are expected to result in expenditures of $100 million or more in the aggregate for the private sector, in any one year (i.e., 139 companies and cooperatives of the total 200 owner entities).
- State/local/tribal government cost test: None of the regulatory options are expected to result in expenditures of $100 million or more for State, local, and tribal governments in the aggregate in any one year (there are 60 state/local government owner entities identified in **Exhibit 7M** below, no known tribal owner entities, plus one Federal owner).

According to the private sector test finding, EPA has prepared an "UMRA Written Statement" which is attached to this RIA as **Appendix P**.

- **Federalism (Executive Order 13132)**

The 1999 Federalism Executive Order 13132 (Federal Register, Vol.64, No. 153, 10 Aug 1999) furthers the policies of the 1995 Unfunded Mandates Reform Act (UMRA) by establishing federalism principles, federalism policymaking criteria, and a state/local government consultation process for the development of Federal regulations that have federalism implications. Federalism implications refers to regulations and other Federal policies and actions that have substantial direct effects on states, on the relationship between the Federal government and the states, or on the distribution of power and responsibilities among the various levels of government.

For purpose of complying with the Section 6 consultation process of EO 13132, this section of the RIA evaluates whether the CCR regulatory options may "impose substantial direct compliance costs" on state/local governments. As summarized in **Exhibit 7L**, the proposed rule might impose four types of direct costs on the 60 state/local government owner entities identified in **Exhibit 7M** below:

- State/local government owned electric utility plants:
    1. Engineering control costs for CCR disposal units located at electric utility plants owned by state/local governments.
    2. Ancillary costs for CCR disposal units located at electric utility plants owned by state/local governments.
    3. Conversion to dry disposal costs for CCR disposal units located at electricity utility plants owned by state/local governments.
- State government environmental agencies:
    4. Regulatory implementation, administration, and enforcement costs to RCRA-authorized state government programs/agencies.

Consistent with the "direct cost" scope of EO 13132, not included in **Exhibit 7L** are potential indirect costs in the form of potential lost annual revenues to electricity plants associated with potential reductions in CCR sold by plants for beneficial use under the three Subtitle C options for which such an possible indirect effect is estimated in this RIA.

EPA's 2008 guidance[194] for compliance with EO 13132 describes two numerical methods (i.e., numerical tests) for evaluating whether an EPA rule may have federalism implications with respect to "substantial direct compliance costs":

1. $25 million test: Annualized direct compliance cost expenditures to state/local governments in aggregate of $25 million or more[195]
2. 1% test: Annualized direct compliance costs faced by state/local governments is likely to equal or exceed 1% of their annual revenues* [* Note: Page 29 of "Attachment A: Guidance for Implementing the Federalism 1% Test" to EPA's Nov 2008 "Guidance on Executive Order 13132: Federalism" defines small government "general revenue" as "made up of intergovernmental revenue plus revenue from their own sources and excludes utility, liquor store and employee retirement revenue." However, given that the CCR proposed rule affects electric utility industry, this RIA applies the "1% Test" in relation to only State/local government electric utility annual revenue.]

[194] The two methods are from page 6 of "EPA's Action Development Process -- Guidance on Executive Order 13132: Federalism," OPEI Regulatory Development Series, Nov 2008, 62 pages at http://intranet.epa.gov/adplibrary/documents/federalismguide11-00-08.pdf
[195] Although one of the stated purposes of EO 13132 in its first paragraph is "to further the policies of the 1995 Unfunded Mandates Reform Act (UMRA), EPA's $25 million annual direct cost trigger is 75% lower than the $100 million annual direct cost trigger prescribed in Section 202 of UMRA.

- **Findings for UMRA Impact and Federalism Implication Tests**

Based on estimated regulatory costs on state/local governments displayed in **Exhibit 4B** of this RIA for each regulatory option, **Exhibit 7L** below displays whether the costs potentially exceed the UMRA and Federalism thresholds defined above.

- o UMRA finding: All options >$100 million private sector test; all options <$100 million state/local government test
- o Federalism finding: All options >$25 million state/local government test; all options <1% state/local government test

However, for consistency with the RFA/SBREFA small business impact analysis presented in a separate section above in this RIA, this RIA estimates it is highly likely that the direct compliance costs under each option may be passed-thru to electricity plant customers in the form of higher electricity prices. The feasibility of such a compliance cost pass-thru scenario is evaluated and confirmed by the information presented in the RFA/SBREFA small business impact section of this RIA.

Exhibit 7L
UMRA and Federalism Tests for CCR Disposal Regulatory Options
($millions average annualized costs @7% discount rate over 50-years 2012 to 2061, 2009$)

Type of Direct Compliance Cost	Subtitle C Hazardous waste	Subtitle D (version 1)	Subtitle C for impoundments Subtitle D for landfills
Average annualized cost (source: **Exhibit 5F**):	**$2,274**	**$492**	**$2,176**
UMRA Test:			
1. Private sector $100 million direct cost threshold test	$1,999.4	$415.3	$1,908.8
2. State/local government $100 million direct cost threshold test*	$96.7	$55.9	$91.6
Federalism Test:			
1. $25 million threshold test: sub-total State/Local govt cost	$96.7	$55.9	$91.6
2. 1% Test: State/local govt cost as percentage of State/Local government electric utility annual revenues	0.227%	0.131%	0.215%

* Note:
Remainder Federal government costs represent costs associated with Federally-owned electric utility plants (i.e., Tennessee Valley Authority) which are not subject to either the UMRA or Federalism tests. Therefore, the sub-total private sector direct cost plus the state/local government direct cost does not add-up to the total annual cost estimate under each option; the remainder cost is for the Federally-owned plants.

Exhibit 7M List of 74 Coal-Fired Electric Utility Generation Plants Which EPA Estimates Are Owned by 60 State/Local Governments Source: Compiled by EPA-OSWER-ORCR based on 2007 data from the US Energy Information Administration*				
Item	Owner Entity Name	Electric Utility Plant Name	State	Owner Entity Size/Type**
1	Grand River Dam Authority	GRDA	OK	Non-Small State
2	Lower Colorado River Authority	Fayette Power Project	TX	Non-Small State
3	Nebraska Public Power District	Gerald Gentleman	NE	Non-Small State
4	Nebraska Public Power District	Sheldon	NE	Non-Small State
5	Omaha Public Power District	Nebraska City	NE	Non-Small State
6	Omaha Public Power District	North Omaha	NE	Non-Small State
7	Platte River Power Authority	Rawhide	CO	Non-Small State
8	Salt River Project	Coronado	AZ	Non-Small State
9	Salt River Project	Navajo	AZ	Non-Small State
10	South Carolina Pub Service Auth	Cross	SC	Non-Small State
11	South Carolina Pub Service Auth	Dolphus M Grainger	SC	Non-Small State
12	South Carolina Pub Service Auth	Jefferies	SC	Non-Small State
13	South Carolina Pub Service Auth	Winyah	SC	Non-Small State
14	American Municipal Power-Ohio, Inc	Richard Gorsuch	OH	Non-Small City
15	Ames City of	Ames Electric Services Power Plant	IA	Non-Small City
16	City of Columbia	Columbia	MO	Non-Small City
17	City of Hamilton	Hamilton	OH	Non-Small City
18	City of Lakeland	C D McIntosh Jr	FL	Non-Small City
19	City of Owensboro	Elmer Smith	KY	Non-Small City
20	City of Springfield	Dallman	IL	Non-Small City
21	City of Springfield	Lakeside	IL	Non-Small City
22	City Utilities of Springfield	James River Power Station	MO	Non-Small City
23	City Utilities of Springfield	Southwest Power Station	MO	Non-Small City
24	Colorado Springs City of	Martin Drake	CO	Non-Small City
25	Colorado Springs City of	Ray D Nixon	CO	Non-Small City
26	Gainesville Regional Utilities	Deerhaven Generating Station	FL	Non-Small City
27	Independence City of	Blue Valley	MO	Non-Small City
28	Independence City of	Missouri City	MO	Non-Small City
29	JEA	Northside Generating Station	FL	Non-Small City
30	JEA	St Johns River Power Park	FL	Non-Small City
31	Kansas City City of	Nearman Creek	KS	Non-Small City
32	Kansas City City of	Quindaro	KS	Non-Small City
33	Lansing Board of Water and Light	Eckert Station	MI	Non-Small City
34	Lansing Board of Water and Light	Erickson Station	MI	Non-Small City
35	Los Angeles City of	Intermountain Power Project	UT	Non-Small City
36	Orlando Utilities Comm	Stanton Energy Center	FL	Non-Small City
37	Rochester Public Utilities	Silver Lake	MN	Non-Small City

Exhibit 7M
List of 74 Coal-Fired Electric Utility Generation Plants Which EPA Estimates Are Owned by 60 State/Local Governments
Source: Compiled by EPA-OSWER-ORCR based on 2007 data from the US Energy Information Administration*

Item	Owner Entity Name	Electric Utility Plant Name	State	Owner Entity Size/Type**
38	San Antonio City of	J K Spruce	TX	Non-Small City
39	San Antonio City of	J T Deely	TX	Non-Small City
40	Vineland City of	Howard Down	NJ	Non-Small City
41	Crisp County Power Comm	Crisp Plant	GA	Small - County
42	Austin City of	Austin Northeast	MN	Small City
43	Board of Water Electric & Communications	Muscatine Plant #1	IA	Small City
44	Cedar Falls Utilities	Streeter Station	IA	Small City
45	City of Dover	Dover	OH	Small City
46	City of Grand Haven	J B Sims	MI	Small City
47	City of Holland	James De Young	MI	Small City
48	City of Jasper	Jasper 2	IN	Small City
49	City of Logansport	Logansport	IN	Small City
50	City of Marquette	Shiras	MI	Small City
51	City of Marshall	Marshall	MO	Small City
52	City of Menasha	Menasha	WI	Small City
53	City of Orrville	Orrville	OH	Small City
54	City of Painesville	Painesville	OH	Small City
55	City of Richmond	Whitewater Valley	IN	Small City
56	City of Shelby	Shelby Municipal Light Plant	OH	Small City
57	City of Sikeston	Sikeston Power Station	MO	Small City
58	City of Virginia	Virginia	MN	Small City
59	Crawfordsville Electric Light & Power	Crawfordsville	IN	Small City
60	Fremont City of	Lon Wright	NE	Small City
61	Grand Island City of	Platte	NE	Small City
62	Greenwood Utilities Commission	Henderson	MS	Small City
63	Hastings City of	Whelan Energy Center	NE	Small City
64	Henderson City Utility Commission	Henderson I	KY	Small City
65	Hibbing Public Utilities Commission	Hibbing	MN	Small City
66	Jamestown Board of Public Utilities	S A Carlson	NY	Small City
67	Manitowoc Public Utilities	Manitowoc	WI	Small City
68	Michigan South Central Power Agency	Endicott Station	MI	Small City
69	New Ulm Public Utilities Commission	New Ulm	MN	Small City
70	Pella City of	Pella	IA	Small City
71	Peru City of	Peru	IN	Small City
72	Texas Municipal Power Agency	Gibbons Creek	TX	Small City
73	Willmar Municipal Utils Commission	Willmar	MN	Small City
74	Wyandotte Municipal Service Commission	Wyandotte	MI	Small City

Exhibit 7M (Continued)
List of 74 Coal-Fired Electric Utility Generation Plants Which EPA Estimates Are Owned by 60 State/Local Governments
Source: Compiled by EPA-OSWER-ORCR based on 2007 data from the US Energy Information Administration*

Footnotes:
* NAICS code 22 electric "utility" generator plants listed in EIA's 2007 data source at: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html
**Type of owner entity assigned by EPA ORCR based on business type disclosed in owner name or plant-by-plant internet research on type of ownership. Size class determined according to the following numerical criteria consistent with EPA's Nov 2006 guidance for Regulatory Flexibility Act (RFA) Small Business Regulatory Enforcement Fairness Act (SBREFA) compliance:

- Small non-government = Based on the US Small Business Administration NAICS code 221112 small business size standard of <4 million megawatt hours per year total annual electricity generation by all plants owned by the entity.
- Non-small non-government = Entity's total annual electricity generation >4 million megawatt hours per year.
- Small government = Based on the RFA'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 a population less than 50,000.
- Non-small government = Entity's jurisdiction population with more than 50,000 people.

Board: Exhibit B

Appendix

for

Regulatory Impact Analysis
For EPA's Proposed RCRA Regulation
Of Coal Combustion Residues
Generated by the Electric Utility Industry

Prepared by:

US Environmental Protection Agency
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30 April 2010

Table of Contents

Prefatory Note

For purpose of launching in April 2009 the Regulatory Impact Analysis (RIA) for the CCR proposed rule, EPA formulated an "initial set" of three regulatory options as listed below. All three options (a) maintain the existing Bevill regulatory exclusion for CCR beneficial uses, and (b) propose the same set of 10 custom-tailored engineering controls (i.e., technical design and operating standards) for CCR disposal units. The "initial set" of options includes:

1. Subtitle C "Hazardous Waste" Option: Regulate CCR disposal as a "*hazardous waste*" and subject CCR to Subtitle C land disposal restriction (LDR) treatment standards prior to disposal consisting of (a) moisture conditioning and compaction to attain 95% dry density value for landfills, and (b) phase-out of impoundments within 5 years after rule's effective date.
2. Subtitle D Option (version 1): This option is different from the "Subtitle D" option in the final set above because it does not require liners for existing impoundments as the final set Subtitle D option does, but it only requires lines for new impoundments (and only for new landfills).
3. Hybrid Subtitle C&D Option: Involves (a) Subtitle C regulation of CCR impoundments, and (b) Subtitle D regulation of CCR landfills.

However, in early 2010, EPA formulated a different "final set" of three options to propose:

4. Subtitle C "Special Waste" Option: Regulate CCR landfills and impoundments as a "*special waste*" under Subtitle C requirements, and would require phase out of impoundments within five years.
5. Subtitle D Option (version 2): Composite liners required for all (i.e., existing and future new) CCR impoundments but only for new landfills. For any CCR landfills and impoundments that closed before the effective date, there would be no regulatory controls over those units, unless the states choose to adopt controls over such units. Also, all surface impoundments (existing and new) would need to have composite liners within 5-years of the effective date.
6. Subtitle "D prime" Option: Composite liners required only for new impoundments and landfills; unlined units could continue to operate. This approach would be the same as the Subtitle D option above, except that existing impoundments would not be required to retrofit and install a composite liner, or close.

Given that the "final set" of options was not defined until early 2010, EPA did not have time to re-calculate all Exhibits which appear in this Appendix, in order to meet EPA Administrator Lisa Jackson's April 2010 deadline for completing the CCR proposed rule. Consequently, the Appendices in this Appendix which contain cost calculations conducted in 2009 relate to the "initial set" of options (i.e., Appendices J, L, M, and P). Appendix K which contains the benefits calculations and background documentation is based on the "final set" because the benefit analysis was conducted in 2010. The other Appendices (A, B, C, D, E, F, G, H, I, N, O and Q) are not specific to any set of options.

Appendix A:

Chronology of EPA's Regulatory Evaluation of CCR (1978 to March 2009)

1978: The EPA's regulatory evaluation of coal combustion wastes (CCW) dates back to 1978. In December 1978, the EPA proposed the first industrial hazardous waste regulations to implement Subtitle C (i.e., Sections 3001 to 3020) of the Resource Conservation and Recovery Act (RCRA). At that time, the EPA recognized that certain large-volume industrial wastes, including wastes from the combustion of fossil fuels, might warrant special treatment. On 18 December 1978, EPA proposed a relatively limited set of ten Subtitle C industrial hazardous waste regulations for the management of CCW.[1]

1980: Although EPA on 19 May 1980 promulgated the initial regulations implementing Subtitle C, during its re-authorization debates for RCRA in 1980, Congress restricted EPA's authority to regulate large-volume wastes under Subtitle C. Thus EPA excluded fossil fuel combustion wastes from the initial Subtitle C regulations. In October 1980, Congress (a) amended RCRA to temporarily exempt four types of large-volume wastes from Subtitle C regulation (i.e., fly ash, bottom ash, boiler slag, and flue gas emission control desulfurization residues)[2], (b) directed EPA to submit a Report to Congress (RTC) evaluating the adverse effects on human health and the environment of these four waste types, (c) directed EPA to conduct public hearings to decide whether Subtitle C regulation of these temporarily exempt wastes was warranted, and (d) within six months of publishing the RTC, decide whether Subtitle C regulation is warranted.

1981: In 1981, EPA issued an interpretation of Subtitle C which exempted these four waste types.[3]

1984: In 1984, Congress again amended RCRA and gave EPA flexibility to promulgate Subtitle C regulations that considered the unique characteristics of some large-volume wastes, including fossil fuel combustion wastes. This amendment also provided EPA (a) flexibility to determine whether some or all of such wastes should be regulated, as well as (b) flexibility to modify certain Subtitle C regulatory requirements to take into account special characteristics and practical difficulties associated with these wastes.

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[1] Federal Register, Vol. 43, No. 243, 18 December 1978, page 59015, section 250.46-2 "Utility Waste" of "Hazardous Waste Guidelines and Regulations." This action proposed the following ten regulatory conditions: (a) waste analysis standards, (b) waste site selection standards, (c) waste site security, (d) waste shipment manifesting, (e) recordkeeping, (f) reporting, (g) waste site visual inspections, (h) waste site closure, (i) waste site post-closure care, and (j) groundwater monitoring.

[2] According to the American Coal Ash Association, in 2006 the US generated about 125 million tons of CCW, of which 43% was beneficially used. The total annual generation consisted of about 72 million tons of fly ash (58%), 19 million tons of bottom ash (15%), 2 million tons of boiler slag (2%), 12 million tons of flue gas emission control desulfurization (10%), and 20 million tons of other material generated primarily from pollution control equipment (16%); Source: Waste & Recycling News, 19 January 2009, page 23: http://wastenews.texterity.com/wastenews/20090119/?fm=2).

[3] 13 January 1981 letter from Gary Dietrich, EPA Associate Deputy Assistant Administrator for Solid Waste, to Paul Emler Jr., Chairman, Utility Solid Waste Activities Group (USWAG); an electronic version of this letter is available at: http://yosemite.epa.gov/osw/rcra.nsf/0c994248c239947e85256d090071175f/DB19FB013F06B99585256E150051C757/$file/12021.pdf

1988: In 1988, EPA published the Report to Congress (RTC) with a scope limited to only coal-fired electric utilities which generate a large majority of all fossil fuel combustion wastes and manage separately from other waste (i.e., in monofills); utilities and non-utilities burning other types of fossil fuels were not addressed by the Report.

1992: Because EPA did not publish a Subtitle C regulatory determination within six months of issuing this RTC, a legal suit was filed on behalf of an Oregon citizens group forcing EPA on 30 June 1992 to enter into a Consent Decree to establish a schedule for the Subtitle C regulatory determination. In accordance with the Consent Decree, EPA notified the litigation parties that it would make by (a) 02 Aug 1993 a Subtitle C regulatory determination for the four waste types from the combustion of coal by electric utilities, and (b) 01 April 1998 a Subtitle C regulatory determination for all remaining fossil fuel combustion wastes generated by other utilities and non-utilities.

1993: On 12 February 1993, EPA published a Notice of Data Availability (NODA) requesting public comment on a proposed methodology to be used in making a final Subtitle C regulatory determination for the coal-fired electric utility wastes.[4] EPA issued a final determination[5] on 09 August 1993 for the first set of four waste types from coal-fired electricity plants, concluding that Subtitle C regulation is inappropriate because of the limited risks posed by them and the existence of generally adequate State and Federal regulatory programs, and thus deciding to continue to exempt these wastes from Subtitle C hazardous waste regulation. This is referred to as the "Part 1" determination. However, EPA indicated that industry and the States should continue to review these wastes, and that EPA would consider these wastes during its ongoing assessment of industrial non-hazardous wastes under RCRA Subtitle D.

1999: On 31 March 1999, EPA published a second Report to Congress (RTC) on the "remaining wastes" (i.e., CCW generated by other types of facilities than coal-fired electricity power plants) not covered by EPA's 1988 RTC. EPA provided a 45-day public comment period in the Federal Register, and held a public meeting with stakeholders on 21 May 1999, to gather feedback on the RTC.

2000: On 22 May 2000, EPA published a regulatory determination[6] of whether the regulation of the other types of fossil fuel combustion wastes generated by other types of facilities not addressed in the 1993 final determination is warranted under RCRA Subtitle C or Subtitle D. This is referred to as the "Part 2" determination. EPA concluded that Subtitle C regulation is not warranted, but determined that national regulations under Subtitle D are warranted when these wastes are used to fill surface or underground mines or are deposited in surface impoundments and landfills. For CCW used as minefill, EPA consulted with the Office of Surface Mining (OSM) in the US Department of the Interior to assess whether equivalent protectiveness could be achieved by using regulatory authorities available under the Surface Mining Control and Reclamation Act (SMCRA). Subsequently, a March 2006 National Academy of Science report[7] recommended that the OSM take the lead in developing standards for CCW minefilling under SMCRA. Indeed, and EPA has deferred to OSM's lead. EPA also concluded that no additional regulations are warranted for CCW used beneficially (other than for mine filling) such as for additions to cement and concrete products, waste stabilization, and use in construction products such as wallboard.

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[4] Federal Register, Vol. 58, No. 28, 12 February 1993, pages 8273 to 8275, "Additional Information on Waste Studied in the Report to Congress on Wastes From the Combustion of Coal by Electric Utility Power Plants."
[5] Federal Register, Vol. 58, No. 151, 09 August 1993, pages 42466 to 42482 "Final Regulatory Determination on Four Large-Volume Wastes From the Combustion of Coal by Electric Utility Power Plants."
[6] Federal Register, Vol. 65, No. 99, 22 May 2000, pages 32214 to 32237, "Notice of Regulatory Determination on Wastes from the Combustion of Fossil Fuels."
[7] The 2006 NAS report on CCW mine filling is available at http://books.nap.edu/openbook.php?isbn=0309100496

2005: In November 2005, EPA completed a report estimating the potential costs to the electric utilities industry to comply with hypothetical new regulatory requirements for CCW management units under EPA's 40 CFR Part 258 RCRA Subtitle D regulations. The hypothetical requirements included groundwater monitoring, liner and leachate collection/detection system design controls, dust controls, storm runoff controls, end-of-lifespan closure controls, post-closure monitoring, financial assurance, siting standards, and corrective action.

2007: For purpose of evaluating and proposing Subtitle D regulations, on 29 August 2007, EPA published a NODA announcing the availability of new information and data concerning the management of coal combustion wastes (CCW) in landfills and surface impoundments, as well as the intent to subject to peer review the new draft EPA risk assessment of these wastes deposited in the two types of management units. In the NODA, EPA requested comments on the following three documents: (a) joint US Department of Energy (DOE) and EPA report entitled "Coal Combustion Waste Management at Landfills and Surface Impoundments 1994-2004"; (b) draft risk assessment conducted by EPA on the management of CCW in landfills and surface impoundments; and (c) EPA's damage case assessment. In addition, the NODA also presented two alternative approaches to managing these wastes: (a) Voluntary Action Plan that was formulated by the electric utility industry through their trade association, the Utility Solid Waste Activities Group (USWAG), and (b) framework prepared by a number of citizens' groups for Federal regulation under RCRA Subtitle D (for non-hazardous wastes).

2008: The externally-conducted peer review of EPA's new draft risk analysis was completed in September 2008.

2009: On 09 March 2009, EPA issued Information Request Letters to 150 electric utility plants that have "surface impoundments or similar diked or bermed management units designated as landfills" which receive, store or dispose liquid-borne coal combustion wastes. The letters request electric utility plants to supply within 10 business days, information to assist EPA in evaluating the structural integrity of these management units. EPA, working closely with other federal agencies and the states, will review the information provided by the facilities to identify impoundments or similar units that need priority attention. As part of this assessment effort, EPA will also be visiting many of these facilities to see first hand that the management units are structurally sound. EPA will require appropriate remedial action at any facility that is found to pose a risk for potential failure. Full text of the March 2009 EPA letter is available at: http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/coalashletter.htm

Appendix B:

List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA

Appendix B
List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA

Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
1	92	WI	18028	State of Wisconsin	54406	Capitol Heat and Power	1.5
2	92	WI	18028	State of Wisconsin	54406	Capitol Heat and Power	1.5
3	92	TN	19724	Vanderbilt University	52048	Vanderbilt University Power Plant	6.5
4	92	TN	19724	Vanderbilt University	52048	Vanderbilt University Power Plant	4.5
5	92	AK	22199	U S Air Force-Eielson AFB	50392	Eielson AFB Central Heat & Power Plant	2.5
6	92	AK	22199	U S Air Force-Eielson AFB	50392	Eielson AFB Central Heat & Power Plant	2.5
7	92	AK	22199	U S Air Force-Eielson AFB	50392	Eielson AFB Central Heat & Power Plant	5
8	92	AK	22199	U S Air Force-Eielson AFB	50392	Eielson AFB Central Heat & Power Plant	5
9	92	AK	22199	U S Air Force-Eielson AFB	50392	Eielson AFB Central Heat & Power Plant	10
10	92	AK	22200	U S Army-Ft Wainwright	50308	Utility Plants Section	5
11	92	AK	22200	U S Army-Ft Wainwright	50308	Utility Plants Section	2.5
12	92	AK	22200	U S Army-Ft Wainwright	50308	Utility Plants Section	5
13	92	AK	22200	U S Army-Ft Wainwright	50308	Utility Plants Section	5
14	92	AK	22200	U S Army-Ft Wainwright	50308	Utility Plants Section	5
15	311	IL	7	A E Staley Manufacturing Co	10867	A E Staley Decatur Plant Cogen	62
16	311	IN	8	Tate & Lyle	50903	Sagamore Plant Cogeneration	7.4
17	311	IA	109	Ag Processing Inc	10223	AG Processing Inc	8.5
18	311	ID	450	The Amalgamated Sugar Co	10504	Amalgamated Sugar Twin Falls	1.5
19	311	ID	450	The Amalgamated Sugar Co	10504	Amalgamated Sugar Twin Falls	2.5
20	311	ID	450	The Amalgamated Sugar Co	10504	Amalgamated Sugar Twin Falls	6.2
21	311	ND	491	American Crystal Sugar Co	54210	American Crystal Sugar Hillsboro	13.3
22	311	MN	491	American Crystal Sugar Co	54211	American Crystal Sugar Moorhead	3
23	311	MN	491	American Crystal Sugar Co	54211	American Crystal Sugar Moorhead	2
24	311	MN	491	American Crystal Sugar Co	54212	American Crystal Sugar Crookston	3.5
25	311	MN	491	American Crystal Sugar Co	54212	American Crystal Sugar Crookston	3
26	311	ND	491	American Crystal Sugar Co	54213	American Crystal Sugar Drayton	6
27	311	MN	491	American Crystal Sugar Co	54214	American Crystal Sugar East Grand Forks	2.5
28	311	MN	491	American Crystal Sugar Co	54214	American Crystal Sugar East Grand Forks	5
29	311	MO	623	Anheuser-Busch Inc	10430	Anheuser Busch St Louis	11
30	311	MO	623	Anheuser-Busch Inc	10430	Anheuser Busch St Louis	11

Appendix B List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA							
Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
31	311	MO	623	Anheuser-Busch Inc	10430	Anheuser Busch St Louis	4.1
32	311	IA	772	Archer Daniels Midland Co	10860	Archer Daniels Midland Clinton	7.5
33	311	IA	772	Archer Daniels Midland Co	10860	Archer Daniels Midland Clinton	3.5
34	311	IA	772	Archer Daniels Midland Co	10860	Archer Daniels Midland Clinton	9.4
35	311	IA	772	Archer Daniels Midland Co	10860	Archer Daniels Midland Clinton	4
36	311	IA	772	Archer Daniels Midland Co	10860	Archer Daniels Midland Clinton	7
37	311	IA	772	Archer Daniels Midland Co	10861	Archer Daniels Midland Des Moines	7.9
38	311	NE	772	Archer Daniels Midland Co	10862	Archer Daniels Midland Lincoln	7.9
39	311	MN	772	Archer Daniels Midland Co	10863	Archer Daniels Midland Mankato	6.1
40	311	IA	772	Archer Daniels Midland Co	10864	Archer Daniels Midland Cedar Rapids	31
41	311	IA	772	Archer Daniels Midland Co	10864	Archer Daniels Midland Cedar Rapids	31
42	311	IA	772	Archer Daniels Midland Co	10864	Archer Daniels Midland Cedar Rapids	31
43	311	IA	772	Archer Daniels Midland Co	10864	Archer Daniels Midland Cedar Rapids	31
44	311	IA	772	Archer Daniels Midland Co	10864	Archer Daniels Midland Cedar Rapids	31
45	311	IA	772	Archer Daniels Midland Co	10864	Archer Daniels Midland Cedar Rapids	101.1
46	311	IL	772	Archer Daniels Midland Co	10865	Archer Daniels Midland Decatur	31
47	311	IL	772	Archer Daniels Midland Co	10865	Archer Daniels Midland Decatur	31
48	311	IL	772	Archer Daniels Midland Co	10865	Archer Daniels Midland Decatur	31
49	311	IL	772	Archer Daniels Midland Co	10865	Archer Daniels Midland Decatur	31
50	311	IL	772	Archer Daniels Midland Co	10865	Archer Daniels Midland Decatur	31
51	311	IL	772	Archer Daniels Midland Co	10865	Archer Daniels Midland Decatur	75
52	311	IL	772	Archer Daniels Midland Co	10865	Archer Daniels Midland Decatur	105
53	311	IL	772	Archer Daniels Midland Co	10866	Archer Daniels Midland Peoria	1.5
54	311	IL	772	Archer Daniels Midland Co	10866	Archer Daniels Midland Peoria	1.5
55	311	IL	772	Archer Daniels Midland Co	10866	Archer Daniels Midland Peoria	4
56	311	IL	772	Archer Daniels Midland Co	10866	Archer Daniels Midland Peoria	4
57	311	IL	772	Archer Daniels Midland Co	10866	Archer Daniels Midland Peoria	4
58	311	ND	772	Archer Daniels Midland Co	55638	Walhalla	2
59	311	IL	2512	Bunge Milling Inc	51000	Bunge Milling Cogen	20
60	311	MI	2769	Cargill Inc	54965	Cargill Salt	2
61	311	TN	3103	Cargill Inc	10729	Cargill Corn Wet Milling Plant	25
62	311	IA	3106	Cargill Inc North America Sweetners	10855	Cargill Corn Milling Division	20
63	311	IA	3106	Cargill Inc North America Sweetners	10855	Cargill Corn Milling Division	20
64	311	IN	3283	Bunge North America East LLC	50316	Bunge North America East LLC	2
65	311	IL	4222	Corn Products Intl Inc	54556	Corn Products Illinois	22.5
66	311	IL	4222	Corn Products Intl Inc	54556	Corn Products Illinois	22.5
67	311	NC	4417	Corn Products Intl Inc	54618	Corn Products Winston Salem	0.9
68	311	NC	4417	Corn Products Intl Inc	54618	Corn Products Winston Salem	7.5

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Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
69	311	VA	14795	Perdue Farms Inc	10515	Oilseed Plant	1.7
70	311	MN	17604	Southern Minnesota Beet Sugar	54533	Southern Minnesota Beet Sugar	7.5
71	311	ID	24206	Amalgamated Sugar Co-Nampa	54690	Amalgamated Sugar LLC Nampa	0.5
72	311	ID	24206	Amalgamated Sugar Co-Nampa	54690	Amalgamated Sugar LLC Nampa	2.2
73	311	ID	24206	Amalgamated Sugar Co-Nampa	54690	Amalgamated Sugar LLC Nampa	6
74	311	GA	27131	Savannah Foods&Industrial Inc	50146	Savannah Sugar Refinery	2.7
75	311	GA	27131	Savannah Foods&Industrial Inc	50146	Savannah Sugar Refinery	3
76	311	GA	27131	Savannah Foods&Industrial Inc	50146	Savannah Sugar Refinery	1
77	311	GA	27131	Savannah Foods&Industrial Inc	50146	Savannah Sugar Refinery	5
78	314	VA	4773	Dan River Inc	50954	Dan River Power Plant	3
79	314	VA	4773	Dan River Inc	50954	Dan River Power Plant	6
80	314	VA	49859	Cinergy Solutions of Narrows LLC	52089	Cinergy Solutions of Narrows	6
81	314	VA	49859	Cinergy Solutions of Narrows LLC	52089	Cinergy Solutions of Narrows	6
82	314	VA	49859	Cinergy Solutions of Narrows LLC	52089	Cinergy Solutions of Narrows	6
83	314	VA	49859	Cinergy Solutions of Narrows LLC	52089	Cinergy Solutions of Narrows	9.2
84	314	DE	50006	Invista	10793	Seaford Delaware Plant	10
85	314	DE	50006	Invista	10793	Seaford Delaware Plant	10
86	314	DE	50006	Invista	10793	Seaford Delaware Plant	10
87	314	NC	50007	Unifi Kinston, LLC	10792	Unifi Kinston LLC	7.5
88	314	NC	50007	Unifi Kinston, LLC	10792	Unifi Kinston LLC	7.5
89	321	MI	49967	Decorative Panels International, Inc.	10149	Louisiana Pacific	7.5
90	322	AL	2053	Bowater Nwprt Coosa Pines Op	54216	U S Alliance Coosa Pines	5
91	322	AL	2053	Bowater Nwprt Coosa Pines Op	54216	U S Alliance Coosa Pines	5
92	322	AL	2053	Bowater Nwprt Coosa Pines Op	54216	U S Alliance Coosa Pines	5
93	322	AL	2053	Bowater Nwprt Coosa Pines Op	54216	U S Alliance Coosa Pines	5
94	322	WI	6739	Smart Papers	50620	Fraser Paper	5.7
95	322	WI	13008	Mosinee Paper Corp	50614	Mosinee Paper	15
96	322	WI	13008	Mosinee Paper Corp	50614	Mosinee Paper	5
97	322	WI	18163	Stora Enso North America	54885	Kimberly Mill	15.9
98	322	WI	18163	Stora Enso North America	54885	Kimberly Mill	19.3
99	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	6
100	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	6
101	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	6
102	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	7
103	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	10
104	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	7.5
105	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	10.4
106	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	10.4

Appendix B List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA							
Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
107	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	10.4
108	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	10.4
109	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	10.4
110	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	15
111	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	15.4
112	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	16.8
113	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	18
114	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	16.6
115	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	6
116	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	6
117	325	TN	5610	Eastman Chemical Co-TN Ops	50481	Tennessee Eastman Operations	6
118	325	MO	8483	Hercules Incorporated	10207	Hercules Missouri Chemical Works	8.6
119	325	MO	8483	Hercules Incorporated	10207	Hercules Missouri Chemical Works	8.6
120	325	OH	12986	Morton Salt Co-Morton Intl Inc	54335	Morton Salt Rittman	1.5
121	325	WV	19433	Union Carbide C&P-Charleston	50151	Union Carbide South Charleston	6
122	325	VA	22218	U S Army-Radford	52072	Radford Army Ammunition Plant	6
123	325	VA	22218	U S Army-Radford	52072	Radford Army Ammunition Plant	6
124	325	VA	22218	U S Army-Radford	52072	Radford Army Ammunition Plant	6
125	325	VA	22218	U S Army-Radford	52072	Radford Army Ammunition Plant	6
126	325	WV	50033	PPG Industries Inc Natrium	50491	PPG Natrium Plant	7.5
127	325	WV	50033	PPG Industries Inc Natrium	50491	PPG Natrium Plant	7.5
128	325	WV	50033	PPG Industries Inc Natrium	50491	PPG Natrium Plant	26
129	325	WV	50033	PPG Industries Inc Natrium	50491	PPG Natrium Plant	82
130	326	OH	7392	Goodyear Tire & Rubber Co	10114	Goodyear Power Plant	7.5
131	326	OH	7392	Goodyear Tire & Rubber Co	10114	Goodyear Power Plant	12.5
132	326	OH	7392	Goodyear Tire & Rubber Co	10114	Goodyear Power Plant	7.5
133	326	OH	7392	Goodyear Tire & Rubber Co	10114	Goodyear Power Plant	12.5
134	327	WI	12635	Minergy Neenah LLC	56037	Minergy Neenah	6.5
135	327	MA	16544	Saint - Gobain Abrasives Inc	50041	Norton Powerhouse	2.5
136	327	MA	16544	Saint - Gobain Abrasives Inc	50041	Norton Powerhouse	3.1
137	327	MI	40430	Lafarge Corp	50305	LaFarge Alpena	3.2
138	327	MI	40430	Lafarge Corp	50305	LaFarge Alpena	12
139	327	MI	40430	Lafarge Corp	50305	LaFarge Alpena	10
140	327	MI	40430	Lafarge Corp	50305	LaFarge Alpena	11
141	327	MI	40430	Lafarge Corp	50305	LaFarge Alpena	11
142	331	MN	3807	Cleveland Cliffs Inc	10849	Silver Bay Power	50
143	331	MN	3807	Cleveland Cliffs Inc	10849	Silver Bay Power	81.6
144	331	PA	21159	Zinc Corp of America	50130	G F Weaton Power Station	60

Appendix B
List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA

Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
145	331	PA	21159	Zinc Corp of America	50130	G F Weaton Power Station	60
146	331	WV	41530	Elkem Metals Co	50012	Alloy Steam Station	40
147	333	IA	9765	John Deere Dubuque Works	54414	John Deere Dubuque Works	3.5
148	333	IA	9765	John Deere Dubuque Works	54414	John Deere Dubuque Works	3
149	333	IA	9765	John Deere Dubuque Works	54414	John Deere Dubuque Works	7.5
150	333	IL	9788	John Deere Harvester Works Co	10039	John Deere Harvester Works	2
151	333	IL	9788	John Deere Harvester Works Co	10039	John Deere Harvester Works	2.5
152	333	IL	9788	John Deere Harvester Works Co	10039	John Deere Harvester Works	3
153	333	IL	9788	John Deere Harvester Works Co	10039	John Deere Harvester Works	2.5
154	336	MI	7240	General Motors Corp-WFGPontiac	10111	GM WFG Pontiac Site Power Plant	28.9
155	337	VA	1311	Bassett Furniture Industl Inc	50911	Bassett Table	1.5
156	339	OH	15400	Procter & Gamble Co	50456	Procter & Gamble Cincinnati Plant	12.5
157	482	PA	13657	Norfork Southern Corp	10302	Juniata Locomotive Shop	2
158	482	PA	13657	Norfork Southern Corp	10302	Juniata Locomotive Shop	2
159	483	VA	42018	Southeastern Public Serv Auth	54998	SPSA Waste To Energy Power Plant	20
160	483	VA	42018	Southeastern Public Serv Auth	54998	SPSA Waste To Energy Power Plant	20
161	483	VA	42018	Southeastern Public Serv Auth	54998	SPSA Waste To Energy Power Plant	20
162	611	IA	9434	Iowa State University	54201	Iowa State University	13.2
163	611	IA	9434	Iowa State University	54201	Iowa State University	6.2
164	611	IA	9434	Iowa State University	54201	Iowa State University	11.5
165	611	IA	9434	Iowa State University	54201	Iowa State University	15.1
166	611	MI	12436	Michigan State University	10328	T B Simon Power Plant	12.5
167	611	MI	12436	Michigan State University	10328	T B Simon Power Plant	12.5
168	611	MI	12436	Michigan State University	10328	T B Simon Power Plant	15
169	611	MI	12436	Michigan State University	10328	T B Simon Power Plant	21
170	611	OH	14060	Ohio University	54923	Ohio University Facilities Management	1
171	611	IN	15526	Purdue University	50240	Purdue University	30.8
172	611	IN	15526	Purdue University	50240	Purdue University	10.6
173	611	MO	17594	Southeast Missouri State Univ	50264	Southeast Missouri State University	6.2
174	611	WI	18028	State of Wisconsin	54408	Univ of Wisc Madison Charter Sreet Plant	9.7
175	611	AK	19511	University of Alaska	50711	University of Alaska Fairbanks	1.5
176	611	AK	19511	University of Alaska	50711	University of Alaska Fairbanks	1.5
177	611	AK	19511	University of Alaska	50711	University of Alaska Fairbanks	10
178	611	IL	19528	University of Illinois	54780	University of Illinois Abbott Power Plt	12.5
179	611	IL	19528	University of Illinois	54780	University of Illinois Abbott Power Plt	12.5
180	611	IL	19528	University of Illinois	54780	University of Illinois Abbott Power Plt	7
181	611	IL	19528	University of Illinois	54780	University of Illinois Abbott Power Plt	7.5
182	611	IL	19528	University of Illinois	54780	University of Illinois Abbott Power Plt	7.5

Appendix B
List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA

Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
183	611	IA	19539	University of Iowa	54775	University of Iowa Main Power Plant	3
184	611	IA	19539	University of Iowa	54775	University of Iowa Main Power Plant	3
185	611	IA	19539	University of Iowa	54775	University of Iowa Main Power Plant	15
186	611	NC	19541	University of North Carolina	54276	Univ of NC Chapel Hill Cogen Facility	28
187	611	IN	19564	University of Notre Dame	50366	University of Notre Dame	3
188	611	IN	19564	University of Notre Dame	50366	University of Notre Dame	1.7
189	611	IN	19564	University of Notre Dame	50366	University of Notre Dame	2
190	611	IN	19564	University of Notre Dame	50366	University of Notre Dame	5
191	611	IN	19564	University of Notre Dame	50366	University of Notre Dame	9.4
192	611	IA	21223	University of Northern Iowa	50088	University of Northern Iowa	7.5
193	611	NY	21508	Cornell University	50368	Cornell University Central Heat	1.8
194	611	NY	21508	Cornell University	50368	Cornell University Central Heat	5.7
195	611	MO	34359	University of Missouri-Columba	50969	University of Missouri Columbia	6.2
196	611	MO	34359	University of Missouri-Columba	50969	University of Missouri Columbia	12.5
197	611	MO	34359	University of Missouri-Columba	50969	University of Missouri Columbia	19.8
198	611	MO	34359	University of Missouri-Columba	50969	University of Missouri Columbia	14.5
199	624	WI	18028	State of Wisconsin	54407	Waupun Correctional Central Heating Plt	1
200	624	WI	18028	State of Wisconsin	54407	Waupun Correctional Central Heating Plt	1
201	2122	UT	49805	Kennecott Utah Copper Corporation	56163	KUCC	50
202	2122	UT	49805	Kennecott Utah Copper Corporation	56163	KUCC	25
203	2122	UT	49805	Kennecott Utah Copper Corporation	56163	KUCC	25
204	2122	UT	49805	Kennecott Utah Copper Corporation	56163	KUCC	82
205	3122	VA	14465	Park 500 Philip Morris USA	50275	Park 500 Philip Morris USA	6.1
206	3122	VA	14465	Park 500 Philip Morris USA	50275	Park 500 Philip Morris USA	13
207	3122	GA	50087	R J Reynolds Tobacco Co	54243	Brown Williamson Tobacco	1.5
208	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	25.6
209	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	25.6
210	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	25.6
211	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	25.6
212	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	17.5
213	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	12.5
214	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	6.3
215	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	10.4
216	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	10.4
217	3345	NY	5624	Eastman Kodak Co	10025	Kodak Park Site	15
218	32213	OH	2999	Caraustar Industries Inc	54235	Rittman Paperboard	3
219	32213	OH	2999	Caraustar Industries Inc	54235	Rittman Paperboard	5
220	32213	OH	2999	Caraustar Industries Inc	54235	Rittman Paperboard	6

Appendix B List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA							
Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
221	32213	VA	7167	Georgia Pacific Corp - Big Island Mill	50479	Georgia Pacific Big Island	7.5
222	32213	GA	7172	Georgia Pacific Corp	54101	Georgia Pacific Cedar Springs	50
223	32213	GA	7172	Georgia Pacific Corp	54101	Georgia Pacific Cedar Springs	51.2
224	32213	GA	9353	International Paper Co-Augusta	54358	International Paper Augusta Mill	27
225	32213	GA	9353	International Paper Co-Augusta	54358	International Paper Augusta Mill	39
226	32213	GA	9353	International Paper Co-Augusta	54358	International Paper Augusta Mill	18.7
227	32213	NC	9407	International Paper Co-Buckspt	50254	International Paper Roanoke Rapid NC	22.5
228	32213	FL	9686	Jefferson Smurfit Corp	10202	Jefferson Smurfit Fernandina Beach	74.4
229	32213	VA	20508	Westvaco Corp	50900	Covington Facility	10.5
230	32213	VA	20508	Westvaco Corp	50900	Covington Facility	10.5
231	32213	VA	20508	Westvaco Corp	50900	Covington Facility	10.5
232	32213	GA	23632	Inland Paperboard & Package Inc	10426	Inland Paperboard Packaging Rome	5
233	32213	GA	23632	Inland Paperboard & Package Inc	10426	Inland Paperboard Packaging Rome	22
234	32213	GA	23632	Inland Paperboard & Package Inc	10426	Inland Paperboard Packaging Rome	38.4
235	32213	GA	30002	International Paper Co	50398	International Paper Savanna Mill	82.8
236	32213	GA	30002	International Paper Co	50398	International Paper Savanna Mill	71.2
237	32731	CA	26940	U S West Financial Service Inc	50557	TXI Riverside Cement Power House	12
238	32731	CA	26940	U S West Financial Service Inc	50557	TXI Riverside Cement Power House	12
239	322122	AZ	56	Abitibi Consolidated Sale Corp	50805	Abitibi Consolidated Snowflake	43.3
240	322122	AZ	56	Abitibi Consolidated Sale Corp	50805	Abitibi Consolidated Snowflake	27.2
241	322122	GA	5473	Durango-Georgia Paper Co	54428	Durango Georgia Paper	4
242	322122	GA	5473	Durango-Georgia Paper Co	54428	Durango Georgia Paper	6.7
243	322122	GA	5473	Durango-Georgia Paper Co	54428	Durango Georgia Paper	18.7
244	322122	MI	5966	MeadWestvaco Corp.	10208	Escanaba Paper Company	54
245	322122	WI	6577	Fort James Operating Co	10360	Green Bay West Mill	28.2
246	322122	WI	6577	Fort James Operating Co	10360	Green Bay West Mill	10
247	322122	WI	6577	Fort James Operating Co	10360	Green Bay West Mill	18.7
248	322122	WI	6577	Fort James Operating Co	10360	Green Bay West Mill	28.9
249	322122	WI	6577	Fort James Operating Co	10360	Green Bay West Mill	43.2
250	322122	OK	6589	Fort James Operating Co	10362	Muskogee Mill	25
251	322122	OK	6589	Fort James Operating Co	10362	Muskogee Mill	44.5
252	322122	OK	6589	Fort James Operating Co	10362	Muskogee Mill	44.5
253	322122	GA	7127	Georgia-Pacific Corp - Savannah	10361	Savannah River Mill	45
254	322122	GA	7127	Georgia-Pacific Corp - Savannah	10361	Savannah River Mill	45
255	322122	AL	7136	Georgia-Pacific Corp	10699	Georgia Pacific Naheola Mill	15.6
256	322122	AL	7136	Georgia-Pacific Corp	10699	Georgia Pacific Naheola Mill	15.6
257	322122	VA	9348	International Paper	52152	International Paper Franklin Mill	5
258	322122	VA	9348	International Paper	52152	International Paper Franklin Mill	3.7

Appendix B List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA							
Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
259	322122	VA	9348	International Paper	52152	International Paper Franklin Mill	2.5
260	322122	VA	9348	International Paper	52152	International Paper Franklin Mill	9.3
261	322122	VA	9348	International Paper	52152	International Paper Franklin Mill	15.6
262	322122	VA	9348	International Paper	52152	International Paper Franklin Mill	32.4
263	322122	VA	9348	International Paper	52152	International Paper Franklin Mill	28
264	322122	MN	9368	International Paper Co-Sartell	50252	International Paper Sartell Mill	20.4
265	322122	SC	9390	International Paper Co-GT Mill	54087	International Paper Georgetown Mill	25.6
266	322122	SC	9390	International Paper Co-GT Mill	54087	International Paper Georgetown Mill	29.5
267	322122	SC	9390	International Paper Co-GT Mill	54087	International Paper Georgetown Mill	40.5
268	322122	SC	9424	International Paper Co-Eastovr	52151	International Paper Eastover Facility	48.4
269	322122	SC	9424	International Paper Co-Eastovr	52151	International Paper Eastover Facility	61.2
270	322122	PA	10273	Kimberly-Clark Corp	50410	Chester Operations	67
271	322122	NY	13458	NewsTech New York Inc	50246	Deferiet New York	8.1
272	322122	PA	14310	P H Glatfelter Co	50397	P H Glatfelter	7.5
273	322122	PA	14310	P H Glatfelter Co	50397	P H Glatfelter	6
274	322122	PA	14310	P H Glatfelter Co	50397	P H Glatfelter	5.9
275	322122	PA	14310	P H Glatfelter Co	50397	P H Glatfelter	5.1
276	322122	PA	14310	P H Glatfelter Co	50397	P H Glatfelter	45.9
277	322122	PA	14310	P H Glatfelter Co	50397	P H Glatfelter	39.1
278	322122	WI	14369	Packaging Corp of America	50476	Packaging of America Tomahawk Mill	6.3
279	322122	WI	14369	Packaging Corp of America	50476	Packaging of America Tomahawk Mill	9.4
280	322122	MI	16719	S D Warren Co	50438	S D Warren Muskegon	3.5
281	322122	MI	16719	S D Warren Co	50438	S D Warren Muskegon	19.1
282	322122	MI	16719	S D Warren Co	50438	S D Warren Muskegon	28.3
283	322122	ME	16721	S D Warren Co.- Westbrook	50447	S D Warren Westbrook	47.5
284	322122	ME	16721	S D Warren Co.- Westbrook	50447	S D Warren Westbrook	15
285	322122	GA	17610	SP Newsprint Company	54004	SP Newsprint	45
286	322122	FL	18157	Stone Container Corp-Panama Ci	50807	Stone Container Panama City Mill	20
287	322122	SC	18162	Smurfit-Stone Container Enterprises Inc	50806	Stone Container Florence Mill	79.1
288	322122	WI	18163	Stora Enso North America	10234	Biron Mill	15.6
289	322122	WI	18163	Stora Enso North America	10234	Biron Mill	17
290	322122	WI	18163	Stora Enso North America	10234	Biron Mill	21.5
291	322122	WI	18163	Stora Enso North America	10234	Biron Mill	7.5
292	322122	WI	18163	Stora Enso North America	10476	Whiting Mill	4.1
293	322122	WI	18163	Stora Enso North America	10477	Wisconsin Rapids Pulp Mill	32
294	322122	WI	18163	Stora Enso North America	10477	Wisconsin Rapids Pulp Mill	40.3
295	322122	WI	18163	Stora Enso North America	54857	Niagara Mill	2.5
296	322122	WI	18163	Stora Enso North America	54857	Niagara Mill	9.3

Appendix B List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA							
Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
297	322122	OH	18189	Sun Premium Paper Advisors LLC	50247	Smart Papers LLC	6
298	322122	OH	18189	Sun Premium Paper Advisors LLC	50247	Smart Papers LLC	1.5
299	322122	OH	18189	Sun Premium Paper Advisors LLC	50247	Smart Papers LLC	7.5
300	322122	OH	18189	Sun Premium Paper Advisors LLC	50247	Smart Papers LLC	10.5
301	322122	NC	20501	Weyerhaeuser Co	50189	Weyerhaeuser Plymouth NC	7.5
302	322122	NC	20501	Weyerhaeuser Co	50189	Weyerhaeuser Plymouth NC	25
303	322122	NC	20501	Weyerhaeuser Co	50189	Weyerhaeuser Plymouth NC	7.5
304	322122	NC	20501	Weyerhaeuser Co	50189	Weyerhaeuser Plymouth NC	72
305	322122	WA	20548	Weyerhaeuser Co	50187	Weyerhaeuser Longview WA	31.4
306	322122	PA	20705	Weyerhaeuser	54638	Johnsonburg Mill	54
307	322122	NC	23815	Blue Ridge Paper Products Inc	50244	Canton North Carolina	7.5
308	322122	NC	23815	Blue Ridge Paper Products Inc	50244	Canton North Carolina	7.5
309	322122	NC	23815	Blue Ridge Paper Products Inc	50244	Canton North Carolina	7.5
310	322122	NC	23815	Blue Ridge Paper Products Inc	50244	Canton North Carolina	7.5
311	322122	NC	23815	Blue Ridge Paper Products Inc	50244	Canton North Carolina	10
312	322122	NC	23815	Blue Ridge Paper Products Inc	50244	Canton North Carolina	12.5
313	322122	TN	23931	Bowater Newsprint Calhoun Ops	50956	Bowater Newsprint Calhoun Operation	19
314	322122	TN	23931	Bowater Newsprint Calhoun Ops	50956	Bowater Newsprint Calhoun Operation	19.2
315	322122	MI	24263	Cellu Tissue Holdings Inc	52017	Menominee Acquisition	1.5
316	322122	MI	24263	Cellu Tissue Holdings Inc	52017	Menominee Acquisition	2.5
317	322122	MI	29820	Smurfit-Stone Corp MI Plant	50812	Stone Container Ontonagon Mill	15.6
318	322122	WI	49801	WAUSAU Paper	50933	Rhinelander Mill	4
319	322122	WI	49801	WAUSAU Paper	50933	Rhinelander Mill	10
320	322122	WI	49801	WAUSAU Paper	50933	Rhinelander Mill	9.3
321	322122	PA	49923	American Eagle Paper Mills	50284	American Eagle Paper Mills	2.5
322	322122	PA	49923	American Eagle Paper Mills	50284	American Eagle Paper Mills	4.5
323	322122	PA	49923	American Eagle Paper Mills	50284	American Eagle Paper Mills	3
324	322122	PA	49923	American Eagle Paper Mills	50284	American Eagle Paper Mills	7.5
325	322122	MI	50021	Neenah Paper Michigan Inc.	54867	Neenah Paper Munising Mill	6.2
326	322122	MD	50097	NewPage Corporation	50282	Luke Mill	35
327	322122	MD	50097	NewPage Corporation	50282	Luke Mill	30
328	322122	OH	50165	Chillicothe Paper Inc	10244	Chillicothe Paper Inc	10.6
329	322122	OH	50165	Chillicothe Paper Inc	10244	Chillicothe Paper Inc	24
330	322122	OH	50165	Chillicothe Paper Inc	10244	Chillicothe Paper Inc	31
331	322122	OH	50165	Chillicothe Paper Inc	10244	Chillicothe Paper Inc	27.2
332	322122	WI	54738	Thilmany LLC	54098	International Paper Kaukauna Mill	12
333	322122	WI	54738	Thilmany LLC	54098	International Paper Kaukauna Mill	6
334	322122	WI	54738	Thilmany LLC	54098	International Paper Kaukauna Mill	11

Appendix B List of Other Industries with Coal-Fired Electricity Plants Not Covered by the Proposed Rule or this RIA							
Boiler count	Industry NAICS Code	State	Utility ID	Company	Plant ID	Plant Name	Nameplate Capacity (Megawatts)
335	322122	WI	54738	Thilmany LLC	54098	International Paper Kaukauna Mill	15.6
336	322122	MN	54823	Wausau Paper of Minnesota LLC	50636	Potlatch Minnesota Pulp Paper	0.6
337	325188	WY	7067	General Chemical Corp	54318	General Chemical	15
338	325188	WY	7067	General Chemical Corp	54318	General Chemical	15
339	325188	TX	35120	Norit Americas Inc	54972	Norit Americas Marshall Plant	2
340	325188	CA	49968	Searles Valley Minerals Operations Inc.	10684	Argus Cogen Plant	27.5
341	325188	CA	49968	Searles Valley Minerals Operations Inc.	10684	Argus Cogen Plant	27.5
342	325211	TN	5543	E I DuPont De Nemours & Co	10797	Old Hickory Plant	1
343	325211	MA	39878	Solutia Inc-Indian	10417	Indian Orchard Plant 1	5.7
344	325211	SC	50006	Invista	10795	Camden South Carolina	5.5
345	325211	SC	50006	Invista	10795	Camden South Carolina	5.5
346	325211	SC	50006	Invista	10795	Camden South Carolina	19
347	325211	VA	50006	Invista	10796	Waynesboro Virginia Plant	3
348	325211	VA	50006	Invista	10796	Waynesboro Virginia Plant	3
349	325211	VA	50006	Invista	10796	Waynesboro Virginia Plant	3
350	325211	VA	50006	Invista	10796	Waynesboro Virginia Plant	3.4
351	331111	PA	5959	Erie Coke Corp	50920	Erie Coke	2.5
352	331312	TX	252	Alcoa Inc	52071	Sandow Station	121
353	331312	TX	252	Alcoa Inc	52071	Sandow Station	121
354	331312	TX	252	Alcoa Inc	52071	Sandow Station	121
						Column total =	5959.1

Appendix C:

List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

Appendix C
List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

Count	Plant Code	Plant Name	Utility Code	Company Name	State	Sector Name	Plant Status	Annual Tons Coal Burned	Annual Tons CCW Generated	LIG	BIT	WC	SUB	SC
1	3	Barry	195	Alabama Power Co	AL	Electric Utility	Operating	4,772,876	282,900	0	1	1	0	0
2	7	Gadsden	195	Alabama Power Co	AL	Electric Utility	Operating	288,146	34,100	0	1	0	0	0
3	8	Gorgas	195	Alabama Power Co	AL	Electric Utility	Operating	3,110,443	381,100	0	1	1	0	0
4	10	Greene County	195	Alabama Power Co	AL	Electric Utility	Operating	1,572,081	214,400	0	1	1	0	0
5	26	E C Gaston	195	Alabama Power Co	AL	Electric Utility	Operating	4,897,480	531,600	0	1	1	0	0
6	47	Colbert	18642	Tennessee Valley Authority	AL	Electric Utility	Operating	3,513,262	295,900	0	1	0	1	0
7	50	Widows Creek	18642	Tennessee Valley Authority	AL	Electric Utility	Operating	4,728,867	1,649,500	0	1	0	0	0
8	51	Dolet Hills	3265	Cleco Power LLC	LA	Electric Utility	Operating	3,100,255	770,300	1	0	0	0	0
9	56	Charles R Lowman	189	Alabama Electric Coop Inc	AL	Electric Utility	Operating	1,573,072	207,900	0	1	0	0	0
10	59	Platte	40606	Grand Island City of	NE	Electric Utility	Operating	398,394	21,400	0	0	0	1	0
11	60	Whelan Energy Center	8245	Hastings City of	NE	Electric Utility	Operating	337,647	19,473	0	0	0	1	0
12	79	Aurora Energy LLC Chena	986	Aurora Energy LLC	AK	NAICS-22 Cogen	Operating	220,529	17,361	0	0	0	1	0
13	87	Escalante	30151	Tri-State G & T Assn, Inc	NM	Electric Utility	Operating	1,113,984	314,900	0	0	0	1	0
14	108	Holcomb	18315	Sunflower Electric Power Corp	KS	Electric Utility	Operating	1,711,956	135,600	0	0	0	1	0
15	113	Cholla	803	Arizona Public Service Co	AZ	Electric Utility	Operating	4,327,008	622,000	0	1	0	0	0
16	126	H Wilson Sundt Generating Station	24211	Tucson Electric Power Co	AZ	Electric Utility	Operating	385,092	13,300	0	0	0	1	0
17	127	Oklaunion	15474	Public Service Co of Oklahoma	TX	Electric Utility	Operating	2,653,110	146,000	0	0	0	1	0
18	130	Cross	17543	South Carolina Pub Serv Auth	SC	Electric Utility	Operating	4,706,513	568,100	0	1	0	0	0
19	136	Seminole	21554	Seminole Electric Coop, Inc	FL	Electric Utility	Operating	3,634,080	1,372,000	0	1	0	0	0
20	160	Apache Station	796	Arizona Electric Pwr Coop Inc	AZ	Electric Utility	Operating	1,588,703	327,000	0	0	0	1	0
21	165	GRDA	7490	Grand River Dam Authority	OK	Electric Utility	Operating	4,539,679	280,300	0	0	0	1	0
22	207	St Johns River Power Park	9617	JEA	FL	Electric Utility	Operating	3,746,438	637,600	0	1	0	0	1
23	298	Limestone	54888	NRG Texas LLC	TX	NAICS-22 Non-Cogen	Operating	9,644,469	1,851,500	1	0	0	1	0
24	384	Joliet 29	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	Operating	3,312,171	135,000	0	0	0	1	0
25	462	W N Clark	770	Aquila, Inc.	CO	Electric Utility	Operating	144,097	20,881	0	1	0	0	0
26	465	Arapahoe	15466	Public Service Co of Colorado	CO	Electric Utility	Operating	652,041	37,800	0	0	0	1	0
27	468	Cameo	15466	Public Service Co of Colorado	CO	Electric Utility	Operating	269,308	33,488	0	1	0	0	0
28	469	Cherokee	15466	Public Service Co of Colorado	CO	Electric Utility	Operating	2,088,085	283,000	0	1	0	0	0
29	470	Comanche	15466	Public Service Co of Colorado	CO	Electric Utility	Operating	2,758,175	116,730	0	0	0	1	0
30	477	Valmont	15466	Public Service Co of Colorado	CO	Electric Utility	Operating	542,522	58,600	0	1	0	0	0
31	492	Martin Drake	3989	Colorado Springs City of	CO	Electric Utility	Operating	1,025,742	132,600	0	1	0	0	0
32	525	Hayden	15466	Public Service Co of Colorado	CO	Electric Utility	Operating	1,735,265	229,600	0	1	0	0	0
33	527	Nucla	30151	Tri-State G & T Assn, Inc	CO	Electric Utility	Operating	397,660	135,600	0	1	0	0	0
34	564	Stanton Energy Center	14610	Orlando Utilities Comm	FL	Electric Utility	Operating	2,428,385	631,100	0	1	0	0	0
35	568	Bridgeport Station	15452	PSEG Power Connecticut LLC	CT	NAICS-22 Non-Cogen	Operating	1,303,786	23,100	0	0	0	1	0
36	593	Edge Moor	4252	Conectiv Delmarva Gen Inc	DE	NAICS-22 Non-Cogen	Operating	695,678	74,600	0	1	0	0	0
37	594	Indian River Generating Station	9332	Indian River Operations Inc	DE	NAICS-22 Non-Cogen	Operating	1,701,673	172,000	0	1	0	1	0
38	602	Brandon Shores	4161	Constellation Power Source Gen	MD	NAICS-22 Non-Cogen	Operating	3,520,615	464,000	0	1	0	0	0
39	628	Crystal River	6455	Progress Energy Florida Inc	FL	Electric Utility	Operating	6,107,761	777,100	0	1	0	0	0
40	641	Crist	7801	Gulf Power Co	FL	Electric Utility	Operating	2,924,687	142,700	0	1	0	0	0
41	642	Scholz	7801	Gulf Power Co	FL	Electric Utility	Operating	213,187	24,825	0	1	0	0	0
42	643	Lansing Smith	7801	Gulf Power Co	FL	Electric Utility	Operating	1,056,359	70,300	0	1	0	0	0

Appendix C
List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

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43	645	Big Bend	18454	Tampa Electric Co	FL	Electric Utility	Operating	3,994,763	1,842,700	0	1	0	0	0
44	663	Deerhaven Generating Station	6909	Gainesville Regional Utilities	FL	Electric Utility	Operating	552,699	72,600	0	1	0	0	0
45	667	Northside Generating Station	9617	JEA	FL	Electric Utility	Operating	251,925	955,700	0	1	0	0	0
46	676	C D McIntosh Jr	10623	City of Lakeland	FL	Electric Utility	Operating	1,049,924	133,274	0	1	0	0	0
47	703	Bowen	7140	Georgia Power Co	GA	Electric Utility	Operating	8,976,591	2,589,500	0	1	0	0	0
48	708	Hammond	7140	Georgia Power Co	GA	Electric Utility	Operating	1,960,558	170,900	0	1	0	0	0
49	709	Harllee Branch	7140	Georgia Power Co	GA	Electric Utility	Operating	4,097,005	435,300	0	1	0	0	0
50	710	Jack McDonough	7140	Georgia Power Co	GA	Electric Utility	Operating	1,467,868	144,790	0	1	0	0	0
51	727	Mitchell	7140	Georgia Power Co	GA	Electric Utility	Operating	236,957	29,300	0	1	0	0	0
52	728	Yates	7140	Georgia Power Co	GA	Electric Utility	Operating	3,105,202	408,900	0	1	0	0	0
53	733	Kraft	7140	Georgia Power Co	GA	Electric Utility	Operating	577,836	50,000	0	1	0	0	0
54	753	Crisp Plant	4538	Crisp County Power Comm	GA	Electric Utility	Operating	497	110	0	1	0	0	0
55	856	E D Edwards	49756	Ameren Energy Resources Generating Co.	IL	Electric Utility	Operating	2,832,688	190,000	0	1	0	1	0
56	861	Coffeen	520	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	Operating	3,238,428	248,000	0	0	0	1	0
57	863	Hutsonville	520	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	Operating	537,900	37,000	0	1	0	1	0
58	864	Meredosia	520	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	Operating	1,145,905	48,000	0	1	0	1	0
59	867	Crawford	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	Operating	1,664,228	87,600	0	0	0	1	0
60	874	Joliet 9	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	Operating	999,645	20,600	0	0	0	1	0
61	876	Kincaid Generation LLC	5269	Dominion Energy Services Co	IL	NAICS-22 Non-Cogen	Operating	3,879,491	180,100	0	0	0	1	0
62	879	Powerton	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	Operating	5,201,694	262,700	0	1	0	1	0
63	883	Waukegan	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	Operating	2,979,856	148,800	0	0	0	1	0
64	884	Will County	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	Operating	3,365,332	146,400	0	0	0	1	0
65	886	Fisk Street	12384	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	Operating	982,077	43,000	0	0	0	1	0
66	887	Joppa Steam	5748	Electric Energy Inc	IL	NAICS-22 Non-Cogen	Operating	4,979,722	224,000	0	0	0	1	0
67	889	Baldwin Energy Complex	5517	Dynegy Midwest Generation Inc	IL		Operating	0	334,000	0	0	0	1	0
68	891	Havana	5517	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	Operating	1,997,273	88,000	0	1	0	1	0
69	892	Hennepin Power Station	5517	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	Operating	1,228,065	55,600	0	0	0	1	0
70	897	Vermilion	5517	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	Operating	538,435	26,500	0	1	0	1	0
71	898	Wood River	5517	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	Operating	1,718,059	118,600	0	0	0	1	0
72	963	Dallman	17828	City of Springfield	IL	Electric Utility	Operating	970,320	433,500	0	1	0	0	0
73	964	Lakeside	17828	City of Springfield	IL	Electric Utility	Operating	162,548	11,512	0	1	0	0	0
74	976	Marion	17632	Southern Illinois Power Coop	IL	Electric Utility	Operating	1,178,991	680,700	0	1	1	0	0

Appendix C
List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

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75	981	State Line Energy	18041	State Line Energy LLC	IN	NAICS-22 Non-Cogen	Operating	1,623,219	51,000	0	0	0	1	0
76	983	Clifty Creek	9269	Indiana-Kentucky Electric Corp	IN	Electric Utility	Operating	4,365,616	293,100	0	1	0	1	0
77	988	Tanners Creek	9324	Indiana Michigan Power Co	IN	Electric Utility	Operating	2,858,126	491,300	0	1	0	0	0
78	990	Harding Street	9273	Indianapolis Power & Light Co	IN	Electric Utility	Operating	1,785,076	516,100	0	1	0	0	0
79	991	Eagle Valley	9273	Indianapolis Power & Light Co	IN	Electric Utility	Operating	766,250	68,898	0	1	0	0	0
80	992	CC Perry K	3599	Citizens Thermal Energy	IN	NAICS-22 Cogen	Operating	186,281	11,810	0	1	0	0	0
81	994	AES Petersburg	9273	Indianapolis Power & Light Co	IN	Electric Utility	Operating	5,587,424	1,195,300	0	1	0	0	0
82	995	Bailly	13756	Northern Indiana Pub Serv Co	IN	Electric Utility	Operating	1,046,812	239,800	0	1	0	0	0
83	997	Michigan City	13756	Northern Indiana Pub Serv Co	IN	Electric Utility	Operating	1,455,561	78,200	0	1	0	1	0
84	1001	Cayuga	15470	Duke Energy Indiana Inc	IN	Electric Utility	Operating	3,092,671	210,900	0	1	0	0	0
85	1004	Edwardsport	15470	Duke Energy Indiana Inc	IN	Electric Utility	Operating	152,960	11,500	0	1	0	0	0
86	1008	R Gallagher	15470	Duke Energy Indiana Inc	IN	Electric Utility	Operating	1,400,823	125,600	0	1	0	0	0
87	1010	Wabash River	15470	Duke Energy Indiana Inc	IN	Electric Utility	Operating	2,039,840	192,100	0	1	0	0	0
88	1012	F B Culley	17633	Southern Indiana Gas & Elec Co	IN	Electric Utility	Operating	1,285,361	535,300	0	1	0	0	0
89	1024	Crawfordsville	4508	Crawfordsville Elec, Lgt & Pwr	IN	Electric Utility	Operating	13,057	2,027	0	1	0	0	0
90	1032	Logansport	11142	City of Logansport	IN	Electric Utility	Operating	108,822	6,599	0	1	0	0	0
91	1037	Peru	14839	Peru City of	IN	Electric Utility	Operating	20,645	1,887	0	1	0	0	0
92	1040	Whitewater Valley	15989	City of Richmond	IN	Electric Utility	Operating	214,240	27,729	0	1	0	0	0
93	1043	Frank E Ratts	9267	Hoosier Energy R E C, Inc	IN	Electric Utility	Operating	797,278	39,800	0	1	0	0	0
94	1046	Dubuque	9417	Interstate Power and Light Co	IA	Electric Utility	Operating	222,716	17,990	0	1	0	1	0
95	1047	Lansing	9417	Interstate Power and Light Co	IA	Electric Utility	Operating	1,064,783	51,000	0	1	0	1	0
96	1048	Milton L Kapp	9417	Interstate Power and Light Co	IA	Electric Utility	Operating	726,461	40,000	0	0	0	1	0
97	1058	Sixth Street	9417	Interstate Power and Light Co	IA	Electric Utility	Operating	110,486	14,193	0	1	0	1	0
98	1073	Prairie Creek	9417	Interstate Power and Light Co	IA	Electric Utility	Operating	543,074	48,500	0	0	0	1	0
99	1077	Sutherland	9417	Interstate Power and Light Co	IA	Electric Utility	Operating	575,423	30,000	0	1	0	1	0
100	1081	Riverside	12341	MidAmerican Energy Co	IA	Electric Utility	Operating	533,513	26,400	0	0	0	1	0
101	1082	Walter Scott Jr Energy Center	12341	MidAmerican Energy Co	IA	Electric Utility	Operating	5,245,451	179,900	0	0	0	1	0
102	1091	George Neal North	12341	MidAmerican Energy Co	IA	Electric Utility	Operating	3,763,842	193,100	0	1	0	1	0
103	1104	Burlington	9417	Interstate Power and Light Co	IA	Electric Utility	Operating	797,543	37,000	0	0	0	1	0
104	1122	Ames Electric Services Power Plant	554	Ames City of	IA	Electric Utility	Operating	301,117	14,598	0	0	0	1	0
105	1131	Streeter Station	3203	Cedar Falls Utilities	IA	Electric Utility	Operating	73,414	6,676	0	1	0	0	0
106	1167	Muscatine Plant #1	13143	Board of Water Electric & Communications	IA	Electric Utility	Operating	1,181,709	91,700	0	0	0	1	0
107	1175	Pella	14645	Pella City of	IA	Electric Utility	Operating	73,524	5,694	0	0	0	1	0
108	1217	Earl F Wisdom	4363	Corn Belt Power Coop	IA	Electric Utility	Operating	39,189	4,829	0	1	0	1	0
109	1218	Fair Station	3258	Central Iowa Power Cooperative	IA	Electric Utility	Operating	188,908	20,209	0	1	0	0	0
110	1239	Riverton	5860	Empire District Electric Co	KS	Electric Utility	Operating	270,105	15,699	0	1	0	1	0
111	1241	La Cygne	10000	Kansas City Power & Light Co	KS	Electric Utility	Operating	6,113,434	509,800	0	1	0	1	0
112	1250	Lawrence Energy Center	22500	Westar Energy Inc	KS	Electric Utility	Operating	2,208,345	115,900	0	1	0	1	0
113	1252	Tecumseh Energy Center	22500	Westar Energy Inc	KS	Electric Utility	Operating	923,062	47,600	0	0	0	1	0
114	1295	Quindaro	9996	Kansas City City of	KS	Electric Utility	Operating	714,871	40,200	0	0	0	1	0
115	1353	Big Sandy	22053	Kentucky Power Co	KY	Electric Utility	Operating	2,971,382	901,300	0	1	0	0	0
116	1355	E W Brown	10171	Kentucky Utilities Co	KY	Electric Utility	Operating	1,657,882	140,500	0	1	0	0	0
117	1356	Ghent	10171	Kentucky Utilities Co	KY	Electric Utility	Operating	5,304,762	1,313,800	0	1	0	0	0
118	1357	Green River	10171	Kentucky Utilities Co	KY	Electric Utility	Operating	484,454	30,600	0	1	0	0	0
119	1361	Tyrone	10171	Kentucky Utilities Co	KY	Electric Utility	Operating	199,026	18,900	0	1	0	0	0

Appendix C
List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

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120	1363	Cane Run	11249	Louisville Gas & Electric Co	KY	Electric Utility	Operating	1,670,209	630,200	0	1	0	0	0
121	1364	Mill Creek	11249	Louisville Gas & Electric Co	KY	Electric Utility	Operating	4,819,017	1,236,800	0	1	0	0	0
122	1372	Henderson I	8449	Henderson City Utility Comm	KY	Electric Utility	Operating	5,085	3,909	0	1	0	0	0
123	1374	Elmer Smith	14268	City of Owensboro	KY	Electric Utility	Operating	1,115,446	380,200	0	1	0	0	0
124	1378	Paradise	18642	Tennessee Valley Authority	KY	Electric Utility	Operating	5,805,348	1,237,600	0	1	0	1	0
125	1379	Shawnee	18642	Tennessee Valley Authority	KY	Electric Utility	Operating	4,626,488	432,400	0	1	0	1	0
126	1381	Kenneth C Coleman	20546	Western Kentucky Energy Corp	KY	NAICS-22 Non-Cogen	Operating	1,468,373	183,900	0	1	0	0	1
127	1382	HMP&L Station Two Henderson	20546	Western Kentucky Energy Corp	KY	NAICS-22 Non-Cogen	Operating	717,167	316,400	0	1	0	0	0
128	1383	Robert A Reid	20546	Western Kentucky Energy Corp	KY	NAICS-22 Non-Cogen	Operating	124,993	19,258	0	1	0	0	0
129	1384	Cooper	5580	East Kentucky Power Coop, Inc	KY	Electric Utility	Operating	834,499	94,300	0	1	0	0	0
130	1385	Dale	5580	East Kentucky Power Coop, Inc	KY	Electric Utility	Operating	485,930	60,100	0	1	0	0	0
131	1393	R S Nelson	55936	Entergy Gulf States Louisiana LLC	LA	Electric Utility	Operating	2,362,399	339,600	0	0	0	1	0
132	1552	C P Crane	4161	Constellation Power Source Gen	MD	NAICS-22 Non-Cogen	Operating	803,821	146,000	0	1	0	0	0
133	1554	Herbert A Wagner	4161	Constellation Power Source Gen	MD	NAICS-22 Non-Cogen	Operating	1,208,996	253,000	0	1	0	0	0
134	1570	R Paul Smith Power Station	23279	Allegheny Energy Supply Co LLC	MD	NAICS-22 Non-Cogen	Operating	322,795	25,100	0	1	0	0	0
135	1571	Chalk Point LLC	12628	Mirant Chalk Point LLC	MD	NAICS-22 Non-Cogen	Operating	1,607,162	184,000	0	1	0	0	0
136	1572	Dickerson	12653	Mirant Mid-Atlantic LLC	MD	NAICS-22 Non-Cogen	Operating	1,182,019	238,000	0	1	0	0	0
137	1573	Morgantown Generating Plant	12653	Mirant Mid-Atlantic LLC	MD	NAICS-22 Non-Cogen	Operating	2,550,944	199,400	0	1	0	0	1
138	1606	Mount Tom	54895	FirstLight Power Resources Services LLC	MA	NAICS-22 Non-Cogen	Operating	502,734	36,700	0	1	0	0	0
139	1613	Somerset Station	29878	Somerset Power LLC	MA	NAICS-22 Non-Cogen	Operating	341,675	30,050	0	1	0	0	0
140	1619	Brayton Point	50018	Dominion Energy New England, LLC	MA	NAICS-22 Non-Cogen	Operating	3,408,933	226,000	0	1	0	0	0
141	1626	Salem Harbor	50018	Dominion Energy New England, LLC	MA	NAICS-22 Non-Cogen	Operating	866,925	70,400	0	1	0	0	0
142	1695	B C Cobb	4254	Consumers Energy Co	MI	Electric Utility	Operating	1,146,793	101,300	0	1	0	1	0
143	1702	Dan E Karn	4254	Consumers Energy Co	MI	Electric Utility	Operating	1,823,068	134,700	0	1	0	1	0
144	1710	J H Campbell	4254	Consumers Energy Co	MI	Electric Utility	Operating	4,239,590	305,300	0	1	0	1	0
145	1720	J C Weadock	4254	Consumers Energy Co	MI	Electric Utility	Operating	917,585	77,700	0	1	0	1	0
146	1723	J R Whiting	4254	Consumers Energy Co	MI	Electric Utility	Operating	1,388,231	81,000	0	1	0	1	0
147	1731	Harbor Beach	5109	Detroit Edison Co	MI	Electric Utility	Operating	32,743	13,100	0	1	0	0	0
148	1733	Monroe	5109	Detroit Edison Co	MI	Electric Utility	Operating	9,475,804	603,000	0	1	0	1	0
149	1740	River Rouge	5109	Detroit Edison Co	MI	Electric Utility	Operating	1,742,710	93,702	0	1	0	1	0
150	1743	St Clair	5109	Detroit Edison Co	MI	Electric Utility	Operating	4,216,268	192,900	0	1	0	1	0
151	1745	Trenton Channel	5109	Detroit Edison Co	MI	Electric Utility	Operating	2,021,669	139,000	0	1	0	1	0
152	1769	Presque Isle	20847	Wisconsin Electric Power Co	MI	Electric Utility	Operating	1,973,777	146,600	0	1	0	1	0
153	1771	Escanaba	19578	Upper Peninsula Power Co	MI	Electric Utility	Operating	73,672	10,109	0	1	0	0	0
154	1825	J B Sims	7483	City of Grand Haven	MI	Electric Utility	Operating	221,457	48,470	0	1	0	0	0
155	1830	James De Young	8723	City of Holland	MI	Electric Utility	Operating	162,142	16,586	0	1	0	0	0
156	1831	Eckert Station	56155	Lansing Board of Water and Light	MI	Electric Utility	Operating	1,152,500	39,100	0	0	0	1	0

Appendix C
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157	1832	Erickson Station	56155	Lansing Board of Water and Light	MI	Electric Utility	Operating	627,114	41,500	0	0	0	1	0
158	1843	Shiras	11701	City of Marquette	MI	Electric Utility	Operating	199,902	20,705	0	1	0	1	0
159	1866	Wyandotte	21048	Wyandotte Municipal Serv Comm	MI	Electric Utility	Operating	178,493	18,593	0	1	0	0	0
160	1891	Syl Laskin	12647	Minnesota Power Inc	MN	Electric Utility	Operating	400,515	26,200	0	0	0	1	0
161	1893	Clay Boswell	12647	Minnesota Power Inc	MN	Electric Utility	Operating	4,070,103	281,200	0	0	0	1	0
162	1897	M L Hibbard	12647	Minnesota Power Inc	MN	Electric Utility	Operating	39,374	2,548	0	0	0	1	0
163	1904	Black Dog	13781	Northern States Power Co	MN	Electric Utility	Operating	934,016	45,000	0	0	0	1	0
164	1915	Allen S King	13781	Northern States Power Co	MN	Electric Utility	Operating	459,422	76,000	0	0	0	1	0
165	1927	Riverside	13781	Northern States Power Co	MN	Electric Utility	Operating	1,236,494	60,400	0	0	0	1	0
166	1943	Hoot Lake	14232	Otter Tail Power Co	MN	Electric Utility	Operating	590,079	21,700	0	0	0	1	0
167	1961	Austin Northeast	1009	Austin City of	MN	Electric Utility	Operating	39,475	4,967	0	1	0	0	0
168	1979	Hibbing	8543	Hibbing Public Utilities Comm	MN	Electric Utility	Operating	144,532	5,623	1	1	0	1	0
169	2001	New Ulm	13488	New Ulm Public Utilities Comm	MN	Electric Utility	Operating	0	7,134	0	1	0	0	0
170	2008	Silver Lake	16181	Rochester Public Utilities	MN	Electric Utility	Operating	187,502	11,900	0	1	0	0	0
171	2018	Virginia	19883	City of Virginia	MN	Electric Utility	Operating	105,970	4,608	0	0	0	1	0
172	2022	Willmar	20737	Willmar Municipal Utils Comm	MN	Electric Utility	Operating	45,733	4,174	0	0	0	1	0
173	2049	Jack Watson	12686	Mississippi Power Co	MS	Electric Utility	Operating	2,146,430	119,200	0	1	0	0	0
174	2062	Henderson	7651	Greenwood Utilities Comm	MS	Electric Utility	Operating	5,833	1,700	0	1	0	0	0
175	2076	Asbury	5860	Empire District Electric Co	MO	Electric Utility	Operating	606,935	78,200	0	1	0	1	0
176	2079	Hawthorn	10000	Kansas City Power & Light Co	MO	Electric Utility	Operating	2,255,247	299,200	0	0	0	1	0
177	2080	Montrose	10000	Kansas City Power & Light Co	MO	Electric Utility	Operating	1,927,580	117,600	0	0	0	1	0
178	2094	Sibley	770	Aquila, Inc.	MO	Electric Utility	Operating	1,726,863	101,200	0	0	0	1	0
179	2098	Lake Road	770	Aquila, Inc.	MO	Electric Utility	Operating	427,418	29,600	0	0	0	1	0
180	2103	Labadie	19436	Union Electric Co	MO	Electric Utility	Operating	10,830,134	559,000	0	0	0	1	0
181	2104	Meramec	19436	Union Electric Co	MO	Electric Utility	Operating	3,646,717	184,000	0	0	0	1	0
182	2107	Sioux	19436	Union Electric Co	MO	Electric Utility	Operating	3,497,864	188,000	0	1	0	1	0
183	2123	Columbia	4045	City of Columbia	MO	Electric Utility	Operating	54,526	3,223	0	1	0	0	0
184	2132	Blue Valley	9231	Independence City of	MO	Electric Utility	Operating	200,155	29,750	0	1	0	0	0
185	2144	Marshall	11732	City of Marshall	MO	Electric Utility	Operating	58,149	2,492	0	1	0	0	0
186	2161	James River Power Station	17833	City Utilities of Springfield	MO	Electric Utility	Operating	1,011,150	50,900	0	0	0	1	0
187	2167	New Madrid	924	Associated Electric Coop, Inc	MO	Electric Utility	Operating	4,437,688	192,400	0	0	0	1	0
188	2168	Thomas Hill	924	Associated Electric Coop, Inc	MO	Electric Utility	Operating	4,200,981	198,800	0	0	0	1	0
189	2169	Chamois	3242	Central Electric Power Coop	MO	Electric Utility	Operating	358,590	16,626	0	1	0	1	0
190	2171	Missouri City	9231	Independence City of	MO	Electric Utility	Operating	76,875	7,251	0	1	0	0	0
191	2187	J E Corette Plant	15298	PPL Montana LLC	MT	NAICS-22 Non-Cogen	Operating	758,317	31,700	0	0	0	1	0
192	2240	Lon Wright	6779	Fremont City of	NE	Electric Utility	Operating	380,187	16,800	0	0	0	1	0
193	2277	Sheldon	13337	Nebraska Public Power District	NE	Electric Utility	Operating	1,014,414	59,000	0	0	0	1	0
194	2291	North Omaha	14127	Omaha Public Power District	NE	Electric Utility	Operating	2,130,891	115,900	0	0	0	1	0
195	2324	Reid Gardner	13407	Nevada Power Co	NV	Electric Utility	Operating	1,767,166	141,700	0	1	0	0	0
196	2364	Merrimack	15472	Public Service Co of NH	NH	Electric Utility	Operating	1,286,065	87,600	0	1	0	0	0
197	2367	Schiller	15472	Public Service Co of NH	NH	Electric Utility	Operating	339,168	89,300	0	1	0	0	0
198	2378	B L England	55768	RC Cape May Holdings LLC	NJ	NAICS-22 Non-Cogen	Operating	646,543	84,100	0	1	0	1	0
199	2384	Deepwater	4158	Conectiv Atlantic Generatn Inc	NJ	NAICS-22 Non-Cogen	Operating	210,883	6,800	0	1	0	0	0
200	2403	PSEG Hudson Generating Station	15147	PSEG Fossil LLC	NJ	NAICS-22 Non-Cogen	Operating	1,174,580	165,100	0	1	0	0	0
201	2408	PSEG Mercer Generating	15147	PSEG Fossil LLC	NJ	NAICS-22 Non-	Operating	1,141,458	102,300	0	1	0	0	0

Appendix C
List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

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		Station				Cogen								
202	2434	Howard Down	19856	Vineland City of	NJ	Electric Utility	Operating	28,634	2,914	0	1	0	0	0
203	2442	Four Corners	803	Arizona Public Service Co	NM	Electric Utility	Operating	8,394,219	2,167,400	0	1	0	0	0
204	2451	San Juan	15473	Public Service Co of NM	NM	Electric Utility	Operating	6,450,559	1,501,000	0	0	0	1	0
205	2480	Danskammer Generating Station	5511	Dynegy Northeast Gen Inc	NY	NAICS-22 Non-Cogen	Operating	1,011,241	104,500	0	1	0	0	0
206	2526	AES Westover	22146	AES Westover LLC	NY	NAICS-22 Cogen	Operating	270,504	46,880	0	1	0	0	0
207	2527	AES Greenidge LLC	25	AES Greenidge	NY	NAICS-22 Non-Cogen	Operating	283,366	54,300	0	1	0	0	0
208	2535	AES Cayuga	22125	AES Cayuga LLC	NY	NAICS-22 Non-Cogen	Operating	882,392	357,700	0	1	0	0	0
209	2549	C R Huntley Generating Station	13168	NRG Huntley Operations Inc	NY	NAICS-22 Non-Cogen	Operating	1,495,325	77,900	0	1	0	1	0
210	2554	Dunkirk Generating Plant	13579	Dunkirk Power LLC	NY	NAICS-22 Non-Cogen	Operating	2,084,921	111,200	0	1	0	1	0
211	2629	Lovett	12792	Mirant New York Inc	NY	NAICS-22 Non-Cogen	Operating	519,354	106,800	0	1	0	0	0
212	2642	Rochester 7	16183	Rochester Gas & Electric Corp	NY	Electric Utility	Operating	542,404	34,220	0	1	0	0	0
213	2682	S A Carlson	9645	Jamestown Board of Public Util	NY	Electric Utility	Operating	92,795	9,402	0	1	0	0	0
214	2706	Asheville	3046	Progress Energy Carolinas Inc	NC	Electric Utility	Operating	969,206	292,200	0	1	0	0	0
215	2708	Cape Fear	3046	Progress Energy Carolinas Inc	NC	Electric Utility	Operating	888,514	101,300	0	1	0	0	0
216	2709	Lee	3046	Progress Energy Carolinas Inc	NC	Electric Utility	Operating	980,639	106,100	0	1	0	0	0
217	2712	Roxboro	3046	Progress Energy Carolinas Inc	NC	Electric Utility	Operating	6,394,213	683,300	0	1	0	0	0
218	2713	L V Sutton	3046	Progress Energy Carolinas Inc	NC	Electric Utility	Operating	1,343,713	166,000	0	1	0	0	0
219	2716	W H Weatherspoon	3046	Progress Energy Carolinas Inc	NC	Electric Utility	Operating	467,502	47,000	0	1	0	0	0
220	2718	G G Allen	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	Operating	2,969,930	720,300	0	1	0	0	0
221	2720	Buck	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	Operating	798,875	121,900	0	1	0	0	0
222	2721	Cliffside	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	Operating	1,675,076	329,100	0	1	0	0	0
223	2723	Dan River	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	Operating	476,023	28,500	0	1	0	0	0
224	2727	Marshall	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	Operating	5,578,502	1,207,600	0	1	0	0	0
225	2732	Riverbend	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	Operating	964,597	93,300	0	1	0	0	0
226	2790	R M Heskett	12199	MDU Resources Group Inc	ND	Electric Utility	Operating	582,804	72,300	1	0	0	1	0
227	2817	Leland Olds	1307	Basin Electric Power Coop	ND	Electric Utility	Operating	3,715,752	370,900	1	0	0	0	0
228	2823	Milton R Young	12658	Minnkota Power Coop, Inc	ND	Electric Utility	Operating	3,843,885	400,100	1	0	0	0	0
229	2824	Stanton	7570	Great River Energy	ND	Electric Utility	Operating	820,394	111,600	1	0	0	1	0
230	2828	Cardinal	3006	Cardinal Operating Co	OH	Electric Utility	Operating	4,469,764	918,700	0	1	0	0	0
231	2830	Walter C Beckjord	3542	Duke Energy Ohio Inc	OH	Electric Utility	Operating	2,812,515	383,300	0	1	0	0	0
232	2832	Miami Fort	3542	Duke Energy Ohio Inc	OH	Electric Utility	Operating	2,983,692	367,300	0	1	0	0	0
233	2835	Ashtabula	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	Operating	824,673	35,200	0	1	0	1	0
234	2836	Avon Lake	14165	Orion Power Midwest LP	OH	NAICS-22 Non-Cogen	Operating	1,147,685	159,600	0	1	0	0	0
235	2837	Eastlake	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	Operating	3,942,045	205,700	0	1	0	1	0
236	2838	Lake Shore	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	Operating	752,814	24,900	0	0	0	1	0
237	2840	Conesville	4062	Columbus Southern Power Co	OH	Electric Utility	Operating	4,627,705	1,118,400	0	1	0	0	0
238	2843	Picway	4062	Columbus Southern Power Co	OH	Electric Utility	Operating	184,197	10,600	0	1	0	0	0
239	2848	O H Hutchings	4922	Dayton Power & Light Co	OH	Electric Utility	Operating	308,004	80,000	0	1	0	0	0
240	2850	J M Stuart	4922	Dayton Power & Light Co	OH	Electric Utility	Operating	6,384,537	818,100	0	1	0	0	0

Appendix C
List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

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241	2861	Niles	14165	Orion Power Midwest LP	OH	NAICS-22 Non-Cogen	Operating	550,139	206,000	0	1	0	0	0
242	2864	R E Burger	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	Operating	832,191	68,700	0	1	0	1	0
243	2866	W H Sammis	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	Operating	7,446,219	638,900	0	1	0	1	0
244	2872	Muskingum River	14006	Ohio Power Co	OH	Electric Utility	Operating	3,249,850	930,600	0	1	0	0	0
245	2876	Kyger Creek	14015	Ohio Valley Electric Corp	OH	Electric Utility	Operating	3,373,943	280,400	0	1	0	1	0
246	2878	Bay Shore	6526	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	Operating	1,792,303	209,400	0	1	0	1	0
247	2914	Dover	5336	City of Dover	OH	Electric Utility	Operating	31,653	2,868	0	1	0	0	0
248	2917	Hamilton	7977	City of Hamilton	OH	Electric Utility	Operating	190,784	31,600	0	1	0	0	0
249	2935	Orrville	14194	City of Orrville	OH	Electric Utility	Operating	209,232	20,027	0	1	0	0	0
250	2936	Painesville	14381	City of Painesville	OH	Electric Utility	Operating	120,646	9,498	0	1	0	0	0
251	2943	Shelby Municipal Light Plant	17043	City of Shelby	OH	Electric Utility	Operating	46,210	4,353	0	1	0	0	0
252	2952	Muskogee	14063	Oklahoma Gas & Electric Co	OK	Electric Utility	Operating	4,998,367	306,200	0	0	0	1	0
253	2963	Northeastern	15474	Public Service Co of Oklahoma	OK	Electric Utility	Operating	3,803,888	181,300	0	0	0	1	0
254	3098	Elrama Power Plant	14165	Orion Power Midwest LP	PA	NAICS-22 Non-Cogen	Operating	913,549	156,200	0	1	0	0	1
255	3113	Portland	17235	Reliant Energy Mid-Atlantic PH LLC	PA	NAICS-22 Non-Cogen	Operating	885,814	61,700	0	1	0	0	0
256	3115	Titus	17235	Reliant Energy Mid-Atlantic PH LLC	PA	NAICS-22 Non-Cogen	Operating	587,743	64,600	0	1	0	0	0
257	3118	Conemaugh	15873	Reliant Engy NE Management Co	PA	NAICS-22 Non-Cogen	Operating	4,835,814	1,935,200	0	1	0	0	1
258	3122	Homer City Station	12384	Midwest Generations EME LLC	PA	NAICS-22 Non-Cogen	Operating	5,371,440	1,048,200	0	1	0	0	0
259	3130	Seward	15998	Reliant Energy Seward LLC	PA	NAICS-22 Non-Cogen	Operating	3,251,474	4,098,000	0	1	1	0	0
260	3131	Shawville	17235	Reliant Energy Mid-Atlantic PH LLC	PA	NAICS-22 Non-Cogen	Operating	1,477,938	200,800	0	1	0	0	0
261	3136	Keystone	15873	Reliant Engy NE Management Co	PA	NAICS-22 Non-Cogen	Operating	4,635,016	562,900	0	1	0	0	1
262	3138	New Castle Plant	14165	Orion Power Midwest LP	PA	NAICS-22 Non-Cogen	Operating	678,628	74,700	0	1	0	0	0
263	3140	PPL Brunner Island	15537	PPL Brunner Island LLC	PA	NAICS-22 Non-Cogen	Operating	3,962,145	388,800	0	1	0	0	1
264	3149	PPL Montour	15534	PPL Montour LLC	PA	NAICS-22 Non-Cogen	Operating	3,669,765	436,700	0	1	0	0	1
265	3152	Sunbury Generation LP	22001	Sunbury Generation LP	PA	NAICS-22 Non-Cogen	Operating	1,153,234	273,800	0	1	1	0	1
266	3159	Cromby Generating Station	6035	Exelon Power	PA	NAICS-22 Non-Cogen	Operating	298,770	29,900	0	1	0	0	0
267	3161	Eddystone Generating Station	6035	Exelon Power	PA	NAICS-22 Non-Cogen	Operating	1,073,133	113,000	0	1	0	0	0
268	3176	Hunlock Power Station	19391	UGI Development Co	PA	NAICS-22 Non-Cogen	Operating	194,916	48,972	0	1	1	0	0
269	3178	Armstrong Power Station	23279	Allegheny Energy Supply Co LLC	PA	NAICS-22 Non-Cogen	Operating	870,575	117,600	0	1	0	0	0

Appendix C
List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

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270	3179	Hatfields Ferry Power Station	23279	Allegheny Energy Supply Co LLC	PA	NAICS-22 Non-Cogen	Operating	4,347,068	250,500	0	1	0	1	0
271	3181	Mitchell Power Station	23279	Allegheny Energy Supply Co LLC	PA	NAICS-22 Non-Cogen	Operating	386,274	255,700	0	1	0	0	0
272	3251	H B Robinson	3046	Progress Energy Carolinas Inc	SC	Electric Utility	Operating	494,013	62,200	0	1	0	0	0
273	3264	W S Lee	5416	Duke Energy Carolinas, LLC	SC	Electric Utility	Operating	662,006	63,500	0	1	0	0	0
274	3280	Canadys Steam	17539	South Carolina Electric&Gas Co	SC	Electric Utility	Operating	950,062	101,100	0	1	0	0	0
275	3287	McMeekin	17539	South Carolina Electric&Gas Co	SC	Electric Utility	Operating	599,159	78,400	0	1	0	0	1
276	3295	Urquhart	17539	South Carolina Electric&Gas Co	SC	Electric Utility	Operating	285,011	20,200	0	1	0	0	1
277	3297	Wateree	17539	South Carolina Electric&Gas Co	SC	Electric Utility	Operating	1,677,458	235,700	0	1	0	0	0
278	3298	Williams	17554	South Carolina Genertg Co, Inc	SC	Electric Utility	Operating	1,458,688	169,800	0	1	0	0	0
279	3317	Dolphus M Grainger	17543	South Carolina Pub Serv Auth	SC	Electric Utility	Operating	370,183	60,800	0	1	0	0	0
280	3319	Jefferies	17543	South Carolina Pub Serv Auth	SC	Electric Utility	Operating	745,729	84,400	0	1	0	0	0
281	3325	Ben French	19545	Black Hills Power Inc	SD	Electric Utility	Operating	123,456	6,453	0	0	0	1	0
282	3393	Allen Steam Plant	18642	Tennessee Valley Authority	TN	Electric Utility	Operating	2,941,594	166,400	0	1	0	1	0
283	3396	Bull Run	18642	Tennessee Valley Authority	TN	Electric Utility	Operating	2,402,700	271,800	0	1	0	0	0
284	3399	Cumberland	18642	Tennessee Valley Authority	TN	Electric Utility	Operating	7,073,872	3,215,520	0	1	0	0	0
285	3403	Gallatin	18642	Tennessee Valley Authority	TN	Electric Utility	Operating	4,177,513	225,700	0	1	0	1	0
286	3405	John Sevier	18642	Tennessee Valley Authority	TN	Electric Utility	Operating	1,968,382	245,000	0	1	0	0	0
287	3406	Johnsonville	18642	Tennessee Valley Authority	TN	Electric Utility	Operating	3,911,197	277,700	0	1	0	1	0
288	3407	Kingston	18642	Tennessee Valley Authority	TN	Electric Utility	Operating	4,873,161	408,000	0	1	0	1	0
289	3470	W A Parish	54888	NRG Texas LLC	TX	NAICS-22 Non-Cogen	Operating	12,265,219	689,000	0	0	0	1	0
290	3497	Big Brown	19323	TXU Generation Co LP	TX	NAICS-22 Non-Cogen	Operating	6,199,050	655,900	1	0	0	1	0
291	3644	Carbon	14354	PacifiCorp	UT	Electric Utility	Operating	625,970	70,000	0	1	0	0	0
292	3775	Clinch River	733	Appalachian Power Co	VA	Electric Utility	Operating	1,594,867	233,300	0	1	0	0	0
293	3776	Glen Lyn	733	Appalachian Power Co	VA	Electric Utility	Operating	658,171	90,300	0	1	0	0	0
294	3788	Potomac River	12588	Mirant Potomac River LLC	VA	NAICS-22 Non-Cogen	Operating	634,665	92,700	0	1	0	0	0
295	3796	Bremo Bluff	19876	Virginia Electric & Power Co	VA	Electric Utility	Operating	657,974	85,000	0	0	0	0	1
296	3797	Chesterfield	19876	Virginia Electric & Power Co	VA	Electric Utility	Operating	3,346,728	348,400	0	0	0	0	1
297	3803	Chesapeake	19876	Virginia Electric & Power Co	VA	Electric Utility	Operating	1,679,916	290,000	0	1	0	0	0
298	3809	Yorktown	19876	Virginia Electric & Power Co	VA	Electric Utility	Operating	799,604	101,900	0	1	0	0	0
299	3845	Transalta Centralia Generation	19099	TransAlta Centralia Gen LLC	WA	NAICS-22 Non-Cogen	Operating	5,681,470	1,405,220	0	0	0	1	0
300	3935	John E Amos	733	Appalachian Power Co	WV	Electric Utility	Operating	7,426,995	2,186,500	0	1	0	0	0
301	3936	Kanawha River	733	Appalachian Power Co	WV	Electric Utility	Operating	884,675	115,800	0	1	0	0	0
302	3938	Philip Sporn	733	Appalachian Power Co	WV	Electric Utility	Operating	2,538,756	256,100	0	1	0	0	0
303	3942	Albright	12796	Monongahela Power Co	WV	Electric Utility	Operating	656,054	84,300	0	1	0	0	0
304	3943	Fort Martin Power Station	12796	Monongahela Power Co	WV	Electric Utility	Operating	2,979,262	254,100	0	1	0	1	0
305	3944	Harrison Power Station	23279	Allegheny Energy Supply Co LLC	WV	NAICS-22 Non-Cogen	Operating	5,603,913	1,453,200	0	1	0	0	0
306	3945	Rivesville	12796	Monongahela Power Co	WV	Electric Utility	Operating	127,988	19,900	0	1	0	0	0
307	3946	Willow Island	12796	Monongahela Power Co	WV	Electric Utility	Operating	419,137	23,700	0	1	0	0	0
308	3947	Kammer	14006	Ohio Power Co	WV	Electric Utility	Operating	1,680,947	124,000	0	1	0	0	0
309	3948	Mitchell	14006	Ohio Power Co	WV	Electric Utility	Operating	3,284,999	993,200	0	1	0	0	0
310	3954	Mt Storm	19876	Virginia Electric & Power Co	WV	Electric Utility	Operating	4,176,917	1,145,000	0	0	0	0	1
311	3982	Bay Front	13781	Northern States Power Co	WI	Electric Utility	Operating	143,456	8,680	0	1	0	1	0

Appendix C
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312	3992	Blount Street	11479	Madison Gas & Electric Co	WI	Electric Utility	Operating	106,045	21,600	0	1	0	0	0
313	4041	South Oak Creek	20847	Wisconsin Electric Power Co	WI	Electric Utility	Operating	3,237,936	138,900	0	0	0	1	0
314	4042	Valley	20847	Wisconsin Electric Power Co	WI	Electric Utility	Operating	791,588	96,600	0	1	0	0	0
315	4050	Edgewater	20856	Wisconsin Power & Light Co	WI	Electric Utility	Operating	2,807,746	105,000	0	1	0	1	0
316	4054	Nelson Dewey	20856	Wisconsin Power & Light Co	WI	Electric Utility	Operating	558,804	24,500	0	0	0	1	0
317	4072	Pulliam	20860	Wisconsin Public Service Corp	WI	Electric Utility	Operating	1,601,049	94,400	0	0	0	1	0
318	4078	Weston	20860	Wisconsin Public Service Corp	WI	Electric Utility	Operating	1,670,203	115,200	0	0	0	1	0
319	4125	Manitowoc	11571	Manitowoc Public Utilities	WI	Electric Utility	Operating	77,438	12,535	0	1	0	1	0
320	4127	Menasha	12298	City of Menasha	WI	Electric Utility	Operating	110,225	10,086	0	0	0	1	0
321	4140	Alma	4716	Dairyland Power Coop	WI	Electric Utility	Operating	551,759	58,800	0	1	0	1	0
322	4143	Genoa	4716	Dairyland Power Coop	WI	Electric Utility	Operating	1,069,027	83,000	0	1	0	1	0
323	4146	E J Stoneman Station	12435	Mid-America Power LLC	WI	NAICS-22 Non-Cogen	Operating	34,871	2,929	0	1	0	0	0
324	4150	Neil Simpson	19545	Black Hills Power Inc	WY	Electric Utility	Operating	132,950	6,766	0	0	0	1	0
325	4151	Osage	19545	Black Hills Power Inc	WY	Electric Utility	Operating	239,485	14,337	0	0	0	1	0
326	4158	Dave Johnston	14354	PacifiCorp	WY	Electric Utility	Operating	4,038,294	219,000	0	0	0	1	0
327	4162	Naughton	14354	PacifiCorp	WY	Electric Utility	Operating	2,834,252	183,000	0	0	0	1	0
328	4259	Endicott Station	12807	Michigan South Central Pwr Agy	MI	Electric Utility	Operating	213,651	38,739	0	1	0	0	0
329	4271	John P Madgett	4716	Dairyland Power Coop	WI	Electric Utility	Operating	1,467,350	85,000	0	0	0	1	0
330	4941	Navajo	16572	Salt River Project	AZ	Electric Utility	Operating	8,215,498	876,250	0	1	0	0	0
331	6002	James H Miller Jr	195	Alabama Power Co	AL	Electric Utility	Operating	12,626,833	297,300	0	0	1	1	0
332	6004	Pleasants Power Station	23279	Allegheny Energy Supply Co LLC	WV	NAICS-22 Non-Cogen	Operating	3,197,373	1,231,700	0	1	0	0	0
333	6009	White Bluff	814	Entergy Arkansas Inc	AR	Electric Utility	Operating	6,220,696	310,900	0	0	0	1	0
334	6016	Duck Creek	49756	Ameren Energy Resources Generating Co.	IL	Electric Utility	Operating	248,459	185,000	0	1	0	0	0
335	6017	Newton	520	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	Operating	5,104,903	231,000	0	1	0	1	0
336	6018	East Bend	55729	Duke Energy Kentucky Inc	KY	Electric Utility	Operating	1,684,411	463,700	0	1	0	0	0
337	6019	W H Zimmer	3542	Duke Energy Ohio Inc	OH	Electric Utility	Operating	3,291,199	2,589,000	0	1	0	0	0
338	6021	Craig	30151	Tri-State G & T Assn, Inc	CO	Electric Utility	Standby	5,087,884	417,700	0	0	0	1	0
339	6030	Coal Creek	7570	Great River Energy	ND	Electric Utility	Operating	7,720,720	1,109,400	1	0	0	0	0
340	6031	Killen Station	4922	Dayton Power & Light Co	OH	Electric Utility	Operating	1,747,138	252,600	0	1	0	0	0
341	6034	Belle River	5109	Detroit Edison Co	MI	Electric Utility	Operating	4,433,409	200,000	0	0	0	1	0
342	6041	H L Spurlock	5580	East Kentucky Power Coop, Inc	KY	Electric Utility	Operating	3,497,117	582,900	0	1	1	0	1
343	6052	Wansley	7140	Georgia Power Co	GA	Electric Utility	Operating	4,879,523	1,544,100	0	1	0	0	0
344	6055	Big Cajun 2	11252	Louisiana Generating LLC	LA	NAICS-22 Non-Cogen	Operating	7,764,847	403,600	0	0	0	1	0
345	6061	R D Morrow	17568	South Mississippi El Pwr Assn	MS	Electric Utility	Operating	1,141,229	164,000	0	1	0	0	0
346	6064	Nearman Creek	9996	Kansas City City of	KS	Electric Utility	Operating	1,113,011	51,100	0	0	0	1	0
347	6065	Iatan	10000	Kansas City Power & Light Co	MO	Electric Utility	Operating	2,485,676	134,500	0	0	0	1	0
348	6068	Jeffrey Energy Center	22500	Westar Energy Inc	KS	Electric Utility	Operating	9,724,866	579,200	0	0	0	1	0
349	6071	Trimble County	11249	Louisville Gas & Electric Co	KY	Electric Utility	Operating	1,553,096	677,400	0	1	1	0	1
350	6073	Victor J Daniel Jr	12686	Mississippi Power Co	MS	Electric Utility	Operating	3,214,779	272,200	0	1	0	1	0
351	6076	Colstrip	15298	PPL Montana LLC	MT	NAICS-22 Non-Cogen	Operating	10,057,544	1,637,200	0	0	0	1	0
352	6077	Gerald Gentleman	13337	Nebraska Public Power District	NE	Electric Utility	Operating	5,443,750	242,500	0	0	0	1	0
353	6082	AES Somerset LLC	22129	AES Somerset LLC	NY	NAICS-22 Non-Cogen	Operating	2,013,663	509,870	0	1	0	0	0

Appendix C
List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

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354	6085	R M Schahfer	13756	Northern Indiana Pub Serv Co	IN	Electric Utility	Operating	5,600,628	980,400	0	1	0	1	0
355	6089	Lewis & Clark	12199	MDU Resources Group Inc	MT	Electric Utility	Operating	302,041	23,725	1	0	0	0	0
356	6090	Sherburne County	13781	Northern States Power Co	MN	Electric Utility	Operating	9,460,044	939,500	0	0	0	1	0
357	6094	Bruce Mansfield	6526	FirstEnergy Generation Corp	PA	NAICS-22 Non-Cogen	Operating	7,047,876	1,582,400	0	1	0	0	0
358	6095	Sooner	14063	Oklahoma Gas & Electric Co	OK	Electric Utility	Operating	3,780,090	213,300	0	0	0	1	0
359	6096	Nebraska City	14127	Omaha Public Power District	NE	Electric Utility	Operating	2,561,682	139,400	0	0	0	1	0
360	6098	Big Stone	14232	Otter Tail Power Co	SD	Electric Utility	Operating	1,567,196	97,300	0	0	0	1	0
361	6101	Wyodak	14354	PacifiCorp	WY	Electric Utility	Operating	2,068,844	221,000	0	0	0	1	0
362	6106	Boardman	15248	Portland General Electric Co	OR	Electric Utility	Operating	2,577,187	99,900	0	0	0	1	0
363	6113	Gibson	15470	Duke Energy Indiana Inc	IN	Electric Utility	Operating	10,443,126	1,862,800	0	1	0	0	0
364	6124	McIntosh	7140	Georgia Power Co	GA	Electric Utility	Operating	339,614	28,100	0	1	0	0	0
365	6136	Gibbons Creek	18715	Texas Municipal Power Agency	TX	Electric Utility	Operating	2,044,184	104,500	0	0	0	1	0
366	6137	A B Brown	17633	Southern Indiana Gas & Elec Co	IN	Electric Utility	Operating	1,615,187	379,250	0	1	0	0	0
367	6138	Flint Creek	17698	Southwestern Electric Power Co	AR	Electric Utility	Operating	2,251,569	103,300	0	0	0	1	0
368	6139	Welsh	17698	Southwestern Electric Power Co	TX	Electric Utility	Operating	6,567,488	217,000	0	0	0	1	0
369	6146	Martin Lake	19323	TXU Generation Co LP	TX	NAICS-22 Non-Cogen	Operating	14,557,392	2,540,700	1	0	0	1	0
370	6147	Monticello	19323	TXU Generation Co LP	TX	NAICS-22 Non-Cogen	Operating	11,783,056	1,455,900	1	0	0	1	0
371	6155	Rush Island	19436	Union Electric Co	MO	Electric Utility	Operating	4,244,900	270,000	0	0	0	1	0
372	6165	Hunter	14354	PacifiCorp	UT	Electric Utility	Operating	4,563,096	653,000	0	1	0	0	0
373	6166	Rockport	9324	Indiana Michigan Power Co	IN	Electric Utility	Operating	8,832,360	620,000	0	1	0	1	0
374	6170	Pleasant Prairie	20847	Wisconsin Electric Power Co	WI	Electric Utility	Operating	5,031,033	325,500	0	0	0	1	0
375	6177	Coronado	16572	Salt River Project	AZ	Electric Utility	Operating	3,372,967	373,500	0	0	0	1	0
376	6178	Coleto Creek	54865	ANP-Coleto Creek	TX	NAICS-22 Non-Cogen	Operating	2,510,370	144,800	0	0	0	1	0
377	6179	Fayette Power Project	11269	Lower Colorado River Authority	TX	Electric Utility	Operating	7,336,844	437,200	1	0	0	1	0
378	6181	J T Deely	16604	San Antonio City of	TX	Electric Utility	Operating	3,332,365	195,300	0	0	0	1	0
379	6183	San Miguel	16624	San Miguel Electric Coop, Inc	TX	Electric Utility	Operating	3,188,788	1,282,100	1	0	0	0	0
380	6190	Rodemacher	3265	Cleco Power LLC	LA	Electric Utility	Operating	2,225,311	101,300	0	0	0	1	0
381	6193	Harrington	17718	Southwestern Public Service Co	TX	Electric Utility	Operating	4,282,626	205,200	0	0	0	1	0
382	6194	Tolk	17718	Southwestern Public Service Co	TX	Electric Utility	Operating	4,079,439	211,300	0	0	0	1	0
383	6195	Southwest Power Station	17833	City Utilities of Springfield	MO	Electric Utility	Operating	831,978	110,000	0	1	0	1	0
384	6204	Laramie River Station	1307	Basin Electric Power Coop	WY	Electric Utility	Operating	7,694,224	493,300	0	0	0	1	0
385	6213	Merom	9267	Hoosier Energy R E C, Inc	IN	Electric Utility	Operating	3,171,112	939,300	0	1	0	0	0
386	6225	Jasper 2	9667	City of Jasper	IN	Electric Utility	Operating	36,088	1,245	0	1	0	0	0
387	6238	Pearl Station	40307	Soyland Power Coop Inc	IL	Electric Utility	Operating	104,319	9,160	0	1	0	0	0
388	6248	Pawnee	15466	Public Service Co of Colorado	CO	Electric Utility	Operating	2,351,370	86,640	0	0	0	1	0
389	6249	Winyah	17543	South Carolina Pub Serv Auth	SC	Electric Utility	Operating	3,252,487	400,390	0	1	0	0	0
390	6250	Mayo	3046	Progress Energy Carolinas Inc	NC	Electric Utility	Operating	1,968,566	230,400	0	1	0	0	0
391	6254	Ottumwa	9417	Interstate Power and Light Co	IA	Electric Utility	Operating	2,518,349	117,000	0	0	0	1	0
392	6257	Scherer	7140	Georgia Power Co	GA	Electric Utility	Operating	15,161,381	740,700	0	0	0	1	0
393	6264	Mountaineer	733	Appalachian Power Co	WV	Electric Utility	Operating	3,736,032	1,281,000	0	1	0	0	0
394	6288	Healy	7353	Golden Valley Elec Assn Inc	AK	Electric Utility	Operating	193,615	28,818	0	0	1	1	0
395	6469	Antelope Valley	1307	Basin Electric Power Coop	ND	Electric Utility	Operating	5,496,053	670,200	1	0	0	0	0
396	6481	Intermountain Power Project	11208	Los Angeles City of	UT	Electric Utility	Operating	5,898,096	801,200	0	1	0	0	0
397	6639	R D Green	20546	Western Kentucky Energy Corp	KY	NAICS-22 Non-	Operating	1,138,336	513,000	0	1	0	0	0

Appendix C
List of 495 Operating Electric Utility Plants Potentially Affected by the CCR Rulemaking (2007)

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						Cogen								
398	6641	Independence	814	Entergy Arkansas Inc	AR	Electric Utility	Operating	7,156,970	330,067	0	0	0	1	0
399	6648	Sandow No 4	19323	TXU Generation Co LP	TX	NAICS-22 Non-Cogen	Operating	4,041,152	907,800	1	0	0	0	0
400	6664	Louisa	12341	MidAmerican Energy Co	IA	Electric Utility	Operating	2,289,229	115,100	0	0	0	1	0
401	6705	Warrick	261	AGC Division of APG Inc	IN	NAICS-22 Cogen	Operating	2,257,115	241,900	0	1	0	0	0
402	6761	Rawhide	15143	Platte River Power Authority	CO	Electric Utility	Operating	1,296,251	83,700	0	0	0	1	0
403	6768	Sikeston Power Station	17177	City of Sikeston	MO	Electric Utility	Operating	1,215,030	107,000	0	0	0	1	0
404	6772	Hugo	20447	Western Farmers Elec Coop, Inc	OK	Electric Utility	Operating	1,932,960	87,300	0	0	0	1	0
405	6823	D B Wilson	20546	Western Kentucky Energy Corp	KY	NAICS-22 Non-Cogen	Operating	901,140	644,400	0	1	0	0	0
406	7030	Twin Oaks Power One	54891	Altura Power	TX	NAICS-22 Non-Cogen	Operating	2,023,276	456,000	1	0	0	1	0
407	7097	J K Spruce	16604	San Antonio City of	TX	Electric Utility	Operating	2,396,353	208,600	0	0	0	1	0
408	7210	Cope	17539	South Carolina Electric&Gas Co	SC	Electric Utility	Operating	1,233,185	215,200	0	1	0	0	1
409	7213	Clover	19876	Virginia Electric & Power Co	VA	Electric Utility	Operating	2,629,609	485,200	0	0	0	0	1
410	7242	Polk	18454	Tampa Electric Co	FL	Electric Utility	Operating	661,705	60,546	0	1	0	0	0
411	7286	Richard Gorsuch	40577	American Mun Power-Ohio, Inc	OH	Electric Utility	Operating	767,733	136,800	0	1	0	0	0
412	7343	George Neal South	12341	MidAmerican Energy Co	IA	Electric Utility	Operating	2,769,875	122,400	0	0	0	1	0
413	7504	Neil Simpson II	19545	Black Hills Power Inc	WY	Electric Utility	Operating	510,207	47,514	0	0	0	1	0
414	7537	North Branch	19876	Virginia Electric & Power Co	WV	Electric Utility	Operating	358,092	112,199	0	0	1	0	0
415	7549	Milwaukee County	20847	Wisconsin Electric Power Co	WI	Electric Utility	Operating	65,434	5,804	0	1	0	0	0
416	7652	US DOE Savannah River Site (D Area)	56190	Savannah River Nuclear Solutions LLC	SC	Electric Utility	Operating	0	20,966	0	1	0	0	0
417	7737	Cogen South	17539	South Carolina Electric&Gas Co	SC	Electric Utility	Operating	89,575	97,604	0	1	0	0	0
418	7790	Bonanza	40230	Deseret Generation & Tran Coop	UT	Electric Utility	Operating	1,860,133	330,200	0	1	0	0	0
419	7902	Pirkey	17698	Southwestern Electric Power Co	TX	Electric Utility	Operating	4,010,607	1,499,400	1	0	0	1	0
420	8023	Columbia	20856	Wisconsin Power & Light Co	WI	Electric Utility	Operating	4,455,807	224,000	0	0	0	1	0
421	8042	Belews Creek	5416	Duke Energy Carolinas, LLC	NC	Electric Utility	Operating	5,559,119	1,290,600	0	1	0	0	0
422	8066	Jim Bridger	14354	PacifiCorp	WY	Electric Utility	Operating	8,543,832	990,000	0	0	0	1	0
423	8069	Huntington	14354	PacifiCorp	UT	Electric Utility	Operating	3,227,226	478,000	0	1	0	0	0
424	8102	General James M Gavin	14006	Ohio Power Co	OH	Electric Utility	Operating	7,348,095	2,464,900	0	1	0	0	0
425	8219	Ray D Nixon	3989	Colorado Springs City of	CO	Electric Utility	Operating	887,504	42,000	0	0	0	1	0
426	8222	Coyote	14232	Otter Tail Power Co	ND	Electric Utility	Operating	2,459,083	303,600	1	0	0	0	0
427	8223	Springerville	24211	Tucson Electric Power Co	AZ	Electric Utility	Operating	3,300,070	1,121,980	0	0	0	1	0
428	8224	North Valmy	17166	Sierra Pacific Power Co	NV	Electric Utility	Operating	1,679,604	249,800	0	1	0	0	0
429	8226	Cheswick Power Plant	14165	Orion Power Midwest LP	PA	NAICS-22 Non-Cogen	Operating	1,189,012	119,700	0	1	0	1	1
430	10002	ACE Cogeneration Facility	52	ACE Cogeneration Co	CA	NAICS-22 Cogen	Operating	390,365	50,400	0	1	0	0	0
431	10003	Colorado Energy Nations Company	19173	Colorado Energy Nations Company LLLP	CO	NAICS-22 Cogen	Operating	296,951	26,094	0	1	0	0	0
432	10030	NRG Energy Center Dover	7860	NRG Energy Center Dover LLC	DE	NAICS-22 Cogen	Operating	65,082	4,605	0	1	0	0	0
433	10043	Logan Generating Company LP	14932	US Operating Services Company	NJ	NAICS-22 Cogen	Operating	602,691	212,000	0	1	0	0	0
434	10071	Cogentrix Virginia Leasing Corporation	3901	Cogentrix-Virginia Leas'g Corp	VA	NAICS-22 Cogen	Operating	354,100	42,000	0	1	0	0	0
435	10075	Taconite Harbor Energy Center	12647	Minnesota Power Inc	MN	Electric Utility	Operating	942,778	32,800	0	1	0	1	0
436	10113	John B Rich Memorial Power Station	7199	Gilberton Power Co	PA	NAICS-22 Cogen	Operating	703,149	272,846	0	0	1	0	0

Appendix C
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437	10143	Colver Power Project	9379	Inter-Power/AhlCon Partners, L.P.	PA	NAICS-22 Non-Cogen	Operating	688,717	421,600	0	0	1	0	0
438	10148	White Pine Electric Power	1951	White Pine Electric Power LLC	MI	NAICS-22 Non-Cogen	Operating	106,995	6,675	0	1	0	0	0
439	10151	Grant Town Power Plant	563	American Bituminous Power LP	WV	NAICS-22 Non-Cogen	Operating	604,050	225,969	0	1	1	0	0
440	10333	Central Power & Lime	3303	Central Power & Lime Inc	FL	NAICS-22 Cogen	Operating	354,744	41,900	0	1	0	0	0
441	10343	Foster Wheeler Mt Carmel Cogen	49889	Mount Carmel Cogen Inc	PA	NAICS-22 Cogen	Operating	531,597	329,721	0	0	1	0	0
442	10377	James River Cogeneration	9628	James River Cogeneration Co	VA	NAICS-22 Cogen	Operating	388,324	46,000	0	1	0	0	0
443	10378	Primary Energy Southport	54708	Primary Energy of North Carolina LLC	NC	NAICS-22 Cogen	Operating	213,692	23,000	0	1	0	0	0
444	10379	Primary Energy Roxboro	54708	Primary Energy of North Carolina LLC	NC	NAICS-22 Cogen	Operating	87,675	7,645	0	1	0	0	0
445	10380	Elizabethtown Power LLC	13695	North Carolina Power Holdings, LLC	NC	NAICS-22 Cogen	Operating	9,108	833	0	1	0	0	0
446	10381	Coastal Carolina Clean Power	54889	Carlyle/Riverstone Renewable Energy	NC	NAICS-22 Cogen	Operating	0	11,653	0	1	0	0	0
447	10382	Lumberton	13695	North Carolina Power Holdings, LLC	NC	NAICS-22 Cogen	Operating	10,774	310	0	1	0	0	0
448	10384	Edgecombe Genco LLC	55739	Edgecombe Operating Services LLC	NC	NAICS-22 Cogen	Operating	382,966	71,000	0	1	0	0	0
449	10464	Black River Generation	1746	Black River Generation LLC	NY	NAICS-22 Non-Cogen	Operating	136,442	204,098	0	1	1	0	0
450	10495	Rumford Cogeneration	54784	NewPage Corporation	ME	NAICS-22 Cogen	Operating	136,499	48,000	0	1	0	0	0
451	10566	Chambers Cogeneration LP	14932	US Operating Services Company	NJ	NAICS-22 Cogen	Operating	864,374	162,000	0	1	0	0	0
452	10603	Ebensburg Power	5670	Ebensburg Power Co	PA	NAICS-22 Cogen	Operating	532,688	225,816	0	0	1	0	0
453	10604	Hawaiian Comm & Sugar Puunene Mill	8286	Hawaiian Com & Sugar Co Ltd	HI	NAICS-22 Cogen	Operating	85,883	7,468	0	1	0	0	0
454	10640	Stockton Cogen	353	Air Products Energy Enterprise	CA	NAICS-22 Cogen	Operating	162,520	66,017	0	1	0	0	0
455	10641	Cambria Cogen	2884	Cambria CoGen Co	PA	NAICS-22 Cogen	Operating	651,666	346,203	0	0	1	0	0
456	10671	AES Shady Point LLC	21	AES Shady Point LLC	OK	NAICS-22 Cogen	Operating	1,492,507	422,400	0	1	0	1	0
457	10672	Cedar Bay Generating Company LP	14932	US Operating Services Company	FL	NAICS-22 Cogen	Operating	920,788	423,000	0	1	0	0	0
458	10673	AES Hawaii	177	AES Hawaii Inc	HI	NAICS-22 Cogen	Operating	692,096	51,500	0	0	1	1	0
459	10675	AES Thames	42	AES Thames LLC	CT	NAICS-22 Cogen	Operating	631,814	149,180	0	1	0	0	0
460	10676	AES Beaver Valley Partners Beaver Valley	142	AES Beaver Valley	PA	NAICS-22 Cogen	Operating	536,230	174,300	0	1	0	0	0
461	10678	AES Warrior Run Cogeneration Facility	35	AES WR Ltd Partnership	MD	NAICS-22 Cogen	Operating	687,485	423,240	0	1	0	0	0
462	10686	Rapids Energy Center	12647	Minnesota Power Inc	MN	NAICS-22 Cogen	Operating	56,860	2,225	0	0	0	1	0
463	10743	Morgantown Energy Facility	12949	Morgantown Energy Associates	WV	NAICS-22 Cogen	Operating	381,214	155,450	0	1	1	0	0
464	10768	Rio Bravo Jasmin	16061	Rio Bravo Jasmin	CA	NAICS-22 Cogen	Operating	66,519	6,863	0	0	0	1	0
465	10769	Rio Bravo Poso	16002	Rio Bravo Poso	CA	NAICS-22 Cogen	Operating	63,262	6,684	0	1	0	0	0
466	10771	Hopewell Power Station	19876	Virginia Electric & Power Co	VA	Electric Utility	Operating	153,862	14,078	0	1	0	0	0
467	10773	Altavista Power Station	19876	Virginia Electric & Power Co	VA	Electric Utility	Operating	152,784	19,849	0	1	0	0	0
468	10774	Southampton Power Station	19876	Virginia Electric & Power Co	VA	Electric Utility	Operating	203,115	90,232	0	1	0	0	0

Appendix C
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469	10784	Colstrip Energy LP	4217	Colstrip Energy LP	MT	NAICS-22 Non-Cogen	Operating	274,088	37,869	0	0	1	0	0
470	50039	Kline Township Cogen Facility	13833	Northeastern Power Co	PA	NAICS-22 Cogen	Operating	580,911	225,502	0	0	1	0	0
471	50202	WPS Power Niagara	55807	Niagara Generation LLC	NY	NAICS-22 Non-Cogen	Operating	53,126	18,249	0	1	1	0	0
472	50407	Mobile Energy Services LLC	34672	DTE Energy Services	AL	NAICS-22 Cogen	Operating	149,915	9,637	0	1	0	0	0
473	50611	WPS Westwood Generation LLC	21025	WPS Power Developement	PA	NAICS-22 Non-Cogen	Operating	265,844	244,867	0	0	1	0	0
474	50651	Trigen Syracuse Energy	19194	Syracuse Energy Corp	NY	NAICS-22 Cogen	Operating	227,449	10,673	0	1	0	0	0
475	50776	Panther Creek Energy Facility	14432	Panther Creek Partners	PA	NAICS-22 Non-Cogen	Operating	670,565	214,260	0	0	1	0	0
476	50835	TES Filer City Station	18414	TES Filer City Station LP	MI	NAICS-22 Cogen	Operating	226,077	40,894	0	1	0	1	0
477	50879	Wheelabrator Frackville Energy	20541	Wheelabrator Environmental Systems	PA	NAICS-22 Cogen	Operating	506,176	266,589	0	0	1	0	0
478	50888	Northampton Generating Company LP	14932	US Operating Services Company	PA		Operating	0	437,000	0	0	1	0	0
479	50951	Sunnyside Cogen Associates	21734	Sunnyside Cogeneration Assoc	UT	NAICS-22 Non-Cogen	Operating	417,998	249,744	0	0	1	0	0
480	50974	Scrubgrass Generating Company LP	14932	US Operating Services Company	PA	NAICS-22 Non-Cogen	Operating	643,115	221,687	0	1	1	1	0
481	50976	Indiantown Cogeneration LP	14932	US Operating Services Company	FL	NAICS-22 Cogen	Operating	928,622	257,000	0	1	0	0	0
482	52007	Mecklenburg Power Station	19876	Virginia Electric & Power Co	VA	Electric Utility	Operating	341,368	173,567	0	1	0	0	0
483	54035	Roanoke Valley Energy Facililty I	55808	Westmoreland Partners	NC	NAICS-22 Cogen	Operating	512,167	131,600	0	1	0	0	0
484	54081	Spruance Genco LLC	55740	Spruance Operating Services LLC	VA	NAICS-22 Cogen	Operating	828,555	158,000	0	1	0	0	0
485	54144	Piney Creek Project	4129	Colmac Clarion Inc	PA	NAICS-22 Non-Cogen	Operating	208,055	77,365	0	0	1	0	0
486	54238	Port of Stockton District Energy Fac	6811	FPL Energy Operating Servs Inc	CA	NAICS-22 Cogen	Operating	127,856	13,395	0	1	0	0	0
487	54304	Birchwood Power	1735	Birchwood Power Partners LP	VA	NAICS-22 Cogen	Operating	489,059	118,000	0	1	0	0	0
488	54626	Mt Poso Cogeneration	13060	Mt Poso Cogeneration Co	CA	NAICS-22 Cogen	Operating	150,284	16,568	0	1	0	0	0
489	54634	St Nicholas Cogen Project	16793	Schuylkill Energy Resource Inc	PA	NAICS-22 Cogen	Operating	1,255,743	752,552	0	0	1	0	0
490	54755	Roanoke Valley Energy Facility II	55808	Westmoreland Partners	NC	NAICS-22 Cogen	Operating	161,528	17,890	0	1	0	0	0
491	54972	Norit Americas Marshall Plant	35120	Norit Americas Inc	TX	Industrial NAICS Non-Cogen	Operating	0	528	1	0	0	0	0
492	55076	Red Hills Generating Facility	3593	Choctaw Generating LP	MS	NAICS-22 Non-Cogen	Standby	3,386,589	672,300	1	0	0	0	0
493	55245	Tuscola Station	19145	Trigen-Cinergy Sol-Tuscola LLC	IL	NAICS-22 Cogen	Operating	171,490	13,976	0	1	0	0	0
494	55479	Wygen 1	19545	Black Hills Power Inc	WY	NAICS-22 Non-Cogen	Operating	523,329	49,931	0	0	0	1	0
495	55749	Hardin Generator Project	16233	Rocky Mountain Power Inc	MT	NAICS-22 Non-Cogen	Operating	536,935	100,130	0	0	0	1	0
							Totals	**1,035,605,206**	**148,980,310**	21	330	33	201	19

Appendix D:

Identity of 200 Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
3393	1	Tennessee Valley Authority	Allen Steam Plant	TN	Non-Small Federal	1	1
3396	2	Tennessee Valley Authority	Bull Run	TN	Non-Small Federal	2	1
47	3	Tennessee Valley Authority	Colbert	AL	Non-Small Federal	3	1
3399	4	Tennessee Valley Authority	Cumberland	TN	Non-Small Federal	4	1
3403	5	Tennessee Valley Authority	Gallatin	TN	Non-Small Federal	5	1
3405	6	Tennessee Valley Authority	John Sevier	TN	Non-Small Federal	6	1
3406	7	Tennessee Valley Authority	Johnsonville	TN	Non-Small Federal	7	1
3407	8	Tennessee Valley Authority	Kingston	TN	Non-Small Federal	8	1
1378	9	Tennessee Valley Authority	Paradise	KY	Non-Small Federal	9	1
1379	10	Tennessee Valley Authority	Shawnee	KY	Non-Small Federal	10	1
50	11	Tennessee Valley Authority	Widows Creek	AL	Non-Small Federal	11	1
165	12	Grand River Dam Authority	GRDA	OK	Non-Small State	1	2
6179	13	Lower Colorado River Authority	Fayette Power Project	TX	Non-Small State	2	3
6077	14	Nebraska Public Power District	Gerald Gentleman	NE	Non-Small State	3	4
2277	15	Nebraska Public Power District	Sheldon	NE	Non-Small State	4	4
6096	16	Omaha Public Power District	Nebraska City	NE	Non-Small State	5	5
2291	17	Omaha Public Power District	North Omaha	NE	Non-Small State	6	5
6761	18	Platte River Power Authority	Rawhide	CO	Non-Small State	7	6
6177	19	Salt River Project	Coronado	AZ	Non-Small State	8	7
4941	20	Salt River Project	Navajo	AZ	Non-Small State	9	7
130	21	South Carolina Pub Serv Auth	Cross	SC	Non-Small State	10	8
3317	22	South Carolina Pub Serv Auth	Dolphus M Grainger	SC	Non-Small State	11	8
3319	23	South Carolina Pub Serv Auth	Jefferies	SC	Non-Small State	12	8
6249	24	South Carolina Pub Serv Auth	Winyah	SC	Non-Small State	13	8
7286	25	American Municipal Power-Ohio, Inc	Richard Gorsuch	OH	Non-Small City	1	9
1122	26	Ames City of	Ames Electric Services Power Plant	IA	Non-Small City	2	10
2123	27	City of Columbia	Columbia	MO	Non-Small City	3	11
2917	28	City of Hamilton	Hamilton	OH	Non-Small City	4	12
676	29	City of Lakeland	C D McIntosh Jr	FL	Non-Small City	5	13
1374	30	City of Owensboro	Elmer Smith	KY	Non-Small City	6	14
963	31	City of Springfield	Dallman	IL	Non-Small City	7	15
964	32	City of Springfield	Lakeside	IL	Non-Small City	8	15
2161	33	City Utilities of Springfield	James River Power Station	MO	Non-Small City	9	16
6195	34	City Utilities of Springfield	Southwest Power Station	MO	Non-Small City	10	16
492	35	Colorado Springs City of	Martin Drake	CO	Non-Small City	11	17
8219	36	Colorado Springs City of	Ray D Nixon	CO	Non-Small City	12	17
663	37	Gainesville Regional Utilities	Deerhaven Generating Station	FL	Non-Small City	13	18
2132	38	Independence City of	Blue Valley	MO	Non-Small City	14	19
2171	39	Independence City of	Missouri City	MO	Non-Small City	15	19
667	40	JEA	Northside Generating Station	FL	Non-Small City	16	20
207	41	JEA	St Johns River Power Park	FL	Non-Small City	17	20
6064	42	Kansas City City of	Nearman Creek	KS	Non-Small City	18	21
1295	43	Kansas City City of	Quindaro	KS	Non-Small City	19	21
1831	44	Lansing Board of Water and Light	Eckert Station	MI	Non-Small City	20	22
1832	45	Lansing Board of Water and Light	Erickson Station	MI	Non-Small City	21	22
6481	46	Los Angeles City of	Intermountain Power Project	UT	Non-Small City	22	23
564	47	Orlando Utilities Comm	Stanton Energy Center	FL	Non-Small City	23	24
2008	48	Rochester Public Utilities	Silver Lake	MN	Non-Small City	24	25

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
7097	49	San Antonio City of	J K Spruce	TX	Non-Small City	25	26
6181	50	San Antonio City of	J T Deely	TX	Non-Small City	26	26
2434	51	Vineland City of	Howard Down	NJ	Non-Small City	27	27
10676	52	AES Corp	AES Beaver Valley Partners Beaver Valley	PA	Non-Small Company	1	28
2535	53	AES Corp	AES Cayuga LLC	NY	Non-Small Company	2	28
2527	54	AES Corp	AES Greenidge LLC	NY	Non-Small Company	3	28
10673	55	AES Corp	AES Hawaii Inc	HI	Non-Small Company	4	28
10671	56	AES Corp	AES Shady Point LLC	OK	Non-Small Company	5	28
6082	57	AES Corp	AES Somerset LLC	NY	Non-Small Company	6	28
10675	58	AES Corp	AES Thames LLC	CT	Non-Small Company	7	28
10678	59	AES Corp	AES Warrior Run Cogeneration Facility	MD	Non-Small Company	8	28
2526	60	AES Corp	AES Westover LLC	NY	Non-Small Company	9	28
6705	61	AGC Division of APG Inc	Warrick	IN	Non-Small Company	10	29
10640	62	Air Products Energy Enterprise	Stockton Cogen	CA	Non-Small Company	11	30
3	63	Alabama Power Co	Barry	AL	Non-Small Company	12	31
26	64	Alabama Power Co	E C Gaston	AL	Non-Small Company	13	31
7	65	Alabama Power Co	Gadsden	AL	Non-Small Company	14	31
8	66	Alabama Power Co	Gorgas	AL	Non-Small Company	15	31
10	67	Alabama Power Co	Greene County	AL	Non-Small Company	16	31
6002	68	Alabama Power Co	James H Miller Jr	AL	Non-Small Company	17	31
3178	69	Allegheny Energy Supply Co LLC	Armstrong Power Station	PA	Non-Small Company	18	32
3944	70	Allegheny Energy Supply Co LLC	Harrison Power Station	WV	Non-Small Company	19	32
3179	71	Allegheny Energy Supply Co LLC	Hatfields Ferry Power Station	PA	Non-Small Company	20	32
3181	72	Allegheny Energy Supply Co LLC	Mitchell Power Station	PA	Non-Small Company	21	32
6004	73	Allegheny Energy Supply Co LLC	Pleasants Power Station	WV	Non-Small Company	22	32
1570	74	Allegheny Energy Supply Co LLC	R Paul Smith Power Station	MD	Non-Small Company	23	32
7030	75	Altura Power	Twin Oaks Power One	TX	Non-Small Company	24	33
861	76	Ameren Energy Generating Co	Coffeen	IL	Non-Small Company	25	34
863	77	Ameren Energy Generating Co	Hutsonville	IL	Non-Small Company	26	34
864	78	Ameren Energy Generating Co	Meredosia	IL	Non-Small Company	27	34
6017	79	Ameren Energy Generating Co	Newton	IL	Non-Small Company	28	34
6016	80	Ameren Energy Resources Generating Co.	Duck Creek	IL	Non-Small Company	29	35
856	81	Ameren Energy Resources Generating Co.	E D Edwards	IL	Non-Small Company	30	35
10151	82	American Bituminous Power LP	Grant Town Power Plant	WV	Non-Small Company	31	36
3775	83	American Electric Power Co -- Appalachian Power Co	Clinch River	VA	Non-Small Company	32	37
3776	84	American Electric Power Co -- Appalachian Power Co	Glen Lyn	VA	Non-Small Company	33	37
3935	85	American Electric Power Co -- Appalachian Power Co	John E Amos	WV	Non-Small Company	34	37
3936	86	American Electric Power Co -- Appalachian Power Co	Kanawha River	WV	Non-Small Company	35	37
6264	87	American Electric Power Co -- Appalachian Power Co	Mountaineer	WV	Non-Small Company	36	37
3938	88	American Electric Power Co -- Appalachian Power Co	Philip Sporn	WV	Non-Small Company	37	37
2840	89	American Electric Power Co -- Columbus Southern Power Co	Conesville	OH	Non-Small Company	38	37
2843	90	American Electric Power Co -- Columbus Southern Power Co	Picway	OH	Non-Small Company	39	37
2850	91	American Electric Power Co -- 26% co-owned by DPL Inc., Duke, CSP)	J M Stuart	OH	Non-Small Company	40	37
6019	92	American Electric Power Co -- Duke Energy Ohio Inc	W H Zimmer	OH	Non-Small Company	41	37
2830	93	American Electric Power Co -- 13% coowned by DPL In.c, Duke Energy Ohio Inc, CSP	Walter C Beckjord	OH	Non-Small Company	42	37
6166	94	American Electric Power Co -- Indiana Michigan Power Co	Rockport	IN	Non-Small Company	43	37

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
988	95	American Electric Power Co -- Indiana Michigan Power Co	Tanners Creek	IN	Non-Small Company	44	37
1353	96	American Electric Power Co -- Kentucky Power Co	Big Sandy	KY	Non-Small Company	45	37
8102	97	American Electric Power Co -- Ohio Power Co	General James M Gavin	OH	Non-Small Company	46	37
3947	98	American Electric Power Co -- Ohio Power Co	Kammer	WV	Non-Small Company	47	37
3948	99	American Electric Power Co -- Ohio Power Co	Mitchell	WV	Non-Small Company	48	37
2872	100	American Electric Power Co -- Ohio Power Co	Muskingum River	OH	Non-Small Company	49	37
2963	101	American Electric Power Co -- Public Service Co of Oklahoma	Northeastern	OK	Non-Small Company	50	37
127	102	American Electric Power Co -- Public Service Co of Oklahoma	Oklaunion	TX	Non-Small Company	51	37
6138	103	American Electric Power Co -- Southwestern Electric Power Co	Flint Creek	AR	Non-Small Company	52	37
7902	104	American Electric Power Co -- Southwestern Electric Power Co	Pirkey	TX	Non-Small Company	53	37
6139	105	American Electric Power Co -- Southwestern Electric Power Co	Welsh	TX	Non-Small Company	54	37
6178	106	ANP-Coleto Creek	Coleto Creek	TX	Non-Small Company	55	38
2098	107	Aquila, Inc.	Lake Road	MO	Non-Small Company	56	39
2094	108	Aquila, Inc.	Sibley	MO	Non-Small Company	57	39
462	109	Aquila, Inc.	W N Clark	CO	Non-Small Company	58	39
113	110	Arizona Public Service Co	Cholla	AZ	Non-Small Company	59	40
2442	111	Arizona Public Service Co	Four Corners	NM	Non-Small Company	60	40
10603	112	Babcock & Wilcox and ESI Energy, Inc. (partnership)	Ebensburg Power Company	PA	Non-Small Company	61	41
54304	113	Birchwood Power Partners LP	Birchwood Power	VA	Non-Small Company	62	42
3325	114	Black Hills Power Inc	Ben French	SD	Non-Small Company	63	43
4150	115	Black Hills Power Inc	Neil Simpson	WY	Non-Small Company	64	43
7504	116	Black Hills Power Inc	Neil Simpson II	WY	Non-Small Company	65	43
4151	117	Black Hills Power Inc	Osage	WY	Non-Small Company	66	43
55479	118	Black Hills Power Inc	Wygen 1	WY	Non-Small Company	67	43
10464	119	Black River Generation LLC	Black River Generation	NY	Non-Small Company	68	44
10641	120	Cambria CoGen Co	Cambria Cogen	PA	Non-Small Company	69	45
2828	121	Cardinal Operating Co	Cardinal	OH	Non-Small Company	70	46
10381	122	Carlyle/Riverstone Renewable Energy	Coastal Carolina Clean Power	NC	Non-Small Company	71	47
10333	123	Central Power & Lime Inc	Central Power & Lime	FL	Non-Small Company	72	48
55076	124	Choctaw Generating LP	Red Hills Generating Facility	MS	Non-Small Company	73	49
992	125	Citizens Thermal Energy	CC Perry K	IN	Non-Small Company	74	50
6190	126	Cleco Power LLC	Rodemacher	LA	Non-Small Company	75	51
51	127	Cleco Power LLC (40% AEP partner)	Dolet Hills	LA	Non-Small Company	76	51
10071	128	Cogentrix Energy	Cogentrix Virginia Leasing Corporation	VA	Non-Small Company	77	52
10377	129	Cogentrix Energy	James River Cogeneration	VA	Non-Small Company	78	52
10743	130	Cogentrix Energy Inc (Morgantown Energy Associates)	Morgantown Energy Facility	WV	Non-Small Company	79	52
54144	131	Colmac Clarion Inc	Piney Creek Project	PA	Non-Small Company	80	53
2384	132	Conectiv Atlantic Generatn Inc	Deepwater	NJ	Non-Small Company	81	54
593	133	Conectiv Delmarva Gen Inc	Edge Moor	DE	Non-Small Company	82	54
10002	134	Constellation Energy	ACE Cogeneration Facility	CA	Non-Small Company	83	55
602	135	Constellation Energy	Brandon Shores	MD	Non-Small Company	84	55
1552	136	Constellation Energy	C P Crane	MD	Non-Small Company	85	55
10143	137	Constellation Energy	Colver Power Project	PA	Non-Small Company	86	55
1554	138	Constellation Energy	Herbert A Wagner	MD	Non-Small Company	87	55
50776	139	Constellation Energy	Panther Creek Energy Facility	PA	Non-Small Company	88	55
10768	140	Constellation Energy	Rio Bravo Jasmin	CA	Non-Small Company	89	55
10769	141	Constellation Energy	Rio Bravo Poso	CA	Non-Small Company	90	55
50951	142	Constellation Energy	Sunnyside Cogeneration Plant	UT	Non-Small Company	91	55

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
3118	143	Constellation Energy (or NRG Energy?)	Conemaugh	PA	Non-Small Company	92	55
3136	144	Constellation Energy (or NRG Energy?)	Keystone	PA	Non-Small Company	93	55
1695	145	Consumers Energy Co	B C Cobb	MI	Non-Small Company	94	56
1702	146	Consumers Energy Co	Dan E Karn	MI	Non-Small Company	95	56
1720	147	Consumers Energy Co	J C Weadock	MI	Non-Small Company	96	56
1710	148	Consumers Energy Co	J H Campbell	MI	Non-Small Company	97	56
1723	149	Consumers Energy Co	J R Whiting	MI	Non-Small Company	98	56
6031	150	DPL Inc -- Dayton Power & Light Co	Killen Station	OH	Non-Small Company	99	57
2848	151	DPL Inc. -- Dayton Power & Light Co	O H Hutchings	OH	Non-Small Company	100	57
6034	152	Detroit Edison Co	Belle River	MI	Non-Small Company	101	58
1731	153	Detroit Edison Co	Harbor Beach	MI	Non-Small Company	102	58
1733	154	Detroit Edison Co	Monroe	MI	Non-Small Company	103	58
1740	155	Detroit Edison Co	River Rouge	MI	Non-Small Company	104	58
1743	156	Detroit Edison Co	St Clair	MI	Non-Small Company	105	58
1745	157	Detroit Edison Co	Trenton Channel	MI	Non-Small Company	106	58
1619	158	Dominion Energy New England, LLC	Brayton Point	MA	Non-Small Company	107	59
1626	159	Dominion Energy New England, LLC	Salem Harbor	MA	Non-Small Company	108	59
876	160	Dominion Energy Services Co	Kincaid Generation LLC	IL	Non-Small Company	109	59
50407	161	DTE Energy Services	Mobile Energy Services LLC	AL	Non-Small Company	110	60
8042	162	Duke Energy Carolinas, LLC	Belews Creek	NC	Non-Small Company	111	61
2720	163	Duke Energy Carolinas, LLC	Buck	NC	Non-Small Company	112	61
2721	164	Duke Energy Carolinas, LLC	Cliffside	NC	Non-Small Company	113	61
2723	165	Duke Energy Carolinas, LLC	Dan River	NC	Non-Small Company	114	61
2718	166	Duke Energy Carolinas, LLC	G G Allen	NC	Non-Small Company	115	61
2727	167	Duke Energy Carolinas, LLC	Marshall	NC	Non-Small Company	116	61
2732	168	Duke Energy Carolinas, LLC	Riverbend	NC	Non-Small Company	117	61
3264	169	Duke Energy Carolinas, LLC	W S Lee	SC	Non-Small Company	118	61
1001	170	Duke Energy Indiana Inc	Cayuga	IN	Non-Small Company	119	61
1004	171	Duke Energy Indiana Inc	Edwardsport	IN	Non-Small Company	120	61
6113	172	Duke Energy Indiana Inc	Gibson	IN	Non-Small Company	121	61
1008	173	Duke Energy Indiana Inc	R Gallagher	IN	Non-Small Company	122	61
1010	174	Duke Energy Indiana Inc	Wabash River	IN	Non-Small Company	123	61
6018	175	Duke Energy Kentucky Inc	East Bend	KY	Non-Small Company	124	61
2832	176	Duke Energy Ohio Inc	Miami Fort	OH	Non-Small Company	125	61
889	177	Dynegy Midwest Generation Inc	Baldwin Energy Complex	IL	Non-Small Company	126	62
891	178	Dynegy Midwest Generation Inc	Havana	IL	Non-Small Company	127	62
892	179	Dynegy Midwest Generation Inc	Hennepin Power Station	IL	Non-Small Company	128	62
897	180	Dynegy Midwest Generation Inc	Vermilion	IL	Non-Small Company	129	62
898	181	Dynegy Midwest Generation Inc	Wood River	IL	Non-Small Company	130	62
2480	182	Dynegy Northeast Gen Inc	Danskammer Generating Station	NY	Non-Small Company	131	62
887	183	Electric Energy Inc	Joppa Steam	IL	Non-Small Company	132	63
2076	184	Empire District Electric Co	Asbury	MO	Non-Small Company	133	64
1239	185	Empire District Electric Co	Riverton	KS	Non-Small Company	134	64
2642	186	Energy East Corporation (Rochester Gas & Electric Corp)	Rochester 7	NY	Non-Small Company	135	65
6641	187	Entergy -- Arkansas Inc	Independence	AR	Non-Small Company	136	66
6009	188	Entergy -- Arkansas Inc	White Bluff	AR	Non-Small Company	137	66
1393	189	Entergy -- Gulf States Louisiana LLC	R S Nelson	LA	Non-Small Company	138	66
1355	190	E-ON USA LLC -- Kentucky Utilities Company	E W Brown	KY	Non-Small Company	139	67

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
1356	191	E-ON USA LLC -- Kentucky Utilities Company	Ghent	KY	Non-Small Company	140	67
1357	192	E-ON USA LLC -- Kentucky Utilities Company	Green River	KY	Non-Small Company	141	67
1361	193	E-ON USA LLC -- Kentucky Utilities Company	Tyrone	KY	Non-Small Company	142	67
3159	194	Exelon Power	Cromby Generating Station	PA	Non-Small Company	143	68
3161	195	Exelon Power	Eddystone Generating Station	PA	Non-Small Company	144	68
2835	196	FirstEnergy Generation Corp	Ashtabula	OH	Non-Small Company	145	69
2878	197	FirstEnergy Generation Corp	Bay Shore	OH	Non-Small Company	146	69
6094	198	FirstEnergy Generation Corp	Bruce Mansfield	PA	Non-Small Company	147	69
2837	199	FirstEnergy Generation Corp	Eastlake	OH	Non-Small Company	148	69
2838	200	FirstEnergy Generation Corp	Lake Shore	OH	Non-Small Company	149	69
2864	201	FirstEnergy Generation Corp	R E Burger	OH	Non-Small Company	150	69
2866	202	FirstEnergy Generation Corp	W H Sammis	OH	Non-Small Company	151	69
1606	203	FirstLight Power Resources Services LLC	Mount Tom	MA	Non-Small Company	152	70
54238	204	FPL Energy Operating Servs Inc	Port of Stockton District Energy Fac	CA	Non-Small Company	153	71
703	205	Georgia Power Co	Bowen	GA	Non-Small Company	154	72
708	206	Georgia Power Co	Hammond	GA	Non-Small Company	155	72
709	207	Georgia Power Co	Harllee Branch	GA	Non-Small Company	156	72
710	208	Georgia Power Co	Jack McDonough	GA	Non-Small Company	157	72
733	209	Georgia Power Co	Kraft	GA	Non-Small Company	158	72
6124	210	Georgia Power Co	McIntosh	GA	Non-Small Company	159	72
727	211	Georgia Power Co	Mitchell	GA	Non-Small Company	160	72
6257	212	Georgia Power Co	Scherer	GA	Non-Small Company	161	72
6052	213	Georgia Power Co	Wansley	GA	Non-Small Company	162	72
728	214	Georgia Power Co	Yates	GA	Non-Small Company	163	72
10113	215	Gilberton Power Co	John B Rich Memorial Power Station	PA	Non-Small Company	164	73
641	216	Gulf Power Co	Crist	FL	Non-Small Company	165	74
643	217	Gulf Power Co	Lansing Smith	FL	Non-Small Company	166	74
642	218	Gulf Power Co	Scholz	FL	Non-Small Company	167	74
10604	219	Hawaiian Com & Sugar Co Ltd	Hawaiian Comm & Sugar Puunene Mill	HI	Non-Small Company	168	75
1043	220	Hoosier Energy R E C, Inc	Frank E Ratts	IN	Non-Small Company	169	76
6213	221	Hoosier Energy R E C, Inc	Merom	IN	Non-Small Company	170	76
983	222	Indiana-Kentucky Electric Corp	Clifty Creek	IN	Non-Small Company	171	77
994	223	Indianapolis Power & Light Co	AES Petersburg	IN	Non-Small Company	172	78
991	224	Indianapolis Power & Light Co	Eagle Valley	IN	Non-Small Company	173	78
990	225	Indianapolis Power & Light Co	Harding Street	IN	Non-Small Company	174	78
4146	226	Integrys Energy Group -- Mid-America Power LLC	E J Stoneman Station	WI	Non-Small Company	175	79
1771	227	Integrys Energy Group -- Upper Peninsula Power Co	Escanaba	MI	Non-Small Company	176	79
50611	228	Integrys Energy Group -- WPS Power Development	WPS Westwood Generation LLC	PA	Non-Small Company	177	79
1104	229	Interstate Power and Light Co	Burlington	IA	Non-Small Company	178	80
1046	230	Interstate Power and Light Co	Dubuque	IA	Non-Small Company	179	80
1047	231	Interstate Power and Light Co	Lansing	IA	Non-Small Company	180	80
1048	232	Interstate Power and Light Co	Milton L Kapp	IA	Non-Small Company	181	80
6254	233	Interstate Power and Light Co	Ottumwa	IA	Non-Small Company	182	80
1073	234	Interstate Power and Light Co	Prairie Creek	IA	Non-Small Company	183	80
1058	235	Interstate Power and Light Co	Sixth Street	IA	Non-Small Company	184	80
1077	236	Interstate Power and Light Co	Sutherland	IA	Non-Small Company	185	80
2079	237	Kansas City Power & Light Co	Hawthorn	MO	Non-Small Company	186	81
6065	238	Kansas City Power & Light Co	Iatan	MO	Non-Small Company	187	81

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
1241	239	Kansas City Power & Light Co	La Cygne	KS	Non-Small Company	188	81
2080	240	Kansas City Power & Light Co	Montrose	MO	Non-Small Company	189	81
1363	241	Louisville Gas & Electric Co	Cane Run	KY	Non-Small Company	190	82
1364	242	Louisville Gas & Electric Co	Mill Creek	KY	Non-Small Company	191	82
6071	243	Louisville Gas & Electric Co	Trimble County	KY	Non-Small Company	192	82
3992	244	Madison Gas & Electric Co	Blount Street	WI	Non-Small Company	193	83
6089	245	MDU Resources Group Inc	Lewis & Clark	MT	Non-Small Company	194	84
2790	246	MDU Resources Group Inc	R M Heskett	ND	Non-Small Company	195	84
1091	247	MidAmerican Energy Co	George Neal North	IA	Non-Small Company	196	85
7343	248	MidAmerican Energy Co	George Neal South	IA	Non-Small Company	197	85
6664	249	MidAmerican Energy Co	Louisa	IA	Non-Small Company	198	85
1081	250	MidAmerican Energy Co	Riverside	IA	Non-Small Company	199	85
1082	251	MidAmerican Energy Co	Walter Scott Jr Energy Center	IA	Non-Small Company	200	85
867	252	Midwest Generations EME LLC	Crawford	IL	Non-Small Company	201	86
886	253	Midwest Generations EME LLC	Fisk Street	IL	Non-Small Company	202	86
3122	254	Midwest Generations EME LLC	Homer City Station	PA	Non-Small Company	203	86
384	255	Midwest Generations EME LLC	Joliet 29	IL	Non-Small Company	204	86
874	256	Midwest Generations EME LLC	Joliet 9	IL	Non-Small Company	205	86
879	257	Midwest Generations EME LLC	Powerton	IL	Non-Small Company	206	86
883	258	Midwest Generations EME LLC	Waukegan	IL	Non-Small Company	207	86
884	259	Midwest Generations EME LLC	Will County	IL	Non-Small Company	208	86
1893	260	Minnesota Power Inc	Clay Boswell	MN	Non-Small Company	209	87
1897	261	Minnesota Power Inc	M L Hibbard	MN	Non-Small Company	210	87
10686	262	Minnesota Power Inc	Rapids Energy Center	MN	Non-Small Company	211	87
1891	263	Minnesota Power Inc	Syl Laskin	MN	Non-Small Company	212	87
10075	264	Minnesota Power Inc	Taconite Harbor Energy Center	MN	Non-Small Company	213	87
1571	265	Mirant -- Chalk Point LLC	Chalk Point LLC	MD	Non-Small Company	214	88
1572	266	Mirant -- Mid-Atlantic LLC	Dickerson	MD	Non-Small Company	215	88
1573	267	Mirant -- Mid-Atlantic LLC	Morgantown Generating Plant	MD	Non-Small Company	216	88
2629	268	Mirant -- New York Inc	Lovett	NY	Non-Small Company	217	88
3788	269	Mirant -- Potomac River LLC	Potomac River	VA	Non-Small Company	218	88
2049	270	Mississippi Power Co	Jack Watson	MS	Non-Small Company	219	89
6073	271	Mississippi Power Co	Victor J Daniel Jr	MS	Non-Small Company	220	89
3942	272	Monongahela Power Co	Albright	WV	Non-Small Company	221	90
3943	273	Monongahela Power Co	Fort Martin Power Station	WV	Non-Small Company	222	90
3945	274	Monongahela Power Co	Rivesville	WV	Non-Small Company	223	90
3946	275	Monongahela Power Co	Willow Island	WV	Non-Small Company	224	90
54626	276	Mt Poso Cogeneration Co	Mt Poso Cogeneration	CA	Non-Small Company	225	91
2324	277	Nevada Power Co	Reid Gardner	NV	Non-Small Company	226	92
10495	278	NewPage Corporation	Rumford Cogeneration	ME	Non-Small Company	227	93
54972	279	Norit Americas Inc	Norit Americas Marshall Plant	TX	Non-Small Company	228	94
10380	280	North Carolina Power Holdings, LLC	Elizabethtown Power LLC	NC	Non-Small Company	229	95
10382	281	North Carolina Power Holdings, LLC	Lumberton	NC	Non-Small Company	230	95
995	282	Northern Indiana Pub Serv Co	Bailly	IN	Non-Small Company	231	96
997	283	Northern Indiana Pub Serv Co	Michigan City	IN	Non-Small Company	232	96
6085	284	Northern Indiana Pub Serv Co	R M Schahfer	IN	Non-Small Company	233	96
1915	285	Northern States Power Co	Allen S King	MN	Non-Small Company	234	97
3982	286	Northern States Power Co	Bay Front	WI	Non-Small Company	235	97

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
1904	287	Northern States Power Co	Black Dog	MN	Non-Small Company	236	97
1927	288	Northern States Power Co	Riverside	MN	Non-Small Company	237	97
6090	289	Northern States Power Co	Sherburne County	MN	Non-Small Company	238	97
2554	290	NRG Energy -- Dunkirk Power LLC	Dunkirk Generating Plant	NY	Non-Small Company	239	98
10030	291	NRG Energy -- Energy Center Dover LLC	NRG Energy Center Dover	DE	Non-Small Company	240	98
2549	292	NRG Energy -- Huntley Operations Inc	C R Huntley Generating Station	NY	Non-Small Company	241	98
594	293	NRG Energy -- Indian River Operations Inc	Indian River Generating Station	DE	Non-Small Company	242	98
6055	294	NRG Energy -- Louisiana Generating LLC	Big Cajun 2	LA	Non-Small Company	243	98
3113	295	NRG Energy -- Reliant Energy Mid-Atlantic PH LLC	Portland	PA	Non-Small Company	244	98
3131	296	NRG Energy -- Reliant Energy Mid-Atlantic PH LLC	Shawville	PA	Non-Small Company	245	98
3115	297	NRG Energy -- Reliant Energy Mid-Atlantic PH LLC	Titus	PA	Non-Small Company	246	98
3130	298	NRG Energy -- Reliant Energy Seward LLC	Seward	PA	Non-Small Company	247	98
1613	299	NRG Energy -- Somerset Power LLC	Somerset Station	MA	Non-Small Company	248	98
298	300	NRG Energy -- Texas LLC	Limestone	TX	Non-Small Company	249	98
3470	301	NRG Energy -- Texas LLC	W A Parish	TX	Non-Small Company	250	98
2876	302	Ohio Valley Electric Corp	Kyger Creek	OH	Non-Small Company	251	99
2952	303	Oklahoma Gas & Electric Co	Muskogee	OK	Non-Small Company	252	100
6095	304	Oklahoma Gas & Electric Co	Sooner	OK	Non-Small Company	253	100
2836	305	Orion Power Midwest LP	Avon Lake	OH	Non-Small Company	254	101
8226	306	Orion Power Midwest LP	Cheswick Power Plant	PA	Non-Small Company	255	101
3098	307	Orion Power Midwest LP	Elrama Power Plant	PA	Non-Small Company	256	101
3138	308	Orion Power Midwest LP	New Castle Plant	PA	Non-Small Company	257	101
2861	309	Orion Power Midwest LP	Niles	OH	Non-Small Company	258	101
6098	310	Otter Tail Power Co	Big Stone	SD	Non-Small Company	259	102
8222	311	Otter Tail Power Co	Coyote	ND	Non-Small Company	260	102
1943	312	Otter Tail Power Co	Hoot Lake	MN	Non-Small Company	261	102
3644	313	PacifiCorp	Carbon	UT	Non-Small Company	262	103
4158	314	PacifiCorp	Dave Johnston	WY	Non-Small Company	263	103
6165	315	PacifiCorp	Hunter	UT	Non-Small Company	264	103
8069	316	PacifiCorp	Huntington	UT	Non-Small Company	265	103
8066	317	PacifiCorp	Jim Bridger	WY	Non-Small Company	266	103
4162	318	PacifiCorp	Naughton	WY	Non-Small Company	267	103
6101	319	PacifiCorp	Wyodak	WY	Non-Small Company	268	103
6106	320	Portland General Electric Co	Boardman	OR	Non-Small Company	269	104
3140	321	PPL -- Brunner Island LLC	PPL Brunner Island	PA	Non-Small Company	270	105
6076	322	PPL -- Montana LLC	Colstrip	MT	Non-Small Company	271	105
2187	323	PPL -- Montana LLC	J E Corette Plant	MT	Non-Small Company	272	105
3149	324	PPL -- Montour LLC	PPL Montour	PA	Non-Small Company	273	105
10379	325	Primary Energy of North Carolina LLC	Primary Energy Roxboro	NC	Non-Small Company	274	106
10378	326	Primary Energy of North Carolina LLC	Primary Energy Southport	NC	Non-Small Company	275	106
2706	327	Progress Energy Carolinas Inc	Asheville	NC	Non-Small Company	276	107
2708	328	Progress Energy Carolinas Inc	Cape Fear	NC	Non-Small Company	277	107
3251	329	Progress Energy Carolinas Inc	H B Robinson	SC	Non-Small Company	278	107
2713	330	Progress Energy Carolinas Inc	L V Sutton	NC	Non-Small Company	279	107
2709	331	Progress Energy Carolinas Inc	Lee	NC	Non-Small Company	280	107
6250	332	Progress Energy Carolinas Inc	Mayo	NC	Non-Small Company	281	107
2712	333	Progress Energy Carolinas Inc	Roxboro	NC	Non-Small Company	282	107
2716	334	Progress Energy Carolinas Inc	W H Weatherspoon	NC	Non-Small Company	283	107

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
628	335	Progress Energy Florida Inc	Crystal River	FL	Non-Small Company	284	107
2403	336	PSEG Fossil LLC	PSEG Hudson Generating Station	NJ	Non-Small Company	285	108
2408	337	PSEG Fossil LLC	PSEG Mercer Generating Station	NJ	Non-Small Company	286	108
568	338	PSEG Power Connecticut LLC	Bridgeport Station	CT	Non-Small Company	287	109
465	339	Public Service Co of Colorado	Arapahoe	CO	Non-Small Company	288	109
468	340	Public Service Co of Colorado	Cameo	CO	Non-Small Company	289	109
469	341	Public Service Co of Colorado	Cherokee	CO	Non-Small Company	290	109
470	342	Public Service Co of Colorado	Comanche	CO	Non-Small Company	291	109
525	343	Public Service Co of Colorado	Hayden	CO	Non-Small Company	292	109
6248	344	Public Service Co of Colorado	Pawnee	CO	Non-Small Company	293	109
477	345	Public Service Co of Colorado	Valmont	CO	Non-Small Company	294	109
2364	346	Public Service Co of NH	Merrimack	NH	Non-Small Company	295	110
2367	347	Public Service Co of NH	Schiller	NH	Non-Small Company	296	110
2451	348	Public Service Co of NM	San Juan	NM	Non-Small Company	297	111
2378	349	RC Cape May Holdings LLC	B L England	NJ	Non-Small Company	298	112
55749	350	Rocky Mountain Power Inc	Hardin Generator Project	MT	Non-Small Company	299	113
7652	351	Savannah River Nuclear Solutions LLC	US DOE Savannah River Site (D Area)	SC	Non-Small Company	300	114
8224	352	Sierra Pacific Power Co	North Valmy	NV	Non-Small Company	301	115
3280	353	South Carolina Electric&Gas Co	Canadys Steam	SC	Non-Small Company	302	115
7737	354	South Carolina Electric&Gas Co	Cogen South	SC	Non-Small Company	303	115
7210	355	South Carolina Electric&Gas Co	Cope	SC	Non-Small Company	304	115
3287	356	South Carolina Electric&Gas Co	McMeekin	SC	Non-Small Company	305	115
3295	357	South Carolina Electric&Gas Co	Urquhart	SC	Non-Small Company	306	115
3297	358	South Carolina Electric&Gas Co	Wateree	SC	Non-Small Company	307	115
3298	359	South Carolina Genertg Co, Inc	Williams	SC	Non-Small Company	308	115
6137	360	Southern Indiana Gas & Elec Co	A B Brown	IN	Non-Small Company	309	116
1012	361	Southern Indiana Gas & Elec Co	F B Culley	IN	Non-Small Company	310	116
6193	362	Southwestern Public Service Co	Harrington	TX	Non-Small Company	311	117
6194	363	Southwestern Public Service Co	Tolk	TX	Non-Small Company	312	117
981	364	State Line Energy LLC	State Line Energy	IN	Non-Small Company	313	118
10003	365	Suez Energy	Colorado Energy Nations Company	CO	Non-Small Company	314	119
50039	366	Suez Energy -- Northeastern Power Co	Kline Township Cogen Facility	PA	Non-Small Company	315	119
3152	367	Sunbury Generation LP	Sunbury Generation LP	PA	Non-Small Company	316	120
108	368	Sunflower Electric Power Corp	Holcomb	KS	Non-Small Company	317	121
645	369	TECO Energy -- Tampa Electric Co	Big Bend	FL	Non-Small Company	318	121
7242	370	TECO Energy -- Tampa Electric Co	Polk	FL	Non-Small Company	319	122
3845	371	TransAlta Centralia Gen LLC	Transalta Centralia Generation	WA	Non-Small Company	320	123
55245	372	Trigen -- Cinergy Sol-Tuscola LLC	Tuscola Station	IL	Non-Small Company	321	123
50651	373	Trigen Energy Corp	Trigen Syracuse Energy	NY	Non-Small Company	322	124
6021	374	Tri-State G & T Assn, Inc	Craig	CO	Non-Small Company	323	125
87	375	Tri-State G & T Assn, Inc	Escalante	NM	Non-Small Company	324	125
527	376	Tri-State G & T Assn, Inc	Nucla	CO	Non-Small Company	325	125
3497	377	TXU Generation Co LP	Big Brown	TX	Non-Small Company	326	126
6146	378	TXU Generation Co LP	Martin Lake	TX	Non-Small Company	327	126
6147	379	TXU Generation Co LP	Monticello	TX	Non-Small Company	328	126
6648	380	TXU Generation Co LP	Sandow No 4	TX	Non-Small Company	329	126
3176	381	UGI Development Co	Hunlock Power Station	PA	Non-Small Company	330	127
2103	382	Union Electric Co	Labadie	MO	Non-Small Company	331	128

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
2104	383	Union Electric Co	Meramec	MO	Non-Small Company	332	128
6155	384	Union Electric Co	Rush Island	MO	Non-Small Company	333	128
2107	385	Union Electric Co	Sioux	MO	Non-Small Company	334	128
126	386	UniSource Energy -- Tucson Electric Power Co	H Wilson Sundt Generating Station	AZ	Non-Small Company	335	129
8223	387	UniSource Energy -- Tucson Electric Power Co	Springerville	AZ	Non-Small Company	336	129
10672	388	US Operating Services Company	Cedar Bay Generating Company LP	FL	Non-Small Company	337	130
10566	389	US Operating Services Company	Chambers Cogeneration LP	NJ	Non-Small Company	338	130
50976	390	US Operating Services Company	Indiantown Cogeneration LP	FL	Non-Small Company	339	130
10043	391	US Operating Services Company	Logan Generating Company LP	NJ	Non-Small Company	340	130
50888	392	US Operating Services Company	Northampton Generating Company LP	PA	Non-Small Company	341	130
50974	393	US Operating Services Company	Scrubgrass Generating Company LP	PA	Non-Small Company	342	130
10773	394	Virginia Electric & Power Co	Altavista Power Station	VA	Non-Small Company	343	131
3796	395	Virginia Electric & Power Co	Bremo Bluff	VA	Non-Small Company	344	131
3803	396	Virginia Electric & Power Co	Chesapeake	VA	Non-Small Company	345	131
3797	397	Virginia Electric & Power Co	Chesterfield	VA	Non-Small Company	346	131
7213	398	Virginia Electric & Power Co	Clover	VA	Non-Small Company	347	131
10771	399	Virginia Electric & Power Co	Hopewell Power Station	VA	Non-Small Company	348	131
52007	400	Virginia Electric & Power Co	Mecklenburg Power Station	VA	Non-Small Company	349	131
3954	401	Virginia Electric & Power Co	Mt Storm	WV	Non-Small Company	350	131
7537	402	Virginia Electric & Power Co	North Branch	WV	Non-Small Company	351	131
10774	403	Virginia Electric & Power Co	Southampton Power Station	VA	Non-Small Company	352	131
3809	404	Virginia Electric & Power Co	Yorktown	VA	Non-Small Company	353	131
6068	405	Westar Energy Inc	Jeffrey Energy Center	KS	Non-Small Company	354	132
1250	406	Westar Energy Inc	Lawrence Energy Center	KS	Non-Small Company	355	132
1252	407	Westar Energy Inc	Tecumseh Energy Center	KS	Non-Small Company	356	132
6823	408	Western Kentucky Energy Corp	D B Wilson	KY	Non-Small Company	357	133
1382	409	Western Kentucky Energy Corp	HMP&L Station Two Henderson	KY	Non-Small Company	358	133
1381	410	Western Kentucky Energy Corp	Kenneth C Coleman	KY	Non-Small Company	359	133
6639	411	Western Kentucky Energy Corp	R D Green	KY	Non-Small Company	360	133
1383	412	Western Kentucky Energy Corp	Robert A Reid	KY	Non-Small Company	361	133
50879	413	Wheelabrator Environmental Systems	Wheelabrator Frackville Energy	PA	Non-Small Company	362	134
7549	414	Wisconsin Electric Power Co	Milwaukee County	WI	Non-Small Company	363	135
6170	415	Wisconsin Electric Power Co	Pleasant Prairie	WI	Non-Small Company	364	135
1769	416	Wisconsin Electric Power Co	Presque Isle	MI	Non-Small Company	365	135
4041	417	Wisconsin Electric Power Co	South Oak Creek	WI	Non-Small Company	366	135
4042	418	Wisconsin Electric Power Co	Valley	WI	Non-Small Company	367	135
8023	419	Wisconsin Power & Light Co	Columbia	WI	Non-Small Company	368	136
4050	420	Wisconsin Power & Light Co	Edgewater	WI	Non-Small Company	369	136
4054	421	Wisconsin Power & Light Co	Nelson Dewey	WI	Non-Small Company	370	136
4072	422	Wisconsin Public Service Corp	Pulliam	WI	Non-Small Company	371	137
4078	423	Wisconsin Public Service Corp	Weston	WI	Non-Small Company	372	137
56	424	Alabama Electric Coop Inc	Charles R Lowman	AL	Non-Small Coop	1	138
160	425	Arizona Electric Pwr Coop Inc	Apache Station	AZ	Non-Small Coop	2	139
2167	426	Associated Electric Coop, Inc	New Madrid	MO	Non-Small Coop	3	140
2168	427	Associated Electric Coop, Inc	Thomas Hill	MO	Non-Small Coop	4	140
6469	428	Basin Electric Power Coop	Antelope Valley	ND	Non-Small Coop	5	141
6204	429	Basin Electric Power Coop	Laramie River Station	WY	Non-Small Coop	6	141
2817	430	Basin Electric Power Coop	Leland Olds	ND	Non-Small Coop	7	141

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
4140	431	Dairyland Power Coop	Alma	WI	Non-Small Coop	8	142
4143	432	Dairyland Power Coop	Genoa	WI	Non-Small Coop	9	142
4271	433	Dairyland Power Coop	John P Madgett	WI	Non-Small Coop	10	142
7790	434	Deseret Generation & Tran Coop	Bonanza	UT	Non-Small Coop	11	143
1384	435	East Kentucky Power Coop, Inc	Cooper	KY	Non-Small Coop	12	144
1385	436	East Kentucky Power Coop, Inc	Dale	KY	Non-Small Coop	13	144
6041	437	East Kentucky Power Coop, Inc	H L Spurlock	KY	Non-Small Coop	14	144
6030	438	Great River Energy	Coal Creek	ND	Non-Small Coop	15	145
2824	439	Great River Energy	Stanton	ND	Non-Small Coop	16	145
2823	440	Minnkota Power Coop, Inc	Milton R Young	ND	Non-Small Coop	17	146
136	441	Seminole Electric Coop, Inc	Seminole	FL	Non-Small Coop	18	147
6061	442	South Mississippi El Pwr Assn	R D Morrow	MS	Non-Small Coop	19	148
6772	443	Western Farmers Elec Coop, Inc	Hugo	OK	Non-Small Coop	20	149
753	444	Crisp County Power Comm	Crisp Plant	GA	Small - County	1	150
1961	445	Austin City of	Austin Northeast	MN	Small City	1	151
1167	446	Board of Water Electric & Communications	Muscatine Plant #1	IA	Small City	2	152
1131	447	Cedar Falls Utilities	Streeter Station	IA	Small City	3	153
2914	448	City of Dover	Dover	OH	Small City	4	154
1825	449	City of Grand Haven	J B Sims	MI	Small City	5	155
1830	450	City of Holland	James De Young	MI	Small City	6	156
6225	451	City of Jasper	Jasper 2	IN	Small City	7	157
1032	452	City of Logansport	Logansport	IN	Small City	8	158
1843	453	City of Marquette	Shiras	MI	Small City	9	159
2144	454	City of Marshall	Marshall	MO	Small City	10	160
4127	455	City of Menasha	Menasha	WI	Small City	11	161
2935	456	City of Orrville	Orrville	OH	Small City	12	162
2936	457	City of Painesville	Painesville	OH	Small City	13	163
1040	458	City of Richmond	Whitewater Valley	IN	Small City	14	164
2943	459	City of Shelby	Shelby Municipal Light Plant	OH	Small City	15	165
6768	460	City of Sikeston	Sikeston Power Station	MO	Small City	16	166
2018	461	City of Virginia	Virginia	MN	Small City	17	167
1024	462	Crawfordsville Electric Light & Power	Crawfordsville	IN	Small City	18	168
2240	463	Fremont City of	Lon Wright	NE	Small City	19	169
59	464	Grand Island City of	Platte	NE	Small City	20	170
2062	465	Greenwood Utilities Comm	Henderson	MS	Small City	21	171
60	466	Hastings City of	Whelan Energy Center	NE	Small City	22	172
1372	467	Henderson City Utility Comm	Henderson I	KY	Small City	23	173
1979	468	Hibbing Public Utilities Comm	Hibbing	MN	Small City	24	174
2682	469	Jamestown Board of Public Util	S A Carlson	NY	Small City	25	175
4125	470	Manitowoc Public Utilities	Manitowoc	WI	Small City	26	176
4259	471	Michigan South Central Power Agency	Endicott Station	MI	Small City	27	177
2001	472	New Ulm Public Utilities Comm	New Ulm	MN	Small City	28	178
1175	473	Pella City of	Pella	IA	Small City	29	179
1037	474	Peru City of	Peru	IN	Small City	30	180
6136	475	Texas Municipal Power Agency	Gibbons Creek	TX	Small City	31	181
2022	476	Willmar Municipal Utils Comm	Willmar	MN	Small City	32	182
1866	477	Wyandotte Municipal Serv Comm	Wyandotte	MI	Small City	33	183
79	478	Aurora Energy LLC	Aurora Energy LLC Chena	AK	Small Company	1	184

Appendix D
Identity of Entities Which Own the 495 Potentially Affected Electric Utility Plants (2007)

Plant Code	Item	Owner Entity Name	Electric Utility Plant Name (NAICS 22)	State	Owner Size/Type	Size/ Type Count	Entity Count
10784	479	Colstrip Energy LP	Colstrip Energy LP	MT	Small Company	2	185
10384	480	Edgecombe Operating Services LLC	Edgecombe Genco LLC	NC	Small Company	3	186
6288	481	Golden Valley Elec Assn Inc	Healy	AK	Small Company	4	187
10343	482	Mount Carmel Cogen Inc	Foster Wheeler Mt Carmel Cogen	PA	Small Company	5	188
50202	483	Niagara Generation LLC	WPS Power Niagara	NY	Small Company	6	189
54634	484	Schuylkill Energy Resource Inc	St Nicholas Cogen Project	PA	Small Company	7	190
54081	485	Spruance Operating Services LLC	Spruance Genco LLC	VA	Small Company	8	191
50835	486	TES Filer City Station LP	TES Filer City Station	MI	Small Company	9	192
54035	487	Westmoreland Partners	Roanoke Valley Energy Facililty I	NC	Small Company	10	193
54755	488	Westmoreland Partners	Roanoke Valley Energy Facility II	NC	Small Company	11	193
10148	489	White Pine Electric Power LLC	White Pine Electric Power	MI	Small Company	12	194
2169	490	Central Electric Power Coop	Chamois	MO	Small Coop	1	195
1218	491	Central Iowa Power Cooperative	Fair Station	IA	Small Coop	2	196
1217	492	Corn Belt Power Coop	Earl F Wisdom	IA	Small Coop	3	197
6183	493	San Miguel Electric Coop, Inc	San Miguel	TX	Small Coop	4	198
976	494	Southern Illinois Power Coop	Marion	IL	Small Coop	5	199
6238	495	Soyland Power Coop Inc	Pearl Station	IL	Small Coop	6	200

Appendix E:

Baseline State Government Regulatory Requirements for CCR Disposal Units in Top-34 Coal Utility States

- **Exhibit E1: Minimum State Groundwater Monitoring Requirements for CCR Landfills**
- **Exhibit E2: Minimum State Groundwater Monitoring Requirements for CCR Impoundments**
- **Exhibit E3: Minimum State Engineering Control Requirements for CCR Landfills for the Top-34 Coal Utility States**
- **Exhibit E4: Minimum State Engineering Control Requirements for CCR Impoundments for the Top-34 Coal Utility States**

Exhibit E1
Minimum State Groundwater Monitoring Requirements for CCR Landfills for Top 34 Coal Utility States [5]

State		Date of Regulation	Monitoring Required	Monitoring Location	Minimum Nr of Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
1	AL	7/26/1996	Yes	unit boundary [1]				Yes
2	AZ [3]	1999	No					No
3	CO	10/9/93 [4]	Yes	unit boundary [1]				Yes
4	FL (new unit construction only)	1/6/93 [4]	Yes	unit boundary		indicator & Appendix VIII	semi-annual	Yes
5	GA	7/1/91 [4]	Yes	unit boundary [1]		Appendix VIII	semi-annual	Yes
6	IA	1971 - 1998 [4] (several amendments)	Yes	unit boundary [1]	1	indicator & Appendix VIII	quarterly (until baseline conditions established) annual (after baseline established)	Yes
7	IL (new units replacing units that existed before 10/9/93)	9/18/90 [4]	Yes	unit boundary [1]	multiple	Appendix VIII	quarterly (first 5 years) annual (after 5 years)	Yes
8	IN (In compliance by 1/1/98)	9/1/89 [4] 4/14/1996 (for closure)	Yes	unit boundary [1]				No
9	KS	5/79 [4] (amended 5/82 through 5/03)	Yes	unit boundary [1]				Yes
10	KY	4/28/1993	Yes		3	indicator	semi-annual	Yes
11	LA (new unit construction only)	5/3/2003	Yes	unit boundary [1]	3		semi-annual	Yes
12	MD	9/16/2002	No					Yes
13	MI (In compliance by 4/19/97)	10/8/93 [4]	Yes	unit boundary [1]		indicator & Appendix VIII	quarterly	Yes
14	MN	6/95 [4]	Yes	unit boundary [1]				Yes
15	MS (new units constructed after 10/9/91)	2/22/1996	Yes	unit boundary [1]				Yes
16	MO (new units	9/97 [4]	Yes	unit boundary [1]	4	Appendix VIII	semi-annual	Yes

Exhibit E1
Minimum State Groundwater Monitoring Requirements for CCR Landfills for Top 34 Coal Utility States [5]

State		Date of Regulation	Monitoring Required	Monitoring Location	Minimum Nr of Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
	constructed after 10/9/93, except all units must comply with post closure monitoring)							
17	MT	6/30/1997	Yes	unit boundary [1]				Yes
18	NC	10/1/1995 [4] (effect. date) 1/1/98 (compliance date)	Yes	unit boundary [1]				No
19	ND	12/1/1992 [4] through 11/02	Yes	unit boundary [1]				Yes
20	NM	11/30/1995	No					No
21	NV (new units constructed after 12/93)	2-Dec	Yes	unit boundary [1]				Yes
22	NY	11/24/1999	Yes	unit boundary [1]				Yes
23	OH	6/1/1994	Yes	unit boundary [1]		indicator & Appendix VIII	semi-annual (for indicators) annual (for metals, TOC, TDS, chloride, sodium and radionuclides)	Yes
24	OK (new unit construction only)	6/1/1994 [4]	Yes	unit boundary [1]	4	indicator	semi-annual	Yes
25	PA	7/4/1992	Yes	unit boundary		indicator	semi-annual (for indicators) annual (for metals and VOCs)	Yes
26	SC	10/25/2002	Yes	unit boundary [1]				Yes
27	TN	3/18/1990 [4]	Yes	unit boundary [1]	3	indicator & Appendix VIII	semi-annual (for indicators) annual (Appendix VIII constituents)	Yes

Exhibit E1
Minimum State Groundwater Monitoring Requirements for CCR Landfills for Top 34 Coal Utility States [5]

State		Date of Regulation	Monitoring Required	Monitoring Location	Minimum Nr of Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
28	TX (new unit construction only, except for post closure monitoring)	3/21/2000	Yes	unit boundary [1]				Yes
29	UT	7/15/1999	Yes		3	indicator & Appendix VIII	semi-annual	Yes
30	VA	5/32/2001	Yes	unit boundary [1]				Yes
31	WA	9/8/2000	Yes	unit boundary [1]				Yes
32	WI (new units constructed after 7/1/96)	Aug 1997	Yes	unit boundary [1]		indicator		Yes
33	WV (new unit construction only)	5/1/1990 [4]	Yes	unit boundary [1]	4	indicator & Appendix VIII	semi-annual	Yes
34	WY	1/1/1998	Yes	unit boundary [1]			semi-annual	Yes

Notes:
1. State regulations regarding monitoring were non-specific. In cases where a specific locations for groundwater monitoring was unavailable or given as within a distance from the waste placement (e.g., “within 500 feet”), Unit Boundary Monitoring was assumed as the least cost alternative. The assumption of Unit Boundary Monitoring may increase the estimated post closure remediation costs.
2. The definition for “solid waste” in the regulations indicates that it does not include fly ash waste from coal combustion/energy production (Title 20, Chapter 9, subpart 1, 105(BV)(2)). No regulations were found for fly ash waste from coal combustion/energy production.
3. The definition is stated in Arizona Code, Chapter 4 Solid Waste Management, Article 1 Section 49.701. "Solid waste landfill" means a facility, area of land or excavation in which solid wastes are placed for permanent disposal. Solid waste landfill does not include a land application unit, surface impoundment, injection well, compost pile or waste pile or an area containing ash from the on-site combustion of coal that does not contain household waste, household hazardous waste or conditionally exempt small quantity generator waste.
4. The date of regulation was retained from the review of state regulations prepared by SAIC Incorporated and submitted to the Municipal, Industrial and Solid Waste Division, Office of Solid Waste, on November 15, 2000.
5. Even though a “no” is specified for a particular engineering control requirement, the State may require the engineering control as a condition under the permit.

Exhibit E2 Minimum State Groundwater Monitoring Requirements for CCR Surface Impoundments for Top 34 Coal Utility States								
Item	State	Date of Regulation	Required Monitoring	Monitoring Location	Minimum Nr of Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
1	AL	None	No					No
2	AZ	9/27/1989 1/1/04 [2]	No					Yes
3	CO (new unit construction only)	8/9/93 [2] 4/4/1997	Yes	unit boundary [1]		indicator	quarterly or annual (depending on groundwater classification)	Yes
4	FL (new unit construction only)	7/1/1982 1/6/1993	Yes	unit boundary [1]	3			No
5	GA	None	No					No
6	IA	None	No					No
7	IL	None	No					No
8	IN	None	No					No
9	KS	5/1/1975 5/1/1987 (amended)	No					No
10	KY (new unit construction only)	8/24/94 [2] through 2003	Yes	unit boundary [1]				Yes
11	LA	5/1/2003	Yes	unit boundary [1]	3		semi-annual	Yes
12	MD	None	No					No
13	MI (new unit construction only)	10/8/93 [2] (monitoring)	Yes (immediate compliance for unlined units only)	unit boundary [1] (if unlined)				Yes
14	MN	6/74 [2]	Yes	unit boundary [1]				No
15	MS (new unit construction only)	2/22/1996	No					No
16	MO	7/97 [2]	Yes	unit boundary [1]	4	Appendix VIII	semi-annual	Yes
17	MT	None	No					No
18	NC (new unit construction only.)	1/4/1994	Yes	unit boundary [1]				Yes
19	ND	12/1/92 [2]	Yes	unit boundary [1]	3		semi-annual	Yes

Exhibit E2
Minimum State Groundwater Monitoring Requirements for CCR Surface Impoundments for Top 34 Coal Utility States

Item	State	Date of Regulation	Required Monitoring	Monitoring Location	Minimum Nr of Wells	Sampling Parameters	Monitoring Frequency	Post-closure Monitoring
20	NM	6/18/1977	No					Yes
21	NV	2-Dec	Yes	unit boundary [1]				Yes
22	NY	11/24/1999	Yes	unit boundary [1]				Yes
23	OH	None	No					No
24	OK	7/1/95 [2]	Yes	unit boundary [1]	3			Yes
25	PA (new unit construction only)	12/23/2000 (amended 3/2001)	Yes	unit boundary [1]		indicator & Appendix VIII	semi-annual (for indicators); annual (for metals & VOCs)	Yes
26	SC	10/25/2002	Yes	unit boundary [1]				Yes
27	TN	3/18/90 [2]	No					Yes
28	TX	None	No					No
29	UT	7/15/1999	Yes	unit boundary [1]				Yes
30	VA	None	No					No
31	WA	9/8/2000	N/A					N/A
32	WI (new unit construction only)	Aug-97	Yes	unit boundary [1]				Yes
33	WV (new unit construction only)	5/1/1990	Yes	unit boundary [1]	3	indicator & Appendix VIII	semi-annual	Yes
34	WY	1/1/1998	No					No

Notes:
1. State regulations regarding monitoring were non-specific. In cases where a specific locations for groundwater monitoring was unavailable or given as within a distance from the waste placement (e.g., “within 500 feet”), Unit Boundary Monitoring was assumed as the least cost alternative. The assumption of Unit Boundary Monitoring may increase the estimated post closure remediation costs.
2. The date of regulation was retained from the review of state regulations prepared by SAIC Incorporated and submitted to the Municipal, Industrial and Solid Waste Division, Office of Solid Waste, on November 15, 2000.

Exhibit E3
Minimum State Engineering Control Requirements for CCR Landfills for the Top 34 Coal Utility States

Item	State	Date of Regulation	Liner?	Leachate Collection System?	Cap?	Financial Assurance?	Daily Cover?	Dust Controls?	Run-on/ Run-off Controls?
1	AL	7/26/1996	composite	Y	synthetic	N	Y	N	Y
2	AZ [3]	1999	N	N	N	N	N	N	N
3	CO	10/9/93 [4] 4/9/1997 for financial assurance	clay or synthetic	Y	clay	Y	N	Y	Y
4	FL (new unit construction only)	1/6/93 [4]	composite or double	Y	synthetic	Y	Y	Y	Y
5	GA	7/1/91 [4]	composite	Y	soil	Y	Y	Y compaction	Y
6	IA	1971-1998 [4] (several amend.)	N	N	clay	Y	N	Y	Y
7	IL (new unit construction after 10/9/93)	9/18/90 [4]	clay or composite	Y	clay or synthetic	Y	Y	Y Compaction	Y
8	IN (In compliance by 1/1/98)	9/1/89 [4] 4/14/96 for closure	clay	Y karst only	Clay	Y	N	Y	Y
9	KS	5/79 [4] (amended 5/82 through 5/2003)	composite	Y	Soil	Y	Y	Y	Y
10	KY	4/28/1993	N	N	Y	Y	Y	N	N
11	LA (new unit construction only)	5/1/2003	composite	Y	clay	Y	Y	Y	Y
12	MD	9/16/2002	N	N	clay	N	Y	N	Y
13	MI (In compliance by April 19, 1997; new units or expansions need financial assurance for most closure costs)	10/8/93 [4]	composite	Y	clay or synthetic	Y	Y	Y	N
14	MN	6/1995 [4]	clay	Y	clay	Y	Y	Y compaction	Y
15	MS (new unit construction after 10/9/91)	2/22/1996	composite	Y	soil	Y	Y	N	Y
16	MO (new units constructed after 10/9/93, except all units must comply with cap and FA reqs)	9/1997 [4]	composite	Y	soil	Y	Y	Y	Y
17	MT	6/30/1997	composite	Y	clay	Y	Y	N	Y
18	NC	10/1/95 [4] effective; 1/1/98 compliance	composite	Y	soil	Y	Y	N	Y
19	ND	12/1/92 [4] through	clay or	Y	clay or	Y	N	Y	N

Exhibit E3
Minimum State Engineering Control Requirements for CCR Landfills for the Top 34 Coal Utility States

Item	State	Date of Regulation	Liner?	Leachate Collection System?	Cap?	Financial Assurance?	Daily Cover?	Dust Controls?	Run-on/ Run-off Controls?
		11/02	synthetic		synthetic			compaction	
20	NM [2]	11/30/1995	N	N	N	N	N	N	N
21	NV (new units after 1993)	2-Dec	composite	Y	soil	Y	Y	Y	Y
22	NY	11/24/1999	composite	Y	synthetic	Y	Y	Y	Y
23	OH	6/1/94 (design criteria/ monitoring) 3/1/96 (operating criteria)	composite	Y	synthetic	Y	Y	Y	Y
24	OK (new unit construction only)	6/1/94 [4]	composite	Y	clay	Y	Y	Y	Y
25	PA	7/4/1992	composite	Y	synthetic	N	Y	Y	Y
26	SC	10/25/2002	composite or clay	Y	synthetic	Y	Y	Y	Y
27	TN	3/18/90 [4]	composite	Y	clay	Y	Y site specific	Y	Y
28	TX (new unit construction, except existing landfills must meet cap and FA reqs)	3/21/2000	composite	Y	synthetic	Y	Y	N	Y
29	UT	7/15/1999	composite	Y	soil	Y	Y	Y	Y
30	VA	5/23/2001	composite	Y	synthetic	Y	Y	Y	Y
31	WA	9/8/2000	composite	Y	synthetic	Y	N	Y	Y
32	WI (new units constructed after 7/1/96)	Aug-97	composite	Y	clay	Y	Y	Y	Y
33	WV (new unit construction, liner permit after 6/2/96)	5/1/90 [4]	composite	Y	soil/clay	Y	Y	Y	Y
34	WY (new unit construction, except existing units must meet FA, daily, and dust reqs.)	1/1/1998	composite	Y	synthetic	Y	N	Y compaction	Y

Notes:
1. Not used.
2. The definition for "solid waste" in the regulations indicates that it does not include fly ash waste from coal combustion/energy production (Title 20, Chapter 9, subpart 1, 105(BV)(2)). No regulations were found for fly ash waste from coal combustion/energy production.
3. The definition as stated in Arizona Code, Chapter 4 Solid Waste Management, Article 1 Section 49.701. "Solid waste landfill" means a facility, area of land or excavation in which solid wastes are placed for permanent disposal. Solid waste landfill does not include a land application unit, surface impoundment, injection well, compost pile or waste pile or an area containing ash from the on-site combustion of coal that does not contain household waste, household hazardous waste or conditionally exempt small quantity generator waste.
4. Date of regulation retained from the review of state regulations prepared by SAIC Inc for the Municipal, Industrial & Solid Waste Division, EPA OSW, 15 Nov 2000.

Exhibit E4
Minimum State Engineering Control Requirements for CCR Surface Impoundments for the Top 34 Coal Utility States

Item	State	Date of Regulation	Liner	Leachate Collection System	Cap	Financial Assurance	Run-on/Run-off Controls
1	AL	None	N	N	N	N	N
2	AZ	9/27/1989 1/1/04 (for new unit construction sites) [1]	N	N	Y synthetic site spec.	Y	N site spec.
3	CO (For new unit construction only)	8/9/93 [1] 4/4/1997	clay or soil deposit	Y	clay or synthetic	Y	N
4	FL	7/1/1982 1/6/1993	composite	Y	N	N	N
5	GA	None	N	N	N	N	N
6	IA	None	N	N	N	N	N
7	IL	None	N	N	N	N	N
8	IN	None	N	N	N	N	N
9	KS	5/1/1975 5/1/1987 (amended)	composite	Y	N	N	N
10	KY	8/24/94 [1] through 2003	composite	Y	synthetic	Y	N
11	LA	5/1/2003	composite	N	clay (if solid waste remains)	Y	Y
12	MD	None	N	N	N	N	N
13	MI (For new unit construction only)	10/8/93 [1] (monitoring) 8/26/1999 (liner requirements)	clay or composite	Y	clay or synthetic	Y	N
14	MN	6/74 [1]	N (yes if within 4 feet of bedrock)	N	N	Y	N
15	MS (For new unit construction only)	2/22/1996	N	N	N	N	N
16	MO	7/97 [1]	Composite	Y	Soil	Y	N
17	MT		N	N	N	N	N
18	NC (For new unit construction only.)	1/4/1994	composite	Y	soil	Y	N
19	ND	12/1/92 [1]	clay or synthetic	Y	clay or synthetic	Y	N

Exhibit E4 Minimum State Engineering Control Requirements for CCR Surface Impoundments for the Top 34 Coal Utility States							
Item	State	Date of Regulation	Liner	Leachate Collection System	Cap	Financial Assurance	Run-on/Run-off Controls
20	NM	6/18/1977	N	N	synthetic	Y	N
21	NV	2-Dec	composite	Y	N	Y	N
22	NY	11/24/1999	composite	Y	N	N	N
23	OH	None	N	N	N	N	N
24	OK	7/1/95 [1]	composite	Y	clay or synthetic	Y	Y
25	PA (For new unit construction, must meet liner reqs)	3/1/2001	composite	Y	clay or synthetic	N	Y
26	SC	10/25/2002	N	N	N	N	N
27	TN	3/18/90 [1]	N	N	synthetic	Y	N
28	TX	None	N	N	N	N	N
29	UT	7/15/1999	N	N	N	Y	N
30	VA		N	N	N	N	N
31	WA	9/8/2000	N	N	N	N	N
32	WI (For new unit construction only)	Aug-97	composite, synthetic or clay.	Y	synthetic	Y	N
33	WV (For new unit construction only)	5/1/1990	composite	Y	N	N	N
34	WY (For new unit construction only)	1/1/1998	composite	N	N	N	N

Notes:
Y = yes; N = no
1. The date of regulation was retained from the review of state regulations prepared by SAIC Incorporated and submitted to the Municipal, Industrial and Solid Waste Division, Office of Solid Waste, on November 15, 2000.

Appendix F:

Baseline Engineering Controls Installed at CCR Disposal Units in the Electric Utility Industry

- **Exhibit F1: List of Engineering Controls for Each of the 337 Landfills (Cost Model Projected Future New Unit Construction)**
- **Exhibit F2: List of Engineering Controls for Each of the 337 Landfills (Existing Units)**
- **Exhibit F3: List of Engineering Controls for Each of the 158 Surface Impoundments (Cost Model Projected Future New Unit Construction)**
- **Exhibit F4: List of Engineering Controls for Each of the 158 Surface Impoundments (Existing Units)**

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

			Groundwater Monitoring		Liner				Cap									
Utility Code	Plant Code	State	UB Mon	150m Mon	Synthetic	Clay	Ash	Leachate Collection System	Synthetic	Clay	Ash	Soil	Clay/ Soil	Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
986	79	AK	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7353	6288	AK	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
195	8	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
195	10	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
195	26	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
18642	47	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
18642	50	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
189	56	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
195	6002	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
34672	50407	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
814	6009	AR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
17698	6138	AR	Y	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
814	6641	AR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
24211	126	AZ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
796	160	AZ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
16572	4941	AZ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
16572	6177	AZ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
24211	8223	AZ	Y	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
52	10002	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
353	10640	CA	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
16061	10768	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
16002	10769	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
6811	54238	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
13060	54626	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
770	462	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	465	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	468	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	477	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
3989	492	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	525	CO	Y	N	Y	N	N	Y	N	Y	N	Y	N	Y	N	Y	Y	Y
30151	527	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	6248	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15143	6761	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

			Groundwater Monitoring		Liner				Cap									
Utility Code	Plant Code	State	UB Mon	150m Mon	Synthetic	Clay	Ash	Leachate Collection System	Synthetic	Clay	Ash	Soil	Clay/ Soil	Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
3989	8219	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
19173	10003	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
9332	594	DE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7860	10030	DE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
21554	136	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
9617	207	FL	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14610	564	FL	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	Y	Y	Y	Y
6455	628	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
7801	641	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
7801	642	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
18454	645	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
6909	663	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
9617	667	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
10623	676	FL	Y	N	Y	N	Y	Y	Y	N	N	Y	N	Y	Y	Y	Y	Y
18454	7242	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14932	10672	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14932	50976	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
7140	703	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	708	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	710	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	727	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	728	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
4538	753	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	6052	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
8286	10604	HI	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9417	1046	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
9417	1058	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
12341	1091	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
554	1122	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
3203	1131	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
13143	1167	IA	Y	N	N	Y	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
14645	1175	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
4363	1217	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
3258	1218	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring UB Mon	Groundwater Monitoring 150m Mon	Liner Synthetic	Liner Clay	Liner Ash	Leachate Collection System	Cap Synthetic	Cap Clay	Cap Ash	Cap Soil	Cap Clay/ Soil	Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
12341	6664	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
12341	7343	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
12384	874	IL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17828	963	IL	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y
17828	964	IL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
520	6017	IL	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	Y	Y	Y	Y
40307	6238	IL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19145	55245	IL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
9269	983	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9324	988	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9273	990	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9273	991	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
3599	992	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9273	994	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
13756	995	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
13756	997	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
17633	1012	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
4508	1024	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
11142	1032	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
14839	1037	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
15989	1040	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
13756	6085	IN	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	N	Y	Y	N
15470	6113	IN	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	N	Y	Y	N
17633	6137	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9324	6166	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9267	6213	IN	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	N	Y	Y	N
9667	6225	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
18315	108	KS	Y	N	Y	N	Y	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
5860	1239	KS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
10000	1241	KS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
22500	1250	KS	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
22500	1252	KS	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
22500	6068	KS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
22053	1353	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
10171	1356	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
11249	1363	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
11249	1364	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
8449	1372	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
18642	1378	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
18642	1379	KY	Y	N	N	N	N	N	Y	Y	N	N	N	Y	Y	N	N	Y
20546	1381	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
20546	1382	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
20546	1383	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
5580	1384	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
55729	6018	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
5580	6041	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
11249	6071	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
20546	6639	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
20546	6823	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
3265	51	LA	Y	N	Y	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
12628	1571	MD	Y	N	N	N	N	N	N	Y	N	Y	N	N	Y	N	Y	Y
12653	1572	MD	Y	N	N	N	N	N	N	Y	N	Y	N	N	Y	N	Y	Y
12653	1573	MD	Y	N	N	N	N	N	N	Y	N	Y	N	N	Y	N	Y	Y
54784	10495	ME	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4254	1695	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
4254	1710	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
4254	1720	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
4254	1723	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	1731	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	1733	MI	Y	N	Y	N	N	Y	Y	Y	N	N	N	Y	Y	Y	N	Y
5109	1740	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	1743	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	1745	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
20847	1769	MI	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	Y	Y	N	Y
19578	1771	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
7483	1825	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
8723	1830	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
11701	1843	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring: UB Mon	Groundwater Monitoring: 150m Mon	Liner: Synthetic	Liner: Clay	Liner: Ash	Leachate Collection System	Cap: Synthetic	Cap: Clay	Cap: Ash	Cap: Soil	Cap: Clay/ Soil	Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
21048	1866	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
12807	4259	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	6034	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
1951	10148	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
18414	50835	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
12647	1891	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
12647	1897	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13781	1904	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13781	1915	MN	Y	N	Y	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13781	1927	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
14232	1943	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
1009	1961	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
8543	1979	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13488	2001	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
16181	2008	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
19883	2018	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
20737	2022	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13781	6090	MN	Y	N	Y	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
12647	10075	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
12647	10686	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
10000	2079	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
10000	2080	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
770	2094	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
4045	2123	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
11732	2144	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
17833	2161	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
924	2168	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
3242	2169	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
9231	2171	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
17833	6195	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
17177	6768	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
12686	2049	MS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	Y
7651	2062	MS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	Y
17568	6061	MS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	Y

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring: UB Mon	Groundwater Monitoring: 150m Mon	Liner: Synthetic	Liner: Clay	Liner: Ash	Leachate Collection System	Cap: Synthetic	Cap: Clay	Cap: Ash	Cap: Soil	Cap: Clay/Soil	Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
12686	6073	MS	Y	N	Y	Y	N	Y	N	N	N	Y	N	Y	Y	N	Y	Y
3593	55076	MS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	Y
15298	6076	MT	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	N	Y	Y
12199	6089	MT	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	N	Y	Y
4217	10784	MT	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	N	Y	Y
16233	55749	MT	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	N	Y	Y
3046	2706	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
3046	2712	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
5416	2718	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
5416	2721	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
5416	2727	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
3046	6250	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
5416	8042	NC	Y	N	Y	N	Y	Y	N	N	N	Y	N	Y	Y	N	Y	N
54708	10379	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
13695	10380	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
54889	10381	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
13695	10382	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
55808	54035	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
55808	54755	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
12199	2790	ND	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	N	Y	N	Y
1307	2817	ND	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	N	Y	N	Y
12658	2823	ND	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	N	Y	N	Y
7570	2824	ND	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	N	Y	N	Y
7570	6030	ND	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	N	Y	N	Y
1307	6469	ND	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	N	Y
14232	8222	ND	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	N	Y
8245	60	NE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
6779	2240	NE	Y	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	N
13337	2277	NE	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
14127	2291	NE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
13337	6077	NE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
14127	6096	NE	N	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	N
15472	2364	NH	Y	N	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
19856	2434	NJ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring: UB Mon	Groundwater Monitoring: 150m Mon	Liner: Synthetic	Liner: Clay	Liner: Ash	Leachate Collection System	Cap: Synthetic	Cap: Clay	Cap: Ash	Cap: Soil	Cap: Clay/ Soil	Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
14932	10043	NJ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
30151	87	NM	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
15473	2451	NM	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
13407	2324	NV	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
17166	8224	NV	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
5511	2480	NY	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	Y	Y	Y	Y
25	2527	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
22125	2535	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
13168	2549	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
13579	2554	NY	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
16183	2642	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
9645	2682	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
22129	6082	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
1746	10464	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
55807	50202	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19194	50651	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
3006	2828	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
3542	2830	OH	Y	N	Y	N	Y	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
4062	2840	OH	Y	N	Y	N	N	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y
4922	2850	OH	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14165	2861	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14006	2872	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
6526	2878	OH	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	Y	Y	Y	Y
5336	2914	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14194	2935	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14381	2936	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17043	2943	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
3542	6019	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
40577	7286	OH	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y
14006	8102	OH	Y	N	Y	N	N	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y
7490	165	OK	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
15474	2963	OK	Y	N	Y	N	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
15248	6106	OR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
17235	3113	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring UB Mon	Groundwater Monitoring 150m Mon	Liner Synthetic	Liner Clay	Liner Ash	Leachate Collection System	Cap Synthetic	Cap Clay	Cap Ash	Cap Soil	Cap Clay/ Soil	Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
15873	3118	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
12384	3122	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
15998	3130	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
17235	3131	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
15873	3136	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
14165	3138	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
22001	3152	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
19391	3176	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
23279	3178	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
23279	3179	PA	Y	N	Y	N	Y	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
23279	3181	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
14165	8226	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
7199	10113	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
9379	10143	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
49889	10343	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
5670	10603	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
2884	10641	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
13833	50039	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
21025	50611	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
14432	50776	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
20541	50879	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
14932	50888	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
14932	50974	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
4129	54144	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
16793	54634	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
17539	3287	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17554	3298	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17543	6249	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17539	7210	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
56190	7652	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17539	7737	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19545	3325	SD	N	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
14232	6098	SD	N	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	N
18642	3393	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

			Groundwater Monitoring		Liner				Cap									
Utility Code	Plant Code	State	UB Mon	150m Mon	Synthetic	Clay	Ash	Leachate Collection System	Synthetic	Clay	Ash	Soil	Clay/ Soil	Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
18642	3396	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
18642	3399	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
18642	3403	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
18642	3405	TN	Y	N	Y	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
18642	3407	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
54888	298	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
54888	3470	TX	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
19323	3497	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
18715	6136	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
17698	6139	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
19323	6146	TX	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	Y	N	Y	Y
19323	6147	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
16604	6181	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
19323	6648	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
54891	7030	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
16604	7097	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
17698	7902	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
35120	54972	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
14354	3644	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
14354	6165	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
11208	6481	UT	Y	N	Y	N	Y	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
40230	7790	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
14354	8069	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
21734	50951	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
733	3775	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
733	3776	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
12588	3788	VA	Y	N	Y	N	N	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y
19876	3809	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	7213	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	10771	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	10773	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	10774	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	52007	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19099	3845	WA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	Y	Y

Exhibit F1
List of Engineering Controls for Each of the 337 Landfills (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
13781	3982	WI	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
20856	4050	WI	Y	N	Y	N	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
20860	4072	WI	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
11571	4125	WI	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
12298	4127	WI	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
4716	4140	WI	Y	N	Y	N	Y	Y	N	Y	Y	N	N	Y	Y	Y	Y	Y
4716	4143	WI	Y	N	Y	N	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
12435	4146	WI	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
4716	4271	WI	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
20847	7549	WI	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
20856	8023	WI	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
733	3935	WV	Y	N	Y	Y	N	Y	N	Y	N	N	Y	Y	Y	Y	Y	Y
733	3938	WV	Y	N	Y	Y	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
12796	3942	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
12796	3943	WV	Y	N	Y	N	N	Y	N	N	N	Y	Y	Y	Y	Y	Y	Y
23279	3944	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
12796	3945	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
12796	3946	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
14006	3948	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
19876	3954	WV	Y	N	Y	Y	N	Y	N	N	N	Y	Y	Y	Y	Y	Y	Y
23279	6004	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
733	6264	WV	Y	N	Y	N	N	Y	N	N	N	Y	Y	Y	Y	Y	Y	Y
19876	7537	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
563	10151	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
12949	10743	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
19545	4150	WY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	Y	Y
19545	4151	WY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	Y	Y
14354	4158	WY	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	N	Y	Y	Y
1307	6204	WY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	Y	Y
19545	7504	WY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	Y	Y
14354	8066	WY	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	N	Y	Y	Y
19545	55479	WY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	Y	Y

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
986	79	AK	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7353	6288	AK	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
195	8	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
195	10	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
195	26	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
18642	47	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
18642	50	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
189	56	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
195	6002	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
34672	50407	AL	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	N	Y	Y
814	6009	AR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
17698	6138	AR	Y	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
814	6641	AR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
24211	126	AZ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
796	160	AZ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
16572	4941	AZ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
16572	6177	AZ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
24211	8223	AZ	Y	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
52	10002	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
353	10640	CA	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
16061	10768	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
16002	10769	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
6811	54238	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
13060	54626	CA	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
770	462	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	465	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	468	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	477	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
3989	492	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	525	CO	Y	N	Y	N	N	Y	N	Y	N	Y	N	Y	N	Y	Y	Y
30151	527	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15466	6248	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
15143	6761	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
3989	8219	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
19173	10003	CO	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	N	Y	Y	Y
9332	594	DE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7860	10030	DE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
21554	136	FL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9617	207	FL	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
14610	564	FL	Y	N	N	N	N	N	N	N	N	Y	N	N	N	N	N	N
6455	628	FL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7801	641	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
7801	642	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
18454	645	FL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
6909	663	FL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9617	667	FL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
10623	676	FL	Y	N	N	N	Y	N	N	N	N	Y	N	N	N	N	N	N
18454	7242	FL	Y	N	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
14932	10672	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14932	50976	FL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
7140	703	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	708	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	710	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	727	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	728	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
4538	753	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
7140	6052	GA	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
8286	10604	HI	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9417	1046	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
9417	1058	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
12341	1091	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
554	1122	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
3203	1131	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
13143	1167	IA	Y	N	N	Y	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
14645	1175	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
4363	1217	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
3258	1218	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
12341	6664	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
12341	7343	IA	Y	N	N	N	N	N	N	Y	N	N	N	Y	N	Y	Y	Y
12384	874	IL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17828	963	IL	Y	N	N	Y	N	N	N	Y	N	N	N	N	N	N	N	N
17828	964	IL	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
520	6017	IL	Y	N	Y	N	N	N	N	N	N	Y	N	N	N	N	N	N
40307	6238	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
19145	55245	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9269	983	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9324	988	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9273	990	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9273	991	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
3599	992	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9273	994	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
13756	995	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
13756	997	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
17633	1012	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
4508	1024	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
11142	1032	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
14839	1037	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
15989	1040	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
13756	6085	IN	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	N	Y	Y	N
15470	6113	IN	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	N	Y	Y	N
17633	6137	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9324	6166	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
9267	6213	IN	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	N	Y	Y	N
9667	6225	IN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	N	Y	Y	N
18315	108	KS	Y	N	Y	N	Y	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
5860	1239	KS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
10000	1241	KS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
22500	1250	KS	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
22500	1252	KS	Y	N	Y	Y	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
22500	6068	KS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
22053	1353	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
10171	1356	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
11249	1363	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
11249	1364	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
8449	1372	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
18642	1378	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
18642	1379	KY	Y	N	N	N	N	N	Y	Y	N	N	N	Y	Y	N	N	Y
20546	1381	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
20546	1382	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
20546	1383	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
5580	1384	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
55729	6018	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
5580	6041	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
11249	6071	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
20546	6639	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
20546	6823	KY	Y	N	N	N	N	N	Y	N	N	N	N	Y	Y	N	N	Y
3265	51	LA	Y	N	N	Y	N	N	N	Y	N	N	N	N	N	N	N	N
12628	1571	MD	Y	N	N	N	N	N	N	Y	N	Y	N	N	Y	N	Y	Y
12653	1572	MD	Y	N	N	N	N	N	N	Y	N	Y	N	N	Y	N	Y	Y
12653	1573	MD	Y	N	N	N	N	N	N	Y	N	Y	N	N	Y	N	Y	Y
54784	10495	ME	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4254	1695	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
4254	1710	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
4254	1720	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
4254	1723	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	1731	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	1733	MI	Y	N	Y	N	N	Y	Y	Y	N	N	N	Y	Y	Y	N	Y
5109	1740	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	1743	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	1745	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
20847	1769	MI	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	Y	Y	N	Y
19578	1771	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
7483	1825	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
8723	1830	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
11701	1843	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
21048	1866	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
12807	4259	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
5109	6034	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
1951	10148	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
18414	50835	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	N	Y
12647	1891	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
12647	1897	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13781	1904	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13781	1915	MN	Y	N	Y	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13781	1927	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
14232	1943	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
1009	1961	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
8543	1979	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13488	2001	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
16181	2008	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
19883	2018	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
20737	2022	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
13781	6090	MN	Y	N	Y	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
12647	10075	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
12647	10686	MN	Y	N	N	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
10000	2079	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
10000	2080	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
770	2094	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
4045	2123	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
11732	2144	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
17833	2161	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
924	2168	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
3242	2169	MO	N	N	N	N	N	N	N	N	N	Y	N	Y	N	N	N	Y
9231	2171	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
17833	6195	MO	N	N	N	N	N	N	N	N	N	Y	N	Y	N	N	N	Y
17177	6768	MO	N	N	N	N	N	N	N	N	N	Y	N	Y	N	N	N	Y
12686	2049	MS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	Y
7651	2062	MS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	Y
17568	6061	MS	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
12686	6073	MS	N	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
3593	55076	MS	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	Y
15298	6076	MT	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	N	Y	Y
12199	6089	MT	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	N	Y	Y
4217	10784	MT	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	N	Y	Y
16233	55749	MT	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	N	Y	Y
3046	2706	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
3046	2712	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
5416	2718	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
5416	2721	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
5416	2727	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
3046	6250	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
5416	8042	NC	Y	N	Y	N	Y	Y	N	N	N	Y	N	Y	Y	N	Y	N
54708	10379	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
13695	10380	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
54889	10381	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
13695	10382	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
55808	54035	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
55808	54755	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	N	Y	N
12199	2790	ND	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	N	Y	N	Y
1307	2817	ND	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	N	Y	N	Y
12658	2823	ND	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	N	Y	N	Y
7570	2824	ND	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	N	Y	N	Y
7570	6030	ND	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	N	Y	N	Y
1307	6469	ND	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	N	Y
14232	8222	ND	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	N	Y
8245	60	NE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
6779	2240	NE	Y	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	N
13337	2277	NE	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
14127	2291	NE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
13337	6077	NE	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
14127	6096	NE	N	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	N
15472	2364	NH	Y	N	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
19856	2434	NJ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
14932	10043	NJ	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
30151	87	NM	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
15473	2451	NM	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
13407	2324	NV	Y	N	N	N	N	N	N	N	N	Y	N	N	N	N	N	N
17166	8224	NV	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
5511	2480	NY	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	Y	Y	Y	Y
25	2527	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
22125	2535	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
13168	2549	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
13579	2554	NY	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
16183	2642	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
9645	2682	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
22129	6082	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
1746	10464	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
55807	50202	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19194	50651	NY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
3006	2828	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
3542	2830	OH	Y	N	Y	N	Y	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
4062	2840	OH	Y	N	Y	N	N	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y
4922	2850	OH	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14165	2861	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14006	2872	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
6526	2878	OH	Y	N	Y	N	N	Y	Y	N	N	Y	N	Y	Y	Y	Y	Y
5336	2914	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14194	2935	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
14381	2936	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17043	2943	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
3542	6019	OH	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
40577	7286	OH	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y
14006	8102	OH	Y	N	Y	N	N	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y
7490	165	OK	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
15474	2963	OK	Y	N	Y	N	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
15248	6106	OR	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
17235	3113	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
15873	3118	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
12384	3122	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
15998	3130	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
17235	3131	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
15873	3136	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
14165	3138	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
22001	3152	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
19391	3176	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
23279	3178	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
23279	3179	PA	Y	N	Y	N	Y	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
23279	3181	PA	Y	N	Y	N	N	Y	Y	N	N	Y	N	N	Y	Y	Y	Y
14165	8226	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
7199	10113	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
9379	10143	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
49889	10343	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
5670	10603	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
2884	10641	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
13833	50039	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
21025	50611	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
14432	50776	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
20541	50879	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
14932	50888	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
14932	50974	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
4129	54144	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
16793	54634	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	Y	Y	Y	Y
17539	3287	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17554	3298	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17543	6249	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17539	7210	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
56190	7652	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
17539	7737	SC	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19545	3325	SD	N	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
14232	6098	SD	N	N	N	N	N	N	N	Y	N	N	N	N	N	N	N	N
18642	3393	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil					
18642	3396	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
18642	3399	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
18642	3403	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
18642	3405	TN	Y	N	Y	Y	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
18642	3407	TN	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
54888	298	TX	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N	N	Y
54888	3470	TX	Y	N	N	Y	N	N	Y	N	N	N	N	Y	N	N	N	Y
19323	3497	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
18715	6136	TX	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N	N	Y
17698	6139	TX	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N	N	Y
19323	6146	TX	Y	N	N	Y	N	N	Y	Y	N	N	N	Y	N	N	N	Y
19323	6147	TX	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N	N	Y
16604	6181	TX	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N	N	Y
19323	6648	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
54891	7030	TX	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N	N	Y
16604	7097	TX	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N	N	Y
17698	7902	TX	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N	N	Y
35120	54972	TX	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	N	Y	Y
14354	3644	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
14354	6165	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
11208	6481	UT	Y	N	Y	N	Y	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
40230	7790	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
14354	8069	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
21734	50951	UT	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	Y	Y	Y	Y
733	3775	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
733	3776	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
12588	3788	VA	Y	N	Y	N	N	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y
19876	3809	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	7213	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	10771	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	10773	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	10774	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19876	52007	VA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	Y	Y	Y	Y
19099	3845	WA	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	Y	Y

Exhibit F2
List of Engineering Controls for Each of the 337 Landfills (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring: UB Mon	Groundwater Monitoring: 150m Mon	Liner: Synthetic	Liner: Clay	Liner: Ash	Leachate Collection System	Cap: Synthetic	Cap: Clay	Cap: Ash	Cap: Soil	Cap: Clay/ Soil	Financial Assurance	Daily Cover	Dust Controls	Run-on/ Run-off	Post Closure Mon.
13781	3982	WI	Y	N	Y	N	N	Y	N	Y	N	N	N	Y	Y	Y	Y	Y
20856	4050	WI	Y	N	Y	N	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
20860	4072	WI	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
11571	4125	WI	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
12298	4127	WI	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4716	4140	WI	Y	N	Y	N	Y	N	N	N	Y	N	N	N	N	N	N	N
4716	4143	WI	Y	N	Y	N	N	Y	N	Y	N	Y	N	Y	Y	Y	Y	Y
12435	4146	WI	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4716	4271	WI	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
20847	7549	WI	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
20856	8023	WI	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
733	3935	WV	Y	N	Y	Y	N	Y	N	Y	N	N	Y	Y	Y	Y	Y	Y
733	3938	WV	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
12796	3942	WV	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
12796	3943	WV	Y	N	Y	N	N	Y	N	N	N	Y	Y	Y	Y	Y	Y	Y
23279	3944	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
12796	3945	WV	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
12796	3946	WV	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
14006	3948	WV	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
19876	3954	WV	Y	N	N	Y	N	Y	N	N	N	Y	N	N	N	N	N	N
23279	6004	WV	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
733	6264	WV	Y	N	Y	N	N	Y	N	N	N	Y	Y	Y	Y	Y	Y	Y
19876	7537	WV	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
563	10151	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
12949	10743	WV	Y	N	Y	N	N	Y	N	N	N	N	Y	Y	Y	Y	Y	Y
19545	4150	WY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	Y	Y
19545	4151	WY	Y	N	N	N	N	N	N	N	N	N	N	Y	N	Y	N	N
14354	4158	WY	Y	N	Y	Y	N	Y	Y	Y	N	N	N	Y	N	Y	Y	Y
1307	6204	WY	Y	N	N	N	N	N	N	N	N	N	N	Y	N	Y	N	N
19545	7504	WY	Y	N	N	N	N	N	N	N	N	N	N	Y	N	Y	N	N
14354	8066	WY	Y	N	N	N	N	N	N	N	N	Y	N	Y	N	Y	N	N
19545	55479	WY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	Y	Y	Y

Exhibit F3
List of Engineering Controls for Each of the 158 Surface Impoundments (New Unit Construction)

			Groundwater Monitoring		Liner			Leachate	Cap							Post
Utility Code	Plant Code	State	UB Mon	150m Mon	Synthetic	Clay	Ash	Collection System	Synthetic	Clay	Ash	Soil	Clay/ Soil	Financial Assurance	Run-on/ Run-off	Closure Mon
195	3	AL	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
195	7	AL	N	N	N	Y	N	N	N	N	N	N	N	N	N	N
195	8	AL	N	N	N	Y	N	N	N	N	N	N	N	N	N	N
195	10	AL	N	N	N	Y	N	N	N	N	N	N	N	N	N	N
18642	47	AL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
18642	50	AL	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
189	56	AL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
195	6002	AL	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N
17698	6138	AR	N	N	N	N	N	N	N	N	N	N	N	N	N	N
803	113	AZ	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N
796	160	AZ	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N
16572	6177	AZ	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N
15143	6761	CO	Y	N	N	Y	N	Y	Y	N	N	N	N	Y	N	N
7801	643	FL	Y	N	Y	N	N	Y	N	N	N	N	N	N	N	N
18454	645	FL	Y	N	Y	N	N	Y	N	N	N	N	N	N	N	N
7140	703	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7140	709	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7140	733	GA	N	N	N	N	N	N	N	N	N	Y	N	N	N	N
7140	6052	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7140	6124	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7140	6257	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9417	1047	IA	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N
12341	1082	IA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
12341	1091	IA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
12341	6664	IA	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N
49756	856	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
520	863	IL	Y	N	Y	N	N	N	N	N	N	N	N	N	N	N
520	864	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
5517	889	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
5517	891	IL	Y	N	Y	N	N	N	N	N	N	N	N	N	N	N
5517	892	IL	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N
5517	897	IL	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N
5517	898	IL	Y	N	Y	N	N	Y	N	N	N	N	N	N	N	N
17828	963	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
49756	6016	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
520	6017	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit F3
List of Engineering Controls for Each of the 158 Surface Impoundments (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Run-on/ Run-off	Post Closure Mon
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil			
9269	983	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9324	988	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9273	990	IN	Y	N	Y	N	N	N	N	N	N	N	N	N	N	N
15470	1001	IN	N	N	N	N	N	N	N	N	N	Y	N	N	N	N
15470	1004	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
15470	1008	IN	N	N	N	Y	N	N	N	N	N	Y	N	N	N	N
15470	1010	IN	N	N	Y	N	N	N	N	N	N	N	N	N	N	N
17633	1012	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9267	1043	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
13756	6085	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
15470	6113	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
17633	6137	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9324	6166	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
261	6705	IN	N	N	N	Y	N	N	N	N	N	N	N	N	N	N
9996	6064	KS	N	N	Y	N	N	Y	N	N	N	N	N	N	N	N
22500	6068	KS	N	N	Y	N	N	Y	N	N	N	N	N	N	N	N
22053	1353	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
10171	1355	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
10171	1356	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
10171	1357	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
10171	1361	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
11249	1363	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
11249	1364	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
18642	1378	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
18642	1379	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
20546	1382	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
5580	1385	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
55729	6018	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
5580	6041	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
11249	6071	KY	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	N	N
20546	6639	KY	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
3265	51	LA	Y	N	Y	N	N	N	N	Y	N	N	N	Y	N	N
11252	6055	LA	Y	N	Y	Y	N	N	N	Y	N	N	N	Y	N	N
23279	1570	MD	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4254	1702	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
4254	1720	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
4254	1723	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N

Exhibit F3
List of Engineering Controls for Each of the 158 Surface Impoundments (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring UB Mon	150m Mon	Liner Synthetic	Clay	Ash	Leachate Collection System	Cap Synthetic	Clay	Ash	Soil	Clay/ Soil	Financial Assurance	Run-on/ Run-off	Post Closure Mon
5109	1733	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
56155	1832	MI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
12647	1891	MN	Y	N	N	N	N	N	N	N	N	Y	N	Y	N	N
12647	1893	MN	Y	N	N	N	N	N	N	N	N	N	N	Y	N	N
13781	1904	MN	Y	N	N	N	N	N	N	N	N	N	N	Y	N	N
13781	1927	MN	Y	N	N	N	N	N	N	N	N	N	N	Y	N	N
13781	6090	MN	Y	N	Y	N	N	N	N	N	N	N	N	Y	N	N
5860	2076	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
19436	2103	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
19436	2104	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
19436	2107	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
9231	2132	MO	Y	N	Y	Y	N	Y	N	N	N	Y	N	Y	N	N
924	2167	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
10000	6065	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
19436	6155	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
17177	6768	MO	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
12686	2049	MS	N	N	N	N	N	N	N	N	N	N	N	N	N	N
15298	6076	MT	N	N	N	N	N	N	N	N	N	N	N	N	N	N
3046	2706	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
3046	2708	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
3046	2709	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
3046	2712	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
3046	2713	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
3046	2716	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
5416	2718	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
5416	2720	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
5416	2721	NC	Y	N	Y	Y	N	Y	N	N	N	Y	N	Y	N	N
5416	2723	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
5416	2727	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
5416	2732	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
3046	6250	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
5416	8042	NC	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N	N
1307	2817	ND	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N
12658	2823	ND	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	N	N
30151	87	NM	N	N	N	N	N	N	Y	N	N	N	N	Y	N	N
803	2442	NM	Y	N	Y	N	N	N	Y	N	N	N	N	Y	N	N
3006	2828	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit F3
List of Engineering Controls for Each of the 158 Surface Impoundments (New Unit Construction)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Run-on/ Run-off	Post Closure Mon
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil			
3542	2830	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
3542	2832	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4062	2840	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4062	2843	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4922	2850	OH	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
14006	2872	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
14015	2876	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4922	6031	OH	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N
14006	8102	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
20447	6772	OK	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	N	N
22001	3152	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	N	N
6526	6094	PA	Y	N	Y	N	N	Y	Y	N	N	N	N	N	N	N
17543	130	SC	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
3046	3251	SC	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
5416	3264	SC	Y	N	N	N	N	N	N	Y	N	N	N	N	N	N
17539	3280	SC	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
17539	3295	SC	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
17543	3317	SC	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
17543	3319	SC	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
17543	6249	SC	Y	N	N	N	N	N	N	N	N	N	N	N	N	N
18642	3393	TN	Y	N	N	N	N	N	Y	N	N	N	N	Y	N	N
18642	3396	TN	Y	N	N	N	N	N	Y	N	N	N	N	Y	N	N
18642	3403	TN	Y	N	N	N	N	N	Y	N	N	N	N	Y	N	N
18642	3405	TN	Y	N	N	N	N	N	Y	N	N	N	N	Y	N	N
18642	3406	TN	Y	N	N	N	N	N	Y	N	N	N	N	Y	N	N
18642	3407	TN	Y	N	N	N	N	N	Y	N	N	N	N	Y	N	N
15474	127	TX	N	N	N	N	N	N	N	N	N	N	N	N	N	N
54865	6178	TX	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N
11269	6179	TX	Y	N	N	Y	N	N	N	N	N	N	N	N	N	N
19323	6648	TX	N	N	N	N	N	N	N	N	N	N	N	N	N	N
17698	7902	TX	N	N	N	N	N	N	N	N	N	N	N	N	N	N
11208	6481	UT	Y	N	Y	N	N	N	N	N	N	N	N	Y	N	N
733	3776	VA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
19876	3796	VA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
19876	3797	VA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
19876	3803	VA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
20856	8023	WI	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N	N

Exhibit F3 List of Engineering Controls for Each of the 158 Surface Impoundments (New Unit Construction)																	
			Groundwater Monitoring		Liner			Leachate Collection System	Cap								Post Closure Mon
Utility Code	Plant Code	State	UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil	Financial Assurance	Run-on/ Run-off		
733	3935	WV	Y	N	Y	N	N	Y	N	N	N	N	N	N	N		N
733	3936	WV	Y	N	Y	N	N	Y	N	N	N	N	N	N	N		N
733	3938	WV	Y	N	Y	N	N	Y	N	N	N	N	N	N	N		N
14006	3947	WV	Y	N	Y	N	N	Y	N	N	N	N	N	N	N		N
14006	3948	WV	Y	N	Y	N	N	Y	N	N	N	N	N	N	N		N
733	6264	WV	Y	N	Y	N	N	Y	N	N	N	N	N	N	N		N
14354	4158	WY	N	N	Y	N	N	N	N	N	N	N	N	N	N		N
14354	4162	WY	N	N	Y	N	N	N	N	N	N	N	N	N	N		N
14354	6101	WY	N	N	Y	N	N	N	N	N	N	N	N	N	N		N
1307	6204	WY	Y	N	Y	Y	N	N	N	N	N	N	N	N	N		N
14354	8066	WY	Y	N	Y	N	N	N	N	N	N	N	N	N	N		N

Exhibit F4 List of Engineering Controls for Each of the 158 Surface Impoundments (Existing Units)																
			Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Run-on/ Run-off	Post Closure Mon
Utility Code	Plant Code	State	UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil			
195	3	AL	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
195	7	AL	N	N	N	N	Y	N	N	N	N	N	N	N	N	N
195	8	AL	N	N	N	N	Y	N	N	N	N	N	N	N	N	N
195	10	AL	N	N	N	N	Y	N	N	N	N	N	N	N	N	N
18642	47	AL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
18642	50	AL	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
189	56	AL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
195	6002	AL	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
17698	6138	AR	N	N	N	N	N	N	N	N	N	N	N	N	N	N
803	113	AZ	N	N	N	N	N	N	N	Y	N	N	N	N	Y	N
796	160	AZ	N	N	N	N	N	N	N	Y	N	N	N	N	Y	N
16572	6177	AZ	N	N	N	N	N	N	N	Y	N	N	N	N	Y	N
15143	6761	CO	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7801	643	FL	N	Y	N	Y	N	N	Y	N	N	N	N	N	N	N
18454	645	FL	N	Y	N	Y	N	N	Y	N	N	N	N	N	N	N
7140	703	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7140	709	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7140	733	GA	N	N	N	N	N	N	N	N	N	N	Y	N	N	N
7140	6052	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7140	6124	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
7140	6257	GA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9417	1047	IA	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
12341	1082	IA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
12341	1091	IA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
12341	6664	IA	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
49756	856	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
520	863	IL	N	Y	N	Y	N	N	N	N	N	N	N	N	N	N
520	864	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
5517	889	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
5517	891	IL	N	Y	N	Y	N	N	N	N	N	N	N	N	N	N
5517	892	IL	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
5517	897	IL	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
5517	898	IL	N	Y	N	Y	N	N	Y	N	N	N	N	N	N	N
17828	963	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
49756	6016	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N
520	6017	IL	N	N	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit F4
List of Engineering Controls for Each of the 158 Surface Impoundments (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Run-on/ Run-off	Post Closure Mon
			UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil			
9269	983	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9324	988	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9273	990	IN	N	Y	N	Y	N	N	N	N	N	N	N	N	N	N
15470	1001	IN	N	N	N	N	N	N	N	N	N	N	Y	N	N	N
15470	1004	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
15470	1008	IN	N	N	N	N	Y	N	N	N	N	N	Y	N	N	N
15470	1010	IN	N	N	N	Y	N	N	N	N	N	N	N	N	N	N
17633	1012	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9267	1043	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
13756	6085	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
15470	6113	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
17633	6137	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
9324	6166	IN	N	N	N	N	N	N	N	N	N	N	N	N	N	N
261	6705	IN	N	N	N	N	Y	N	N	N	N	N	N	N	N	N
9996	6064	KS	N	N	N	Y	N	N	Y	N	N	N	N	N	N	N
22500	6068	KS	N	N	N	Y	N	N	Y	N	N	N	N	N	N	N
22053	1353	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
10171	1355	KY	N	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N
10171	1356	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
10171	1357	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
10171	1361	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
11249	1363	KY	N	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N
11249	1364	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
18642	1378	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
18642	1379	KY	N	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N
20546	1382	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
5580	1385	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
55729	6018	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
5580	6041	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
11249	6071	KY	N	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	N
20546	6639	KY	N	N	N	Y	N	N	Y	Y	N	N	N	N	Y	N
3265	51	LA	N	Y	N	Y	N	N	N	N	Y	N	N	N	Y	N
11252	6055	LA	N	Y	N	Y	Y	N	N	N	Y	N	N	N	Y	N
23279	1570	MD	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4254	1702	MI	N	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N
4254	1720	MI	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
4254	1723	MI	N	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N

Exhibit F4
List of Engineering Controls for Each of the 158 Surface Impoundments (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring: UB Mon	Groundwater Monitoring: 150m Mon	Liner: Synthetic	Liner: Clay	Liner: Ash	Leachate Collection System	Cap: Synthetic	Cap: Clay	Cap: Ash	Cap: Soil	Cap: Clay/Soil	Financial Assurance	Run-on/ Run-off	Post Closure Mon
5109	1733	MI	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
56155	1832	MI	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
12647	1891	MN	N	Y	N	N	N	N	N	N	N	N	Y	N	N	N
12647	1893	MN	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
13781	1904	MN	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
13781	1927	MN	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
13781	6090	MN	N	Y	N	Y	N	N	N	N	N	N	N	N	N	N
5860	2076	MO	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
19436	2103	MO	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
19436	2104	MO	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
19436	2107	MO	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
9231	2132	MO	N	Y	N	Y	Y	N	Y	N	N	N	Y	N	Y	N
924	2167	MO	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
10000	6065	MO	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
19436	6155	MO	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
17177	6768	MO	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
12686	2049	MS	N	N	N	N	N	N	N	N	N	N	N	N	N	N
15298	6076	MT	N	N	N	N	N	N	N	N	N	N	N	N	N	N
3046	2706	NC	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
3046	2708	NC	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
3046	2709	NC	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
3046	2712	NC	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
3046	2713	NC	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
3046	2716	NC	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
5416	2718	NC	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
5416	2720	NC	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
5416	2721	NC	N	Y	N	Y	Y	N	Y	N	N	N	Y	N	Y	N
5416	2723	NC	N	N	N	N	N	N	N	N	N	N	N	N	N	N
5416	2727	NC	N	N	N	N	N	N	N	N	N	N	N	N	N	N
5416	2732	NC	N	N	N	N	N	N	N	N	N	N	N	N	N	N
3046	6250	NC	N	Y	N	Y	N	N	Y	N	N	N	Y	N	Y	N
5416	8042	NC	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
1307	2817	ND	N	Y	N	Y	N	N	Y	Y	N	N	N	N	Y	N
12658	2823	ND	N	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	N
30151	87	NM	N	N	N	N	N	N	N	Y	N	N	N	N	Y	N
803	2442	NM	N	Y	N	Y	N	N	N	Y	N	N	N	N	Y	N
3006	2828	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit F4
List of Engineering Controls for Each of the 158 Surface Impoundments (Existing Units)

Utility Code	Plant Code	State	Groundwater Monitoring UB Mon	Groundwater Monitoring 150m Mon	Liner Synthetic	Liner Clay	Liner Ash	Leachate Collection System	Cap Synthetic	Cap Clay	Cap Ash	Cap Soil	Cap Clay/ Soil	Financial Assurance	Run-on/ Run-off	Post Closure Mon
3542	2830	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
3542	2832	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4062	2840	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4062	2843	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4922	2850	OH	N	Y	N	N	N	N	N	N	N	N	N	N	N	N
14006	2872	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
14015	2876	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
4922	6031	OH	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
14006	8102	OH	N	N	N	N	N	N	N	N	N	N	N	N	N	N
20447	6772	OK	N	Y	N	Y	Y	N	Y	Y	N	N	N	N	Y	N
22001	3152	PA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
6526	6094	PA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
17543	130	SC	N	Y	N	N	N	N	N	N	N	N	N	N	Y	N
3046	3251	SC	N	Y	N	N	N	N	N	N	N	N	N	N	Y	N
5416	3264	SC	N	Y	N	N	N	N	N	N	Y	N	N	N	Y	N
17539	3280	SC	N	Y	N	N	N	N	N	N	N	N	N	N	Y	N
17539	3295	SC	N	Y	N	N	N	N	N	N	N	N	N	N	Y	N
17543	3317	SC	N	Y	N	N	N	N	N	N	N	N	N	N	Y	N
17543	3319	SC	N	Y	N	N	N	N	N	N	N	N	N	N	Y	N
17543	6249	SC	N	Y	N	N	N	N	N	N	N	N	N	N	Y	N
18642	3393	TN	N	Y	N	N	N	N	N	Y	N	N	N	N	Y	N
18642	3396	TN	N	Y	N	N	N	N	N	Y	N	N	N	N	Y	N
18642	3403	TN	N	Y	N	N	N	N	N	Y	N	N	N	N	Y	N
18642	3405	TN	N	Y	N	N	N	N	N	Y	N	N	N	N	Y	N
18642	3406	TN	N	Y	N	N	N	N	N	Y	N	N	N	N	Y	N
18642	3407	TN	N	Y	N	N	N	N	N	Y	N	N	N	N	Y	N
15474	127	TX	N	N	N	N	N	N	N	N	N	N	N	N	N	N
54865	6178	TX	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
11269	6179	TX	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
19323	6648	TX	N	N	N	N	N	N	N	N	N	N	N	N	N	N
17698	7902	TX	N	N	N	N	N	N	N	N	N	N	N	N	N	N
11208	6481	UT	N	Y	N	Y	N	N	N	N	N	N	N	N	Y	N
733	3776	VA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
19876	3796	VA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
19876	3797	VA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
19876	3803	VA	N	N	N	N	N	N	N	N	N	N	N	N	N	N
20856	8023	WI	N	N	N	N	N	N	N	N	N	N	N	N	N	N

Exhibit F4 List of Engineering Controls for Each of the 158 Surface Impoundments (Existing Units)																
			Groundwater Monitoring		Liner			Leachate Collection System	Cap					Financial Assurance	Run-on/ Run-off	Post Closure Mon
Utility Code	Plant Code	State	UB Mon	150m Mon	Synthetic	Clay	Ash		Synthetic	Clay	Ash	Soil	Clay/ Soil			
733	3935	WV	N	N	N	N	N	N	N	N	N	N	N	N	N	N
733	3936	WV	N	Y	N	Y	N	N	Y	N	N	N	N	N	Y	N
733	3938	WV	N	N	N	N	N	N	N	N	N	N	N	N	N	N
14006	3947	WV	N	Y	N	Y	N	N	Y	N	N	N	N	N	Y	N
14006	3948	WV	N	Y	N	Y	N	N	Y	N	N	N	N	N	Y	N
733	6264	WV	N	Y	N	Y	N	N	Y	N	N	N	N	N	Y	N
14354	4158	WY	N	N	N	Y	N	N	N	N	N	N	N	N	N	N
14354	4162	WY	N	N	N	Y	N	N	N	N	N	N	N	N	N	N
14354	6101	WY	N	N	N	N	N	N	N	N	N	N	N	N	N	N
1307	6204	WY	N	Y	N	N	Y	N	N	N	N	N	N	N	N	N
14354	8066	WY	N	Y	N	N	N	N	N	N	N	N	N	N	N	N

Appendix G:

Description of CCR Landfill & Surface Impoundment Engineering Control Cost Model

A. Introduction to Cost Model

The CCR landfill and surface impoundment engineering control cost model consists of two electronic (computer) components:

1. Single Disposal Unit Cost Estimation Model: The first component is a Fortran computer programmed cost model which dates back to 1988. This model specifies the various steps and physical units (e.g., specified square footage size and associated quantities of labor, equipment and materials for the specified size) involved in designing, constructing, operating, and closing a landfill or impoundment. Then it combines this information with data on the costs/fees for the physical components to estimate the capital and annual O&M costs of a specified landfill or impoundment. The cost components include a wide range of items, such as land, clearing, excavation, equipment, labor, liner materials, and cover materials. The model was re-run multiple times to generate individual cost estimates for a series of five alternatively-sized landfills and surface impoundments to represent the range of sizes in the population of 495 electric utility plants. The size categories are defined in tons per day of CCR disposed. Each landfill or impoundment is assumed to operate 300 days per year (average number of operating days for coal-fired boilers based on 2005 DOE EIA 767 database). The size categories are 10,000, 50,000, 200,000, 500,000 and 2,000,000 tons of CCR per year. Size is the primary determinant of overall cost; however, landfills and impoundments exhibit increasing returns to scale: the larger the landfill or impoundment, the lower the cost per ton of CCR managed.
2. Plant-by-Plant & Industry-Wide Cost Aggregation Model: The second component of the model consists of cost data and calculations formulated using Excel spreadsheets. This second component computes landfill and impoundment cost curves across the low-to-high annual tonnage size ranges so that a unique baseline and regulatory option cost may be estimated for each of the 495 electric utility plants based on each plant's 2007 aggregate annual CCR tonnage disposed.

Additional details about each of the cost modeling components are supplied below.

B. Cost Model Component #1 of 2: Single Disposal Unit Cost Estimation

- **Facility Design in Model Component #1**

The model's initial computer program routine calculates the physical dimensions and variables of the landfill or impoundment. The model includes several basic assumptions (e.g., the landfill unit is square) but allows the user to specify a range of variables:

- Waste characteristics: quantity, density, and operating life
- Unit dimensions: depth of excavation, below-grade slopes, cover slopes, and height above grade
- Containment and cover designs: drainage systems, cover materials and thicknesses (up to ten layers), containment system materials and thicknesses (up to ten layers), and leachate collection and treatment systems
- Groundwater monitoring options: the algorithm for estimating number of wells and monitoring costs are calculated outside model for CCR landfills and impoundments.

The model then calculates the materials and activities required to support these options:

- Labor inputs: hours needed to design, construct, and operate systems at the facility
- Materials costs: costs for land, heavy machinery and equipment, roads, fencing, fill material, and liner and cover material
- Indirect costs: engineering, testing, quality assurance (QA), contingency, and contractors' fees on materials and installation

Within a model run, the model specifies the components required to construct and operate a landfill and the costs associated with each.

- **Facility Costs in Model Component #1**

The model summarizes the estimated facility costs for each design simulated, calculating costs for direct capital, indirect capital, operation and maintenance, closure, and post-closure. Corrective action costs may apply to some facilities, but these are estimated outside the model because the need for corrective action is estimated through risk assessment and added separately. The corrective action cost methodology is described later in this report.

Direct Capital

Capital costs are substantial for these landfills; they include the large initial costs, such as equipment purchase, land purchase, excavation, site preparation, design, and any environmental monitoring or containment systems. Capital costs also occur intermittently throughout the operating life of the landfill when equipment used to operate the landfill is purchased (i.e., sheepsfoot rollers and water trucks). The number of equipment pieces used depends on the size of the landfill. Capital costs for covering the landfill occur at closure and are discussed below.

Indirect Capital

Indirect capital costs constitute a substantial fraction of the total cost of capital:

- Contractor's fee: profit for construction contractor
- Construction and field expenses: cost of temporary construction and other overhead
- Spare parts: cost of equipment and parts for maintenance
- Contingency: costs for unpredicted events and design changes
- Inspection and testing: cost for a testing company to ensure that design specifications are met
- Quality assurance: additional fee to cover added cost of inspecting, testing, and documenting that design specifications for containment and cover systems have been met

The percentages used for each of these costs are set by the user.

Operation and Maintenance

The model determines the need for labor hours on the basis of the quantity of waste handled; the different categories of labor hours required are linked to the equipment costs described earlier as direct capital costs. Other annual cost components include equipment maintenance and fuel, fees for licenses or permits, environmental-monitoring costs (which are estimated outside the model; discussed below), and costs for leachate management (if applicable). For this analysis, all collected leachate is assumed to be trucked off site to a publicly owned treatment works (POTW).

Closure

The dominant cost at closure is for the final cover applied to the landfill. The model includes the direct and indirect capital cost components for the cover, its design, the appropriate drainage system, and final vegetation for the site.

Post-Closure

Post-closure care costs after the unit no longer accepts waste includes applicable environmental monitoring, leachate treatment, cover and slope maintenance, and annual inspections for a 30-year period of care.

- **Generic Design and Operating Inputs to the Model Component #1**

The model is cable of analyzing a wide range of environmental control options for baseline and regulatory options, so constrained the number of possible user inputs to focus on design variables affected by the proposed rule. The specifications for the baseline and CCR proposed rule design options are discussed later. Other physical design variables were set independently of the requirements so they do not vary over the different options. These variables are described below.

Design Inputs

The landfills and impoundments are assumed to operate in one construction phase (i.e., one large cell or monofill) as a simplifying assumption. All the excavation is done initially and the final cover is placed over the waste at the end of the operating life. Technically, landfill units (as opposed to surface impoundment units) likely are constructed in several phases (e.g., one cell per year).

The compacted dry waste density for landfills is assumed to be 1,190 kg/m^3; the in-situ wet waste density for surface impoundments is assumed to be 900 $kg/m^{3.}$ A compaction factor of 1.25 to convert bulk waste volumes to compacted waste volumes is assumed.

The side slopes of the excavation are set at 3:1 (rise:run). The amount of fill below grade is assumed to be 50 percent for combination fill landfills (with a maximum depth of 15 feet), five percent for pile-design landfills (with a maximum depth of 1 foot), and 100 percent for surface impoundments (with a maximum depth of 15 feet).

The slope of the cover (cap) is set at 0.02:1 (rise:run) with a cover toe slope of 4:1 (rise:run).

Operating Parameters

All the landfills are assumed to either use a combination-fill method or pile-design method of operation. For combination-fill landfills the operator excavates a large trench (monofill area) and places waste both below grade (in the excavation trench) and above grade (in the mound). For a pile-design landfill the operator places wastes above grade (in the mound). The more economical choice (least cost) of constructing a combination fill landfill versus a pile-design landfill is assumed for existing units. The more economical choice of constructing a combination fill landfill versus a pile-design landfill versus off-site commercial landfill is assumed when new units are constructed. All landfill operators are assumed to compact ash in landfills to conserve landfill space and maximize the return on their investment. All impoundments are assumed to have their 100 percent of their capacity below grade. A berm is constructed around the impoundment for use as freeboard. The more economical choice of constructing a surface impoundment versus combination fill landfill versus a pile-design landfill versus off-site commercial landfill is assumed when new units are constructed.

All new landfills and impoundments are assumed to operate for 40 years; existing landfills and impoundments have remaining lives based on either their actual (if known) or estimated start date. Impoundments are closed as landfills with CCR materials left in place. Post-closure care is assumed to extend for 30 years after closure of the unit.

- **Time Value of Money Adjustments to the Engineering Cost Estimates**

The model's unadjusted output presents the sum of all costs (in current, 2009 dollars) for each year of operation and, if applicable, throughout the post-closure period. To apply the results to the economic analysis and take account of the time value of money, the model discounts the costs using a 7% discount rate to provide the present value of the stream of future annual costs.

The cost model generates annual before-tax cost estimates for baseline state-regulated landfills and impoundments, and subtracts costs from the annual before-tax costs for regulated units. The difference equals the incremental cost attributable to the regulation. In estimating the incremental cost per year, the model assumed that the operator will recover the costs over the entire active life of the disposal unit. The present value of the incremental cost estimated by the model for 40 years of operation and for 30 years of post-closure care is annualized over the 40-year operating period. A sample of electric utility industry representatives provided a 40-year estimate for both types of disposal units (landfills and impoundments). This estimate is supported by data provided by industry in the 1995 EPRI Comanagement Survey. In the EPRI Survey, data describing six landfills noted the year the unit was opened and the estimated date of closure. The average life expectancy is 34 years and the median life expectancy is 38 years. Similarly, data provided for 18 surface impoundments indicate an average life expectancy of 45 years and a median life expectancy of 46 years. Therefore, a 40-year life expectancy for ash landfills and surface impoundments is assumed. For existing waste management units, the remaining years of the unit's operating life is assumed as the borrowing period (n) for application of new environmental controls (e.g., groundwater monitoring).

Some elements of the regulatory options have different requirements for new and existing landfills and impoundments. This difference has implications for adjustments to the cost model results, and the approach taken is described next.

New Landfills and Impoundments

All requirements that affect new units are assumed to apply from the time construction begins. The incremental cost is the cost difference between replacing the unit with a new regulated unit and a new state-regulated unit, taking into account the time at which construction begins. The model assumed that each landfill identified will be replaced at the end of its active life with a new landfill that conforms to the appropriate requirements. If the landfill is estimated to close before the effective date of the rule (2012), the model assumed a new state-regulated unit would be opened. This assumption provides a reasonable upper-bound estimate of the regulatory costs because it does not allow for lower-cost compliance approaches, such as regionalized units or beneficial use.

Existing Landfills and Impoundments

The approach for estimating costs for existing units is more complicated. As described for new units, a landfill owner is likely to estimate all the costs that will be incurred over the lifetime of the unit and the revenue required to offset those costs. If EPA promulgates new regulations applicable to the unit, any incremental costs are added to the cost burden for which the owner has already planned. The key point is that between the first year of operation and the year in which new rules take effect, the owner has no notion of the increase and did not set aside funds for such contingencies.

If a landfill has an expected life of 40 years and has 10 years remaining, all the costs paid over the first 30 years are considered sunk costs and do not affect the calculation of incremental costs resulting from the regulation. The difference measured is the increase in costs (over the remaining life) brought about by the new regulations. These could include capital costs for new equipment in the year the regulation become effective, incremental O&M costs in subsequent years of operation, incremental closure costs assuming more stringent closure requirements, continued monitoring costs after closure, and, possibly, corrective action.

The incremental present-value costs of such requirements can be annualized over the remaining life of the landfill or impoundment or some of the costs can be passed on to future landfills and impoundments, particularly when publicly owned. The longer the remaining life of the unit, the smaller the incremental cost and the less likely that costs will be passed on to the future. For this analysis costs to comply with the regulation at existing units are annualized over the remaining life of the landfill or impoundment. This assumption provides an upper-bound estimate of the regulatory costs.

- **Combination of New and Existing Units**

To develop a combined estimate of average annualized compliance costs from the regulatory option, the costs for existing units plus new replacement landfills and impoundments have been discounted to a present value that spans the existing landfill’s remaining life plus the ongoing life of the new landfill that is replaced every 40 years for a 50-year time horizon (2012 – 2061). This present value is then annualized over 50 years to calculate a level annual cost of the regulatory option. This figure is the best single point estimate of the overall cost impact of the option; however, it does not reflect the actual cash flows that would be required, particularly for capital costs. Instead, the annualized cost figure represents level annual payments as though the landfill owner borrowed funds to pay capital costs. This combined annualized cost estimate is used to calculate economic impacts.

C. Cost Model Component #2 of 2: Plant-by-Plant and Industry-Wide Cost Aggregation

To estimate the costs and effects of the regulatory options compared to those of the baseline, numerous baseline and regulatory cost equations were developed to account for the variability in state regulatory requirements and site-specific practices being conducted at each landfill or impoundment. For each possible combination of engineering controls (e.g., no controls; groundwater monitoring only; groundwater monitoring and synthetic liner; groundwater monitoring and composite liner; groundwater monitoring and clay cap; groundwater monitoring, clay cap and post-closure monitoring; groundwater monitoring, clay cap and financial assurance; etc.), the model was run for each CCR disposal unit size category (i.e., 10,000, 50,000, 200,000, 500,000 and 2,000,000 tons CCR per year). Cost outputs from model runs were entered into an Excel spreadsheet. A linear cost equation in the form of Y = aX + b using regression functions available in Excel Spreadsheet software were calculated. “Y” represents the total annualized cost estimate for a facility of size “X”. A linear cost equation was developed for each combination of engineering controls.

The cost equations for each proposed engineering control (i.e., technical standard) were entered into a separate Excel spreadsheet developed to estimate annualized cost estimates on a plant-by-plant specific basis. Each plant’s unit size (i.e., tons of CCR landfilled or impounded per year) was entered into the appropriate cost equation to determine the annualized cost estimate. The spreadsheet assigned a cost equation to each plant to estimate baseline costs for their existing units and assigned a second equation to each plant to estimate baseline costs for their projected future new disposal units to replace existing units upon end-of-lifespan (within the future 50-year period-of-analysis). The spreadsheet also assigned a cost equation to each plant to estimate the average annualized total cost for each regulatory option under consideration.

Appendix H:

Baseline Cost Estimates for CCR Disposal by the Electric Utility Industry

- **Exhibit H1: Plant-by-Plant Cost Estimates**
- **Exhibit H2: Entity-by-Entity Cost Estimates for Each Owner Entity**

Exhibit H1
Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants

Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
1	3	Barry	Alabama Power Co	AL	Electric Utility	-	$0	282,900	$10,158,571	282,900	$10,158,571
2	7	Gadsden	Alabama Power Co	AL	Electric Utility	-	$0	34,100	$2,591,342	34,100	$2,591,342
3	8	Gorgas	Alabama Power Co	AL	Electric Utility	48,000	$3,168,622	304,900	$18,976,030	352,900	$22,144,652
4	10	Greene County	Alabama Power Co	AL	Electric Utility	2,500	$645,916	211,900	$12,647,117	214,400	$13,293,033
5	26	E C Gaston	Alabama Power Co	AL	Electric Utility	373,100	$20,152,159	-	$0	373,100	$20,152,159
6	47	Colbert	Tennessee Valley Authority	AL	Electric Utility	262,900	$14,395,205	29,200	$1,111,011	292,100	$15,506,216
7	50	Widows Creek	Tennessee Valley Authority	AL	Electric Utility	796,000	$43,198,524	852,800	$30,342,664	1,648,800	$73,541,188
8	51	Dolet Hills	Cleco Power LLC	LA	Electric Utility	676,600	$36,115,272	51,900	$3,930,017	728,500	$40,045,288
9	56	Charles R Lowman	Alabama Electric Coop Inc	AL	Electric Utility	18,900	$1,648,410	33,100	$1,261,871	52,000	$2,910,281
10	59	Platte	Grand Island City of	NE	Electric Utility	-	$0	-	$0	-	$0
11	60	Whelan Energy Center	Hastings City of	NE	Electric Utility	19,473	$710,021	-	$0	19,473	$710,021
12	79	Aurora Energy LLC Chena	Aurora Energy LLC	AK	NAICS-22 Cogen	17,361	$1,103,027	-	$0	17,361	$1,103,027
13	87	Escalante	Tri-State G & T Assn, Inc	NM	Electric Utility	89,300	$1,416,196	15,700	$721,300	105,000	$2,137,495
14	108	Holcomb	Sunflower Electric Power Corp	KS	Electric Utility	121,800	$7,681,103	-	$0	121,800	$7,681,103
15	113	Cholla	Arizona Public Service Co	AZ	Electric Utility	-	$0	298,000	$11,002,062	298,000	$11,002,062
16	126	H Wilson Sundt Generating Station	Tucson Electric Power Co	AZ	Electric Utility	3,200	$609,634	-	$0	3,200	$609,634
17	127	Oklaunion	Public Service Co of Oklahoma	TX	Electric Utility	-	$0	39,000	$1,408,679	39,000	$1,408,679
18	130	Cross	South Carolina Pub Serv Auth	SC	Electric Utility	-	$0	10,900	$495,112	10,900	$495,112
19	136	Seminole	Seminole Electric Coop, Inc	FL	Electric Utility	710,000	$21,727,619	-	$0	710,000	$21,727,619
20	160	Apache Station	Arizona Electric Pwr Coop Inc	AZ	Electric Utility	139,000	$1,855,464	33,000	$1,124,556	172,000	$2,980,020
21	165	GRDA	Grand River Dam Authority	OK	Electric Utility	148,100	$5,661,224	-	$0	148,100	$5,661,224
22	207	St Johns River Power Park	JEA	FL	Electric Utility	191,400	$9,124,677	-	$0	191,400	$9,124,677

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23	298	Limestone	NRG Texas LLC	TX	NAICS-22 Non-Cogen	1,349,300	$34,417,971	-	$0	1,349,300	$34,417,971
24	384	Joliet 29	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
25	462	W N Clark	Aquila, Inc.	CO	Electric Utility	20,881	$1,822,120	-	$0	20,881	$1,822,120
26	465	Arapahoe	Public Service Co of Colorado	CO	Electric Utility	2,000	$532,331	-	$0	2,000	$532,331
27	468	Cameo	Public Service Co of Colorado	CO	Electric Utility	33,488	$2,600,453	-	$0	33,488	$2,600,453
28	469	Cherokee	Public Service Co of Colorado	CO	Electric Utility	-	$0	-	$0	-	$0
29	470	Comanche	Public Service Co of Colorado	CO	Electric Utility	-	$0	-	$0	-	$0
30	477	Valmont	Public Service Co of Colorado	CO	Electric Utility	54,700	$3,910,042	-	$0	54,700	$3,910,042
31	492	Martin Drake	Colorado Springs City of	CO	Electric Utility	132,100	$8,688,575	-	$0	132,100	$8,688,575
32	525	Hayden	Public Service Co of Colorado	CO	Electric Utility	229,600	$14,675,608	-	$0	229,600	$14,675,608
33	527	Nucla	Tri-State G & T Assn, Inc	CO	Electric Utility	135,600	$8,904,658	-	$0	135,600	$8,904,658
34	564	Stanton Energy Center	Orlando Utilities Comm	FL	Electric Utility	386,400	$11,261,922	-	$0	386,400	$11,261,922
35	568	Bridgeport Station	PSEG Power Connecticut LLC	CT	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
36	593	Edge Moor	Conectiv Delmarva Gen Inc	DE	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
37	594	Indian River Generating Station	Indian River Operations Inc	DE	NAICS-22 Non-Cogen	171,200	$2,571,716	-	$0	171,200	$2,571,716
38	602	Brandon Shores	Constellation Power Source Gen	MD	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
39	628	Crystal River	Progress Energy Florida Inc	FL	Electric Utility	57,100	$1,261,056	-	$0	57,100	$1,261,056
40	641	Crist	Gulf Power Co	FL	Electric Utility	138,800	$8,412,616	-	$0	138,800	$8,412,616
41	642	Scholz	Gulf Power Co	FL	Electric Utility	24,825	$2,067,205	-	$0	24,825	$2,067,205
42	643	Lansing Smith	Gulf Power Co	FL	Electric	-	$0	70,300	$6,556,027	70,300	$6,556,027

Exhibit H1
Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants

Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
					Utility						
43	645	Big Bend	Tampa Electric Co	FL	Electric Utility	850,000	$10,485,470	3,700	$688,967	853,700	$11,174,437
44	663	Deerhaven Generating Station	Gainesville Regional Utilities	FL	Electric Utility	400	$519,887	-	$0	400	$519,887
45	667	Northside Generating Station	JEA	FL	Electric Utility	811,200	$11,271,949	-	$0	811,200	$11,271,949
46	676	C D McIntosh Jr	City of Lakeland	FL	Electric Utility	133,274	$5,633,207	-	$0	133,274	$5,633,207
47	703	Bowen	Georgia Power Co	GA	Electric Utility	1,815,200	$96,636,959	93,300	$3,334,572	1,908,500	$99,971,531
48	708	Hammond	Georgia Power Co	GA	Electric Utility	170,200	$9,497,313	-	$0	170,200	$9,497,313
49	709	Harllee Branch	Georgia Power Co	GA	Electric Utility	-	$0	416,300	$14,603,323	416,300	$14,603,323
50	710	Jack McDonough	Georgia Power Co	GA	Electric Utility	119,790	$6,879,365	-	$0	119,790	$6,879,365
51	727	Mitchell	Georgia Power Co	GA	Electric Utility	29,300	$2,179,936	-	$0	29,300	$2,179,936
52	728	Yates	Georgia Power Co	GA	Electric Utility	382,300	$20,921,749	-	$0	382,300	$20,921,749
53	733	Kraft	Georgia Power Co	GA	Electric Utility	-	$0	10,000	$426,249	10,000	$426,249
54	753	Crisp Plant	Crisp County Power Comm	GA	Electric Utility	110	$472,673	-	$0	110	$472,673
55	856	E D Edwards	Ameren Energy Resources Generating Co.	IL	Electric Utility	-	$0	52,000	$2,487,160	52,000	$2,487,160
56	861	Coffeen	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
57	863	Hutsonville	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	-	$0	31,000	$1,728,949	31,000	$1,728,949
58	864	Meredosia	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	-	$0	48,000	$2,303,876	48,000	$2,303,876
59	867	Crawford	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
60	874	Joliet 9	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	20,600	$2,316,525	-	$0	20,600	$2,316,525
61	876	Kincaid Generation LLC	Dominion Energy Services Co	IL	NAICS-22 Non-	-	$0	-	$0	-	$0

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					Cogen						
62	879	Powerton	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
63	883	Waukegan	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
64	884	Will County	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
65	886	Fisk Street	Midwest Generations EME LLC	IL	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
66	887	Joppa Steam	Electric Energy Inc	IL	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
67	889	Baldwin Energy Complex	Dynegy Midwest Generation Inc	IL		-	$0	116,000	$5,419,702	116,000	$5,419,702
68	891	Havana	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	-	$0	86,000	$4,389,563	86,000	$4,389,563
69	892	Hennepin Power Station	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	-	$0	20,800	$2,258,364	20,800	$2,258,364
70	897	Vermilion	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	-	$0	13,700	$1,610,928	13,700	$1,610,928
71	898	Wood River	Dynegy Midwest Generation Inc	IL	NAICS-22 Non-Cogen	-	$0	14,200	$2,003,530	14,200	$2,003,530
72	963	Dallman	City of Springfield	IL	Electric Utility	102,000	$6,098,818	72,100	$3,408,162	174,100	$9,506,980
73	964	Lakeside	City of Springfield	IL	Electric Utility	11,512	$1,604,173	-	$0	11,512	$1,604,173
74	976	Marion	Southern Illinois Power Coop	IL	Electric Utility	-	$0	-	$0	-	$0
75	981	State Line Energy	State Line Energy LLC	IN	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
76	983	Clifty Creek	Indiana-Kentucky Electric Corp	IN	Electric Utility	113,200	$7,126,862	21,700	$991,839	134,900	$8,118,701
77	988	Tanners Creek	Indiana Michigan Power Co	IN	Electric Utility	242,800	$14,404,932	140,600	$5,909,683	383,400	$20,314,616
78	990	Harding Street	Indianapolis Power & Light Co	IN	Electric Utility	329,000	$19,245,747	175,900	$7,887,938	504,900	$27,133,685
79	991	Eagle Valley	Indianapolis Power	IN	Electric		$4,638,952	-	$0	68,898	$4,638,952

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			& Light Co		Utility	68,898					
80	992	CC Perry K	Citizens Thermal Energy	IN	NAICS-22 Cogen	11,810	$1,402,299	-	$0	11,810	$1,402,299
81	994	AES Petersburg	Indianapolis Power & Light Co	IN	Electric Utility	3,500	$676,778	-	$0	3,500	$676,778
82	995	Bailly	Northern Indiana Pub Serv Co	IN	Electric Utility	168,500	$10,804,093	-	$0	168,500	$10,804,093
83	997	Michigan City	Northern Indiana Pub Serv Co	IN	Electric Utility	25,700	$2,213,041	-	$0	25,700	$2,213,041
84	1001	Cayuga	Duke Energy Indiana Inc	IN	Electric Utility	-	$0	210,900	$9,127,150	210,900	$9,127,150
85	1004	Edwardsport	Duke Energy Indiana Inc	IN	Electric Utility	-	$0	11,500	$569,955	11,500	$569,955
86	1008	R Gallagher	Duke Energy Indiana Inc	IN	Electric Utility	-	$0	125,600	$10,333,601	125,600	$10,333,601
87	1010	Wabash River	Duke Energy Indiana Inc	IN	Electric Utility	-	$0	192,100	$13,005,857	192,100	$13,005,857
88	1012	F B Culley	Southern Indiana Gas & Elec Co	IN	Electric Utility	170,000	$10,356,779	35,600	$1,566,760	205,600	$11,923,539
89	1024	Crawfordsville	Crawfordsville Elec, Lgt & Pwr	IN	Electric Utility	2,027	$697,628	-	$0	2,027	$697,628
90	1032	Logansport	City of Logansport	IN	Electric Utility	6,599	$1,026,950	-	$0	6,599	$1,026,950
91	1037	Peru	Peru City of	IN	Electric Utility	1,887	$687,544	-	$0	1,887	$687,544
92	1040	Whitewater Valley	City of Richmond	IN	Electric Utility	27,729	$2,751,156	-	$0	27,729	$2,751,156
93	1043	Frank E Ratts	Hoosier Energy R E C, Inc	IN	Electric Utility	-	$0	39,800	$1,740,477	39,800	$1,740,477
94	1046	Dubuque	Interstate Power and Light Co	IA	Electric Utility	17,990	$897,464	-	$0	17,990	$897,464
95	1047	Lansing	Interstate Power and Light Co	IA	Electric Utility	-	$0	24,000	$1,895,349	24,000	$1,895,349
96	1048	Milton L Kapp	Interstate Power and Light Co	IA	Electric Utility	-	$0	-	$0	-	$0
97	1058	Sixth Street	Interstate Power and Light Co	IA	Electric Utility	14,193	$845,355	-	$0	14,193	$845,355
98	1073	Prairie Creek	Interstate Power and Light Co	IA	Electric Utility	-	$0	-	$0	-	$0
99	1077	Sutherland	Interstate Power and Light Co	IA	Electric Utility	-	$0	-	$0	-	$0
100	1081	Riverside	MidAmerican Energy Co	IA	Electric Utility	-	$0	-	$0	-	$0
101	1082	Walter Scott Jr Energy Center	MidAmerican Energy Co	IA	Electric Utility	-	$0	104,500	$2,939,779	104,500	$2,939,779

Exhibit H1
Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants

Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
102	1091	George Neal North	MidAmerican Energy Co	IA	Electric Utility	91,500	$1,906,292	50,200	$1,620,941	141,700	$3,527,233
103	1104	Burlington	Interstate Power and Light Co	IA	Electric Utility	-	$0	-	$0	-	$0
104	1122	Ames Electric Services Power Plant	Ames City of	IA	Electric Utility	14,598	$850,913	-	$0	14,598	$850,913
105	1131	Streeter Station	Cedar Falls Utilities	IA	Electric Utility	6,676	$742,194	-	$0	6,676	$742,194
106	1167	Muscatine Plant #1	Board of Water Electric & Communications	IA	Electric Utility	9,700	$1,438,263	-	$0	9,700	$1,438,263
107	1175	Pella	Pella City of	IA	Electric Utility	5,694	$728,717	-	$0	5,694	$728,717
108	1217	Earl F Wisdom	Corn Belt Power Coop	IA	Electric Utility	4,829	$716,846	-	$0	4,829	$716,846
109	1218	Fair Station	Central Iowa Power Cooperative	IA	Electric Utility	20,209	$927,916	-	$0	20,209	$927,916
110	1239	Riverton	Empire District Electric Co	KS	Electric Utility	15,699	$1,534,850	-	$0	15,699	$1,534,850
111	1241	La Cygne	Kansas City Power & Light Co	KS	Electric Utility	282,600	$16,546,347	-	$0	282,600	$16,546,347
112	1250	Lawrence Energy Center	Westar Energy Inc	KS	Electric Utility	115,900	$7,631,131	-	$0	115,900	$7,631,131
113	1252	Tecumseh Energy Center	Westar Energy Inc	KS	Electric Utility	18,900	$1,759,437	-	$0	18,900	$1,759,437
114	1295	Quindaro	Kansas City City of	KS	Electric Utility	-	$0	-	$0	-	$0
115	1353	Big Sandy	Kentucky Power Co	KY	Electric Utility	603,000	$9,324,420	298,300	$22,715,732	901,300	$32,040,152
116	1355	E W Brown	Kentucky Utilities Co	KY	Electric Utility	-	$0	140,500	$13,048,400	140,500	$13,048,400
117	1356	Ghent	Kentucky Utilities Co	KY	Electric Utility	243,000	$3,877,700	634,700	$18,272,622	877,700	$22,150,322
118	1357	Green River	Kentucky Utilities Co	KY	Electric Utility	-	$0	30,600	$2,114,098	30,600	$2,114,098
119	1361	Tyrone	Kentucky Utilities Co	KY	Electric Utility	-	$0	18,900	$1,666,509	18,900	$1,666,509
120	1363	Cane Run	Louisville Gas & Electric Co	KY	Electric Utility	593,100	$9,101,752	37,100	$3,724,190	630,200	$12,825,942
121	1364	Mill Creek	Louisville Gas & Electric Co	KY	Electric Utility	191,300	$3,511,918	64,700	$1,807,605	256,000	$5,319,523
122	1372	Henderson I	Henderson City Utility Comm	KY	Electric Utility	3,909	$693,769	-	$0	3,909	$693,769
123	1374	Elmer Smith	City of Owensboro	KY	Electric Utility	-	$0	-	$0	-	$0

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124	1378	Paradise	Tennessee Valley Authority	KY	Electric Utility	339,500	$5,209,456	557,700	$27,473,973	897,200	$32,683,429
125	1379	Shawnee	Tennessee Valley Authority	KY	Electric Utility	370,300	$5,414,084	61,100	$6,171,166	431,400	$11,585,250
126	1381	Kenneth C Coleman	Western Kentucky Energy Corp	KY	NAICS-22 Non-Cogen	183,900	$3,012,642	-	$0	183,900	$3,012,642
127	1382	HMP&L Station Two Henderson	Western Kentucky Energy Corp	KY	NAICS-22 Non-Cogen	304,100	$5,183,560	12,300	$906,211	316,400	$6,089,771
128	1383	Robert A Reid	Western Kentucky Energy Corp	KY	NAICS-22 Non-Cogen	19,258	$891,515	-	$0	19,258	$891,515
129	1384	Cooper	East Kentucky Power Coop, Inc	KY	Electric Utility	94,300	$1,858,301	-	$0	94,300	$1,858,301
130	1385	Dale	East Kentucky Power Coop, Inc	KY	Electric Utility	-	$0	60,000	$2,776,462	60,000	$2,776,462
131	1393	R S Nelson	Entergy Gulf States Louisiana LLC	LA	Electric Utility	-	$0	-	$0	-	$0
132	1552	C P Crane	Constellation Power Source Gen	MD	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
133	1554	Herbert A Wagner	Constellation Power Source Gen	MD	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
134	1570	R Paul Smith Power Station	Allegheny Energy Supply Co LLC	MD	NAICS-22 Non-Cogen	-	$0	25,100	$987,489	25,100	$987,489
135	1571	Chalk Point LLC	Mirant Chalk Point LLC	MD	NAICS-22 Non-Cogen	167,000	$2,405,813	-	$0	167,000	$2,405,813
136	1572	Dickerson	Mirant Mid-Atlantic LLC	MD	NAICS-22 Non-Cogen	202,000	$2,773,793	-	$0	202,000	$2,773,793
137	1573	Morgantown Generating Plant	Mirant Mid-Atlantic LLC	MD	NAICS-22 Non-Cogen	54,300	$1,220,915	-	$0	54,300	$1,220,915
138	1606	Mount Tom	FirstLight Power Resources Services LLC	MA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
139	1613	Somerset Station	Somerset Power LLC	MA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
140	1619	Brayton Point	Dominion Energy New England, LLC	MA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0

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Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
141	1626	Salem Harbor	Dominion Energy New England, LLC	MA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
142	1695	B C Cobb	Consumers Energy Co	MI	Electric Utility	101,300	$7,459,290	-	$0	101,300	$7,459,290
143	1702	Dan E Karn	Consumers Energy Co	MI	Electric Utility	-	$0	108,800	$12,167,459	108,800	$12,167,459
144	1710	J H Campbell	Consumers Energy Co	MI	Electric Utility	200,400	$13,971,352	-	$0	200,400	$13,971,352
145	1720	J C Weadock	Consumers Energy Co	MI	Electric Utility	7,800	$1,195,837	69,900	$3,613,156	77,700	$4,808,993
146	1723	J R Whiting	Consumers Energy Co	MI	Electric Utility	30,500	$2,805,270	3,400	$824,980	33,900	$3,630,250
147	1731	Harbor Beach	Detroit Edison Co	MI	Electric Utility	13,100	$1,620,137	-	$0	13,100	$1,620,137
148	1733	Monroe	Detroit Edison Co	MI	Electric Utility	121,000	$8,754,264	482,000	$23,685,841	603,000	$32,440,105
149	1740	River Rouge	Detroit Edison Co	MI	Electric Utility	93,702	$6,959,837	-	$0	93,702	$6,959,837
150	1743	St Clair	Detroit Edison Co	MI	Electric Utility	133,900	$9,602,242	-	$0	133,900	$9,602,242
151	1745	Trenton Channel	Detroit Edison Co	MI	Electric Utility	139,000	$9,937,490	-	$0	139,000	$9,937,490
152	1769	Presque Isle	Wisconsin Electric Power Co	MI	Electric Utility	82,100	$6,197,183	-	$0	82,100	$6,197,183
153	1771	Escanaba	Upper Peninsula Power Co	MI	Electric Utility	10,109	$1,380,687	-	$0	10,109	$1,380,687
154	1825	J B Sims	City of Grand Haven	MI	Electric Utility	48,470	$4,453,966	-	$0	48,470	$4,453,966
155	1830	James De Young	City of Holland	MI	Electric Utility	16,586	$1,890,637	-	$0	16,586	$1,890,637
156	1831	Eckert Station	Lansing Board of Water and Light	MI	Electric Utility	-	$0	-	$0	-	$0
157	1832	Erickson Station	Lansing Board of Water and Light	MI	Electric Utility	-	$0	5,100	$909,873	5,100	$909,873
158	1843	Shiras	City of Marquette	MI	Electric Utility	20,705	$2,610,129	-	$0	20,705	$2,610,129
159	1866	Wyandotte	Wyandotte Municipal Serv Comm	MI	Electric Utility	18,593	$2,022,566	-	$0	18,593	$2,022,566
160	1891	Syl Laskin	Minnesota Power Inc	MN	Electric Utility	6,000	$1,069,047	20,200	$2,275,005	26,200	$3,344,052
161	1893	Clay Boswell	Minnesota Power Inc	MN	Electric Utility	-	$0	281,200	$12,906,957	281,200	$12,906,957
162	1897	M L Hibbard	Minnesota Power	MN	Electric		$960,866	-	$0	2,548	$960,866

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			Inc		Utility	2,548					
163	1904	Black Dog	Northern States Power Co	MN	Electric Utility	1,000	$742,057	4,800	$404,320	5,800	$1,146,377
164	1915	Allen S King	Northern States Power Co	MN	Electric Utility	38,600	$3,564,787	-	$0	38,600	$3,564,787
165	1927	Riverside	Northern States Power Co	MN	Electric Utility	14,300	$1,702,012	6,700	$490,148	21,000	$2,192,160
166	1943	Hoot Lake	Otter Tail Power Co	MN	Electric Utility	21,700	$2,145,522	-	$0	21,700	$2,145,522
167	1961	Austin Northeast	Austin City of	MN	Electric Utility	4,967	$1,142,650	-	$0	4,967	$1,142,650
168	1979	Hibbing	Hibbing Public Utilities Comm	MN	Electric Utility	5,623	$1,181,967	-	$0	5,623	$1,181,967
169	2001	New Ulm	New Ulm Public Utilities Comm	MN	Electric Utility	7,134	$1,272,527	-	$0	7,134	$1,272,527
170	2008	Silver Lake	Rochester Public Utilities	MN	Electric Utility	11,900	$1,558,171	-	$0	11,900	$1,558,171
171	2018	Virginia	City of Virginia	MN	Electric Utility	4,608	$1,121,134	-	$0	4,608	$1,121,134
172	2022	Willmar	Willmar Municipal Utils Comm	MN	Electric Utility	4,174	$1,095,123	-	$0	4,174	$1,095,123
173	2049	Jack Watson	Mississippi Power Co	MS	Electric Utility	68,100	$3,855,501	39,100	$1,331,693	107,200	$5,187,194
174	2062	Henderson	Greenwood Utilities Comm	MS	Electric Utility	1,700	$515,373	-	$0	1,700	$515,373
175	2076	Asbury	Empire District Electric Co	MO	Electric Utility	-	$0	53,500	$5,981,342	53,500	$5,981,342
176	2079	Hawthorn	Kansas City Power & Light Co	MO	Electric Utility	161,000	$10,771,907	-	$0	161,000	$10,771,907
177	2080	Montrose	Kansas City Power & Light Co	MO	Electric Utility	53,800	$4,111,073	-	$0	53,800	$4,111,073
178	2094	Sibley	Aquila, Inc.	MO	Electric Utility	51,500	$3,968,834	-	$0	51,500	$3,968,834
179	2098	Lake Road	Aquila, Inc.	MO	Electric Utility	-	$0	-	$0	-	$0
180	2103	Labadie	Union Electric Co	MO	Electric Utility	-	$0	250,000	$26,339,384	250,000	$26,339,384
181	2104	Meramec	Union Electric Co	MO	Electric Utility	-	$0	111,000	$11,206,382	111,000	$11,206,382
182	2107	Sioux	Union Electric Co	MO	Electric Utility	-	$0	102,000	$10,924,601	102,000	$10,924,601
183	2123	Columbia	City of Columbia	MO	Electric Utility	3,223	$803,273	-	$0	3,223	$803,273
184	2132	Blue Valley	Independence City of	MO	Electric Utility	-	$0	29,750	$3,318,596	29,750	$3,318,596

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185	2144	Marshall	City of Marshall	MO	Electric Utility	2,492	$746,753	-	$0	2,492	$746,753
186	2161	James River Power Station	City Utilities of Springfield	MO	Electric Utility	22,500	$2,175,384	-	$0	22,500	$2,175,384
187	2167	New Madrid	Associated Electric Coop, Inc	MO	Electric Utility	-	$0	109,200	$7,810,059	109,200	$7,810,059
188	2168	Thomas Hill	Associated Electric Coop, Inc	MO	Electric Utility	54,000	$4,123,442	-	$0	54,000	$4,123,442
189	2169	Chamois	Central Electric Power Coop	MO	Electric Utility	16,626	$1,067,480	-	$0	16,626	$1,067,480
190	2171	Missouri City	Independence City of	MO	Electric Utility	7,251	$1,114,710	-	$0	7,251	$1,114,710
191	2187	J E Corette Plant	PPL Montana LLC	MT	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
192	2240	Lon Wright	Fremont City of	NE	Electric Utility	5,300	$664,414	-	$0	5,300	$664,414
193	2277	Sheldon	Nebraska Public Power District	NE	Electric Utility	25,800	$1,499,783	-	$0	25,800	$1,499,783
194	2291	North Omaha	Omaha Public Power District	NE	Electric Utility	5,600	$591,590	-	$0	5,600	$591,590
195	2324	Reid Gardner	Nevada Power Co	NV	Electric Utility	141,700	$6,385,615	-	$0	141,700	$6,385,615
196	2364	Merrimack	Public Service Co of NH	NH	Electric Utility	2,600	$657,824	-	$0	2,600	$657,824
197	2367	Schiller	Public Service Co of NH	NH	Electric Utility	-	$0	-	$0	-	$0
198	2378	B L England	RC Cape May Holdings LLC	NJ	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
199	2384	Deepwater	Conectiv Atlantic Generatn Inc	NJ	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
200	2403	PSEG Hudson Generating Station	PSEG Fossil LLC	NJ	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
201	2408	PSEG Mercer Generating Station	PSEG Fossil LLC	NJ	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
202	2434	Howard Down	Vineland City of	NJ	Electric Utility	2,914	$765,683	-	$0	2,914	$765,683
203	2442	Four Corners	Arizona Public Service Co	NM	Electric Utility	-	$0	501,400	$42,735,069	501,400	$42,735,069
204	2451	San Juan	Public Service Co of NM	NM	Electric Utility	184,000	$2,408,353	-	$0	184,000	$2,408,353

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205	2480	Danskammer Generating Station	Dynegy Northeast Gen Inc	NY	NAICS-22 Non-Cogen	24,800	$2,776,579	-	$0	24,800	$2,776,579
206	2526	AES Westover	AES Westover LLC	NY	NAICS-22 Cogen	-	$0	-	$0	-	$0
207	2527	AES Greenidge LLC	AES Greenidge	NY	NAICS-22 Non-Cogen	49,200	$4,602,403	-	$0	49,200	$4,602,403
208	2535	AES Cayuga	AES Cayuga LLC	NY	NAICS-22 Non-Cogen	221,700	$18,188,633	-	$0	221,700	$18,188,633
209	2549	C R Huntley Generating Station	NRG Huntley Operations Inc	NY	NAICS-22 Non-Cogen	23,500	$2,679,301	-	$0	23,500	$2,679,301
210	2554	Dunkirk Generating Plant	Dunkirk Power LLC	NY	NAICS-22 Non-Cogen	59,000	$5,335,726	-	$0	59,000	$5,335,726
211	2629	Lovett	Mirant New York Inc	NY	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
212	2642	Rochester 7	Rochester Gas & Electric Corp	NY	Electric Utility	5,620	$1,341,361	-	$0	5,620	$1,341,361
213	2682	S A Carlson	Jamestown Board of Public Util	NY	Electric Utility	9,402	$1,624,364	-	$0	9,402	$1,624,364
214	2706	Asheville	Progress Energy Carolinas Inc	NC	Electric Utility	177,000	$9,105,650	106,000	$8,720,151	283,000	$17,825,801
215	2708	Cape Fear	Progress Energy Carolinas Inc	NC	Electric Utility	-	$0	101,300	$8,348,425	101,300	$8,348,425
216	2709	Lee	Progress Energy Carolinas Inc	NC	Electric Utility	-	$0	106,100	$8,594,851	106,100	$8,594,851
217	2712	Roxboro	Progress Energy Carolinas Inc	NC	Electric Utility	345,200	$17,112,972	46,300	$3,909,179	391,500	$21,022,151
218	2713	L V Sutton	Progress Energy Carolinas Inc	NC	Electric Utility	-	$0	166,000	$13,590,854	166,000	$13,590,854
219	2716	W H Weatherspoon	Progress Energy Carolinas Inc	NC	Electric Utility	-	$0	47,000	$3,980,583	47,000	$3,980,583
220	2718	G G Allen	Duke Energy Carolinas, LLC	NC	Electric Utility	506,800	$25,374,442	143,400	$11,753,703	650,200	$37,128,145
221	2720	Buck	Duke Energy Carolinas, LLC	NC	Electric Utility	-	$0	121,900	$10,171,560	121,900	$10,171,560
222	2721	Cliffside	Duke Energy Carolinas, LLC	NC	Electric Utility	150,000	$7,793,239	96,900	$8,050,937	246,900	$15,844,176
223	2723	Dan River	Duke Energy Carolinas, LLC	NC	Electric Utility	-	$0	28,500	$1,600,430	28,500	$1,600,430
224	2727	Marshall	Duke Energy	NC	Electric		$53,131,984	33,500	$1,822,849	1,116,100	$54,954,833

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			Carolinas, LLC		Utility	1,082,600					
225	2732	Riverbend	Duke Energy Carolinas, LLC	NC	Electric Utility	-	$0	93,100	$4,304,048	93,100	$4,304,048
226	2790	R M Heskett	MDU Resources Group Inc	ND	Electric Utility	69,400	$4,584,350	-	$0	69,400	$4,584,350
227	2817	Leland Olds	Basin Electric Power Coop	ND	Electric Utility	147,800	$8,977,983	194,800	$14,084,043	342,600	$23,062,027
228	2823	Milton R Young	Minnkota Power Coop, Inc	ND	Electric Utility	191,500	$11,426,986	140,000	$13,087,746	331,500	$24,514,731
229	2824	Stanton	Great River Energy	ND	Electric Utility	109,900	$7,267,772	-	$0	109,900	$7,267,772
230	2828	Cardinal	Cardinal Operating Co	OH	Electric Utility	425,500	$29,371,641	490,400	$21,017,157	915,900	$50,388,797
231	2830	Walter C Beckjord	Duke Energy Ohio Inc	OH	Electric Utility	306,600	$20,835,878	76,700	$3,369,194	383,300	$24,205,072
232	2832	Miami Fort	Duke Energy Ohio Inc	OH	Electric Utility	-	$0	224,300	$9,665,639	224,300	$9,665,639
233	2835	Ashtabula	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
234	2836	Avon Lake	Orion Power Midwest LP	OH	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
235	2837	Eastlake	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
236	2838	Lake Shore	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
237	2840	Conesville	Columbus Southern Power Co	OH	Electric Utility	7,300	$1,141,211	493,800	$21,178,175	501,100	$22,319,386
238	2843	Picway	Columbus Southern Power Co	OH	Electric Utility	-	$0	10,600	$549,444	10,600	$549,444
239	2848	O H Hutchings	Dayton Power & Light Co	OH	Electric Utility	-	$0	-	$0	-	$0
240	2850	J M Stuart	Dayton Power & Light Co	OH	Electric Utility	147,100	$10,447,548	653,300	$28,124,940	800,400	$38,572,487
241	2861	Niles	Orion Power Midwest LP	OH	NAICS-22 Non-Cogen	60,000	$4,666,508	-	$0	60,000	$4,666,508
242	2864	R E Burger	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
243	2866	W H Sammis	FirstEnergy Generation Corp	OH	NAICS-22 Non-	-	$0	-	$0	-	$0

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Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
					Cogen						
244	2872	Muskingum River	Ohio Power Co	OH	Electric Utility	734,400	$49,543,987	143,400	$6,214,538	877,800	$55,758,526
245	2876	Kyger Creek	Ohio Valley Electric Corp	OH	Electric Utility	-	$0	231,500	$9,972,782	231,500	$9,972,782
246	2878	Bay Shore	FirstEnergy Generation Corp	OH	NAICS-22 Non-Cogen	38,200	$3,310,175	-	$0	38,200	$3,310,175
247	2914	Dover	City of Dover	OH	Electric Utility	2,868	$793,765	-	$0	2,868	$793,765
248	2917	Hamilton	City of Hamilton	OH	Electric Utility	-	$0	-	$0	-	$0
249	2935	Orrville	City of Orrville	OH	Electric Utility	20,027	$2,119,106	-	$0	20,027	$2,119,106
250	2936	Painesville	City of Painesville	OH	Electric Utility	9,498	$1,313,523	-	$0	9,498	$1,313,523
251	2943	Shelby Municipal Light Plant	City of Shelby	OH	Electric Utility	4,353	$910,182	-	$0	4,353	$910,182
252	2952	Muskogee	Oklahoma Gas & Electric Co	OK	Electric Utility	-	$0	-	$0	-	$0
253	2963	Northeastern	Public Service Co of Oklahoma	OK	Electric Utility	36,800	$2,439,609	-	$0	36,800	$2,439,609
254	3098	Elrama Power Plant	Orion Power Midwest LP	PA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
255	3113	Portland	Reliant Energy Mid-Atlantic PH LLC	PA	NAICS-22 Non-Cogen	61,700	$4,790,133	-	$0	61,700	$4,790,133
256	3115	Titus	Reliant Energy Mid-Atlantic PH LLC	PA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
257	3118	Conemaugh	Reliant Engy NE Management Co	PA	NAICS-22 Non-Cogen	1,192,600	$78,853,334	-	$0	1,192,600	$78,853,334
258	3122	Homer City Station	Midwest Generations EME LLC	PA	NAICS-22 Non-Cogen	702,400	$46,578,020	-	$0	702,400	$46,578,020
259	3130	Seward	Reliant Energy Seward LLC	PA	NAICS-22 Non-Cogen	2,546,718	$166,720,024	-	$0	2,546,718	$166,720,024
260	3131	Shawville	Reliant Energy Mid-Atlantic PH LLC	PA	NAICS-22 Non-Cogen	200,800	$13,757,540	-	$0	200,800	$13,757,540
261	3136	Keystone	Reliant Engy NE Management Co	PA	NAICS-22 Non-Cogen	562,900	$37,101,163	-	$0	562,900	$37,101,163

Exhibit H1 Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants											
Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
262	3138	New Castle Plant	Orion Power Midwest LP	PA	NAICS-22 Non-Cogen	73,100	$5,525,061	-	$0	73,100	$5,525,061
263	3140	PPL Brunner Island	PPL Brunner Island LLC	PA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
264	3149	PPL Montour	PPL Montour LLC	PA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
265	3152	Sunbury Generation LP	Sunbury Generation LP	PA	NAICS-22 Non-Cogen	192,300	$13,209,567	500	$216,279	192,800	$13,425,846
266	3159	Cromby Generating Station	Exelon Power	PA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
267	3161	Eddystone Generating Station	Exelon Power	PA	NAICS-22 Non-Cogen	-	$0	-	$0	-	$0
268	3176	Hunlock Power Station	UGI Development Co	PA	NAICS-22 Non-Cogen	48,972	$3,969,593	-	$0	48,972	$3,969,593
269	3178	Armstrong Power Station	Allegheny Energy Supply Co LLC	PA	NAICS-22 Non-Cogen	39,800	$3,378,298	-	$0	39,800	$3,378,298
270	3179	Hatfields Ferry Power Station	Allegheny Energy Supply Co LLC	PA	NAICS-22 Non-Cogen	90,700	$6,659,686	-	$0	90,700	$6,659,686
271	3181	Mitchell Power Station	Allegheny Energy Supply Co LLC	PA	NAICS-22 Non-Cogen	16,900	$1,901,996	-	$0	16,900	$1,901,996
272	3251	H B Robinson	Progress Energy Carolinas Inc	SC	Electric Utility	-	$0	62,200	$2,175,610	62,200	$2,175,610
273	3264	W S Lee	Duke Energy Carolinas, LLC	SC	Electric Utility	-	$0	63,500	$2,389,345	63,500	$2,389,345
274	3280	Canadys Steam	South Carolina Electric&Gas Co	SC	Electric Utility	-	$0	101,100	$3,449,905	101,100	$3,449,905
275	3287	McMeekin	South Carolina Electric&Gas Co	SC	Electric Utility	39,000	$2,574,423	-	$0	39,000	$2,574,423
276	3295	Urquhart	South Carolina Electric&Gas Co	SC	Electric Utility	-	$0	12,500	$547,525	12,500	$547,525
277	3297	Wateree	South Carolina Electric&Gas Co	SC	Electric Utility	-	$0	-	$0	-	$0
278	3298	Williams	South Carolina Genertg Co, Inc	SC	Electric Utility	39,900	$2,619,583	-	$0	39,900	$2,619,583
279	3317	Dolphus M Grainger	South Carolina Pub Serv Auth	SC	Electric Utility	-	$0	7,000	$367,355	7,000	$367,355

Exhibit H1
Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants

Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
280	3319	Jefferies	South Carolina Pub Serv Auth	SC	Electric Utility	-	$0	34,900	$1,281,310	34,900	$1,281,310
281	3325	Ben French	Black Hills Power Inc	SD	Electric Utility	6,453	$763,613	-	$0	6,453	$763,613
282	3393	Allen Steam Plant	Tennessee Valley Authority	TN	Electric Utility	41,600	$2,083,471	39,600	$1,735,570	81,200	$3,819,041
283	3396	Bull Run	Tennessee Valley Authority	TN	Electric Utility	243,500	$9,876,924	22,400	$1,055,001	265,900	$10,931,925
284	3399	Cumberland	Tennessee Valley Authority	TN	Electric Utility	1,728,300	$68,920,183	-	$0	1,728,300	$68,920,183
285	3403	Gallatin	Tennessee Valley Authority	TN	Electric Utility	45,000	$2,214,713	180,500	$7,310,696	225,500	$9,525,410
286	3405	John Sevier	Tennessee Valley Authority	TN	Electric Utility	111,300	$4,773,930	10,000	$564,358	121,300	$5,338,288
287	3406	Johnsonville	Tennessee Valley Authority	TN	Electric Utility	-	$0	53,700	$2,293,478	53,700	$2,293,478
288	3407	Kingston	Tennessee Valley Authority	TN	Electric Utility	81,600	$3,627,494	325,900	$13,059,025	407,500	$16,686,518
289	3470	W A Parish	NRG Texas LLC	TX	NAICS-22 Non-Cogen	215,900	$9,408,673	-	$0	215,900	$9,408,673
290	3497	Big Brown	TXU Generation Co LP	TX	NAICS-22 Non-Cogen	335,600	$15,161,347	-	$0	335,600	$15,161,347
291	3644	Carbon	PacifiCorp	UT	Electric Utility	70,000	$4,781,166	-	$0	70,000	$4,781,166
292	3775	Clinch River	Appalachian Power Co	VA	Electric Utility	158,900	$9,364,374	-	$0	158,900	$9,364,374
293	3776	Glen Lyn	Appalachian Power Co	VA	Electric Utility	84,500	$5,294,945	5,800	$287,653	90,300	$5,582,598
294	3788	Potomac River	Mirant Potomac River LLC	VA	NAICS-22 Non-Cogen	92,100	$5,710,639	-	$0	92,100	$5,710,639
295	3796	Bremo Bluff	Virginia Electric & Power Co	VA	Electric Utility	-	$0	85,000	$3,107,231	85,000	$3,107,231
296	3797	Chesterfield	Virginia Electric & Power Co	VA	Electric Utility	-	$0	322,600	$11,565,968	322,600	$11,565,968
297	3803	Chesapeake	Virginia Electric & Power Co	VA	Electric Utility	-	$0	34,800	$1,320,074	34,800	$1,320,074
298	3809	Yorktown	Virginia Electric & Power Co	VA	Electric Utility	101,900	$6,246,666	-	$0	101,900	$6,246,666
299	3845	Transalta Centralia Generation	TransAlta Centralia Gen LLC	WA	NAICS-22 Non-Cogen	424,220	$29,632,233	-	$0	424,220	$29,632,233
300	3935	John E Amos	Appalachian	WV	Electric		$112,544,201	391,900	$20,924,595	2,107,300	$133,468,796

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Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
			Power Co		Utility	1,715,400					
301	3936	Kanawha River	Appalachian Power Co	WV	Electric Utility	-	$0	1,600	$577,041	1,600	$577,041
302	3938	Philip Sporn	Appalachian Power Co	WV	Electric Utility	118,700	$6,311,235	137,100	$6,868,107	255,800	$13,179,342
303	3942	Albright	Monongahela Power Co	WV	Electric Utility	78,000	$2,334,061	-	$0	78,000	$2,334,061
304	3943	Fort Martin Power Station	Monongahela Power Co	WV	Electric Utility	12,500	$1,562,211	-	$0	12,500	$1,562,211
305	3944	Harrison Power Station	Allegheny Energy Supply Co LLC	WV	NAICS-22 Non-Cogen	1,390,000	$90,408,133	-	$0	1,390,000	$90,408,133
306	3945	Rivesville	Monongahela Power Co	WV	Electric Utility	19,900	$1,396,001	-	$0	19,900	$1,396,001
307	3946	Willow Island	Monongahela Power Co	WV	Electric Utility	14,900	$1,074,144	-	$0	14,900	$1,074,144
308	3947	Kammer	Ohio Power Co	WV	Electric Utility	-	$0	48,700	$5,247,263	48,700	$5,247,263
309	3948	Mitchell	Ohio Power Co	WV	Electric Utility	685,100	$43,077,618	307,400	$21,146,004	992,500	$64,223,622
310	3954	Mt Storm	Virginia Electric & Power Co	WV	Electric Utility	627,100	$37,464,183	-	$0	627,100	$37,464,183
311	3982	Bay Front	Northern States Power Co	WI	Electric Utility	8,680	$1,237,352	-	$0	8,680	$1,237,352
312	3992	Blount Street	Madison Gas & Electric Co	WI	Electric Utility	-	$0	-	$0	-	$0
313	4041	South Oak Creek	Wisconsin Electric Power Co	WI	Electric Utility	-	$0	-	$0	-	$0
314	4042	Valley	Wisconsin Electric Power Co	WI	Electric Utility	-	$0	-	$0	-	$0
315	4050	Edgewater	Wisconsin Power & Light Co	WI	Electric Utility	38,500	$3,430,108	-	$0	38,500	$3,430,108
316	4054	Nelson Dewey	Wisconsin Power & Light Co	WI	Electric Utility	-	$0	-	$0	-	$0
317	4072	Pulliam	Wisconsin Public Service Corp	WI	Electric Utility	90,300	$4,045,789	-	$0	90,300	$4,045,789
318	4078	Weston	Wisconsin Public Service Corp	WI	Electric Utility	-	$0	-	$0	-	$0
319	4125	Manitowoc	Manitowoc Public Utilities	WI	Electric Utility	12,535	$1,363,375	-	$0	12,535	$1,363,375
320	4127	Menasha	City of Menasha	WI	Electric Utility	10,086	$888,696	-	$0	10,086	$888,696
321	4140	Alma	Dairyland Power Coop	WI	Electric Utility	24,000	$2,221,113	-	$0	24,000	$2,221,113
322	4143	Genoa	Dairyland Power	WI	Electric		$1,640,764	-	$0	14,000	$1,640,764

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Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
			Coop		Utility	14,000					
323	4146	E J Stoneman Station	Mid-America Power LLC	WI	NAICS-22 Non-Cogen	2,929	$719,218	-	$0	2,929	$719,218
324	4150	Neil Simpson	Black Hills Power Inc	WY	Electric Utility	6,766	$990,343	-	$0	6,766	$990,343
325	4151	Osage	Black Hills Power Inc	WY	Electric Utility	14,337	$945,798	-	$0	14,337	$945,798
326	4158	Dave Johnston	PacifiCorp	WY	Electric Utility	192,000	$10,609,006	17,000	$1,504,767	209,000	$12,113,773
327	4162	Naughton	PacifiCorp	WY	Electric Utility	-	$0	170,000	$12,967,502	170,000	$12,967,502
328	4259	Endicott Station	Michigan South Central Pwr Agy	MI	Electric Utility	38,739	$3,799,748	-	$0	38,739	$3,799,748
329	4271	John P Madgett	Dairyland Power Coop	WI	Electric Utility	31,000	$2,219,893	-	$0	31,000	$2,219,893
330	4941	Navajo	Salt River Project	AZ	Electric Utility	372,550	$4,556,434	-	$0	372,550	$4,556,434
331	6002	James H Miller Jr	Alabama Power Co	AL	Electric Utility	200,600	$11,140,593	61,500	$4,037,250	262,100	$15,177,843
332	6004	Pleasants Power Station	Allegheny Energy Supply Co LLC	WV	NAICS-22 Non-Cogen	741,800	$32,776,012	-	$0	741,800	$32,776,012
333	6009	White Bluff	Entergy Arkansas Inc	AR	Electric Utility	128,800	$1,533,206	-	$0	128,800	$1,533,206
334	6016	Duck Creek	Ameren Energy Resources Generating Co.	IL	Electric Utility	-	$0	185,000	$8,598,511	185,000	$8,598,511
335	6017	Newton	Ameren Energy Generating Co	IL	NAICS-22 Non-Cogen	8,000	$1,301,214	109,000	$5,098,955	117,000	$6,400,169
336	6018	East Bend	Duke Energy Kentucky Inc	KY	Electric Utility	290,800	$4,537,368	172,900	$9,851,841	463,700	$14,389,209
337	6019	W H Zimmer	Duke Energy Ohio Inc	OH	Electric Utility	1,895,000	$126,049,630	-	$0	1,895,000	$126,049,630
338	6021	Craig	Tri-State G & T Assn, Inc	CO	Electric Utility	-	$0	-	$0	-	$0
339	6030	Coal Creek	Great River Energy	ND	Electric Utility	298,500	$17,889,023	-	$0	298,500	$17,889,023
340	6031	Killen Station	Dayton Power & Light Co	OH	Electric Utility	-	$0	252,600	$19,599,174	252,600	$19,599,174
341	6034	Belle River	Detroit Edison Co	MI	Electric Utility	116,000	$8,425,591	-	$0	116,000	$8,425,591
342	6041	H L Spurlock	East Kentucky Power Coop, Inc	KY	Electric Utility	575,400	$8,056,443	4,300	$758,289	579,700	$8,814,731

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Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
343	6052	Wansley	Georgia Power Co	GA	Electric Utility	1,000,000	$53,327,884	536,700	$18,803,811	1,536,700	$72,131,694
344	6055	Big Cajun 2	Louisiana Generating LLC	LA	NAICS-22 Non-Cogen	-	$0	139,400	$10,166,828	139,400	$10,166,828
345	6061	R D Morrow	South Mississippi El Pwr Assn	MS	Electric Utility	115,500	$4,754,369	-	$0	115,500	$4,754,369
346	6064	Nearman Creek	Kansas City City of	KS	Electric Utility	-	$0	10,200	$1,222,770	10,200	$1,222,770
347	6065	Iatan	Kansas City Power & Light Co	MO	Electric Utility	-	$0	16,400	$1,968,810	16,400	$1,968,810
348	6068	Jeffrey Energy Center	Westar Energy Inc	KS	Electric Utility	93,000	$5,683,591	184,100	$12,956,983	277,100	$18,640,574
349	6071	Trimble County	Louisville Gas & Electric Co	KY	Electric Utility	215,000	$3,491,284	183,100	$17,722,010	398,100	$21,213,294
350	6073	Victor J Daniel Jr	Mississippi Power Co	MS	Electric Utility	97,100	$4,028,473	-	$0	97,100	$4,028,473
351	6076	Colstrip	PPL Montana LLC	MT	NAICS-22 Non-Cogen	650,000	$41,143,947	963,600	$38,173,100	1,613,600	$79,317,047
352	6077	Gerald Gentleman	Nebraska Public Power District	NE	Electric Utility	88,500	$1,299,291	-	$0	88,500	$1,299,291
353	6082	AES Somerset LLC	AES Somerset LLC	NY	NAICS-22 Non-Cogen	509,870	$39,773,120	-	$0	509,870	$39,773,120
354	6085	R M Schahfer	Northern Indiana Pub Serv Co	IN	Electric Utility	306,600	$20,570,327	2,500	$182,114	309,100	$20,752,441
355	6089	Lewis & Clark	MDU Resources Group Inc	MT	Electric Utility	23,725	$2,204,833	-	$0	23,725	$2,204,833
356	6090	Sherburne County	Northern States Power Co	MN	Electric Utility	425,700	$31,310,048	501,000	$13,122,958	926,700	$44,433,006
357	6094	Bruce Mansfield	FirstEnergy Generation Corp	PA	NAICS-22 Non-Cogen	-	$0	1,038,900	$62,270,172	1,038,900	$62,270,172
358	6095	Sooner	Oklahoma Gas & Electric Co	OK	Electric Utility	-	$0	-	$0	-	$0
359	6096	Nebraska City	Omaha Public Power District	NE	Electric Utility	41,300	$995,102	-	$0	41,300	$995,102
360	6098	Big Stone	Otter Tail Power Co	SD	Electric Utility	80,100	$1,396,207	-	$0	80,100	$1,396,207
361	6101	Wyodak	PacifiCorp	WY	Electric Utility	-	$0	28,000	$1,252,066	28,000	$1,252,066
362	6106	Boardman	Portland General Electric Co	OR	Electric Utility	17,500	$891,807	-	$0	17,500	$891,807
363	6113	Gibson	Duke Energy	IN	Electric		$61,876,031	897,800	$37,228,367	1,862,800	$99,104,398

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Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
			Indiana Inc		Utility	965,000					
364	6124	McIntosh	Georgia Power Co	GA	Electric Utility	-	$0	15,000	$602,859	15,000	$602,859
365	6136	Gibbons Creek	Texas Municipal Power Agency	TX	Electric Utility	1,500	$525,022	-	$0	1,500	$525,022
366	6137	A B Brown	Southern Indiana Gas & Elec Co	IN	Electric Utility	204,200	$12,311,703	165,750	$6,949,917	369,950	$19,261,620
367	6138	Flint Creek	Southwestern Electric Power Co	AR	Electric Utility	33,100	$774,494	19,400	$720,653	52,500	$1,495,147
368	6139	Welsh	Southwestern Electric Power Co	TX	Electric Utility	35,400	$1,666,638	-	$0	35,400	$1,666,638
369	6146	Martin Lake	TXU Generation Co LP	TX	NAICS-22 Non-Cogen	1,553,800	$62,809,103	-	$0	1,553,800	$62,809,103
370	6147	Monticello	TXU Generation Co LP	TX	NAICS-22 Non-Cogen	961,500	$37,538,809	-	$0	961,500	$37,538,809
371	6155	Rush Island	Union Electric Co	MO	Electric Utility	-	$0	96,000	$7,775,718	96,000	$7,775,718
372	6165	Hunter	PacifiCorp	UT	Electric Utility	597,000	$35,741,911	-	$0	597,000	$35,741,911
373	6166	Rockport	Indiana Michigan Power Co	IN	Electric Utility	399,400	$23,199,267	11,800	$582,364	411,200	$23,781,631
374	6170	Pleasant Prairie	Wisconsin Electric Power Co	WI	Electric Utility	-	$0	-	$0	-	$0
375	6177	Coronado	Salt River Project	AZ	Electric Utility	71,000	$1,227,480	56,900	$1,612,179	127,900	$2,839,660
376	6178	Coleto Creek	ANP-Coleto Creek	TX	NAICS-22 Non-Cogen	-	$0	63,500	$4,070,714	63,500	$4,070,714
377	6179	Fayette Power Project	Lower Colorado River Authority	TX	Electric Utility	-	$0	39,910	$2,926,501	39,910	$2,926,501
378	6181	J T Deely	San Antonio City of	TX	Electric Utility	4,100	$620,593	-	$0	4,100	$620,593
379	6183	San Miguel	San Miguel Electric Coop, Inc	TX	Electric Utility	-	$0	-	$0	-	$0
380	6190	Rodemacher	Cleco Power LLC	LA	Electric Utility	-	$0	-	$0	-	$0
381	6193	Harrington	Southwestern Public Service Co	TX	Electric Utility	-	$0	-	$0	-	$0
382	6194	Tolk	Southwestern Public Service Co	TX	Electric Utility	-	$0	-	$0	-	$0
383	6195	Southwest Power Station	City Utilities of Springfield	MO	Electric Utility	104,900	$6,297,519	-	$0	104,900	$6,297,519
384	6204	Laramie River Station	Basin Electric	WY	Electric		$7,262,361	79,100	$5,263,114	441,500	$12,525,475

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Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
			Power Coop		Utility	362,400					
385	6213	Merom	Hoosier Energy R E C, Inc	IN	Electric Utility	939,300	$60,479,992	-	$0	939,300	$60,479,992
386	6225	Jasper 2	City of Jasper	IN	Electric Utility	1,245	$641,300	-	$0	1,245	$641,300
387	6238	Pearl Station	Soyland Power Coop Inc	IL	Electric Utility	9,160	$840,312	-	$0	9,160	$840,312
388	6248	Pawnee	Public Service Co of Colorado	CO	Electric Utility	1,380	$618,165	-	$0	1,380	$618,165
389	6249	Winyah	South Carolina Pub Serv Auth	SC	Electric Utility	62,000	$3,674,635	8,950	$431,233	70,950	$4,105,868
390	6250	Mayo	Progress Energy Carolinas Inc	NC	Electric Utility	3,400	$597,320	212,800	$17,374,180	216,200	$17,971,500
391	6254	Ottumwa	Interstate Power and Light Co	IA	Electric Utility	-	$0	-	$0	-	$0
392	6257	Scherer	Georgia Power Co	GA	Electric Utility	-	$0	470,600	$16,497,729	470,600	$16,497,729
393	6264	Mountaineer	Appalachian Power Co	WV	Electric Utility	1,238,300	$80,737,824	9,500	$1,391,778	1,247,800	$82,129,601
394	6288	Healy	Golden Valley Elec Assn Inc	AK	Electric Utility	28,818	$1,840,873	-	$0	28,818	$1,840,873
395	6469	Antelope Valley	Basin Electric Power Coop	ND	Electric Utility	670,200	$38,560,727	-	$0	670,200	$38,560,727
396	6481	Intermountain Power Project	Los Angeles City of	UT	Electric Utility	495,000	$29,919,388	96,700	$7,381,664	591,700	$37,301,052
397	6639	R D Green	Western Kentucky Energy Corp	KY	NAICS-22 Non-Cogen	491,200	$7,699,143	21,800	$1,603,873	513,000	$9,303,016
398	6641	Independence	Entergy Arkansas Inc	AR	Electric Utility	122,740	$1,484,939	-	$0	122,740	$1,484,939
399	6648	Sandow No 4	TXU Generation Co LP	TX	NAICS-22 Non-Cogen	419,000	$19,340,697	314,400	$10,906,298	733,400	$30,246,996
400	6664	Louisa	MidAmerican Energy Co	IA	Electric Utility	35,600	$1,139,138	23,000	$1,092,571	58,600	$2,231,709
401	6705	Warrick	AGC Division of APG Inc	IN	NAICS-22 Cogen	-	$0	241,900	$17,973,773	241,900	$17,973,773
402	6761	Rawhide	Platte River Power Authority	CO	Electric Utility	78,000	$5,769,032	5,700	$561,243	83,700	$6,330,275
403	6768	Sikeston Power Station	City of Sikeston	MO	Electric Utility	92,000	$3,616,845	11,300	$1,540,525	103,300	$5,157,370
404	6772	Hugo	Western Farmers Elec Coop, Inc	OK	Electric Utility	-	$0	16,560	$1,575,926	16,560	$1,575,926
405	6823	D B Wilson	Western Kentucky Energy Corp	KY	NAICS-22 Non-	644,400	$9,790,916	-	$0	644,400	$9,790,916

Exhibit H1
Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants

Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
					Cogen						
406	7030	Twin Oaks Power One	Altura Power	TX	NAICS-22 Non-Cogen	224,800	$5,117,785	-	$0	224,800	$5,117,785
407	7097	J K Spruce	San Antonio City of	TX	Electric Utility	46,700	$1,802,905	-	$0	46,700	$1,802,905
408	7210	Cope	South Carolina Electric&Gas Co	SC	Electric Utility	211,200	$11,687,864	-	$0	211,200	$11,687,864
409	7213	Clover	Virginia Electric & Power Co	VA	Electric Utility	485,200	$27,591,939	-	$0	485,200	$27,591,939
410	7242	Polk	Tampa Electric Co	FL	Electric Utility	60,546	$3,857,097	-	$0	60,546	$3,857,097
411	7286	Richard Gorsuch	American Mun Power-Ohio, Inc	OH	Electric Utility	130,800	$9,379,236	-	$0	130,800	$9,379,236
412	7343	George Neal South	MidAmerican Energy Co	IA	Electric Utility	14,800	$853,685	-	$0	14,800	$853,685
413	7504	Neil Simpson II	Black Hills Power Inc	WY	Electric Utility	47,514	$2,580,675	-	$0	47,514	$2,580,675
414	7537	North Branch	Virginia Electric & Power Co	WV	Electric Utility	112,199	$5,230,609	-	$0	112,199	$5,230,609
415	7549	Milwaukee County	Wisconsin Electric Power Co	WI	Electric Utility	5,804	$888,480	-	$0	5,804	$888,480
416	7652	US DOE Savannah River Site (D Area)	Savannah River Nuclear Solutions LLC	SC	Electric Utility	20,966	$1,669,511	-	$0	20,966	$1,669,511
417	7737	Cogen South	South Carolina Electric&Gas Co	SC	Electric Utility	97,604	$5,911,014	-	$0	97,604	$5,911,014
418	7790	Bonanza	Deseret Generation & Tran Coop	UT	Electric Utility	330,200	$20,319,204	-	$0	330,200	$20,319,204
419	7902	Pirkey	Southwestern Electric Power Co	TX	Electric Utility	1,309,200	$33,284,231	120,000	$4,211,260	1,429,200	$37,495,491
420	8023	Columbia	Wisconsin Power & Light Co	WI	Electric Utility	53,000	$3,690,499	11,000	$1,224,541	64,000	$4,915,040
421	8042	Belews Creek	Duke Energy Carolinas, LLC	NC	Electric Utility	781,500	$38,748,388	41,400	$2,146,579	822,900	$40,894,967
422	8066	Jim Bridger	PacifiCorp	WY	Electric Utility	396,000	$14,633,534	154,000	$5,647,109	550,000	$20,280,643
423	8069	Huntington	PacifiCorp	UT	Electric Utility	478,000	$28,801,666	-	$0	478,000	$28,801,666
424	8102	General James M Gavin	Ohio Power Co	OH	Electric Utility	2,328,700	$154,518,498	90,700	$3,966,417	2,419,400	$158,484,915
425	8219	Ray D Nixon	Colorado Springs City of	CO	Electric Utility	37,700	$2,860,494	-	$0	37,700	$2,860,494
426	8222	Coyote	Otter Tail Power Co	ND	Electric Utility	286,100	$17,106,471	-	$0	286,100	$17,106,471

Exhibit H1 Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants											
Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
427	8223	Springerville	Tucson Electric Power Co	AZ	Electric Utility	1,121,980	$11,757,449	-	$0	1,121,980	$11,757,449
428	8224	North Valmy	Sierra Pacific Power Co	NV	Electric Utility	234,200	$10,421,134	-	$0	234,200	$10,421,134
429	8226	Cheswick Power Plant	Orion Power Midwest LP	PA	NAICS-22 Non-Cogen	89,100	$6,556,538	-	$0	89,100	$6,556,538
430	10002	ACE Cogeneration Facility	ACE Cogeneration Co	CA	NAICS-22 Cogen	50,000	$1,339,603	-	$0	50,000	$1,339,603
431	10003	Colorado Energy Nations Company	Colorado Energy Nations Company LLLP	CO	NAICS-22 Cogen	26,094	$2,143,961	-	$0	26,094	$2,143,961
432	10030	NRG Energy Center Dover	NRG Energy Center Dover LLC	DE	NAICS-22 Cogen	4,605	$747,803	-	$0	4,605	$747,803
433	10043	Logan Generating Company LP	US Operating Services Company	NJ	NAICS-22 Cogen	90,000	$1,720,098	-	$0	90,000	$1,720,098
434	10071	Cogentrix Virginia Leasing Corporation	Cogentrix-Virginia Leas'g Corp	VA	NAICS-22 Cogen	-	$0	-	$0	-	$0
435	10075	Taconite Harbor Energy Center	Minnesota Power Inc	MN	Electric Utility	32,800	$2,810,787	-	$0	32,800	$2,810,787
436	10113	John B Rich Memorial Power Station	Gilberton Power Co	PA	NAICS-22 Cogen	272,846	$18,402,154	-	$0	272,846	$18,402,154
437	10143	Colver Power Project	Inter-Power/AhlCon Partners, L.P.	PA	NAICS-22 Non-Cogen	394,300	$26,231,970	-	$0	394,300	$26,231,970
438	10148	White Pine Electric Power	White Pine Electric Power LLC	MI	NAICS-22 Non-Cogen	6,675	$1,105,773	-	$0	6,675	$1,105,773
439	10151	Grant Town Power Plant	American Bituminous Power LP	WV	NAICS-22 Non-Cogen	225,969	$15,230,999	-	$0	225,969	$15,230,999
440	10333	Central Power & Lime	Central Power & Lime Inc	FL	NAICS-22 Cogen	-	$0	-	$0	-	$0
441	10343	Foster Wheeler Mt Carmel Cogen	Mount Carmel Cogen Inc	PA	NAICS-22 Cogen	329,721	$22,068,733	-	$0	329,721	$22,068,733
442	10377	James River Cogeneration	James River Cogeneration Co	VA	NAICS-22 Cogen	-	$0	-	$0	-	$0
443	10378	Primary Energy Southport	Primary Energy of North Carolina LLC	NC	NAICS-22 Cogen	-	$0	-	$0	-	$0
444	10379	Primary Energy Roxboro	Primary Energy of North Carolina LLC	NC	NAICS-22 Cogen	7,645	$805,717	-	$0	7,645	$805,717
445	10380	Elizabethtown Power LLC	North Carolina Power Holdings, LLC	NC	NAICS-22 Cogen	833	$471,299	-	$0	833	$471,299

Exhibit H1
Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants

Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
446	10381	Coastal Carolina Clean Power	Carlyle/Riverstone Renewable Energy	NC	NAICS-22 Cogen	11,653	$1,002,479	-	$0	11,653	$1,002,479
447	10382	Lumberton	North Carolina Power Holdings, LLC	NC	NAICS-22 Cogen	310	$445,624	-	$0	310	$445,624
448	10384	Edgecombe Genco LLC	Edgecombe Operating Services LLC	NC	NAICS-22 Cogen	-	$0	-	$0	-	$0
449	10464	Black River Generation	Black River Generation LLC	NY	NAICS-22 Non-Cogen	204,098	$16,907,959	-	$0	204,098	$16,907,959
450	10495	Rumford Cogeneration	NewPage Corporation	ME	NAICS-22 Cogen	15,000	$735,319	-	$0	15,000	$735,319
451	10566	Chambers Cogeneration LP	US Operating Services Company	NJ	NAICS-22 Cogen	-	$0	-	$0	-	$0
452	10603	Ebensburg Power	Ebensburg Power Co	PA	NAICS-22 Cogen	225,816	$15,370,255	-	$0	225,816	$15,370,255
453	10604	Hawaiian Comm & Sugar Puunene Mill	Hawaiian Com & Sugar Co Ltd	HI	NAICS-22 Cogen	7,468	$936,197	-	$0	7,468	$936,197
454	10640	Stockton Cogen	Air Products Energy Enterprise	CA	NAICS-22 Cogen	66,017	$5,737,672	-	$0	66,017	$5,737,672
455	10641	Cambria Cogen	Cambria CoGen Co	PA	NAICS-22 Cogen	346,203	$23,131,284	-	$0	346,203	$23,131,284
456	10671	AES Shady Point LLC	AES Shady Point LLC	OK	NAICS-22 Cogen	-	$0	-	$0	-	$0
457	10672	Cedar Bay Generating Company LP	US Operating Services Company	FL	NAICS-22 Cogen	183,000	$10,919,996	-	$0	183,000	$10,919,996
458	10673	AES Hawaii	AES Hawaii Inc	HI	NAICS-22 Cogen	-	$0	-	$0	-	$0
459	10675	AES Thames	AES Thames LLC	CT	NAICS-22 Cogen	-	$0	-	$0	-	$0
460	10676	AES Beaver Valley Partners Beaver Valley	AES Beaver Valley	PA	NAICS-22 Cogen	-	$0	-	$0	-	$0
461	10678	AES Warrior Run Cogeneration Facility	AES WR Ltd Partnership	MD	NAICS-22 Cogen	-	$0	-	$0	-	$0
462	10686	Rapids Energy Center	Minnesota Power Inc	MN	NAICS-22 Cogen	2,225	$915,210	-	$0	2,225	$915,210
463	10743	Morgantown Energy Facility	Morgantown Energy Associates	WV	NAICS-22 Cogen	155,450	$10,740,044	-	$0	155,450	$10,740,044
464	10768	Rio Bravo Jasmin	Rio Bravo Jasmin	CA	NAICS-22 Cogen	6,863	$831,361	-	$0	6,863	$831,361
465	10769	Rio Bravo Poso	Rio Bravo Poso	CA	NAICS-22 Cogen	6,684	$829,252	-	$0	6,684	$829,252
466	10771	Hopewell Power	Virginia Electric &	VA	Electric		$1,350,448	-	$0	14,078	$1,350,448

Exhibit H1
Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants

Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
		Station	Power Co		Utility	14,078					
467	10773	Altavista Power Station	Virginia Electric & Power Co	VA	Electric Utility	19,849	$1,709,405	-	$0	19,849	$1,709,405
468	10774	Southampton Power Station	Virginia Electric & Power Co	VA	Electric Utility	90,232	$6,030,573	-	$0	90,232	$6,030,573
469	10784	Colstrip Energy LP	Colstrip Energy LP	MT	NAICS-22 Non-Cogen	37,869	$3,073,127	-	$0	37,869	$3,073,127
470	50039	Kline Township Cogen Facility	Northeastern Power Co	PA	NAICS-22 Cogen	225,502	$15,350,012	-	$0	225,502	$15,350,012
471	50202	WPS Power Niagara	Niagara Generation LLC	NY	NAICS-22 Non-Cogen	18,249	$2,286,375	-	$0	18,249	$2,286,375
472	50407	Mobile Energy Services LLC	DTE Energy Services	AL	NAICS-22 Cogen	9,637	$1,146,157	-	$0	9,637	$1,146,157
473	50611	WPS Westwood Generation LLC	WPS Power Developement	PA	NAICS-22 Non-Cogen	244,867	$16,598,422	-	$0	244,867	$16,598,422
474	50651	Trigen Syracuse Energy	Syracuse Energy Corp	NY	NAICS-22 Cogen	10,673	$1,719,471	-	$0	10,673	$1,719,471
475	50776	Panther Creek Energy Facility	Panther Creek Partners	PA	NAICS-22 Non-Cogen	214,260	$14,625,270	-	$0	214,260	$14,625,270
476	50835	TES Filer City Station	TES Filer City Station LP	MI	NAICS-22 Cogen	40,894	$3,953,881	-	$0	40,894	$3,953,881
477	50879	Wheelabrator Frackville Energy	Wheelabrator Environmental Systems	PA	NAICS-22 Cogen	266,589	$17,998,781	-	$0	266,589	$17,998,781
478	50888	Northampton Generating Company LP	US Operating Services Company	PA		132,000	$9,322,187	-	$0	132,000	$9,322,187
479	50951	Sunnyside Cogen Associates	Sunnyside Cogeneration Assoc	UT	NAICS-22 Non-Cogen	249,744	$15,175,811	-	$0	249,744	$15,175,811
480	50974	Scrubgrass Generating Company LP	US Operating Services Company	PA	NAICS-22 Non-Cogen	221,687	$15,104,069	-	$0	221,687	$15,104,069
481	50976	Indiantown Cogeneration LP	US Operating Services Company	FL	NAICS-22 Cogen	52,000	$3,511,559	-	$0	52,000	$3,511,559
482	52007	Mecklenburg Power Station	Virginia Electric & Power Co	VA	Electric Utility	173,567	$10,650,046	-	$0	173,567	$10,650,046
483	54035	Roanoke Valley Energy Facililty I	Westmoreland Partners	NC	NAICS-22 Cogen	1,500	$504,044	-	$0	1,500	$504,044
484	54081	Spruance Genco LLC	Spruance Operating Services LLC	VA	NAICS-22 Cogen	-	$0	-	$0	-	$0

Exhibit H1
Plant-by-Plant Estimated Baseline Costs for Disposal of CCR Generated by 495 Electric Utility Plants

Row	Plant Code	Plant Name	Company Name	State	Sector Name	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
485	54144	Piney Creek Project	Colmac Clarion Inc	PA	NAICS-22 Non-Cogen	77,365	$5,800,014	-	$0	77,365	$5,800,014
486	54238	Port of Stockton District Energy Fac	FPL Energy Operating Servs Inc	CA	NAICS-22 Cogen	13,395	$908,321	-	$0	13,395	$908,321
487	54304	Birchwood Power	Birchwood Power Partners LP	VA	NAICS-22 Cogen	-	$0	-	$0	-	$0
488	54626	Mt Poso Cogeneration	Mt Poso Cogeneration Co	CA	NAICS-22 Cogen	16,568	$945,706	-	$0	16,568	$945,706
489	54634	St Nicholas Cogen Project	Schuylkill Energy Resource Inc	PA	NAICS-22 Cogen	752,552	$49,327,523	-	$0	752,552	$49,327,523
490	54755	Roanoke Valley Energy Facility II	Westmoreland Partners	NC	NAICS-22 Cogen	17,890	$1,308,668	-	$0	17,890	$1,308,668
491	54972	Norit Americas Marshall Plant	Norit Americas Inc	TX	Industrial NAICS Non-Cogen	528	$482,441	-	$0	528	$482,441
492	55076	Red Hills Generating Facility	Choctaw Generating LP	MS	NAICS-22 Non-Cogen	426,300	$20,941,917	-	$0	426,300	$20,941,917
493	55245	Tuscola Station	Trigen-Cinergy Sol-Tuscola LLC	IL	NAICS-22 Cogen	13,976	$1,071,173	-	$0	13,976	$1,071,173
494	55479	Wygen 1	Black Hills Power Inc	WY	NAICS-22 Non-Cogen	49,931	$3,607,447	-	$0	49,931	$3,607,447
495	55749	Hardin Generator Project	Rocky Mountain Power Inc	MT	NAICS-22 Non-Cogen	100,130	$7,346,637	-	$0	100,130	$7,346,637
					Totals =	71,573,055	**$3,738,976,000**	22,365,420	**$1,196,286,000**	93,938,475	**$4,935,262,000**

Exhibit H2
Company-by-Company Estimated Baseline Costs for Disposal of CCR Generated at 495 Electric Plants for 251 Owner Companies

Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
1	21	AES Shady Point LLC	Small	1	-	$0	-	$0	-	$0
2	25	AES Greenidge	Small	1	49,200	$4,602,403	-	$0	49,200	$4,602,403
3	35	AES WR Ltd Partnership	Small	1	-	$0	-	$0	-	$0
4	42	AES Thames LLC	Small	1	-	$0	-	$0	-	$0
5	52	ACE Cogeneration Co	Small	1	50,000	$1,339,603	-	$0	50,000	$1,339,603
6	142	AES Beaver Valley	Small	1	-	$0	-	$0	-	$0
7	177	AES Hawaii Inc	Small	1	-	$0	-	$0	-	$0
8	189	Alabama Electric Coop Inc	Large	1	18,900	$1,648,410	33,100	$1,261,871	52,000	$2,910,281
9	195	Alabama Power Co	Large	6	624,200	$35,107,290	895,300	$48,410,310	1,519,500	$83,517,601
10	261	AGC Division of APG Inc	Large	1	-	$0	241,900	$17,973,773	241,900	$17,973,773
11	353	Air Products Energy Enterprise	Small	1	66,017	$5,737,672	-	$0	66,017	$5,737,672
12	520	Ameren Energy Generating Co	Large	4	8,000	$1,301,214	188,000	$9,131,781	196,000	$10,432,995
13	554	Ames City of	Large City	1	14,598	$850,913	-	$0	14,598	$850,913
14	563	American Bituminous Power LP	Small	1	225,969	$15,230,999	-	$0	225,969	$15,230,999
15	733	Appalachian Power Co	Large	6	3,315,800	$214,252,579	545,900	$30,049,173	3,861,700	$244,301,752
16	770	Aquila, Inc.	Large	3	72,381	$5,790,954	-	$0	72,381	$5,790,954
17	796	Arizona Electric Pwr Coop Inc	Large	1	139,000	$1,855,464	33,000	$1,124,556	172,000	$2,980,020
18	803	Arizona Public Service Co	Large	2	-	$0	799,400	$53,737,131	799,400	$53,737,131
19	814	Entergy Arkansas Inc	Large	2	251,540	$3,018,145	-	$0	251,540	$3,018,145
20	924	Associated Electric Coop, Inc	Large	2	54,000	$4,123,442	109,200	$7,810,059	163,200	$11,933,501
21	986	Aurora Energy LLC	Small	1	17,361	$1,103,027	-	$0	17,361	$1,103,027
22	1009	Austin City of	Small City	1	4,967	$1,142,650	-	$0	4,967	$1,142,650

Exhibit H2

Company-by-Company Estimated Baseline Costs for Disposal of CCR Generated at 495 Electric Plants for 251 Owner Companies

Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
23	1307	Basin Electric Power Coop	Large	3	1,180,400	$54,801,071	273,900	$19,347,158	1,454,300	$74,148,228
24	1735	Birchwood Power Partners LP	Small	1	-	$0	-	$0	-	$0
25	1746	Black River Generation LLC	Small	1	204,098	$16,907,959	-	$0	204,098	$16,907,959
26	1951	White Pine Electric Power LLC	Small	1	6,675	$1,105,773	-	$0	6,675	$1,105,773
27	2884	Cambria CoGen Co	Small	1	346,203	$23,131,284	-	$0	346,203	$23,131,284
28	3006	Cardinal Operating Co	Large	1	425,500	$29,371,641	490,400	$21,017,157	915,900	$50,388,797
29	3046	Progress Energy Carolinas Inc	Large	8	525,600	$26,815,941	847,700	$66,693,833	1,373,300	$93,509,775
30	3203	Cedar Falls Utilities	Small City	1	6,676	$742,194	-	$0	6,676	$742,194
31	3242	Central Electric Power Coop	Small	1	16,626	$1,067,480	-	$0	16,626	$1,067,480
32	3258	Central Iowa Power Cooperative	Small	1	20,209	$927,916	-	$0	20,209	$927,916
33	3265	Cleco Power LLC	Large	2	676,600	$36,115,272	51,900	$3,930,017	728,500	$40,045,288
34	3303	Central Power & Lime Inc	Small	1	-	$0	-	$0	-	$0
35	3542	Duke Energy Ohio Inc	Large	3	2,201,600	$146,885,509	301,000	$13,034,832	2,502,600	$159,920,341
36	3593	Choctaw Generating LP	Large	1	426,300	$20,941,917	-	$0	426,300	$20,941,917
37	3599	Citizens Thermal Energy	Small	1	11,810	$1,402,299	-	$0	11,810	$1,402,299
38	3901	Cogentrix-Virginia Leas'g Corp	Small	1	-	$0	-	$0	-	$0
39	3989	Colorado Springs City of	Large City	2	169,800	$11,549,069	-	$0	169,800	$11,549,069
40	4045	City of Columbia	Large City	1	3,223	$803,273	-	$0	3,223	$803,273
41	4062	Columbus Southern Power Co	Large	2	7,300	$1,141,211	504,400	$21,727,619	511,700	$22,868,830
42	4129	Colmac Clarion Inc	Small	1	77,365	$5,800,014	-	$0	77,365	$5,800,014

Exhibit H2
Company-by-Company Estimated Baseline Costs for Disposal of CCR Generated at 495 Electric Plants for 251 Owner Companies

Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
43	4158	Conectiv Atlantic Generatn Inc	Large	1	-	$0	-	$0	-	$0
44	4161	Constellation Power Source Gen	Large	3	-	$0	-	$0	-	$0
45	4217	Colstrip Energy LP	Small City	1	37,869	$3,073,127	-	$0	37,869	$3,073,127
46	4252	Conectiv Delmarva Gen Inc	Large	1	-	$0	-	$0	-	$0
47	4254	Consumers Energy Co	Large	5	340,000	$25,431,748	182,100	$16,605,596	522,100	$42,037,344
48	4363	Corn Belt Power Coop	Small	1	4,829	$716,846	-	$0	4,829	$716,846
49	4508	Crawfordsville Elec, Lgt & Pwr	Small City	1	2,027	$697,628	-	$0	2,027	$697,628
50	4538	Crisp County Power Comm	Small	1	110	$472,673	-	$0	110	$472,673
51	4716	Dairyland Power Coop	Large	3	69,000	$6,081,771	-	$0	69,000	$6,081,771
52	4922	Dayton Power & Light Co	Large	3	147,100	$10,447,548	905,900	$47,724,114	1,053,000	$58,171,662
53	5109	Detroit Edison Co	Large	6	616,702	$45,299,561	482,000	$23,685,841	1,098,702	$68,985,402
54	5269	Dominion Energy Services Co	Large	1	-	$0	-	$0	-	$0
55	5336	City of Dover	Small City	1	2,868	$793,765	-	$0	2,868	$793,765
56	5416	Duke Energy Carolinas, LLC	Large	8	2,520,900	$125,048,053	622,200	$42,239,450	3,143,100	$167,287,503
57	5511	Dynegy Northeast Gen Inc	Large	1	24,800	$2,776,579	-	$0	24,800	$2,776,579
58	5517	Dynegy Midwest Generation Inc	Large	5	-	$0	250,700	$15,682,087	250,700	$15,682,087
59	5580	East Kentucky Power Coop, Inc	Large	3	669,700	$9,914,744	64,300	$3,534,751	734,000	$13,449,495
60	5670	Ebensburg Power Co	Small City	1	225,816	$15,370,255	-	$0	225,816	$15,370,255
61	5748	Electric Energy Inc	Large	1	-	$0	-	$0	-	$0
62	5860	Empire District Electric Co	Large	2	15,699	$1,534,850	53,500	$5,981,342	69,199	$7,516,192
63	6035	Exelon Power	Large	2		$0	-	$0		$0

Exhibit H2
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Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
					-				-	
64	6455	Progress Energy Florida Inc	Large	1	57,100	$1,261,056	-	$0	57,100	$1,261,056
65	6526	FirstEnergy Generation Corp	Large	7	38,200	$3,310,175	1,038,900	$62,270,172	1,077,100	$65,580,347
66	6779	Fremont City of	Small City	1	5,300	$664,414	-	$0	5,300	$664,414
67	6811	FPL Energy Operating Servs Inc	Small	1	13,395	$908,321	-	$0	13,395	$908,321
68	6909	Gainesville Regional Utilities	Large City	1	400	$519,887	-	$0	400	$519,887
69	7140	Georgia Power Co	Large	10	3,516,790	$189,443,207	1,541,900	$54,268,543	5,058,690	$243,711,750
70	7199	Gilberton Power Co	Small	1	272,846	$18,402,154	-	$0	272,846	$18,402,154
71	7353	Golden Valley Elec Assn Inc	Small	1	28,818	$1,840,873	-	$0	28,818	$1,840,873
72	7483	City of Grand Haven	Small City	1	48,470	$4,453,966	-	$0	48,470	$4,453,966
73	7490	Grand River Dam Authority	Large	1	148,100	$5,661,224	-	$0	148,100	$5,661,224
74	7570	Great River Energy	Large	2	408,400	$25,156,795	-	$0	408,400	$25,156,795
75	7651	Greenwood Utilities Comm	Small City	1	1,700	$515,373	-	$0	1,700	$515,373
76	7801	Gulf Power Co	Large	3	163,625	$10,479,821	70,300	$6,556,027	233,925	$17,035,848
77	7860	NRG Energy Center Dover LLC	Small	1	4,605	$747,803	-	$0	4,605	$747,803
78	7977	City of Hamilton	Large City	1	-	$0	-	$0	-	$0
79	8245	Hastings City of	Small City	1	19,473	$710,021	-	$0	19,473	$710,021
80	8286	Hawaiian Com & Sugar Co Ltd	Small	1	7,468	$936,197	-	$0	7,468	$936,197
81	8449	Henderson City Utility Comm	Small City	1	3,909	$693,769	-	$0	3,909	$693,769
82	8543	Hibbing Public Utilities Comm	Small City	1	5,623	$1,181,967	-	$0	5,623	$1,181,967
83	8723	City of Holland	Small City	1		$1,890,637	-	$0		$1,890,637

Exhibit H2
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Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
					16,586				16,586	
84	9231	Independence City of	Large City	2	7,251	$1,114,710	29,750	$3,318,596	37,001	$4,433,306
85	9267	Hoosier Energy R E C, Inc	Large	2	939,300	$60,479,992	39,800	$1,740,477	979,100	$62,220,469
86	9269	Indiana-Kentucky Electric Corp	Large	1	113,200	$7,126,862	21,700	$991,839	134,900	$8,118,701
87	9273	Indianapolis Power & Light Co	Large	3	401,398	$24,561,477	175,900	$7,887,938	577,298	$32,449,415
88	9324	Indiana Michigan Power Co	Large	2	642,200	$37,604,199	152,400	$6,492,047	794,600	$44,096,247
89	9332	Indian River Operations Inc	Large	1	171,200	$2,571,716	-	$0	171,200	$2,571,716
90	9379	Inter-Power/AhlCon Partners, L.P.	Small	1	394,300	$26,231,970	-	$0	394,300	$26,231,970
91	9417	Interstate Power and Light Co	Large	8	32,183	$1,742,818	24,000	$1,895,349	56,183	$3,638,167
92	9617	JEA	Large City	2	1,002,600	$20,396,626	-	$0	1,002,600	$20,396,626
93	9628	James River Cogeneration Co	Small	1	-	$0	-	$0	-	$0
94	9645	Jamestown Board of Public Util	Small City	1	9,402	$1,624,364	-	$0	9,402	$1,624,364
95	9667	City of Jasper	Small City	1	1,245	$641,300	-	$0	1,245	$641,300
96	9996	Kansas City City of	Large City	2	-	$0	10,200	$1,222,770	10,200	$1,222,770
97	10000	Kansas City Power & Light Co	Large	4	497,400	$31,429,328	16,400	$1,968,810	513,800	$33,398,137
98	10171	Kentucky Utilities Co	Large	4	243,000	$3,877,700	824,700	$35,101,629	1,067,700	$38,979,329
99	10623	City of Lakeland	Large City	1	133,274	$5,633,207	-	$0	133,274	$5,633,207
100	11142	City of Logansport	Small City	1	6,599	$1,026,950	-	$0	6,599	$1,026,950
101	11208	Los Angeles City of	Large City	1	495,000	$29,919,388	96,700	$7,381,664	591,700	$37,301,052
102	11249	Louisville Gas & Electric Co	Large	3	999,400	$16,104,954	284,900	$23,253,805	1,284,300	$39,358,759
103	11252	Louisiana Generating	Large	1		$0		$10,166,828	139,400	$10,166,828

Exhibit H2
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Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
		LLC			-		139,400			
104	11269	Lower Colorado River Authority	Large	1	-	$0	39,910	$2,926,501	39,910	$2,926,501
105	11479	Madison Gas & Electric Co	Large	1	-	$0	-	$0	-	$0
106	11571	Manitowoc Public Utilities	Small City	1	12,535	$1,363,375	-	$0	12,535	$1,363,375
107	11701	City of Marquette	Small City	1	20,705	$2,610,129	-	$0	20,705	$2,610,129
108	11732	City of Marshall	Small City	1	2,492	$746,753	-	$0	2,492	$746,753
109	12199	MDU Resources Group Inc	Small	2	93,125	$6,789,183	-	$0	93,125	$6,789,183
110	12298	City of Menasha	Small City	1	10,086	$888,696	-	$0	10,086	$888,696
111	12341	MidAmerican Energy Co	Large	5	141,900	$3,899,115	177,700	$5,653,291	319,600	$9,552,406
112	12384	Midwest Generations EME LLC	Large	8	723,000	$48,894,545	-	$0	723,000	$48,894,545
113	12435	Mid-America Power LLC	Small	1	2,929	$719,218	-	$0	2,929	$719,218
114	12588	Mirant Potomac River LLC	Large	1	92,100	$5,710,639	-	$0	92,100	$5,710,639
115	12628	Mirant Chalk Point LLC	Large	1	167,000	$2,405,813	-	$0	167,000	$2,405,813
116	12647	Minnesota Power Inc	Large	5	43,573	$5,755,912	301,400	$15,181,961	344,973	$20,937,873
117	12653	Mirant Mid-Atlantic LLC	Large	2	256,300	$3,994,708	-	$0	256,300	$3,994,708
118	12658	Minnkota Power Coop, Inc	Large	1	191,500	$11,426,986	140,000	$13,087,746	331,500	$24,514,731
119	12686	Mississippi Power Co	Large	2	165,200	$7,883,974	39,100	$1,331,693	204,300	$9,215,667
120	12792	Mirant New York Inc	Large	1	-	$0	-	$0	-	$0
121	12796	Monongahela Power Co	Large	4	125,300	$6,366,417	-	$0	125,300	$6,366,417
122	12807	Michigan South Central Pwr Agy	Small	1	38,739	$3,799,748	-	$0	38,739	$3,799,748
123	12949	Morgantown Energy	Small City	1		$10,740,044	-	$0	155,450	$10,740,044

Exhibit H2
Company-by-Company Estimated Baseline Costs for Disposal of CCR Generated at 495 Electric Plants for 251 Owner Companies

Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
		Associates			155,450					
124	13060	Mt Poso Cogeneration Co	Small	1	16,568	$945,706	-	$0	16,568	$945,706
125	13143	Board of Water Electric & Communications	Small City	1	9,700	$1,438,263	-	$0	9,700	$1,438,263
126	13168	NRG Huntley Operations Inc	Large	1	23,500	$2,679,301	-	$0	23,500	$2,679,301
127	13337	Nebraska Public Power District	Large	2	114,300	$2,799,074	-	$0	114,300	$2,799,074
128	13407	Nevada Power Co	Large	1	141,700	$6,385,615	-	$0	141,700	$6,385,615
129	13488	New Ulm Public Utilities Comm	Small City	1	7,134	$1,272,527	-	$0	7,134	$1,272,527
130	13579	Dunkirk Power LLC	Small City	1	59,000	$5,335,726	-	$0	59,000	$5,335,726
131	13695	North Carolina Power Holdings, LLC	Small	2	1,143	$916,923	-	$0	1,143	$916,923
132	13756	Northern Indiana Pub Serv Co	Large	3	500,800	$33,587,461	2,500	$182,114	503,300	$33,769,575
133	13781	Northern States Power Co	Large	5	488,280	$38,556,257	512,500	$14,017,426	1,000,780	$52,573,682
134	13833	Northeastern Power Co	Small	1	225,502	$15,350,012	-	$0	225,502	$15,350,012
135	14006	Ohio Power Co	Large	4	3,748,200	$247,140,103	590,200	$36,574,223	4,338,400	$283,714,326
136	14015	Ohio Valley Electric Corp	Large	1	-	$0	231,500	$9,972,782	231,500	$9,972,782
137	14063	Oklahoma Gas & Electric Co	Large	2	-	$0	-	$0	-	$0
138	14127	Omaha Public Power District	Large	2	46,900	$1,586,693	-	$0	46,900	$1,586,693
139	14165	Orion Power Midwest LP	Large	5	222,200	$16,748,107	-	$0	222,200	$16,748,107
140	14194	City of Orrville	Small City	1	20,027	$2,119,106	-	$0	20,027	$2,119,106
141	14232	Otter Tail Power Co	Large	3	387,900	$20,648,201	-	$0	387,900	$20,648,201
142	14268	City of Owensboro	Large City	1	-	$0	-	$0	-	$0

Exhibit H2
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Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
143	14354	PacifiCorp	Large	7	1,733,000	$94,567,283	369,000	$21,371,444	2,102,000	$115,938,727
144	14381	City of Painesville	Small City	1	9,498	$1,313,523	-	$0	9,498	$1,313,523
145	14432	Panther Creek Partners	Small	1	214,260	$14,625,270	-	$0	214,260	$14,625,270
146	14610	Orlando Utilities Comm	Large City	1	386,400	$11,261,922	-	$0	386,400	$11,261,922
147	14645	Pella City of	Small City	1	5,694	$728,717	-	$0	5,694	$728,717
148	14839	Peru City of	Small City	1	1,887	$687,544	-	$0	1,887	$687,544
149	14932	US Operating Services Company	Large	6	678,687	$40,577,909	-	$0	678,687	$40,577,909
150	15143	Platte River Power Authority	Large	1	78,000	$5,769,032	5,700	$561,243	83,700	$6,330,275
151	15147	PSEG Fossil LLC	Large	2	-	$0	-	$0	-	$0
152	15248	Portland General Electric Co	Large	1	17,500	$891,807	-	$0	17,500	$891,807
153	15298	PPL Montana LLC	Large	2	650,000	$41,143,947	963,600	$38,173,100	1,613,600	$79,317,047
154	15452	PSEG Power Connecticut LLC	Large	1	-	$0	-	$0	-	$0
155	15466	Public Service Co of Colorado	Large	7	321,168	$22,336,599	-	$0	321,168	$22,336,599
156	15470	Duke Energy Indiana Inc	Large	5	965,000	$61,876,031	1,437,900	$70,264,930	2,402,900	$132,140,961
157	15472	Public Service Co of NH	Large	2	2,600	$657,824	-	$0	2,600	$657,824
158	15473	Public Service Co of NM	Large	1	184,000	$2,408,353	-	$0	184,000	$2,408,353
159	15474	Public Service Co of Oklahoma	Large	2	36,800	$2,439,609	39,000	$1,408,679	75,800	$3,848,288
160	15534	PPL Montour LLC	Large	1	-	$0	-	$0	-	$0
161	15537	PPL Brunner Island LLC	Large	1	-	$0	-	$0	-	$0
162	15873	Reliant Engy NE Management Co	Large	2	1,755,500	$115,954,497	-	$0	1,755,500	$115,954,497

Exhibit H2
Company-by-Company Estimated Baseline Costs for Disposal of CCR Generated at 495 Electric Plants for 251 Owner Companies

Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
163	15989	City of Richmond	Small City	1	27,729	$2,751,156	-	$0	27,729	$2,751,156
164	15998	Reliant Energy Seward LLC	Large	1	2,546,718	$166,720,024	-	$0	2,546,718	$166,720,024
165	16002	Rio Bravo Poso	Small	1	6,684	$829,252	-	$0	6,684	$829,252
166	16061	Rio Bravo Jasmin	Small	1	6,863	$831,361	-	$0	6,863	$831,361
167	16181	Rochester Public Utilities	Large City	1	11,900	$1,558,171	-	$0	11,900	$1,558,171
168	16183	Rochester Gas & Electric Corp	Large City	1	5,620	$1,341,361	-	$0	5,620	$1,341,361
169	16233	Rocky Mountain Power Inc	Small	1	100,130	$7,346,637	-	$0	100,130	$7,346,637
170	16572	Salt River Project	Large	2	443,550	$5,783,914	56,900	$1,612,179	500,450	$7,396,094
171	16604	San Antonio City of	Large City	2	50,800	$2,423,499	-	$0	50,800	$2,423,499
172	16624	San Miguel Electric Coop, Inc	Small	1	-	$0	-	$0	-	$0
173	16793	Schuylkill Energy Resource Inc	Small	1	752,552	$49,327,523	-	$0	752,552	$49,327,523
174	17043	City of Shelby	Small City	1	4,353	$910,182	-	$0	4,353	$910,182
175	17166	Sierra Pacific Power Co	Large	1	234,200	$10,421,134	-	$0	234,200	$10,421,134
176	17177	City of Sikeston	Small City	1	92,000	$3,616,845	11,300	$1,540,525	103,300	$5,157,370
177	17235	Reliant Energy Mid-Atlantic PH LLC	Large	3	262,500	$18,547,673	-	$0	262,500	$18,547,673
178	17539	South Carolina Electric&Gas Co	Large	6	347,804	$20,173,301	113,600	$3,997,431	461,404	$24,170,732
179	17543	South Carolina Pub Serv Auth	Large	4	62,000	$3,674,635	61,750	$2,575,010	123,750	$6,249,645
180	17554	South Carolina Genertg Co, Inc	Large	1	39,900	$2,619,583	-	$0	39,900	$2,619,583
181	17568	South Mississippi El Pwr Assn	Large	1	115,500	$4,754,369	-	$0	115,500	$4,754,369
182	17632	Southern Illinois Power Coop	Small	1	-	$0	-	$0	-	$0

Exhibit H2
Company-by-Company Estimated Baseline Costs for Disposal of CCR Generated at 495 Electric Plants for 251 Owner Companies

Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
183	17633	Southern Indiana Gas & Elec Co	Large	2	374,200	$22,668,482	201,350	$8,516,677	575,550	$31,185,159
184	17698	Southwestern Electric Power Co	Large	3	1,377,700	$35,725,363	139,400	$4,931,913	1,517,100	$40,657,276
185	17718	Southwestern Public Service Co	Large	2	-	$0	-	$0	-	$0
186	17828	City of Springfield	Large City	2	113,512	$7,702,991	72,100	$3,408,162	185,612	$11,111,153
187	17833	City Utilities of Springfield	Large City	2	127,400	$8,472,903	-	$0	127,400	$8,472,903
188	18041	State Line Energy LLC	Large	1	-	$0	-	$0	-	$0
189	18315	Sunflower Electric Power Corp	Large	1	121,800	$7,681,103	-	$0	121,800	$7,681,103
190	18414	TES Filer City Station LP	Small	1	40,894	$3,953,881	-	$0	40,894	$3,953,881
191	18454	Tampa Electric Co	Large City	2	910,546	$14,342,567	3,700	$688,967	914,246	$15,031,534
192	18642	Tennessee Valley Authority	Large	11	4,020,000	$159,713,985	2,132,900	$91,116,941	6,152,900	$250,830,926
193	18715	Texas Municipal Power Agency	Small	1	1,500	$525,022	-	$0	1,500	$525,022
194	19099	TransAlta Centralia Gen LLC	Large	1	424,220	$29,632,233	-	$0	424,220	$29,632,233
195	19145	Trigen-Cinergy Sol-Tuscola LLC	Small	1	13,976	$1,071,173	-	$0	13,976	$1,071,173
196	19173	Colorado Energy Nations Company LLLP	Small	1	26,094	$2,143,961	-	$0	26,094	$2,143,961
197	19194	Syracuse Energy Corp	Large City	1	10,673	$1,719,471	-	$0	10,673	$1,719,471
198	19323	TXU Generation Co LP	Large	4	3,269,900	$134,849,956	314,400	$10,906,298	3,584,300	$145,756,255
199	19391	UGI Development Co	Small	1	48,972	$3,969,593	-	$0	48,972	$3,969,593
200	19436	Union Electric Co	Large	4	-	$0	559,000	$56,246,085	559,000	$56,246,085
201	19545	Black Hills Power Inc	Large	5	125,001	$8,887,876	-	$0	125,001	$8,887,876
202	19578	Upper Peninsula	Small	1		$1,380,687	-	$0		$1,380,687

Exhibit H2
Company-by-Company Estimated Baseline Costs for Disposal of CCR Generated at 495 Electric Plants for 251 Owner Companies

Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
		Power Co			10,109				10,109	
203	19856	Vineland City of	Large City	1	2,914	$765,683	-	$0	2,914	$765,683
204	19876	Virginia Electric & Power Co	Large	11	1,624,125	$96,273,869	442,400	$15,993,274	2,066,525	$112,267,143
205	19883	City of Virginia	Small City	1	4,608	$1,121,134	-	$0	4,608	$1,121,134
206	20447	Western Farmers Elec Coop, Inc	Large	1	-	$0	16,560	$1,575,926	16,560	$1,575,926
207	20541	Wheelabrator Environmental Systems	Large	1	266,589	$17,998,781	-	$0	266,589	$17,998,781
208	20546	Western Kentucky Energy Corp	Large	5	1,642,858	$26,577,776	34,100	$2,510,084	1,676,958	$29,087,860
209	20737	Willmar Municipal Utils Comm	Small City	1	4,174	$1,095,123	-	$0	4,174	$1,095,123
210	20847	Wisconsin Electric Power Co	Large	5	87,904	$7,085,663	-	$0	87,904	$7,085,663
211	20856	Wisconsin Power & Light Co	Large	3	91,500	$7,120,607	11,000	$1,224,541	102,500	$8,345,148
212	20860	Wisconsin Public Service Corp	Large	2	90,300	$4,045,789	-	$0	90,300	$4,045,789
213	21025	WPS Power Developement	Small	1	244,867	$16,598,422	-	$0	244,867	$16,598,422
214	21048	Wyandotte Municipal Serv Comm	Small City	1	18,593	$2,022,566	-	$0	18,593	$2,022,566
215	21554	Seminole Electric Coop, Inc	Large	1	710,000	$21,727,619	-	$0	710,000	$21,727,619
216	21734	Sunnyside Cogeneration Assoc	Small City	1	249,744	$15,175,811	-	$0	249,744	$15,175,811
217	22001	Sunbury Generation LP	Large	1	192,300	$13,209,567	500	$216,279	192,800	$13,425,846
218	22053	Kentucky Power Co	Large	1	603,000	$9,324,420	298,300	$22,715,732	901,300	$32,040,152
219	22125	AES Cayuga LLC	Small	1	221,700	$18,188,633	-	$0	221,700	$18,188,633
220	22129	AES Somerset LLC	Large	1	509,870	$39,773,120	-	$0	509,870	$39,773,120
221	22146	AES Westover LLC	Small	1	-	$0	-	$0	-	$0
222	22500	Westar Energy Inc	Large	3		$15,074,160		$12,956,983	411,900	$28,031,143

Exhibit H2
Company-by-Company Estimated Baseline Costs for Disposal of CCR Generated at 495 Electric Plants for 251 Owner Companies

Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
					227,800		184,100			
223	23279	Allegheny Energy Supply Co LLC	Large	6	2,279,200	$135,124,125	25,100	$987,489	2,304,300	$136,111,614
224	24211	Tucson Electric Power Co	Large City	2	1,125,180	$12,367,083	-	$0	1,125,180	$12,367,083
225	29878	Somerset Power LLC	Small City	1	-	$0	-	$0	-	$0
226	30151	Tri-State G & T Assn, Inc	Large	3	224,900	$10,320,854	15,700	$721,300	240,600	$11,042,154
227	34672	DTE Energy Services	Small	1	9,637	$1,146,157	-	$0	9,637	$1,146,157
228	35120	Norit Americas Inc	Small	1	528	$482,441	-	$0	528	$482,441
229	40230	Deseret Generation & Tran Coop	Large	1	330,200	$20,319,204	-	$0	330,200	$20,319,204
230	40307	Soyland Power Coop Inc	Small	1	9,160	$840,312	-	$0	9,160	$840,312
231	40577	American Mun Power-Ohio, Inc	Large	1	130,800	$9,379,236	-	$0	130,800	$9,379,236
232	40606	Grand Island City of	Small City	1	-	$0	-	$0	-	$0
233	49756	Ameren Energy Resources Generating Co.	Large	2	-	$0	237,000	$11,085,672	237,000	$11,085,672
234	49889	Mount Carmel Cogen Inc	Small	1	329,721	$22,068,733	-	$0	329,721	$22,068,733
235	50018	Dominion Energy New England, LLC	Large	2	-	$0	-	$0	-	$0
236	54708	Primary Energy of North Carolina LLC	Small	2	7,645	$805,717	-	$0	7,645	$805,717
237	54784	NewPage Corporation	Small	1	15,000	$735,319	-	$0	15,000	$735,319
238	54865	ANP-Coleto Creek	Large	1	-	$0	63,500	$4,070,714	63,500	$4,070,714
239	54888	NRG Texas LLC	Large	2	1,565,200	$43,826,644	-	$0	1,565,200	$43,826,644
240	54889	Carlyle/Riverstone Renewable Energy	Small	1	11,653	$1,002,479	-	$0	11,653	$1,002,479
241	54891	Altura Power	Small	1	224,800	$5,117,785	-	$0	224,800	$5,117,785

Exhibit H2

Company-by-Company Estimated Baseline Costs for Disposal of CCR Generated at 495 Electric Plants for 251 Owner Companies

Row	Utility Code	Company Name	Size of Company or City	Number of Affected Plants	Company-Owned Landfill Baseline CCW Quantity (tons/year)	Landfill Annual Baseline Cost (2009$)	Company-Owned Surface Impoundment Baseline CCW Quantity (tons/year)	Surface Impoundment Annual Baseline Cost (2009$)	Total Company-Owned Unit Baseline CCW Quantity (tons/year)	Total Annual Baseline Costs (2009$)
242	54895	FirstLight Power Resources Services LLC	Large	1	-	$0	-	$0	-	$0
243	55729	Duke Energy Kentucky Inc	Large	1	290,800	$4,537,368	172,900	$9,851,841	463,700	$14,389,209
244	55739	Edgecombe Operating Services LLC	Small	1	-	$0	-	$0	-	$0
245	55740	Spruance Operating Services LLC	Small	1	-	$0	-	$0	-	$0
246	55768	RC Cape May Holdings LLC	Large	1	-	$0	-	$0	-	$0
247	55807	Niagara Generation LLC	Large City	1	18,249	$2,286,375	-	$0	18,249	$2,286,375
248	55808	Westmoreland Partners	Small	2	19,390	$1,812,712	-	$0	19,390	$1,812,712
249	55936	Entergy Gulf States Louisiana LLC	Large	1	-	$0	-	$0	-	$0
250	56155	Lansing Board of Water and Light	Large City	2	-	$0	5,100	$909,873	5,100	$909,873
251	56190	Savannah River Nuclear Solutions LLC	Small	1	20,966	$1,669,511	-	$0	20,966	$1,669,511
				495	71,573,055	**$3,738,976,000**	22,365,420	**$1,196,286,000**	93,938,475	**$4,935,262,000**

Appendix I:

Geological Conditions at Electric Utility Industry CCR Disposal Unit Locations

Appendix I Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants											
Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
1	3	Barry	0	0	0	0		0		0	0
2	7	Gadsden	0	0	0	1	long	1	long	1	1
3	8	Gorgas	0	0	0	0		0		1	1
4	10	Greene County	0	0	0	0		1	absent	0	0
5	26	E C Gaston	0	0	0	1	long	1	long	1	1
6	47	Colbert	0	0	0	1	long	1	long	1	1
7	50	Widows Creek	0	0	0	1	long	1	long	1	1
8	51	Dolet Hills	0	0	0	0		0		0	0
9	56	Charles R Lowman	0	0	0	0		0		0	0
10	59	Platte	0	0	0	1	short	1	short	0	0
11	60	Whelan Energy Center	0	0	0	1	short	1	short	0	0
12	79	Aurora Energy LLC Chena	1	0	0	0		0		0	0
13	87	Escalante	0	0	0	0		1	short	1	1
14	108	Holcomb	0	0	0	0		0		0	0
15	113	Cholla	0	0	0	0		0		0	0
16	126	H Wilson Sundt Generating Station	0	0	0	0		0		1	1
17	127	Oklaunion	0	0	0	0		0		0	0
18	130	Cross	0	0	0	1	short	1	short	1	1
19	136	Seminole	0	0	0	1	long	1	long	0	0
20	160	Apache Station	0	0	0	0		0		1	1
21	165	GRDA	0	0	0	1	short	1	short	0	0
22	207	St Johns River Power Park	0	0	0	1	short	1	short	0	0
23	298	Limestone	0	0	0	0		0		0	0
24	384	Joliet 29	0	0	0	1	short	1	short	0	0
25	462	W N Clark	0	0	0	0		0		1	1
26	465	Arapahoe	0	0	0	0		0		0	0
27	468	Cameo	0	0	0	0		0		1	1
28	469	Cherokee	0	0	0	0		0		0	0
29	470	Comanche	0	0	0	0		0		0	0
30	477	Valmont	0	0	0	0		1	long	1	1
31	492	Martin Drake	0	0	0	1	long	1	long	0	0

Appendix I
Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants

Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
32	525	Hayden	0	0	0	0		0		1	1
33	527	Nucla	0	0	0	0		0		1	1
34	564	Stanton Energy Center	0	0	0	1	long	1	long	0	0
35	568	Bridgeport Station	0	0	0	0		0		1	1
36	593	Edge Moor	0	0	0	0		0		1	1
37	594	Indian River Generating Station	0	0	0	0		0		0	0
38	602	Brandon Shores	0	0	0	0		0		0	0
39	628	Crystal River	0	0	0	1	long	1	long	0	0
40	641	Crist	0	0	0	0		0		0	0
41	642	Scholz	0	0	0	1	short	1	short	0	0
42	643	Lansing Smith	0	0	0	1	short	1	short	0	0
43	645	Big Bend	0	0	0	1	long	1	long	0	0
44	663	Deerhaven Generating Station	0	0	0	1	long	1	long	0	0
45	667	Northside Generating Station	0	0	0	1	short	1	short	0	0
46	676	C D McIntosh Jr	0	0	0	1	long	1	long	0	0
47	703	Bowen	0	0	0	1	long	1	long	1	1
48	708	Hammond	0	0	0	0		0		1	1
49	709	Harllee Branch	0	0	0	0		0		0	0
50	710	Jack McDonough	0	0	0	0		0		0	0
51	727	Mitchell	0	0	0	1	short	1	short	0	0
52	728	Yates	0	0	0	0		0		0	0
53	733	Kraft	0	0	0	1	short	1	short	1	1
54	753	Crisp Plant	0	0	0	1	short	1	short	0	0
55	856	E D Edwards	0	0	0	0		0		0	0
56	861	Coffeen	0	0	0	0		0		1	1
57	863	Hutsonville	0	0	0	0		0		1	1
58	864	Meredosia	0	0	0	1	short	1	short	0	0
59	867	Crawford	0	0	0	1	short	1	short	0	0
60	874	Joliet 9	0	0	0	1	short	1	short	0	0
61	876	Kincaid Generation LLC	0	0	0	0		0		1	1
62	879	Powerton	0	0	0	0		0		0	0
63	883	Waukegan	0	0	0	1	short	1	short	0	0

Appendix I
Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants

Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
64	884	Will County	0	0	0	1	short	1	short	0	0
65	886	Fisk Street	0	0	0	1	short	1	short	0	0
66	887	Joppa Steam	0	0	0	0		1	short	1	1
67	889	Baldwin Energy Complex	0	0	0	0		1	short	1	1
68	891	Havana	0	0	0	0		0		0	0
69	892	Hennepin Power Station	0	0	0	0		0		0	0
70	897	Vermilion	0	0	0	0		0		0	0
71	898	Wood River	0	0	0	1	short	1	short	1	1
72	963	Dallman	0	0	0	0		0		1	1
73	964	Lakeside	0	0	0	0		0		1	1
74	976	Marion	0	0	0	0		0		1	1
75	981	State Line Energy	0	0	0	1	short	1	short	0	0
76	983	Clifty Creek	0	0	0	1	short	1	short	0	0
77	988	Tanners Creek	0	0	0	1	short	1	short	0	0
78	990	Harding Street	0	0	0	0		0		0	0
79	991	Eagle Valley	0	0	0	0		0		0	0
80	992	CC Perry K	0	0	0	0		1	short	0	0
81	994	AES Petersburg	0	0	0	0		0		1	1
82	995	Bailly	0	0	0	0		1	short	0	0
83	997	Michigan City	0	0	0	0		0		0	0
84	1001	Cayuga	0	0	0	0		0		0	0
85	1004	Edwardsport	0	0	0	0		0		1	1
86	1008	R Gallagher	0	0	0	0		1	short	0	1
87	1010	Wabash River	0	0	0	0		0		1	1
88	1012	F B Culley	0	0	0	0		0		1	1
89	1024	Crawfordsville	0	0	0	0		0		0	0
90	1032	Logansport	0	0	0	0		1	short	0	0
91	1037	Peru	0	0	0	0		1	short	0	0
92	1040	Whitewater Valley	0	0	0	1	short	1	short	0	0
93	1043	Frank E Ratts	0	0	0	0		0		1	1
94	1046	Dubuque	0	0	0	0		1	short	0	0
95	1047	Lansing	0	0	0	1	short	1	short	0	0
96	1048	Milton L Kapp	0	0	0	1	short	1	short	0	0

Appendix I
Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants

Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
97	1058	Sixth Street	0	0	0	1	short	1	short	0	0
98	1073	Prairie Creek	0	0	0	1	short	1	short	0	0
99	1077	Sutherland	0	0	0	1	short	1	short	0	0
100	1081	Riverside	0	0	0	1	short	1	short	0	0
101	1082	Walter Scott Jr Energy Center	0	0	0	1	short	1	short	0	0
102	1091	George Neal North	0	0	0	0		0		0	0
103	1104	Burlington	0	0	0	0		1	short	0	0
104	1122	Ames Electric Services Power Plant	0	0	0	1	short	1	short	0	0
105	1131	Streeter Station	0	0	0	1	short	1	short	0	0
106	1167	Muscatine Plant #1	0	0	0	1	short	1	short	0	0
107	1175	Pella	0	0	0	1	short	1	short	0	0
108	1217	Earl F Wisdom	0	0	0	0		0		0	0
109	1218	Fair Station	0	0	0	1	short	1	short	0	0
110	1239	Riverton	0	0	0	1	short	1	short	0	0
111	1241	La Cygne	0	0	0	0		0		0	0
112	1250	Lawrence Energy Center	0	0	0	0		0		0	0
113	1252	Tecumseh Energy Center	0	0	0	0		0		0	0
114	1295	Quindaro	0	0	0	0		0		0	0
115	1353	Big Sandy	0	0	0	0		0		0	0
116	1355	E W Brown	0	0	0	1	long	1	long	0	0
117	1356	Ghent	0	0	0	1	short	1	short	0	0
118	1357	Green River	0	0	0	0		0		1	1
119	1361	Tyrone	0	0	0	1	long	1	long	0	0
120	1363	Cane Run	0	0	0	0		0		1	1
121	1364	Mill Creek	0	0	0	0		0		1	1
122	1372	Henderson I	0	0	0	0		0		1	1
123	1374	Elmer Smith	0	0	0	0		0		1	1
124	1378	Paradise	0	0	0	0		0		1	1
125	1379	Shawnee	0	0	0	0		0		1	1
126	1381	Kenneth C Coleman	0	0	0	0		0		1	1
127	1382	HMP&L Station Two Henderson	0	0	0	0		0		1	1

Appendix I
Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants

Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
128	1383	Robert A Reid	0	0	0	0		0		1	1
129	1384	Cooper	0	0	0	1	long	1	long	0	0
130	1385	Dale	0	0	0	1	long	1	long	0	0
131	1393	R S Nelson	0	0	0	0		0		0	0
132	1552	C P Crane	0	0	0	0		0		0	0
133	1554	Herbert A Wagner	0	0	0	0		0		0	0
134	1570	R Paul Smith Power Station	0	0	0	1	short	1	short	0	0
135	1571	Chalk Point LLC	0	0	0	0		0		0	0
136	1572	Dickerson	0	0	0	1	short	1	short	0	0
137	1573	Morgantown Generating Plant	0	0	0	0		0		0	0
138	1606	Mount Tom	0	0	0	0		0		0	0
139	1613	Somerset Station	0	0	0	0		0		0	0
140	1619	Brayton Point	0	0	0	0		0		0	0
141	1626	Salem Harbor	0	0	0	0		0		1	1
142	1695	B C Cobb	0	0	0	0		0		0	0
143	1702	Dan E Karn	0	0	0	0		0		0	0
144	1710	J H Campbell	0	0	0	0		0		0	0
145	1720	J C Weadock	0	0	0	0		0		0	0
146	1723	J R Whiting	0	0	0	1	short	1	short	0	0
147	1731	Harbor Beach	0	0	0	0		0		0	0
148	1733	Monroe	0	0	0	1	short	1	short	0	0
149	1740	River Rouge	0	0	0	1	short	1	short	0	0
150	1743	St Clair	0	0	0	0		1	short	0	0
151	1745	Trenton Channel	0	0	0	1	short	1	short	0	0
152	1769	Presque Isle	0	0	0	0		0		0	0
153	1771	Escanaba	0	0	0	1	short	1	short	0	0
154	1825	J B Sims	0	0	0	0		0		0	0
155	1830	James De Young	0	0	0	0		0		0	0
156	1831	Eckert Station	0	0	0	0		0		0	0
157	1832	Erickson Station	0	0	0	0		0		0	0
158	1843	Shiras	0	0	0	0		0		0	0
159	1866	Wyandotte	0	0	0	1	short	1	short	0	0

Appendix I
Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants

Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
160	1891	Syl Laskin	0	0	0	0		0		0	0
161	1893	Clay Boswell	0	0	0	0		0		0	0
162	1897	M L Hibbard	0	0	0	0		0		0	0
163	1904	Black Dog	0	0	0	1	short	1	short	0	0
164	1915	Allen S King	0	0	0	1	short	1	short	0	0
165	1927	Riverside	0	0	0	1	short	1	short	0	0
166	1943	Hoot Lake	0	0	0	0		0		0	0
167	1961	Austin Northeast	0	0	0	1	short	1	short	0	0
168	1979	Hibbing	0	0	0	0		0		0	0
169	2001	New Ulm	0	0	0	0		0		0	0
170	2008	Silver Lake	0	0	0	1	short	1	short	0	0
171	2018	Virginia	0	0	0	0		0		0	0
172	2022	Willmar	0	0	0	0		0		0	0
173	2049	Jack Watson	0	0	0	0		0		0	0
174	2062	Henderson	0	0	0	0		0		1	1
175	2076	Asbury	0	0	0	0		0		0	0
176	2079	Hawthorn	0	0	0	1	short	1	short	0	0
177	2080	Montrose	0	0	0	0		0		0	0
178	2094	Sibley	0	0	0	0		0		0	0
179	2098	Lake Road	0	0	0	0		0		0	0
180	2103	Labadie	0	0	0	0		1	long	1	1
181	2104	Meramec	0	0	0	1	long	1	long	1	1
182	2107	Sioux	0	0	0	0		1	short	1	1
183	2123	Columbia	0	0	0	0		1	long	0	0
184	2132	Blue Valley	0	0	0	0		0		0	0
185	2144	Marshall	0	0	0	1	short	1	short	0	0
186	2161	James River Power Station	0	0	0	1	short	1	short	0	0
187	2167	New Madrid	0	0	0	0		0		1	1
188	2168	Thomas Hill	0	0	0	0		0		0	0
189	2169	Chamois	0	0	0	1	short	1	short	1	1
190	2171	Missouri City	0	0	0	0		1	short	0	0
191	2187	J E Corette Plant	0	0	0	0		0		0	0
192	2240	Lon Wright	0	0	0	0		0		0	0

Appendix I Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants											
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193	2277	Sheldon	0	0	0	0		0		0	0
194	2291	North Omaha	0	0	0	0		0		0	0
195	2324	Reid Gardner	0	0	1	0		1	long	1	1
196	2364	Merrimack	0	0	0	0		0		1	1
197	2367	Schiller	0	0	0	0		0		1	1
198	2378	B L England	0	0	0	0		0		0	0
199	2384	Deepwater	0	0	0	0		0		1	1
200	2403	PSEG Hudson Generating Station	0	0	0	0		0		1	1
201	2408	PSEG Mercer Generating Station	0	0	0	0		0		1	1
202	2434	Howard Down	0	0	0	0		0		0	0
203	2442	Four Corners	0	0	0	0		0		0	0
204	2451	San Juan	0	0	0	0		0		0	0
205	2480	Danskammer Generating Station	0	0	0	1	short	1	short	1	1
206	2526	AES Westover	0	0	0	0		0		0	0
207	2527	AES Greenidge LLC	0	0	0	1	short	1	short	0	0
208	2535	AES Cayuga	0	0	0	0		1	short	0	0
209	2549	C R Huntley Generating Station	0	0	0	1	short	1	short	1	1
210	2554	Dunkirk Generating Plant	0	0	0	0		0		0	0
211	2629	Lovett	0	0	0	0		1	short	1	1
212	2642	Rochester 7	0	0	0	0		0		0	0
213	2682	S A Carlson	0	0	0	0		0		0	0
214	2706	Asheville	0	0	0	0		0		1	1
215	2708	Cape Fear	0	0	0	0		0		0	0
216	2709	Lee	0	0	0	0		0		0	0
217	2712	Roxboro	0	0	0	0		0		0	0
218	2713	L V Sutton	0	0	0	1	short	1	short	1	1
219	2716	W H Weatherspoon	0	0	0	0		0		1	1
220	2718	G G Allen	0	0	0	0		0		1	1
221	2720	Buck	0	0	0	0		0		0	0
222	2721	Cliffside	0	0	0	0		0		1	1

Appendix I
Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants

Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
223	2723	Dan River	0	0	0	0		0		0	0
224	2727	Marshall	0	0	0	0		0		1	1
225	2732	Riverbend	0	0	0	0		0		1	1
226	2790	R M Heskett	0	0	0	0		0		0	0
227	2817	Leland Olds	0	0	0	0		0		0	0
228	2823	Milton R Young	0	0	0	0		0		0	0
229	2824	Stanton	0	0	0	0		0		0	0
230	2828	Cardinal	0	0	0	0		1	short	0	0
231	2830	Walter C Beckjord	0	0	0	1	short	1	short	0	0
232	2832	Miami Fort	0	0	0	1	short	1	short	0	0
233	2835	Ashtabula	0	0	0	0		0		1	1
234	2836	Avon Lake	0	0	0	0		0		0	0
235	2837	Eastlake	0	0	0	0		0		1	1
236	2838	Lake Shore	0	0	0	0		0		1	1
237	2840	Conesville	0	0	0	0		0		0	0
238	2843	Picway	0	0	0	0		1	short	0	0
239	2848	O H Hutchings	0	0	0	0		0		0	0
240	2850	J M Stuart	0	0	0	1	short	1	short	0	0
241	2861	Niles	0	0	0	0		1	short	0	0
242	2864	R E Burger	0	0	0	0		0		0	0
243	2866	W H Sammis	0	0	0	0		0		0	0
244	2872	Muskingum River	0	0	0	0		0		0	0
245	2876	Kyger Creek	0	0	0	0		0		0	0
246	2878	Bay Shore	0	0	0	1	short	1	short	0	0
247	2914	Dover	0	0	0	0		0		0	0
248	2917	Hamilton	0	0	0	0		0		0	0
249	2935	Orrville	0	0	0	0		0		0	0
250	2936	Painesville	0	0	0	0		0		1	1
251	2943	Shelby Municipal Light Plant	0	0	0	0		0		0	0
252	2952	Muskogee	0	0	0	0		1	short	0	0
253	2963	Northeastern	0	0	0	1	short	1	short	0	0
254	3098	Elrama Power Plant	0	0	0	1	short	1	short	0	0

Appendix I
Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants

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255	3113	Portland	0	0	0	1	short	1	short	1	1
256	3115	Titus	0	0	0	1	short	1	short	1	1
257	3118	Conemaugh	0	0	0	0		0		0	0
258	3122	Homer City Station	0	0	0	0		0		0	0
259	3130	Seward	0	0	0	0		0		0	0
260	3131	Shawville	0	0	0	0		0		0	0
261	3136	Keystone	0	0	0	0		0		0	0
262	3138	New Castle Plant	0	0	0	1	short	1	short	0	0
263	3140	PPL Brunner Island	0	0	0	0		0		0	0
264	3149	PPL Montour	0	0	0	1	long	1	long	0	0
265	3152	Sunbury Generation LP	0	0	0	1	long	1	long	0	0
266	3159	Cromby Generating Station	0	0	0	0		0		1	1
267	3161	Eddystone Generating Station	0	0	0	0		0		1	1
268	3176	Hunlock Power Station	0	0	0	0		0		0	0
269	3178	Armstrong Power Station	0	0	0	1	short	1	short	0	0
270	3179	Hatfields Ferry Power Station	0	0	0	1	short	1	short	0	0
271	3181	Mitchell Power Station	0	0	0	1	short	1	short	0	0
272	3251	H B Robinson	0	0	0	0		0		1	1
273	3264	W S Lee	0	0	0	0		0		1	1
274	3280	Canadys Steam	0	0	0	1	short	1	short	1	1
275	3287	McMeekin	0	0	0	0		0		1	1
276	3295	Urquhart	0	0	0	0		0		1	1
277	3297	Wateree	0	0	0	0		0		1	1
278	3298	Williams	0	0	0	1	short	1	short	1	1
279	3317	Dolphus M Grainger	0	0	0	0		0		1	1
280	3319	Jefferies	0	0	0	1	short	1	short	1	1
281	3325	Ben French	0	0	0	1	long	1	long	0	0
282	3393	Allen Steam Plant	0	0	0	0		0		1	1
283	3396	Bull Run	0	0	0	0		1	long	1	1
284	3399	Cumberland	0	0	0	1	short	1	short	1	1
285	3403	Gallatin	0	0	0	1	long	1	long	1	1
286	3405	John Sevier	0	0	0	1	long	1	long	1	1

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287	3406	Johnsonville	0	0	0	0		1	short	1	1
288	3407	Kingston	0	0	0	1	long	1	long	1	1
289	3470	W A Parish	0	0	0	0		0		0	0
290	3497	Big Brown	0	0	0	0		0		0	0
291	3644	Carbon	0	0	0	0		0		1	1
292	3775	Clinch River	0	0	0	1	long	1	long	1	1
293	3776	Glen Lyn	0	0	0	1	long	1	long	1	1
294	3788	Potomac River	0	0	0	0		0		0	0
295	3796	Bremo Bluff	0	0	0	0		0		1	1
296	3797	Chesterfield	0	0	0	0		0		0	0
297	3803	Chesapeake	0	0	0	0		0		0	0
298	3809	Yorktown	0	0	0	0		0		0	0
299	3845	Transalta Centralia Generation	0	0	0	0		0		1	1
300	3935	John E Amos	0	0	0	0		0		0	0
301	3936	Kanawha River	0	0	0	0		0		0	0
302	3938	Philip Sporn	0	0	0	0		0		0	0
303	3942	Albright	0	0	0	1	short	1	short	0	0
304	3943	Fort Martin Power Station	0	0	0	1	short	1	short	0	0
305	3944	Harrison Power Station	0	0	0	0		1	short	0	0
306	3945	Rivesville	0	0	0	0		1	short	0	0
307	3946	Willow Island	0	0	0	0		0		0	0
308	3947	Kammer	0	0	0	0		0		0	0
309	3948	Mitchell	0	0	0	0		0		0	0
310	3954	Mt Storm	0	0	0	0		1	long	0	0
311	3982	Bay Front	0	0	0	0		0		0	0
312	3992	Blount Street	0	0	0	0		1	short	0	0
313	4041	South Oak Creek	0	0	0	1	short	1	short	0	0
314	4042	Valley	0	0	0	1	short	1	short	0	0
315	4050	Edgewater	0	0	0	1	short	1	short	0	0
316	4054	Nelson Dewey	0	0	0	1	short	1	short	0	0
317	4072	Pulliam	0	0	0	1	short	1	short	0	0
318	4078	Weston	0	0	0	0		0		0	0

Appendix I
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319	4125	Manitowoc	0	0	0	1	short	1	short	0	0
320	4140	Alma	0	0	0	0		0		0	0
321	4143	Genoa	0	0	0	0		1	short	0	0
322	4146	E J Stoneman Station	0	0	0	1	short	1	short	0	0
323	4150	Neil Simpson	0	0	0	0		0		1	1
324	4151	Osage	0	0	0	0		0		0	0
325	4158	Dave Johnston	0	0	0	0		0		1	1
326	4162	Naughton	0	0	0	0		0		1	1
327	4259	Endicott Station	0	0	0	0		0		0	0
328	4271	John P Madgett	0	0	0	0		0		0	0
329	4941	Navajo	0	0	0	0		0		1	1
330	6002	James H Miller Jr	0	0	0	0		0		1	1
331	6004	Pleasants Power Station	0	0	0	0		0		0	0
332	6009	White Bluff	0	0	0	0		0		1	1
333	6016	Duck Creek	0	0	0	0		0		0	0
334	6017	Newton	0	0	0	0		0		1	1
335	6018	East Bend	0	0	0	1	short	1	short	0	0
336	6019	W H Zimmer	0	0	0	1	short	1	short	0	0
337	6021	Craig	0	0	0	0		0		1	1
338	6030	Coal Creek	0	0	0	0		0		0	0
339	6031	Killen Station	0	0	0	0		0		0	0
340	6034	Belle River	0	0	0	0		1	short	0	0
341	6041	H L Spurlock	0	0	0	1	short	1	short	0	0
342	6052	Wansley	0	0	0	0		0		0	0
343	6055	Big Cajun 2	0	0	0	0		0		0	0
344	6061	R D Morrow	0	0	0	0		0		0	0
345	6064	Nearman Creek	0	0	0	0		0		0	0
346	6065	Iatan	0	0	0	0		0		0	0
347	6068	Jeffrey Energy Center	0	0	0	0		0		0	0
348	6071	Trimble County	0	0	0	1	short	1	short	0	0
349	6073	Victor J Daniel Jr	0	0	0	0		1	pseudo	0	0
350	6076	Colstrip	0	0	0	0		0		0	0
351	6077	Gerald Gentleman	0	0	0	0		0		0	0

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352	6082	AES Somerset LLC	0	0	0	0		0		1	1
353	6085	R M Schahfer	0	0	0	0		1	short	0	0
354	6089	Lewis & Clark	0	0	0	0		0		0	0
355	6090	Sherburne County	0	0	0	0		0		0	0
356	6094	Bruce Mansfield	0	0	0	0		0		0	0
357	6095	Sooner	0	0	0	1	short	1	short	0	0
358	6096	Nebraska City	0	0	0	0		0		0	0
359	6098	Big Stone	0	0	0	0		0		0	0
360	6101	Wyodak	0	0	0	0		0		1	1
361	6106	Boardman	0	0	0	0		0		1	1
362	6113	Gibson	0	0	0	0		0		1	1
363	6124	McIntosh	0	0	0	1	short	1	short	1	1
364	6136	Gibbons Creek	0	0	0	0		0		0	0
365	6137	A B Brown	0	0	0	0		0		1	1
366	6138	Flint Creek	0	0	0	1	short	1	short	0	0
367	6139	Welsh	0	0	0	0		0		0	0
368	6146	Martin Lake	0	0	0	0		0		0	0
369	6147	Monticello	0	0	0	0		0		0	0
370	6155	Rush Island	0	0	0	1	long	1	long	1	1
371	6165	Hunter	0	0	0	0		0		1	1
372	6166	Rockport	0	0	0	0		0		1	1
373	6170	Pleasant Prairie	0	0	0	1	short	1	short	0	0
374	6177	Coronado	0	0	0	0		0		0	0
375	6178	Coleto Creek	0	0	0	0		0		0	0
376	6179	Fayette Power Project	0	0	0	0		0		0	0
377	6181	J T Deely	0	0	0	0		0		0	0
378	6183	San Miguel	0	0	0	0		0		0	0
379	6190	Rodemacher	0	0	0	0		0		0	0
380	6193	Harrington	0	0	0	1	pseudo	1	pseudo	0	0
381	6194	Tolk	0	0	0	1	pseudo	1	pseudo	0	0
382	6195	Southwest Power Station	0	0	0	1	short	1	short	0	0
383	6213	Merom	0	0	0	0		0		1	1
384	6225	Jasper 2	0	0	0	0		0		1	1

Appendix I
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385	6238	Pearl Station	0	0	0	1	short	1	short	0	0
386	6248	Pawnee	0	0	0	0		0		0	0
387	6249	Winyah	0	0	0	0		0		1	1
388	6250	Mayo	0	0	0	0		0		0	0
389	6254	Ottumwa	0	0	0	1	short	1	short	0	0
390	6257	Scherer	0	0	0	0		0		0	0
391	6264	Mountaineer	0	0	0	0		0		0	0
392	6288	Healy	1	0	0	0		0		0	0
393	6469	Antelope Valley	0	0	0	0		0		0	0
394	6481	Intermountain Power Project	0	1	1	0		0		1	1
395	6639	R D Green	0	0	0	0		0		1	1
396	6641	Independence	0	0	0	0		1	short	1	1
397	6648	Sandow No 4	0	0	0	0		0		0	0
398	6664	Louisa	0	0	0	0		0		0	0
399	6705	Warrick	0	0	0	0		0		1	1
400	6761	Rawhide	0	0	0	0		0		0	0
401	6768	Sikeston Power Station	0	0	0	0		0		1	1
402	6772	Hugo	0	0	0	1	short	1	short	0	0
403	6823	D B Wilson	0	0	0	0		0		1	1
404	7030	Twin Oaks Power One	0	0	0	0		0		0	0
405	7097	J K Spruce	0	0	0	0		0		0	0
406	7210	Cope	0	0	0	1	short	1	short	1	1
407	7213	Clover	0	0	0	0		0		0	0
408	7242	Polk	0	0	0	1	long	1	long	0	0
409	7286	Richard Gorsuch	0	0	0	0		0		0	0
410	7343	George Neal South	0	0	0	0		0		0	0
411	7504	Neil Simpson II	0	0	0	0		0		1	1
412	7537	North Branch	0	0	0	1	short	1	short	0	0
413	7549	Milwaukee County	0	0	0	1	short	1	short	0	0
414	7652	US DOE Savannah River Site (D Area)	0	0	0	0		0		1	1
415	7737	Cogen South	0	0	0	1	short	1	short	1	1
416	7790	Bonanza	0	0	0	0		0		1	1

Appendix I
Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants

Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
417	7902	Pirkey	0	0	0	0		0		0	0
418	8023	Columbia	0	0	0	0		0		0	0
419	8042	Belews Creek	0	0	0	0		0		0	0
420	8066	Jim Bridger	0	0	0	0		0		1	1
421	8069	Huntington	0	0	0	0		0		1	1
422	8102	General James M Gavin	0	0	0	0		0		0	0
423	8219	Ray D Nixon	0	0	0	0		0		0	0
424	8222	Coyote	0	0	0	0		0		0	0
425	8223	Springerville	0	0	0	0		1	pseudo	1	1
426	8224	North Valmy	0	0	1	0		0		1	1
427	8226	Cheswick Power Plant	0	0	0	0		0		0	0
428	10002	ACE Cogeneration Facility	0	0	0	0		0		1	1
429	10003	Colorado Energy Nations Company	0	0	0	1	long	1	long	1	1
430	10030	NRG Energy Center Dover	0	0	0	0		0		0	0
431	10043	Logan Generating Company LP	0	0	0	0		0		1	1
432	10071	Cogentrix Virginia Leasing Corporation	0	0	0	0		0		0	0
433	10075	Taconite Harbor Energy Center	0	0	0	0		0		0	0
434	10113	John B Rich Memorial Power Station	0	0	0	0		0		0	0
435	10143	Colver Power Project	0	0	0	0		0		0	0
436	10148	White Pine Electric Power	1	0	0	0		0		0	0
437	10151	Grant Town Power Plant	0	0	0	1	short	1	short	0	0
438	10333	Central Power & Lime	0	0	0	1	long	1	long	0	0
439	10343	Foster Wheeler Mt Carmel Cogen	0	0	0	0		0		0	0
440	10377	James River Cogeneration	0	0	0	0		0		0	0
441	10378	Primary Energy Southport	0	0	0	0		0		1	1
442	10379	Primary Energy Roxboro	0	0	0	0		0		0	0
443	10380	Elizabethtown Power LLC	0	0	0	0		0		1	1
444	10381	Coastal Carolina Clean	0	0	0	0		0		0	0

Appendix I
Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants

Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
		Power									
445	10382	Lumberton	0	0	0	0		0		1	1
446	10384	Edgecombe Genco LLC	0	0	0	0		0		0	0
447	10464	Black River Generation	0	0	0	1	short	1	short	1	1
448	10495	Rumford Cogeneration	0	0	0	0		0		1	1
449	10566	Chambers Cogeneration LP	0	0	0	0		0		1	1
450	10603	Ebensburg Power	0	0	0	0		0		0	0
451	10604	Hawaiian Comm & Sugar Puunene Mill	1	0	0	0		0		0	0
452	10640	Stockton Cogen	0	0	0	0		0		1	1
453	10641	Cambria Cogen	0	0	0	0		0		0	0
454	10671	AES Shady Point LLC	0	0	0	0		0		0	0
455	10672	Cedar Bay Generating Company LP	0	0	0	1	short	1	short	0	0
456	10673	AES Hawaii	0	0	0	0		0		0	0
457	10675	AES Thames	0	0	0	0		0		0	0
458	10676	AES Beaver Valley Partners Beaver Valley	0	0	0	0		0		0	0
459	10678	AES Warrior Run Cogeneration Facility	0	0	0	1	long	1	long	0	0
460	10686	Rapids Energy Center	0	0	0	0		0		0	0
461	10743	Morgantown Energy Facility	0	0	0	0		1	short	0	0
462	10768	Rio Bravo Jasmin	0	0	0	0		0		1	1
463	10769	Rio Bravo Poso	0	0	0	0		0		1	1
464	10773	Altavista Power Station	0	0	0	0		1	short	0	0
465	10774	Southampton Power Station	0	0	0	0		0		0	0
466	10784	Colstrip Energy LP	1	0	0	0		0		0	0
467	50039	Kline Township Cogen Facility	0	0	0	0		0		0	0
468	50202	WPS Power Niagara	0	0	0	1	short	1	short	1	1
469	50407	Mobile Energy Services LLC	0	0	0	0		0		0	0
470	50611	WPS Westwood Generation LLC	0	0	0	0		0		0	0
471	50651	Trigen Syracuse Energy	0	0	0	0		0		0	0

Appendix I Fault Line, Karst and Seismic Zone Site Location Data for List of 495 Electric Utility Plants											
Row	Plant Code	Plant name	County centroid used? (1=yes, 0=no)	Fault line - one mile buffer (1=yes, 0=no)	Fault line - three mile buffer (1=yes, 0=no)	Karst - one mile buffer (1=yes, 0=no)	Karst type - one mile buffer	Karst - three mile buffer (1=yes, 0=no)	Karst type - three mile buffer	Seismic zone - one mile buffer (1=yes, 0=no)	Seismic zone - three mile buffer (1=yes, 0=no)
472	50776	Panther Creek Energy Facility	0	0	0	0		0		0	0
473	50835	TES Filer City Station	0	0	0	0		0		0	0
474	50879	Wheelabrator Frackville Energy	0	0	0	0		0		0	0
475	50888	Northampton Generating Company LP	0	0	0	1	short	1	short	1	1
476	50951	Sunnyside Cogen Associates	0	0	0	0		0		1	1
477	50974	Scrubgrass Generating Company LP	0	0	0	0		1	short	0	0
478	50976	Indiantown Cogeneration LP	0	0	0	1	short	1	short	0	0
479	52007	Mecklenburg Power Station	0	0	0	0		0		0	0
480	54035	Roanoke Valley Energy Facililty I	0	0	0	0		0		0	0
481	54081	Spruance Genco LLC	0	0	0	0		0		1	1
482	54144	Piney Creek Project	0	0	0	1	short	1	short	0	0
483	54238	Port of Stockton District Energy Fac	0	0	0	0		0		1	1
484	54304	Birchwood Power	0	0	0	0		0		0	0
485	54626	Mt Poso Cogeneration	0	0	0	0		0		1	1
486	54634	St Nicholas Cogen Project	0	0	0	0		0		0	0
487	54755	Roanoke Valley Energy Facility II	0	0	0	0		0		0	0
488	54972	Norit Americas Marshall Plant	1	0	0	0		0		0	0
489	55076	Red Hills Generating Facility	0	0	0	0		0		1	1
490	55245	Tuscola Station	0	0	0	0		0		1	1
491	55479	Wygen 1	0	0	0	0		0		1	1

Appendix J:

Incremental Regulatory Cost Estimates
for Compliance with the CCR Proposed Rule Regulatory Options

- **Exhibit J1: Cost for Options 1 and 2 Without Land Treatment Dewatering Sub-Option**
- **Exhibit J2: Cost for Hybrid C & D Withou Land Treatment Dewatering Sub-Option**

- **Exhibit J3: Cost for Options 1 and 2 With Land Treatment Dewatering Sub-Option**
- **Exhibit J4: High End Cost for Hybrid C & D With Land Treatment Dewatering Sub-Option**

- **Exhibit J5: Entity-by-Entity Aggregation of Regulatory Cost Estimates Without Land Treatment Dewatering Sub-Option**
- **Exhibit J6: Entity-by-Entity Aggregation of Regulatory Cost Estimates With Land Treatment Dewatering Sub-Option**

Exhibit J1
Cost for Subtitle C haz waste and Subtitle D Version 1 Without Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
1	79	Aurora Energy LLC Chena	Aurora Energy LLC	AK	$591,115	$0	$0	$0	$591,115	$558,212	$0	$0	$0	$558,212
2	6288	Healy	Golden Valley Elec Assn Inc	AK	$413,908	$0	$0	$0	$413,908	$390,869	$0	$0	$0	$390,869
3	56	Charles R Lowman	Alabama Electric Coop Inc	AL	$259,869	$548,026	$0	$0	$807,895	$245,404	$0	$0	$0	$245,404
4	3	Barry	Alabama Power Co	AL	$4,378,685	$0	$0	$0	$4,378,685	$4,134,958	$0	$0	$0	$4,134,958
5	26	E C Gaston	Alabama Power Co	AL	$413,334	$0	$0	$0	$413,334	$390,327	$0	$0	$0	$390,327
6	7	Gadsden	Alabama Power Co	AL	$286,057	$0	$0	$0	$286,057	$270,134	$0	$0	$0	$270,134
7	8	Gorgas	Alabama Power Co	AL	$5,528,503	$0	$0	$0	$5,528,503	$5,220,774	$0	$0	$0	$5,220,774
8	10	Greene County	Alabama Power Co	AL	$5,692,168	$0	$0	$0	$5,692,168	$5,375,329	$0	$0	$0	$5,375,329
9	6002	James H Miller Jr	Alabama Power Co	AL	$2,347,384	$0	$0	$0	$2,347,384	$2,216,723	$0	$0	$0	$2,216,723
10	50407	Mobile Energy Services LLC	DTE Energy Services	AL	$12,105	$49,358	$0	$0	$61,463	$11,431	$0	$0	$0	$11,431
11	47	Colbert	Tennessee Valley Authority	AL	$779,441	$2,049	$0	$0	$781,489	$736,055	$0	$0	$0	$736,055
12	50	Widows Creek	Tennessee Valley Authority	AL	$2,414,692	$512	$0	$0	$2,415,204	$2,280,285	$0	$0	$0	$2,280,285
13	6641	Independence	Entergy Arkansas Inc	AR	$2,599,094	$0	$0	$0	$2,599,094	$2,454,422	$0	$0	$0	$2,454,422
14	6009	White Bluff	Entergy Arkansas Inc	AR	$3,239,418	$0	$0	$0	$3,239,418	$3,059,105	$0	$0	$0	$3,059,105
15	6138	Flint Creek	Southwestern Electric Power Co	AR	$446,835	$0	$0	$0	$446,835	$421,963	$0	$0	$0	$421,963
16	160	Apache Station	Arizona Electric Pwr Coop Inc	AZ	$5,390,167	$0	$0	$0	$5,390,167	$5,090,139	$0	$0	$0	$5,090,139
17	113	Cholla	Arizona Public Service Co	AZ	$1,615,591	$0	$0	$0	$1,615,591	$1,525,664	$0	$0	$0	$1,525,664
18	6177	Coronado	Salt River Project	AZ	$3,530,886	$0	$0	$0	$3,530,886	$3,334,349	$0	$0	$0	$3,334,349
19	4941	Navajo	Salt River Project	AZ	$16,621,306	$0	$0	$0	$16,621,306	$15,696,128	$0	$0	$0	$15,696,128
20	126	H Wilson Sundt Generating Station	Tucson Electric Power Co	AZ	$130,706	$33,291	$0	$0	$163,997	$123,431	$0	$0	$0	$123,431
21	8223	Springerville	Tucson Electric Power Co	AZ	$12,531,134	$0	$0	$0	$12,531,134	$11,833,624	$0	$0	$0	$11,833,624
22	10002	ACE Cogeneration Facility	ACE Cogeneration Co	CA	$0	$2,049	$0	$0	$2,049	$0	$0	$0	$0	$0
23	10640	Stockton Cogen	Air Products Energy Enterprise	CA	$1,266,176	$0	$0	$0	$1,266,176	$1,195,698	$0	$0	$0	$1,195,698
24	54238	Port of Stockton District Energy Fac	FPL Energy Operating Servs Inc	CA	$537,621	$0	$0	$0	$537,621	$507,696	$0	$0	$0	$507,696
25	5462	Mt Poso	Mt Poso	CA	$566,514	$0	$0	$0	$566,514	$534,981	$0	$0	$0	$534,981

Exhibit J1
Cost for Subtitle C haz waste and Subtitle D Version 1 Without Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
	6	Cogeneration	Cogeneration Co											
26	10768	Rio Bravo Jasmin	Rio Bravo Jasmin	CA	$326,459	$0	$0	$0	$326,459	$308,288	$0	$0	$0	$308,288
27	10769	Rio Bravo Poso	Rio Bravo Poso	CA	$319,852	$0	$0	$0	$319,852	$302,048	$0	$0	$0	$302,048
28	462	W N Clark	Aquila, Inc.	CO	$0	$106,947	$0	$0	$106,947	$0	$0	$0	$0	$0
29	10003	Colorado Energy Nations Company	Colorado Energy Nations Company LLLP	CO	$0	$133,647	$0	$0	$133,647	$0	$0	$0	$0	$0
30	492	Martin Drake	Colorado Springs City of	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	8219	Ray D Nixon	Colorado Springs City of	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	6761	Rawhide	Platte River Power Authority	CO	$268,977	$0	$0	$0	$268,977	$254,005	$0	$0	$0	$254,005
33	465	Arapahoe	Public Service Co of Colorado	CO	$0	$193,602	$0	$0	$193,602	$0	$0	$0	$0	$0
34	468	Cameo	Public Service Co of Colorado	CO	$0	$171,517	$0	$0	$171,517	$0	$0	$0	$0	$0
35	469	Cherokee	Public Service Co of Colorado	CO	$0	$1,449,452	$0	$0	$1,449,452	$0	$0	$0	$0	$0
36	470	Comanche	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	525	Hayden	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
38	6248	Pawnee	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
39	477	Valmont	Public Service Co of Colorado	CO	$0	$19,975	$0	$0	$19,975	$0	$0	$0	$0	$0
40	6021	Craig	Tri-State G & T Assn, Inc	CO	$0	$2,116,302	$0	$0	$2,116,302	$0	$0	$0	$0	$0
41	527	Nucla	Tri-State G & T Assn, Inc	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	10675	AES Thames	AES Thames LLC	CT	$0	$764,061	$0	$0	$764,061	$0	$0	$0	$0	$0
43	568	Bridgeport Station	PSEG Power Connecticut LLC	CT	$0	$118,312	$0	$0	$118,312	$0	$0	$0	$0	$0
44	593	Edge Moor	Conectiv Delmarva Gen Inc	DE	$0	$382,082	$0	$0	$382,082	$0	$0	$0	$0	$0
45	594	Indian River Generating Station	Indian River Operations Inc	DE	$2,069,032	$0	$0	$0	$2,069,032	$1,953,865	$0	$0	$0	$1,953,865
46	10030	NRG Energy Center Dover	NRG Energy Center Dover LLC	DE	$303,134	$0	$0	$0	$303,134	$286,261	$0	$0	$0	$286,261

Exhibit J1 Cost for Subtitle C haz waste and Subtitle D Version 1 Without Land Treatment Dewatering Sub-Option														
Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
47	10333	Central Power & Lime	Central Power & Lime Inc	FL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
48	676	C D McIntosh Jr	City of Lakeland	FL	$966,487	$0	$0	$0	$966,487	$912,690	$0	$0	$0	$912,690
49	663	Deerhaven Generating Station	Gainesville Regional Utilities	FL	$67,978	$0	$0	$0	$67,978	$64,194	$0	$0	$0	$64,194
50	641	Crist	Gulf Power Co	FL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	643	Lansing Smith	Gulf Power Co	FL	$318,500	$0	$0	$0	$318,500	$300,771	$0	$0	$0	$300,771
52	642	Scholz	Gulf Power Co	FL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
53	667	Northside Generating Station	JEA	FL	$2,919,534	$0	$0	$0	$2,919,534	$2,757,027	$0	$0	$0	$2,757,027
54	207	St Johns River Power Park	JEA	FL	$1,994,615	$0	$0	$0	$1,994,615	$1,883,591	$0	$0	$0	$1,883,591
55	564	Stanton Energy Center	Orlando Utilities Comm	FL	$2,261,748	$0	$0	$0	$2,261,748	$2,135,854	$0	$0	$0	$2,135,854
56	628	Crystal River	Progress Energy Florida Inc	FL	$311,466	$0	$0	$0	$311,466	$294,129	$0	$0	$0	$294,129
57	136	Seminole	Seminole Electric Coop, Inc	FL	$3,165,825	$5,122	$0	$0	$3,170,947	$2,989,608	$0	$0	$0	$2,989,608
58	645	Big Bend	Tampa Electric Co	FL	$43,365	$0	$0	$0	$43,365	$40,951	$0	$0	$0	$40,951
59	7242	Polk	Tampa Electric Co	FL	$966,156	$0	$0	$0	$966,156	$912,377	$0	$0	$0	$912,377
60	10672	Cedar Bay Generating Company LP	US Operating Services Company	FL	$0	$1,229,217	$0	$0	$1,229,217	$0	$0	$0	$0	$0
61	50976	Indiantown Cogeneration LP	US Operating Services Company	FL	$0	$1,049,956	$0	$0	$1,049,956	$0	$0	$0	$0	$0
62	753	Crisp Plant	Crisp County Power Comm	GA	$9,664	$563	$0	$0	$10,227	$9,126	$0	$0	$0	$9,126
63	703	Bowen	Georgia Power Co	GA	$10,245,803	$0	$0	$0	$10,245,803	$9,675,500	$0	$0	$0	$9,675,500
64	708	Hammond	Georgia Power Co	GA	$484,420	$0	$0	$0	$484,420	$457,456	$0	$0	$0	$457,456
65	709	Harllee Branch	Georgia Power Co	GA	$1,311,079	$0	$0	$0	$1,311,079	$1,238,102	$0	$0	$0	$1,238,102
66	710	Jack McDonough	Georgia Power Co	GA	$142,177	$0	$0	$0	$142,177	$134,263	$0	$0	$0	$134,263
67	733	Kraft	Georgia Power Co	GA	$213,517	$204,870	$0	$0	$418,386	$201,632	$0	$0	$0	$201,632
68	6124	McIntosh	Georgia Power Co	GA	$453,669	$0	$0	$0	$453,669	$428,417	$0	$0	$0	$428,417
69	727	Mitchell	Georgia Power Co	GA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
70	6257	Scherer	Georgia Power Co	GA	$4,037,865	$0	$0	$0	$4,037,865	$3,813,108	$0	$0	$0	$3,813,108
71	6052	Wansley	Georgia Power Co	GA	$2,740,389	$0	$0	$0	$2,740,389	$2,587,853	$0	$0	$0	$2,587,853
72	728	Yates	Georgia Power Co	GA	$612,666	$0	$0	$0	$612,666	$578,563	$0	$0	$0	$578,563
73	10673	AES Hawaii	AES Hawaii Inc	HI	$0	$263,770	$0	$0	$263,770	$0	$0	$0	$0	$0
74	10604	Hawaiian Comm & Sugar Puunene Mill	Hawaiian Com & Sugar Co Ltd	HI	$747,673	$0	$0	$0	$747,673	$706,056	$0	$0	$0	$706,056
75	1122	Ames Electric	Ames City of	IA	$20,521	$0	$0	$0	$20,521	$19,379	$0	$0	$0	$19,379

Exhibit J1
Cost for Subtitle C haz waste and Subtitle D Version 1 Without Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
		Services Power Plant												
76	1167	Muscatine Plant #1	Board of Water Electric & Communications	IA	$6,366	$0	$0	$0	$6,366	$6,012	$0	$0	$0	$6,012
77	1131	Streeter Station	Cedar Falls Utilities	IA	$3,526	$0	$0	$0	$3,526	$3,330	$0	$0	$0	$3,330
78	1218	Fair Station	Central Iowa Power Cooperative	IA	$67,091	$0	$0	$0	$67,091	$63,356	$0	$0	$0	$63,356
79	1217	Earl F Wisdom	Corn Belt Power Coop	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
80	1104	Burlington	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
81	1046	Dubuque	Interstate Power and Light Co	IA	$25,247	$0	$0	$0	$25,247	$23,842	$0	$0	$0	$23,842
82	1047	Lansing	Interstate Power and Light Co	IA	$345,083	$23,048	$0	$0	$368,130	$325,875	$0	$0	$0	$325,875
83	1048	Milton L Kapp	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
84	6254	Ottumwa	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
85	1073	Prairie Creek	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
86	1058	Sixth Street	Interstate Power and Light Co	IA	$38,522	$0	$0	$0	$38,522	$36,378	$0	$0	$0	$36,378
87	1077	Sutherland	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
88	1091	George Neal North	MidAmerican Energy Co	IA	$3,026,631	$0	$0	$0	$3,026,631	$2,858,162	$0	$0	$0	$2,858,162
89	7343	George Neal South	MidAmerican Energy Co	IA	$191,715	$0	$0	$0	$191,715	$181,043	$0	$0	$0	$181,043
90	6664	Louisa	MidAmerican Energy Co	IA	$2,085,220	$0	$0	$0	$2,085,220	$1,969,152	$0	$0	$0	$1,969,152
91	1081	Riverside	MidAmerican Energy Co	IA	$0	$94,240	$0	$0	$94,240	$0	$0	$0	$0	$0
92	1082	Walter Scott Jr Energy Center	MidAmerican Energy Co	IA	$3,645,385	$0	$0	$0	$3,645,385	$3,442,475	$0	$0	$0	$3,442,475
93	1175	Pella	Pella City of	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
94	861	Coffeen	Ameren Energy Generating Co	IL	$0	$491,687	$0	$0	$491,687	$0	$0	$0	$0	$0
95	863	Hutsonville	Ameren Energy Generating Co	IL	$423,723	$0	$0	$0	$423,723	$400,137	$0	$0	$0	$400,137
96	864	Meredosia	Ameren Energy Generating Co	IL	$938,878	$0	$0	$0	$938,878	$886,618	$0	$0	$0	$886,618

Exhibit J1
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97	6017	Newton	Ameren Energy Generating Co	IL	$1,230,014	$0	$0	$0	$1,230,014	$1,161,549	$0	$0	$0	$1,161,549
98	6016	Duck Creek	Ameren Energy Resources Generating Co.	IL	$5,697,004	$0	$0	$0	$5,697,004	$5,379,897	$0	$0	$0	$5,379,897
99	856	E D Edwards	Ameren Energy Resources Generating Co.	IL	$385,602	$537,783	$0	$0	$923,385	$364,139	$0	$0	$0	$364,139
100	963	Dallman	City of Springfield	IL	$917,434	$0	$0	$0	$917,434	$866,367	$0	$0	$0	$866,367
101	964	Lakeside	City of Springfield	IL	$0	$58,961	$0	$0	$58,961	$0	$0	$0	$0	$0
102	876	Kincaid Generation LLC	Dominion Energy Services Co	IL	$0	$407,178	$0	$0	$407,178	$0	$0	$0	$0	$0
103	889	Baldwin Energy Complex	Dynegy Midwest Generation Inc	IL	$3,094,926	$0	$0	$0	$3,094,926	$2,922,656	$0	$0	$0	$2,922,656
104	891	Havana	Dynegy Midwest Generation Inc	IL	$1,411,644	$0	$0	$0	$1,411,644	$1,333,068	$0	$0	$0	$1,333,068
105	892	Hennepin Power Station	Dynegy Midwest Generation Inc	IL	$229,530	$0	$0	$0	$229,530	$216,754	$0	$0	$0	$216,754
106	897	Vermilion	Dynegy Midwest Generation Inc	IL	$148,092	$0	$0	$0	$148,092	$139,849	$0	$0	$0	$139,849
107	898	Wood River	Dynegy Midwest Generation Inc	IL	$291,864	$0	$0	$0	$291,864	$275,618	$0	$0	$0	$275,618
108	887	Joppa Steam	Electric Energy Inc	IL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
109	867	Crawford	Midwest Generations EME LLC	IL	$0	$97,313	$0	$0	$97,313	$0	$0	$0	$0	$0
110	886	Fisk Street	Midwest Generations EME LLC	IL	$0	$46,608	$0	$0	$46,608	$0	$0	$0	$0	$0
111	384	Joliet 29	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
112	874	Joliet 9	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
113	879	Powerton	Midwest Generations EME LLC	IL	$0	$649,436	$0	$0	$649,436	$0	$0	$0	$0	$0
114	883	Waukegan	Midwest Generations EME LLC	IL	$0	$329,328	$0	$0	$329,328	$0	$0	$0	$0	$0
115	884	Will County	Midwest Generations EME LLC	IL	$0	$491,687	$0	$0	$491,687	$0	$0	$0	$0	$0

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116	976	Marion	Southern Illinois Power Coop	IL	$0	$2,573,162	$0	$0	$2,573,162	$0	$0	$0	$0	$0
117	6238	Pearl Station	Soyland Power Coop Inc	IL	$181,857	$0	$0	$0	$181,857	$171,734	$0	$0	$0	$171,734
118	55245	Tuscola Station	Trigen-Cinergy Sol-Tuscola LLC	IL	$272,329	$0	$0	$0	$272,329	$257,171	$0	$0	$0	$257,171
119	6705	Warrick	AGC Division of APG Inc	IN	$4,723,116	$0	$0	$0	$4,723,116	$4,460,217	$0	$0	$0	$4,460,217
120	992	CC Perry K	Citizens Thermal Energy	IN	$8,378	$60,488	$0	$0	$68,865	$7,911	$0	$0	$0	$7,911
121	6225	Jasper 2	City of Jasper	IN	$6,866	$6,377	$0	$0	$13,243	$6,484	$0	$0	$0	$6,484
122	1032	Logansport	City of Logansport	IN	$12,288	$33,798	$0	$0	$46,086	$11,604	$0	$0	$0	$11,604
123	1040	Whitewater Valley	City of Richmond	IN	$61,216	$0	$0	$0	$61,216	$57,809	$0	$0	$0	$57,809
124	1024	Crawfordsville	Crawfordsville Elec, Lgt & Pwr	IN	$14,202	$10,382	$0	$0	$24,584	$13,412	$0	$0	$0	$13,412
125	1001	Cayuga	Duke Energy Indiana Inc	IN	$4,479,646	$0	$0	$0	$4,479,646	$4,230,299	$0	$0	$0	$4,230,299
126	1004	Edwardsport	Duke Energy Indiana Inc	IN	$325,746	$0	$0	$0	$325,746	$307,614	$0	$0	$0	$307,614
127	6113	Gibson	Duke Energy Indiana Inc	IN	$5,747,055	$0	$0	$0	$5,747,055	$5,427,162	$0	$0	$0	$5,427,162
128	1008	R Gallagher	Duke Energy Indiana Inc	IN	$1,001,584	$0	$0	$0	$1,001,584	$945,834	$0	$0	$0	$945,834
129	1010	Wabash River	Duke Energy Indiana Inc	IN	$7,170,015	$0	$0	$0	$7,170,015	$6,770,916	$0	$0	$0	$6,770,916
130	1043	Frank E Ratts	Hoosier Energy R E C, Inc	IN	$309,765	$0	$0	$0	$309,765	$292,523	$0	$0	$0	$292,523
131	6213	Merom	Hoosier Energy R E C, Inc	IN	$40,197	$0	$0	$0	$40,197	$37,960	$0	$0	$0	$37,960
132	6166	Rockport	Indiana Michigan Power Co	IN	$1,750,027	$0	$0	$0	$1,750,027	$1,652,617	$0	$0	$0	$1,652,617
133	988	Tanners Creek	Indiana Michigan Power Co	IN	$2,123,216	$0	$0	$0	$2,123,216	$2,005,033	$0	$0	$0	$2,005,033
134	983	Clifty Creek	Indiana-Kentucky Electric Corp	IN	$599,778	$6,658	$0	$0	$606,436	$566,393	$0	$0	$0	$566,393
135	994	AES Petersburg	Indianapolis Power & Light Co	IN	$6,105	$3,568,315	$0	$0	$3,574,420	$5,765	$0	$0	$0	$5,765
136	991	Eagle Valley	Indianapolis Power & Light Co	IN	$169,089	$0	$0	$0	$169,089	$159,677	$0	$0	$0	$159,677
137	990	Harding Street	Indianapolis Power & Light Co	IN	$1,041,055	$0	$0	$0	$1,041,055	$983,108	$0	$0	$0	$983,108
138	995	Bailly	Northern Indiana Pub Serv Co	IN	$617,121	$93,216	$0	$0	$710,336	$582,771	$0	$0	$0	$582,771

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139	997	Michigan City	Northern Indiana Pub Serv Co	IN	$195,438	$0	$0	$0	$195,438	$184,559	$0	$0	$0	$184,559
140	6085	R M Schahfer	Northern Indiana Pub Serv Co	IN	$258,847	$0	$0	$0	$258,847	$244,439	$0	$0	$0	$244,439
141	1037	Peru	Peru City of	IN	$18,454	$9,665	$0	$0	$28,118	$17,426	$0	$0	$0	$17,426
142	6137	A B Brown	Southern Indiana Gas & Elec Co	IN	$1,671,692	$0	$0	$0	$1,671,692	$1,578,642	$0	$0	$0	$1,578,642
143	1012	F B Culley	Southern Indiana Gas & Elec Co	IN	$440,769	$581,830	$0	$0	$1,022,598	$416,235	$0	$0	$0	$416,235
144	981	State Line Energy	State Line Energy LLC	IN	$0	$102,435	$0	$0	$102,435	$0	$0	$0	$0	$0
145	1239	Riverton	Empire District Electric Co	KS	$87,419	$0	$0	$0	$87,419	$82,553	$0	$0	$0	$82,553
146	6064	Nearman Creek	Kansas City City of	KS	$345,968	$33,803	$0	$0	$379,772	$326,711	$0	$0	$0	$326,711
147	1295	Quindaro	Kansas City City of	KS	$0	$205,894	$0	$0	$205,894	$0	$0	$0	$0	$0
148	1241	La Cygne	Kansas City Power & Light Co	KS	$2,092,681	$0	$0	$0	$2,092,681	$1,976,197	$0	$0	$0	$1,976,197
149	108	Holcomb	Sunflower Electric Power Corp	KS	$939,036	$0	$0	$0	$939,036	$886,767	$0	$0	$0	$886,767
150	6068	Jeffrey Energy Center	Westar Energy Inc	KS	$5,139,666	$0	$0	$0	$5,139,666	$4,853,581	$0	$0	$0	$4,853,581
151	1250	Lawrence Energy Center	Westar Energy Inc	KS	$12,777	$0	$0	$0	$12,777	$12,066	$0	$0	$0	$12,066
152	1252	Tecumseh Energy Center	Westar Energy Inc	KS	$19,574	$0	$0	$0	$19,574	$18,484	$0	$0	$0	$18,484
153	1374	Elmer Smith	City of Owensboro	KY	$0	$989,520	$0	$0	$989,520	$0	$0	$0	$0	$0
154	6018	East Bend	Duke Energy Kentucky Inc	KY	$2,156,819	$0	$0	$0	$2,156,819	$2,036,766	$0	$0	$0	$2,036,766
155	1384	Cooper	East Kentucky Power Coop, Inc	KY	$221,475	$0	$0	$0	$221,475	$209,147	$0	$0	$0	$209,147
156	1385	Dale	East Kentucky Power Coop, Inc	KY	$946,558	$512	$0	$0	$947,070	$893,870	$0	$0	$0	$893,870
157	6041	H L Spurlock	East Kentucky Power Coop, Inc	KY	$8,470,552	$0	$0	$0	$8,470,552	$7,999,063	$0	$0	$0	$7,999,063
158	1372	Henderson I	Henderson City Utility Comm	KY	$11,335	$0	$0	$0	$11,335	$10,704	$0	$0	$0	$10,704
159	1353	Big Sandy	Kentucky Power Co	KY	$5,925,754	$0	$0	$0	$5,925,754	$5,595,914	$0	$0	$0	$5,595,914
160	1355	E W Brown	Kentucky Utilities Co	KY	$332,892	$0	$0	$0	$332,892	$314,362	$0	$0	$0	$314,362
161	1356	Ghent	Kentucky Utilities Co	KY	$11,850,771	$0	$0	$0	$11,850,771	$11,191,131	$0	$0	$0	$11,191,131
162	1357	Green River	Kentucky Utilities Co	KY	$363,941	$0	$0	$0	$363,941	$343,683	$0	$0	$0	$343,683

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163	1361	Tyrone	Kentucky Utilities Co	KY	$193,099	$0	$0	$0	$193,099	$182,351	$0	$0	$0	$182,351
164	1363	Cane Run	Louisville Gas & Electric Co	KY	$1,798,400	$0	$0	$0	$1,798,400	$1,698,297	$0	$0	$0	$1,698,297
165	1364	Mill Creek	Louisville Gas & Electric Co	KY	$5,472,515	$3,735,796	$0	$0	$9,208,312	$5,167,903	$0	$0	$0	$5,167,903
166	6071	Trimble County	Louisville Gas & Electric Co	KY	$216,810	$0	$0	$0	$216,810	$204,742	$0	$0	$0	$204,742
167	1378	Paradise	Tennessee Valley Authority	KY	$7,613,454	$16,390	$0	$0	$7,629,844	$7,189,673	$0	$0	$0	$7,189,673
168	1379	Shawnee	Tennessee Valley Authority	KY	$650,109	$5,122	$0	$0	$655,231	$613,923	$0	$0	$0	$613,923
169	6823	D B Wilson	Western Kentucky Energy Corp	KY	$6,395,337	$0	$0	$0	$6,395,337	$6,039,359	$0	$0	$0	$6,039,359
170	1382	HMP&L Station Two Henderson	Western Kentucky Energy Corp	KY	$6,253,316	$0	$0	$0	$6,253,316	$5,905,243	$0	$0	$0	$5,905,243
171	1381	Kenneth C Coleman	Western Kentucky Energy Corp	KY	$321,609	$0	$0	$0	$321,609	$303,708	$0	$0	$0	$303,708
172	6639	R D Green	Western Kentucky Energy Corp	KY	$6,990,611	$0	$0	$0	$6,990,611	$6,601,499	$0	$0	$0	$6,601,499
173	1383	Robert A Reid	Western Kentucky Energy Corp	KY	$37,535	$0	$0	$0	$37,535	$35,446	$0	$0	$0	$35,446
174	51	Dolet Hills	Cleco Power LLC	LA	$1,306,329	$0	$0	$0	$1,306,329	$1,233,616	$0	$0	$0	$1,233,616
175	6190	Rodemacher	Cleco Power LLC	LA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
176	1393	R S Nelson	Entergy Gulf States Louisiana LLC	LA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
177	6055	Big Cajun 2	Louisiana Generating LLC	LA	$145,914	$0	$0	$0	$145,914	$137,792	$0	$0	$0	$137,792
178	1619	Brayton Point	Dominion Energy New England, LLC	MA	$0	$291,939	$0	$0	$291,939	$0	$0	$0	$0	$0
179	1626	Salem Harbor	Dominion Energy New England, LLC	MA	$0	$360,570	$0	$0	$360,570	$0	$0	$0	$0	$0
180	1606	Mount Tom	FirstLight Power Resources Services LLC	MA	$0	$164,408	$0	$0	$164,408	$0	$0	$0	$0	$0
181	1613	Somerset Station	Somerset Power LLC	MA	$0	$153,908	$0	$0	$153,908	$0	$0	$0	$0	$0
182	10678	AES Warrior Run Cogeneration Facility	AES WR Ltd Partnership	MD	$0	$1,933,969	$0	$0	$1,933,969	$0	$0	$0	$0	$0
183	1570	R Paul Smith Power Station	Allegheny Energy Supply Co LLC	MD	$733,529	$0	$0	$0	$733,529	$692,699	$0	$0	$0	$692,699
184	602	Brandon Shores	Constellation Power	MD	$0	$624,852	$0	$0	$624,852	$0	$0	$0	$0	$0

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			Source Gen											
185	1552	C P Crane	Constellation Power Source Gen	MD	$0	$471,200	$0	$0	$471,200	$0	$0	$0	$0	$0
186	1554	Herbert A Wagner	Constellation Power Source Gen	MD	$0	$1,008,983	$0	$0	$1,008,983	$0	$0	$0	$0	$0
187	1571	Chalk Point LLC	Mirant Chalk Point LLC	MD	$721,532	$0	$0	$0	$721,532	$681,370	$0	$0	$0	$681,370
188	1572	Dickerson	Mirant Mid-Atlantic LLC	MD	$161,578	$0	$0	$0	$161,578	$152,585	$0	$0	$0	$152,585
189	1573	Morgantown Generating Plant	Mirant Mid-Atlantic LLC	MD	$103,241	$0	$0	$0	$103,241	$97,495	$0	$0	$0	$97,495
190	10495	Rumford Cogeneration	NewPage Corporation	ME	$403,394	$169,017	$0	$0	$572,411	$380,940	$0	$0	$0	$380,940
191	1825	J B Sims	City of Grand Haven	MI	$22,612	$0	$0	$0	$22,612	$21,353	$0	$0	$0	$21,353
192	1830	James De Young	City of Holland	MI	$13,556	$0	$0	$0	$13,556	$12,802	$0	$0	$0	$12,802
193	1843	Shiras	City of Marquette	MI	$11,334	$0	$0	$0	$11,334	$10,703	$0	$0	$0	$10,703
194	1695	B C Cobb	Consumers Energy Co	MI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
195	1702	Dan E Karn	Consumers Energy Co	MI	$17,064	$0	$0	$0	$17,064	$16,114	$0	$0	$0	$16,114
196	1720	J C Weadock	Consumers Energy Co	MI	$716,539	$0	$0	$0	$716,539	$676,655	$0	$0	$0	$676,655
197	1710	J H Campbell	Consumers Energy Co	MI	$26,334	$0	$0	$0	$26,334	$24,868	$0	$0	$0	$24,868
198	1723	J R Whiting	Consumers Energy Co	MI	$27,319	$0	$0	$0	$27,319	$25,798	$0	$0	$0	$25,798
199	6034	Belle River	Detroit Edison Co	MI	$29,704	$0	$0	$0	$29,704	$28,050	$0	$0	$0	$28,050
200	1731	Harbor Beach	Detroit Edison Co	MI	$9,597	$0	$0	$0	$9,597	$9,063	$0	$0	$0	$9,063
201	1733	Monroe	Detroit Edison Co	MI	$5,505,806	$0	$0	$0	$5,505,806	$5,199,341	$0	$0	$0	$5,199,341
202	1740	River Rouge	Detroit Edison Co	MI	$20,784	$0	$0	$0	$20,784	$19,627	$0	$0	$0	$19,627
203	1743	St Clair	Detroit Edison Co	MI	$26,800	$0	$0	$0	$26,800	$25,308	$0	$0	$0	$25,308
204	1745	Trenton Channel	Detroit Edison Co	MI	$28,904	$0	$0	$0	$28,904	$27,295	$0	$0	$0	$27,295
205	1831	Eckert Station	Lansing Board of Water and Light	MI	$0	$41,998	$0	$0	$41,998	$0	$0	$0	$0	$0
206	1832	Erickson Station	Lansing Board of Water and Light	MI	$314,522	$32,267	$0	$0	$346,789	$297,015	$0	$0	$0	$297,015
207	4259	Endicott Station	Michigan South Central Pwr Agy	MI	$21,113	$0	$0	$0	$21,113	$19,938	$0	$0	$0	$19,938
208	50835	TES Filer City Station	TES Filer City Station LP	MI	$16,820	$0	$0	$0	$16,820	$15,884	$0	$0	$0	$15,884
209	1771	Escanaba	Upper Peninsula Power Co	MI	$9,188	$51,776	$0	$0	$60,963	$8,676	$0	$0	$0	$8,676

Exhibit J1
Cost for Subtitle C haz waste and Subtitle D Version 1 Without Land Treatment Dewatering Sub-Option

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210	10148	White Pine Electric Power	White Pine Electric Power LLC	MI	$8,810	$34,188	$0	$0	$42,998	$8,320	$0	$0	$0	$8,320
211	1769	Presque Isle	Wisconsin Electric Power Co	MI	$18,541	$0	$0	$0	$18,541	$17,509	$0	$0	$0	$17,509
212	1866	Wyandotte	Wyandotte Municipal Serv Comm	MI	$14,677	$0	$0	$0	$14,677	$13,860	$0	$0	$0	$13,860
213	1961	Austin Northeast	Austin City of	MN	$1,504	$0	$0	$0	$1,504	$1,421	$0	$0	$0	$1,421
214	2018	Virginia	City of Virginia	MN	$6,881	$0	$0	$0	$6,881	$6,498	$0	$0	$0	$6,498
215	1979	Hibbing	Hibbing Public Utilities Comm	MN	$3,362	$0	$0	$0	$3,362	$3,175	$0	$0	$0	$3,175
216	1893	Clay Boswell	Minnesota Power Inc	MN	$2,626,096	$0	$0	$0	$2,626,096	$2,479,922	$0	$0	$0	$2,479,922
217	1897	M L Hibbard	Minnesota Power Inc	MN	$0	$13,050	$0	$0	$13,050	$0	$0	$0	$0	$0
218	10686	Rapids Energy Center	Minnesota Power Inc	MN	$0	$11,396	$0	$0	$11,396	$0	$0	$0	$0	$0
219	1891	Syl Laskin	Minnesota Power Inc	MN	$184,819	$0	$0	$0	$184,819	$174,531	$0	$0	$0	$174,531
220	10075	Taconite Harbor Energy Center	Minnesota Power Inc	MN	$40,719	$0	$0	$0	$40,719	$38,453	$0	$0	$0	$38,453
221	2001	New Ulm	New Ulm Public Utilities Comm	MN	$8,623	$0	$0	$0	$8,623	$8,143	$0	$0	$0	$8,143
222	1915	Allen S King	Northern States Power Co	MN	$13,829	$0	$0	$0	$13,829	$13,059	$0	$0	$0	$13,059
223	1904	Black Dog	Northern States Power Co	MN	$191,066	$0	$0	$0	$191,066	$180,431	$0	$0	$0	$180,431
224	1927	Riverside	Northern States Power Co	MN	$294,653	$0	$0	$0	$294,653	$278,252	$0	$0	$0	$278,252
225	6090	Sherburne County	Northern States Power Co	MN	$16,660,660	$0	$0	$0	$16,660,660	$15,733,291	$0	$0	$0	$15,733,291
226	1943	Hoot Lake	Otter Tail Power Co	MN	$8,759	$0	$0	$0	$8,759	$8,271	$0	$0	$0	$8,271
227	2008	Silver Lake	Rochester Public Utilities	MN	$28,341	$0	$0	$0	$28,341	$26,763	$0	$0	$0	$26,763
228	2022	Willmar	Willmar Municipal Utils Comm	MN	$8,914	$0	$0	$0	$8,914	$8,418	$0	$0	$0	$8,418
229	2098	Lake Road	Aquila, Inc.	MO	$0	$82,972	$0	$0	$82,972	$0	$0	$0	$0	$0
230	2094	Sibley	Aquila, Inc.	MO	$158,415	$0	$0	$0	$158,415	$149,597	$0	$0	$0	$149,597
231	2167	New Madrid	Associated Electric Coop, Inc	MO	$2,692,832	$0	$0	$0	$2,692,832	$2,542,943	$0	$0	$0	$2,542,943
232	2168	Thomas Hill	Associated Electric Coop, Inc	MO	$105,092	$0	$0	$0	$105,092	$99,243	$0	$0	$0	$99,243
233	2169	Chamois	Central Electric	MO	$199,093	$0	$0	$0	$199,093	$188,011	$0	$0	$0	$188,011

Exhibit J1
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			Power Coop											
234	2123	Columbia	City of Columbia	MO	$22,287	$16,507	$0	$0	$38,795	$21,047	$0	$0	$0	$21,047
235	2144	Marshall	City of Marshall	MO	$20,817	$12,763	$0	$0	$33,580	$19,658	$0	$0	$0	$19,658
236	6768	Sikeston Power Station	City of Sikeston	MO	$992,160	$0	$0	$0	$992,160	$936,935	$0	$0	$0	$936,935
237	2161	James River Power Station	City Utilities of Springfield	MO	$90,801	$0	$0	$0	$90,801	$85,747	$0	$0	$0	$85,747
238	6195	Southwest Power Station	City Utilities of Springfield	MO	$1,238,757	$0	$0	$0	$1,238,757	$1,169,805	$0	$0	$0	$1,169,805
239	2076	Asbury	Empire District Electric Co	MO	$148,487	$0	$0	$0	$148,487	$140,222	$0	$0	$0	$140,222
240	2132	Blue Valley	Independence City of	MO	$313,003	$0	$0	$0	$313,003	$295,580	$0	$0	$0	$295,580
241	2171	Missouri City	Independence City of	MO	$43,020	$37,138	$0	$0	$80,158	$40,625	$0	$0	$0	$40,625
242	2079	Hawthorn	Kansas City Power & Light Co	MO	$225,229	$574,147	$0	$0	$799,376	$212,692	$0	$0	$0	$212,692
243	6065	Iatan	Kansas City Power & Light Co	MO	$330,101	$0	$0	$0	$330,101	$311,727	$0	$0	$0	$311,727
244	2080	Montrose	Kansas City Power & Light Co	MO	$189,353	$0	$0	$0	$189,353	$178,813	$0	$0	$0	$178,813
245	2103	Labadie	Union Electric Co	MO	$594,710	$225,357	$0	$0	$820,066	$561,607	$0	$0	$0	$561,607
246	2104	Meramec	Union Electric Co	MO	$876,216	$0	$0	$0	$876,216	$827,444	$0	$0	$0	$827,444
247	6155	Rush Island	Union Electric Co	MO	$1,968,536	$256,087	$0	$0	$2,224,623	$1,858,963	$0	$0	$0	$1,858,963
248	2107	Sioux	Union Electric Co	MO	$328,197	$0	$0	$0	$328,197	$309,929	$0	$0	$0	$309,929
249	55076	Red Hills Generating Facility	Choctaw Generating LP	MS	$741,001	$0	$0	$0	$741,001	$699,755	$0	$0	$0	$699,755
250	2062	Henderson	Greenwood Utilities Comm	MS	$14,106	$8,707	$0	$0	$22,813	$13,321	$0	$0	$0	$13,321
251	2049	Jack Watson	Mississippi Power Co	MS	$351,171	$0	$0	$0	$351,171	$331,624	$0	$0	$0	$331,624
252	6073	Victor J Daniel Jr	Mississippi Power Co	MS	$875,047	$0	$0	$0	$875,047	$826,340	$0	$0	$0	$826,340
253	6061	R D Morrow	South Mississippi El Pwr Assn	MS	$1,881,414	$0	$0	$0	$1,881,414	$1,776,690	$0	$0	$0	$1,776,690
254	10784	Colstrip Energy LP	Colstrip Energy LP	MT	$12,687	$0	$0	$0	$12,687	$11,981	$0	$0	$0	$11,981
255	6089	Lewis & Clark	MDU Resources Group Inc	MT	$10,408	$0	$0	$0	$10,408	$9,828	$0	$0	$0	$9,828
256	6076	Colstrip	PPL Montana LLC	MT	$21,054,622	$0	$0	$0	$21,054,622	$19,882,676	$0	$0	$0	$19,882,676
257	2187	J E Corette Plant	PPL Montana LLC	MT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
258	55749	Hardin Generator Project	Rocky Mountain Power Inc	MT	$38,192	$0	$0	$0	$38,192	$36,066	$0	$0	$0	$36,066

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259	10381	Coastal Carolina Clean Power	Carlyle/Riverstone Renewable Energy	NC	$92,974	$59,684	$0	$0	$152,658	$87,799	$0	$0	$0	$87,799
260	8042	Belews Creek	Duke Energy Carolinas, LLC	NC	$4,713,588	$0	$0	$0	$4,713,588	$4,451,220	$0	$0	$0	$4,451,220
261	2720	Buck	Duke Energy Carolinas, LLC	NC	$213,083	$0	$0	$0	$213,083	$201,222	$0	$0	$0	$201,222
262	2721	Cliffside	Duke Energy Carolinas, LLC	NC	$525,124	$0	$0	$0	$525,124	$495,894	$0	$0	$0	$495,894
263	2723	Dan River	Duke Energy Carolinas, LLC	NC	$765,880	$0	$0	$0	$765,880	$723,250	$0	$0	$0	$723,250
264	2718	G G Allen	Duke Energy Carolinas, LLC	NC	$720,969	$0	$0	$0	$720,969	$680,838	$0	$0	$0	$680,838
265	2727	Marshall	Duke Energy Carolinas, LLC	NC	$4,182,041	$0	$0	$0	$4,182,041	$3,949,260	$0	$0	$0	$3,949,260
266	2732	Riverbend	Duke Energy Carolinas, LLC	NC	$1,977,516	$0	$0	$0	$1,977,516	$1,867,444	$0	$0	$0	$1,867,444
267	10384	Edgecombe Genco LLC	Edgecombe Operating Services LLC	NC	$0	$363,643	$0	$0	$363,643	$0	$0	$0	$0	$0
268	10380	Elizabethtown Power LLC	North Carolina Power Holdings, LLC	NC	$36,724	$4,266	$0	$0	$40,990	$34,680	$0	$0	$0	$34,680
269	10382	Lumberton	North Carolina Power Holdings, LLC	NC	$33,816	$1,588	$0	$0	$35,404	$31,934	$0	$0	$0	$31,934
270	10379	Primary Energy Roxboro	Primary Energy of North Carolina LLC	NC	$68,871	$39,156	$0	$0	$108,027	$65,038	$0	$0	$0	$65,038
271	10378	Primary Energy Southport	Primary Energy of North Carolina LLC	NC	$0	$117,800	$0	$0	$117,800	$0	$0	$0	$0	$0
272	2706	Asheville	Progress Energy Carolinas Inc	NC	$330,332	$35,852	$0	$0	$366,184	$311,945	$0	$0	$0	$311,945
273	2708	Cape Fear	Progress Energy Carolinas Inc	NC	$316,743	$0	$0	$0	$316,743	$299,113	$0	$0	$0	$299,113
274	2713	L V Sutton	Progress Energy Carolinas Inc	NC	$397,621	$0	$0	$0	$397,621	$375,488	$0	$0	$0	$375,488
275	2709	Lee	Progress Energy Carolinas Inc	NC	$436,699	$0	$0	$0	$436,699	$412,392	$0	$0	$0	$412,392
276	6250	Mayo	Progress Energy Carolinas Inc	NC	$484,142	$0	$0	$0	$484,142	$457,194	$0	$0	$0	$457,194
277	2712	Roxboro	Progress Energy Carolinas Inc	NC	$970,739	$0	$0	$0	$970,739	$916,705	$0	$0	$0	$916,705
278	2716	W H Weatherspoon	Progress Energy Carolinas Inc	NC	$222,235	$0	$0	$0	$222,235	$209,865	$0	$0	$0	$209,865

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279	54035	Roanoke Valley Energy Facililty I	Westmoreland Partners	NC	$28,807	$666,338	$0	$0	$695,145	$27,204	$0	$0	$0	$27,204
280	54755	Roanoke Valley Energy Facility II	Westmoreland Partners	NC	$82,194	$91,628	$0	$0	$173,822	$77,619	$0	$0	$0	$77,619
281	6469	Antelope Valley	Basin Electric Power Coop	ND	$98,638	$0	$0	$0	$98,638	$93,148	$0	$0	$0	$93,148
282	2817	Leland Olds	Basin Electric Power Coop	ND	$56,183	$0	$0	$0	$56,183	$53,056	$0	$0	$0	$53,056
283	6030	Coal Creek	Great River Energy	ND	$40,909	$0	$0	$0	$40,909	$38,632	$0	$0	$0	$38,632
284	2824	Stanton	Great River Energy	ND	$17,661	$0	$0	$0	$17,661	$16,678	$0	$0	$0	$16,678
285	2790	R M Heskett	MDU Resources Group Inc	ND	$24,647	$14,853	$0	$0	$39,500	$23,275	$0	$0	$0	$23,275
286	2823	Milton R Young	Minnkota Power Coop, Inc	ND	$43,007	$263,770	$0	$0	$306,776	$40,613	$0	$0	$0	$40,613
287	8222	Coyote	Otter Tail Power Co	ND	$38,673	$0	$0	$0	$38,673	$36,520	$0	$0	$0	$36,520
288	2240	Lon Wright	Fremont City of	NE	$36,263	$58,900	$0	$0	$95,163	$34,244	$0	$0	$0	$34,244
289	59	Platte	Grand Island City of	NE	$0	$29,706	$0	$0	$29,706	$0	$0	$0	$0	$0
290	60	Whelan Energy Center	Hastings City of	NE	$708,766	$0	$0	$0	$708,766	$669,314	$0	$0	$0	$669,314
291	6077	Gerald Gentleman	Nebraska Public Power District	NE	$2,879,798	$0	$0	$0	$2,879,798	$2,719,502	$0	$0	$0	$2,719,502
292	2277	Sheldon	Nebraska Public Power District	NE	$259,199	$0	$0	$0	$259,199	$244,771	$0	$0	$0	$244,771
293	6096	Nebraska City	Omaha Public Power District	NE	$349,000	$0	$0	$0	$349,000	$329,574	$0	$0	$0	$329,574
294	2291	North Omaha	Omaha Public Power District	NE	$146,240	$0	$0	$0	$146,240	$138,100	$0	$0	$0	$138,100
295	2364	Merrimack	Public Service Co of NH	NH	$39,842	$0	$0	$0	$39,842	$37,624	$0	$0	$0	$37,624
296	2367	Schiller	Public Service Co of NH	NH	$0	$457,371	$0	$0	$457,371	$0	$0	$0	$0	$0
297	2384	Deepwater	Conectiv Atlantic Generatn Inc	NJ	$0	$34,828	$0	$0	$34,828	$0	$0	$0	$0	$0
298	2403	PSEG Hudson Generating Station	PSEG Fossil LLC	NJ	$0	$806,674	$0	$0	$806,674	$0	$0	$0	$0	$0
299	2408	PSEG Mercer Generating Station	PSEG Fossil LLC	NJ	$0	$406,154	$0	$0	$406,154	$0	$0	$0	$0	$0
300	2378	B L England	RC Cape May Holdings LLC	NJ	$0	$26,121	$0	$0	$26,121	$0	$0	$0	$0	$0
301	10566	Chambers Cogeneration LP	US Operating Services Company	NJ	$0	$829,722	$0	$0	$829,722	$0	$0	$0	$0	$0
302	1004	Logan Generating	US Operating	NJ	$1,649,019	$624,852	$0	$0	$2,273,871	$1,557,231	$0	$0	$0	$1,557,231

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	3	Company LP	Services Company											
303	2434	Howard Down	Vineland City of	NJ	$171,666	$0	$0	$0	$171,666	$162,111	$0	$0	$0	$162,111
304	2442	Four Corners	Arizona Public Service Co	NM	$1,382,099	$4,968,087	$0	$0	$6,350,186	$1,305,168	$0	$0	$0	$1,305,168
305	2451	San Juan	Public Service Co of NM	NM	$8,853,679	$5,562,208	$0	$0	$14,415,888	$8,360,864	$0	$0	$0	$8,360,864
306	87	Escalante	Tri-State G & T Assn, Inc	NM	$2,463,098	$0	$0	$0	$2,463,098	$2,325,997	$0	$0	$0	$2,325,997
307	2324	Reid Gardner	Nevada Power Co	NV	$1,279,054	$0	$0	$0	$1,279,054	$1,207,859	$0	$0	$0	$1,207,859
308	8224	North Valmy	Sierra Pacific Power Co	NV	$4,272,935	$0	$0	$0	$4,272,935	$4,035,094	$0	$0	$0	$4,035,094
309	2535	AES Cayuga	AES Cayuga LLC	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
310	2527	AES Greenidge LLC	AES Greenidge	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
311	6082	AES Somerset LLC	AES Somerset LLC	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
312	2526	AES Westover	AES Westover LLC	NY	$0	$212,962	$0	$0	$212,962	$0	$0	$0	$0	$0
313	1046 4	Black River Generation	Black River Generation LLC	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
314	2554	Dunkirk Generating Plant	Dunkirk Power LLC	NY	$0	$267,355	$0	$0	$267,355	$0	$0	$0	$0	$0
315	2480	Danskammer Generating Station	Dynegy Northeast Gen Inc	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
316	2682	S A Carlson	Jamestown Board of Public Util	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
317	2629	Lovett	Mirant New York Inc	NY	$0	$547,002	$0	$0	$547,002	$0	$0	$0	$0	$0
318	5020 2	WPS Power Niagara	Niagara Generation LLC	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
319	2549	C R Huntley Generating Station	NRG Huntley Operations Inc	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
320	2642	Rochester 7	Rochester Gas & Electric Corp	NY	$0	$125,687	$0	$0	$125,687	$0	$0	$0	$0	$0
321	5065 1	Trigen Syracuse Energy	Syracuse Energy Corp	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
322	7286	Richard Gorsuch	American Mun Power-Ohio, Inc	OH	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
323	2828	Cardinal	Cardinal Operating Co	OH	$1,988,900	$0	$0	$0	$1,988,900	$1,878,193	$0	$0	$0	$1,878,193
324	2914	Dover	City of Dover	OH	$0	$14,689	$0	$0	$14,689	$0	$0	$0	$0	$0
325	2917	Hamilton	City of Hamilton	OH	$0	$157,750	$0	$0	$157,750	$0	$0	$0	$0	$0
326	2935	Orrville	City of Orrville	OH	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
327	2936	Painesville	City of Painesville	OH	$0	$48,646	$0	$0	$48,646	$0	$0	$0	$0	$0

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328	2943	Shelby Municipal Light Plant	City of Shelby	OH	$0	$22,295	$0	$0	$22,295	$0	$0	$0	$0	$0
329	2840	Conesville	Columbus Southern Power Co	OH	$4,268,300	$0	$0	$0	$4,268,300	$4,030,717	$0	$0	$0	$4,030,717
330	2843	Picway	Columbus Southern Power Co	OH	$274,795	$0	$0	$0	$274,795	$259,499	$0	$0	$0	$259,499
331	2850	J M Stuart	Dayton Power & Light Co	OH	$4,691,773	$0	$0	$0	$4,691,773	$4,430,618	$0	$0	$0	$4,430,618
332	6031	Killen Station	Dayton Power & Light Co	OH	$5,303,401	$0	$0	$0	$5,303,401	$5,008,202	$0	$0	$0	$5,008,202
333	2848	O H Hutchings	Dayton Power & Light Co	OH	$0	$409,739	$0	$0	$409,739	$0	$0	$0	$0	$0
334	2832	Miami Fort	Duke Energy Ohio Inc	OH	$5,401,738	$0	$0	$0	$5,401,738	$5,101,066	$0	$0	$0	$5,101,066
335	6019	W H Zimmer	Duke Energy Ohio Inc	OH	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
336	2830	Walter C Beckjord	Duke Energy Ohio Inc	OH	$627,855	$0	$0	$0	$627,855	$592,907	$0	$0	$0	$592,907
337	2835	Ashtabula	FirstEnergy Generation Corp	OH	$0	$61,973	$0	$0	$61,973	$0	$0	$0	$0	$0
338	2878	Bay Shore	FirstEnergy Generation Corp	OH	$0	$263,770	$0	$0	$263,770	$0	$0	$0	$0	$0
339	2837	Eastlake	FirstEnergy Generation Corp	OH	$0	$649,436	$0	$0	$649,436	$0	$0	$0	$0	$0
340	2838	Lake Shore	FirstEnergy Generation Corp	OH	$0	$126,507	$0	$0	$126,507	$0	$0	$0	$0	$0
341	2864	R E Burger	FirstEnergy Generation Corp	OH	$0	$318,060	$0	$0	$318,060	$0	$0	$0	$0	$0
342	2866	W H Sammis	FirstEnergy Generation Corp	OH	$0	$2,664,841	$0	$0	$2,664,841	$0	$0	$0	$0	$0
343	8102	General James M Gavin	Ohio Power Co	OH	$584,266	$0	$0	$0	$584,266	$551,744	$0	$0	$0	$551,744
344	2872	Muskingum River	Ohio Power Co	OH	$1,708,190	$0	$0	$0	$1,708,190	$1,613,109	$0	$0	$0	$1,613,109
345	2876	Kyger Creek	Ohio Valley Electric Corp	OH	$2,355,662	$0	$0	$0	$2,355,662	$2,224,541	$0	$0	$0	$2,224,541
346	2836	Avon Lake	Orion Power Midwest LP	OH	$0	$798,991	$0	$0	$798,991	$0	$0	$0	$0	$0
347	2861	Niles	Orion Power Midwest LP	OH	$0	$289,378	$0	$0	$289,378	$0	$0	$0	$0	$0
348	10671	AES Shady Point LLC	AES Shady Point LLC	OK	$0	$2,163,422	$0	$0	$2,163,422	$0	$0	$0	$0	$0
349	165	GRDA	Grand River Dam Authority	OK	$2,202,508	$0	$0	$0	$2,202,508	$2,079,912	$0	$0	$0	$2,079,912

Exhibit J1
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Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
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350	2952	Muskogee	Oklahoma Gas & Electric Co	OK	$0	$263,770	$0	$0	$263,770	$0	$0	$0	$0	$0
351	6095	Sooner	Oklahoma Gas & Electric Co	OK	$0	$376,448	$0	$0	$376,448	$0	$0	$0	$0	$0
352	2963	Northeastern	Public Service Co of Oklahoma	OK	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
353	6772	Hugo	Western Farmers Elec Coop, Inc	OK	$5,393	$0	$0	$0	$5,393	$5,093	$0	$0	$0	$5,093
354	6106	Boardman	Portland General Electric Co	OR	$837,912	$0	$0	$0	$837,912	$791,272	$0	$0	$0	$791,272
355	10676	AES Beaver Valley Partners Beaver Valley	AES Beaver Valley	PA	$0	$892,719	$0	$0	$892,719	$0	$0	$0	$0	$0
356	3178	Armstrong Power Station	Allegheny Energy Supply Co LLC	PA	$49,994	$0	$0	$0	$49,994	$47,212	$0	$0	$0	$47,212
357	3179	Hatfields Ferry Power Station	Allegheny Energy Supply Co LLC	PA	$84,721	$446,616	$0	$0	$531,336	$80,005	$0	$0	$0	$80,005
358	3181	Mitchell Power Station	Allegheny Energy Supply Co LLC	PA	$12,752	$989,008	$0	$0	$1,001,759	$12,042	$0	$0	$0	$12,042
359	10641	Cambria Cogen	Cambria CoGen Co	PA	$599,870	$0	$0	$0	$599,870	$566,480	$0	$0	$0	$566,480
360	54144	Piney Creek Project	Colmac Clarion Inc	PA	$137,508	$0	$0	$0	$137,508	$129,854	$0	$0	$0	$129,854
361	10603	Ebensburg Power	Ebensburg Power Co	PA	$426,147	$0	$0	$0	$426,147	$402,427	$0	$0	$0	$402,427
362	3159	Cromby Generating Station	Exelon Power	PA	$0	$153,140	$0	$0	$153,140	$0	$0	$0	$0	$0
363	3161	Eddystone Generating Station	Exelon Power	PA	$0	$548,538	$0	$0	$548,538	$0	$0	$0	$0	$0
364	6094	Bruce Mansfield	FirstEnergy Generation Corp	PA	$32,902,363	$0	$0	$0	$32,902,363	$31,070,945	$0	$0	$0	$31,070,945
365	10113	John B Rich Memorial Power Station	Gilberton Power Co	PA	$553,314	$0	$0	$0	$553,314	$522,515	$0	$0	$0	$522,515
366	10143	Colver Power Project	Inter-Power/AhlCon Partners, L.P.	PA	$0	$139,823	$0	$0	$139,823	$0	$0	$0	$0	$0
367	3122	Homer City Station	Midwest Generations EME LLC	PA	$426,599	$0	$0	$0	$426,599	$402,854	$0	$0	$0	$402,854
368	10343	Foster Wheeler Mt Carmel Cogen	Mount Carmel Cogen Inc	PA	$602,175	$0	$0	$0	$602,175	$568,656	$0	$0	$0	$568,656
369	50039	Kline Township Cogen Facility	Northeastern Power Co	PA	$445,975	$0	$0	$0	$445,975	$421,151	$0	$0	$0	$421,151

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370	8226	Cheswick Power Plant	Orion Power Midwest LP	PA	$27,155	$0	$0	$0	$27,155	$25,643	$0	$0	$0	$25,643
371	3098	Elrama Power Plant	Orion Power Midwest LP	PA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
372	3138	New Castle Plant	Orion Power Midwest LP	PA	$22,733	$0	$0	$0	$22,733	$21,468	$0	$0	$0	$21,468
373	50776	Panther Creek Energy Facility	Panther Creek Partners	PA	$366,856	$0	$0	$0	$366,856	$346,436	$0	$0	$0	$346,436
374	3140	PPL Brunner Island	PPL Brunner Island LLC	PA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
375	3149	PPL Montour	PPL Montour LLC	PA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
376	3113	Portland	Reliant Energy Mid-Atlantic PH LLC	PA	$19,584	$0	$0	$0	$19,584	$18,494	$0	$0	$0	$18,494
377	3131	Shawville	Reliant Energy Mid-Atlantic PH LLC	PA	$270,973	$0	$0	$0	$270,973	$255,890	$0	$0	$0	$255,890
378	3115	Titus	Reliant Energy Mid-Atlantic PH LLC	PA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
379	3130	Seward	Reliant Energy Seward LLC	PA	$2,113,798	$0	$0	$0	$2,113,798	$1,996,139	$0	$0	$0	$1,996,139
380	3118	Conemaugh	Reliant Engy NE Management Co	PA	$1,195,674	$0	$0	$0	$1,195,674	$1,129,120	$0	$0	$0	$1,129,120
381	3136	Keystone	Reliant Engy NE Management Co	PA	$144,792	$0	$0	$0	$144,792	$136,733	$0	$0	$0	$136,733
382	54634	St Nicholas Cogen Project	Schuylkill Energy Resource Inc	PA	$1,318,498	$0	$0	$0	$1,318,498	$1,245,108	$0	$0	$0	$1,245,108
383	3152	Sunbury Generation LP	Sunbury Generation LP	PA	$222,711	$221,771	$0	$0	$444,482	$210,314	$0	$0	$0	$210,314
384	3176	Hunlock Power Station	UGI Development Co	PA	$56,098	$0	$0	$0	$56,098	$52,975	$0	$0	$0	$52,975
385	50888	Northampton Generating Company LP	US Operating Services Company	PA	$193,328	$1,562,130	$0	$0	$1,755,459	$182,567	$0	$0	$0	$182,567
386	50974	Scrubgrass Generating Company LP	US Operating Services Company	PA	$357,627	$0	$0	$0	$357,627	$337,720	$0	$0	$0	$337,720
387	50879	Wheelabrator Frackville Energy	Wheelabrator Environmental Systems	PA	$541,766	$0	$0	$0	$541,766	$511,610	$0	$0	$0	$511,610
388	50611	WPS Westwood Generation LLC	WPS Power Developement	PA	$522,486	$0	$0	$0	$522,486	$493,403	$0	$0	$0	$493,403
389	3264	W S Lee	Duke Energy	SC	$41,846	$0	$0	$0	$41,846	$39,517	$0	$0	$0	$39,517

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			Carolinas, LLC											
390	3251	H B Robinson	Progress Energy Carolinas Inc	SC	$323,042	$0	$0	$0	$323,042	$305,061	$0	$0	$0	$305,061
391	7652	US DOE Savannah River Site (D Area)	Savannah River Nuclear Solutions LLC	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
392	3280	Canadys Steam	South Carolina Electric&Gas Co	SC	$474,088	$0	$0	$0	$474,088	$447,699	$0	$0	$0	$447,699
393	7737	Cogen South	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
394	7210	Cope	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
395	3287	McMeekin	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
396	3295	Urquhart	South Carolina Electric&Gas Co	SC	$146,086	$0	$0	$0	$146,086	$137,955	$0	$0	$0	$137,955
397	3297	Wateree	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
398	3298	Williams	South Carolina Genertg Co, Inc	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
399	130	Cross	South Carolina Pub Serv Auth	SC	$292,817	$95,777	$0	$0	$388,593	$276,518	$0	$0	$0	$276,518
400	3317	Dolphus M Grainger	South Carolina Pub Serv Auth	SC	$61,281	$275,550	$0	$0	$336,830	$57,870	$0	$0	$0	$57,870
401	3319	Jefferies	South Carolina Pub Serv Auth	SC	$108,532	$0	$0	$0	$108,532	$102,491	$0	$0	$0	$102,491
402	6249	Winyah	South Carolina Pub Serv Auth	SC	$422,248	$196,521	$0	$0	$618,769	$398,745	$0	$0	$0	$398,745
403	3325	Ben French	Black Hills Power Inc	SD	$127,596	$33,051	$0	$0	$160,647	$120,494	$0	$0	$0	$120,494
404	6098	Big Stone	Otter Tail Power Co	SD	$215,020	$0	$0	$0	$215,020	$203,051	$0	$0	$0	$203,051
405	3393	Allen Steam Plant	Tennessee Valley Authority	TN	$11,886	$0	$0	$0	$11,886	$11,225	$0	$0	$0	$11,225
406	3396	Bull Run	Tennessee Valley Authority	TN	$12,593	$24,584	$0	$0	$37,177	$11,892	$0	$0	$0	$11,892
407	3399	Cumberland	Tennessee Valley Authority	TN	$0	$102	$0	$0	$102	$0	$0	$0	$0	$0
408	3403	Gallatin	Tennessee Valley Authority	TN	$12,860	$1,024	$0	$0	$13,884	$12,144	$0	$0	$0	$12,144
409	3405	John Sevier	Tennessee Valley Authority	TN	$9,118	$36,364	$0	$0	$45,482	$8,610	$0	$0	$0	$8,610
410	3406	Johnsonville	Tennessee Valley Authority	TN	$10,445	$1,144,196	$0	$0	$1,154,642	$9,864	$0	$0	$0	$9,864

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411	3407	Kingston	Tennessee Valley Authority	TN	$3,049	$0	$0	$0	$3,049	$2,879	$0	$0	$0	$2,879
412	7030	Twin Oaks Power One	Altura Power	TX	$180,354	$0	$0	$0	$180,354	$170,315	$0	$0	$0	$170,315
413	6178	Coleto Creek	ANP-Coleto Creek	TX	$957,479	$0	$0	$0	$957,479	$904,183	$0	$0	$0	$904,183
414	6179	Fayette Power Project	Lower Colorado River Authority	TX	$210,585	$0	$0	$0	$210,585	$198,863	$0	$0	$0	$198,863
415	54972	Norit Americas Marshall Plant	Norit Americas Inc	TX	$2,685	$2,704	$0	$0	$5,389	$2,536	$0	$0	$0	$2,536
416	298	Limestone	NRG Texas LLC	TX	$598,430	$0	$0	$0	$598,430	$565,120	$0	$0	$0	$565,120
417	3470	W A Parish	NRG Texas LLC	TX	$66,365	$0	$0	$0	$66,365	$62,671	$0	$0	$0	$62,671
418	127	Oklaunion	Public Service Co of Oklahoma	TX	$660,126	$0	$0	$0	$660,126	$623,382	$0	$0	$0	$623,382
419	7097	J K Spruce	San Antonio City of	TX	$83,652	$185,919	$0	$0	$269,571	$78,995	$0	$0	$0	$78,995
420	6181	J T Deely	San Antonio City of	TX	$45,108	$0	$0	$0	$45,108	$42,597	$0	$0	$0	$42,597
421	6183	San Miguel	San Miguel Electric Coop, Inc	TX	$0	$6,543,021	$0	$0	$6,543,021	$0	$0	$0	$0	$0
422	7902	Pirkey	Southwestern Electric Power Co	TX	$2,407,485	$0	$0	$0	$2,407,485	$2,273,479	$0	$0	$0	$2,273,479
423	6139	Welsh	Southwestern Electric Power Co	TX	$52,960	$0	$0	$0	$52,960	$50,012	$0	$0	$0	$50,012
424	6193	Harrington	Southwestern Public Service Co	TX	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
425	6194	Tolk	Southwestern Public Service Co	TX	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
426	6136	Gibbons Creek	Texas Municipal Power Agency	TX	$63,877	$0	$0	$0	$63,877	$60,321	$0	$0	$0	$60,321
427	3497	Big Brown	TXU Generation Co LP	TX	$109,055	$0	$0	$0	$109,055	$102,985	$0	$0	$0	$102,985
428	6146	Martin Lake	TXU Generation Co LP	TX	$411,947	$0	$0	$0	$411,947	$389,017	$0	$0	$0	$389,017
429	6147	Monticello	TXU Generation Co LP	TX	$202,180	$0	$0	$0	$202,180	$190,926	$0	$0	$0	$190,926
430	6648	Sandow No 4	TXU Generation Co LP	TX	$1,992,979	$0	$0	$0	$1,992,979	$1,882,045	$0	$0	$0	$1,882,045
431	7790	Bonanza	Deseret Generation & Tran Coop	UT	$1,430,987	$0	$0	$0	$1,430,987	$1,351,335	$0	$0	$0	$1,351,335
432	6481	Intermountain Power Project	Los Angeles City of	UT	$2,146,602	$0	$0	$0	$2,146,602	$2,027,117	$0	$0	$0	$2,027,117
433	3644	Carbon	PacifiCorp	UT	$171,246	$0	$0	$0	$171,246	$161,714	$0	$0	$0	$161,714
434	6165	Hunter	PacifiCorp	UT	$2,309,513	$0	$0	$0	$2,309,513	$2,180,961	$0	$0	$0	$2,180,961
435	8069	Huntington	PacifiCorp	UT	$3,299,563	$0	$0	$0	$3,299,563	$3,115,902	$0	$0	$0	$3,115,902
436	5095	Sunnyside Cogen	Sunnyside	UT	$1,073,584	$0	$0	$0	$1,073,584	$1,013,826	$0	$0	$0	$1,013,826

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	1	Associates	Cogeneration Assoc											
437	3775	Clinch River	Appalachian Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
438	3776	Glen Lyn	Appalachian Power Co	VA	$292,058	$0	$0	$0	$292,058	$275,801	$0	$0	$0	$275,801
439	54304	Birchwood Power	Birchwood Power Partners LP	VA	$0	$604,365	$0	$0	$604,365	$0	$0	$0	$0	$0
440	10071	Cogentrix Virginia Leasing Corporation	Cogentrix-Virginia Leas'g Corp	VA	$0	$215,113	$0	$0	$215,113	$0	$0	$0	$0	$0
441	10377	James River Cogeneration	James River Cogeneration Co	VA	$0	$235,600	$0	$0	$235,600	$0	$0	$0	$0	$0
442	3788	Potomac River	Mirant Potomac River LLC	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
443	54081	Spruance Genco LLC	Spruance Operating Services LLC	VA	$0	$809,235	$0	$0	$809,235	$0	$0	$0	$0	$0
444	10773	Altavista Power Station	Virginia Electric & Power Co	VA	$0	$101,661	$0	$0	$101,661	$0	$0	$0	$0	$0
445	3796	Bremo Bluff	Virginia Electric & Power Co	VA	$1,061,237	$0	$0	$0	$1,061,237	$1,002,166	$0	$0	$0	$1,002,166
446	3803	Chesapeake	Virginia Electric & Power Co	VA	$457,568	$1,307,068	$0	$0	$1,764,636	$432,099	$0	$0	$0	$432,099
447	3797	Chesterfield	Virginia Electric & Power Co	VA	$3,207,906	$0	$0	$0	$3,207,906	$3,029,347	$0	$0	$0	$3,029,347
448	7213	Clover	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
449	10771	Hopewell Power Station	Virginia Electric & Power Co	VA	$0	$72,104	$0	$0	$72,104	$0	$0	$0	$0	$0
450	52007	Mecklenburg Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
451	10774	Southampton Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
452	3809	Yorktown	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
453	3845	Transalta Centralia Generation	TransAlta Centralia Gen LLC	WA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
454	4127	Menasha	City of Menasha	WI	$219,000	$0	$0	$0	$219,000	$206,810	$0	$0	$0	$206,810
455	4140	Alma	Dairyland Power Coop	WI	$35,784	$0	$0	$0	$35,784	$33,792	$0	$0	$0	$33,792
456	4143	Genoa	Dairyland Power Coop	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
457	4271	John P Madgett	Dairyland Power Coop	WI	$786,749	$0	$0	$0	$786,749	$742,957	$0	$0	$0	$742,957

Exhibit J1 Cost for Subtitle C haz waste and Subtitle D Version 1 Without Land Treatment Dewatering Sub-Option														
Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
458	3992	Blount Street	Madison Gas & Electric Co	WI	$0	$2,561	$0	$0	$2,561	$0	$0	$0	$0	$0
459	4125	Manitowoc	Manitowoc Public Utilities	WI	$394,903	$0	$0	$0	$394,903	$372,922	$0	$0	$0	$372,922
460	4146	E J Stoneman Station	Mid-America Power LLC	WI	$161,240	$0	$0	$0	$161,240	$152,265	$0	$0	$0	$152,265
461	3982	Bay Front	Northern States Power Co	WI	$0	$44,457	$0	$0	$44,457	$0	$0	$0	$0	$0
462	7549	Milwaukee County	Wisconsin Electric Power Co	WI	$222,398	$0	$0	$0	$222,398	$210,019	$0	$0	$0	$210,019
463	6170	Pleasant Prairie	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
464	4041	South Oak Creek	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
465	4042	Valley	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
466	8023	Columbia	Wisconsin Power & Light Co	WI	$1,982,225	$0	$0	$0	$1,982,225	$1,871,890	$0	$0	$0	$1,871,890
467	4050	Edgewater	Wisconsin Power & Light Co	WI	$11,284	$0	$0	$0	$11,284	$10,656	$0	$0	$0	$10,656
468	4054	Nelson Dewey	Wisconsin Power & Light Co	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
469	4072	Pulliam	Wisconsin Public Service Corp	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
470	4078	Weston	Wisconsin Public Service Corp	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
471	3944	Harrison Power Station	Allegheny Energy Supply Co LLC	WV	$1,410,544	$0	$0	$0	$1,410,544	$1,332,030	$0	$0	$0	$1,332,030
472	6004	Pleasants Power Station	Allegheny Energy Supply Co LLC	WV	$5,409,133	$0	$0	$0	$5,409,133	$5,108,049	$0	$0	$0	$5,108,049
473	1015 1	Grant Town Power Plant	American Bituminous Power LP	WV	$742,420	$0	$0	$0	$742,420	$701,095	$0	$0	$0	$701,095
474	3935	John E Amos	Appalachian Power Co	WV	$9,047,022	$0	$0	$0	$9,047,022	$8,543,445	$0	$0	$0	$8,543,445
475	3936	Kanawha River	Appalachian Power Co	WV	$78,028	$0	$0	$0	$78,028	$73,685	$0	$0	$0	$73,685
476	6264	Mountaineer	Appalachian Power Co	WV	$2,298,069	$0	$0	$0	$2,298,069	$2,170,153	$0	$0	$0	$2,170,153
477	3938	Philip Sporn	Appalachian Power Co	WV	$3,106,102	$0	$0	$0	$3,106,102	$2,933,210	$0	$0	$0	$2,933,210
478	3942	Albright	Monongahela Power Co	WV	$755,162	$0	$0	$0	$755,162	$713,128	$0	$0	$0	$713,128

Exhibit J1 Cost for Subtitle C haz waste and Subtitle D Version 1 Without Land Treatment Dewatering Sub-Option														
Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
479	3943	Fort Martin Power Station	Monongahela Power Co	WV	$23,363	$1,046,371	$0	$0	$1,069,734	$22,062	$0	$0	$0	$22,062
480	3945	Rivesville	Monongahela Power Co	WV	$414,830	$0	$0	$0	$414,830	$391,740	$0	$0	$0	$391,740
481	3946	Willow Island	Monongahela Power Co	WV	$284,624	$0	$0	$0	$284,624	$268,781	$0	$0	$0	$268,781
482	10743	Morgantown Energy Facility	Morgantown Energy Associates	WV	$547,721	$0	$0	$0	$547,721	$517,234	$0	$0	$0	$517,234
483	3947	Kammer	Ohio Power Co	WV	$400,961	$0	$0	$0	$400,961	$378,643	$0	$0	$0	$378,643
484	3948	Mitchell	Ohio Power Co	WV	$25,937,363	$0	$0	$0	$25,937,363	$24,493,632	$0	$0	$0	$24,493,632
485	3954	Mt Storm	Virginia Electric & Power Co	WV	$5,495,529	$2,117,327	$0	$0	$7,612,856	$5,189,636	$0	$0	$0	$5,189,636
486	7537	North Branch	Virginia Electric & Power Co	WV	$2,081,521	$0	$0	$0	$2,081,521	$1,965,659	$0	$0	$0	$1,965,659
487	6204	Laramie River Station	Basin Electric Power Coop	WY	$2,266,763	$0	$0	$0	$2,266,763	$2,140,590	$0	$0	$0	$2,140,590
488	4150	Neil Simpson	Black Hills Power Inc	WY	$0	$34,654	$0	$0	$34,654	$0	$0	$0	$0	$0
489	7504	Neil Simpson II	Black Hills Power Inc	WY	$723,864	$0	$0	$0	$723,864	$683,572	$0	$0	$0	$683,572
490	4151	Osage	Black Hills Power Inc	WY	$163,905	$0	$0	$0	$163,905	$154,782	$0	$0	$0	$154,782
491	55479	Wygen 1	Black Hills Power Inc	WY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
492	4158	Dave Johnston	PacifiCorp	WY	$193,893	$0	$0	$0	$193,893	$183,100	$0	$0	$0	$183,100
493	8066	Jim Bridger	PacifiCorp	WY	$6,246,594	$0	$0	$0	$6,246,594	$5,898,895	$0	$0	$0	$5,898,895
494	4162	Naughton	PacifiCorp	WY	$905,116	$0	$0	$0	$905,116	$854,735	$0	$0	$0	$854,735
495	6101	Wyodak	PacifiCorp	WY	$355,027	$988,496	$0	$0	$1,343,522	$335,265	$0	$0	$0	$335,265
			Total Costs:		$521,000,000	$77,000,000	$0	$0	$598,000,000	$492,000,000	$0	$0	$0	$492,000,000

Exhibit J2 Cost for Hybrid C & D Without Land Treatment Sub-Option									
Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
1	79	Aurora Energy LLC Chena	Aurora Energy LLC	AK	$567,289	$0	$0	$0	$567,289
2	6288	Healy	Golden Valley Elec Assn Inc	AK	$397,225	$0	$0	$0	$397,225
3	56	Charles R Lowman	Alabama Electric Coop Inc	AL	$249,394	$0	$0	$0	$249,394
4	3	Barry	Alabama Power Co	AL	$4,202,193	$0	$0	$0	$4,202,193
5	26	E C Gaston	Alabama Power Co	AL	$396,674	$0	$0	$0	$396,674
6	7	Gadsden	Alabama Power Co	AL	$274,527	$0	$0	$0	$274,527
7	8	Gorgas	Alabama Power Co	AL	$5,305,665	$0	$0	$0	$5,305,665
8	10	Greene County	Alabama Power Co	AL	$5,462,733	$0	$0	$0	$5,462,733
9	6002	James H Miller Jr	Alabama Power Co	AL	$2,252,768	$0	$0	$0	$2,252,768
10	50407	Mobile Energy Services LLC	DTE Energy Services	AL	$11,617	$0	$0	$0	$11,617
11	47	Colbert	Tennessee Valley Authority	AL	$748,024	$0	$0	$0	$748,024
12	50	Widows Creek	Tennessee Valley Authority	AL	$2,317,362	$0	$0	$0	$2,317,362
13	6641	Independence	Entergy Arkansas Inc	AR	$2,494,332	$0	$0	$0	$2,494,332
14	6009	White Bluff	Entergy Arkansas Inc	AR	$3,108,847	$0	$0	$0	$3,108,847
15	6138	Flint Creek	Southwestern Electric Power Co	AR	$428,824	$0	$0	$0	$428,824
16	160	Apache Station	Arizona Electric Pwr Coop Inc	AZ	$5,172,905	$0	$0	$0	$5,172,905
17	113	Cholla	Arizona Public Service Co	AZ	$1,550,471	$0	$0	$0	$1,550,471
18	6177	Coronado	Salt River Project	AZ	$3,388,566	$0	$0	$0	$3,388,566
19	4941	Navajo	Salt River Project	AZ	$15,951,350	$0	$0	$0	$15,951,350
20	126	H Wilson Sundt Generating Station	Tucson Electric Power Co	AZ	$125,438	$0	$0	$0	$125,438
21	8223	Springerville	Tucson Electric Power Co	AZ	$12,026,040	$0	$0	$0	$12,026,040
22	10002	ACE Cogeneration Facility	ACE Cogeneration Co	CA	$0	$0	$0	$0	$0
23	10640	Stockton Cogen	Air Products Energy Enterprise	CA	$1,215,140	$0	$0	$0	$1,215,140
24	54238	Port of Stockton District Energy Fac	FPL Energy Operating Servs Inc	CA	$515,951	$0	$0	$0	$515,951
25	54626	Mt Poso Cogeneration	Mt Poso Cogeneration Co	CA	$543,680	$0	$0	$0	$543,680
26	10768	Rio Bravo Jasmin	Rio Bravo Jasmin	CA	$313,301	$0	$0	$0	$313,301
27	10769	Rio Bravo Poso	Rio Bravo Poso	CA	$306,959	$0	$0	$0	$306,959
28	462	W N Clark	Aquila, Inc.	CO	$0	$0	$0	$0	$0
29	10003	Colorado Energy Nations Company	Colorado Energy Nations Company LLLP	CO	$0	$0	$0	$0	$0
30	492	Martin Drake	Colorado Springs City of	CO	$0	$0	$0	$0	$0
31	8219	Ray D Nixon	Colorado Springs City of	CO	$0	$0	$0	$0	$0
32	6761	Rawhide	Platte River Power Authority	CO	$258,135	$0	$0	$0	$258,135
33	465	Arapahoe	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
34	468	Cameo	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
35	469	Cherokee	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
36	470	Comanche	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
37	525	Hayden	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
38	6248	Pawnee	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
39	477	Valmont	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0

Exhibit J2 Cost for Hybrid C & D Without Land Treatment Sub-Option										
Plant Identity					**Hybrid C & D**					
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
40	6021	Craig	Tri-State G & T Assn, Inc	CO	$0	$0	$0	$0	$0
41	527	Nucla	Tri-State G & T Assn, Inc	CO	$0	$0	$0	$0	$0
42	10675	AES Thames	AES Thames LLC	CT	$0	$0	$0	$0	$0
43	568	Bridgeport Station	PSEG Power Connecticut LLC	CT	$0	$0	$0	$0	$0
44	593	Edge Moor	Conectiv Delmarva Gen Inc	DE	$0	$0	$0	$0	$0
45	594	Indian River Generating Station	Indian River Operations Inc	DE	$1,985,635	$0	$0	$0	$1,985,635
46	10030	NRG Energy Center Dover	NRG Energy Center Dover LLC	DE	$290,916	$0	$0	$0	$290,916
47	10333	Central Power & Lime	Central Power & Lime Inc	FL	$0	$0	$0	$0	$0
48	676	C D McIntosh Jr	City of Lakeland	FL	$927,531	$0	$0	$0	$927,531
49	663	Deerhaven Generating Station	Gainesville Regional Utilities	FL	$65,238	$0	$0	$0	$65,238
50	641	Crist	Gulf Power Co	FL	$0	$0	$0	$0	$0
51	643	Lansing Smith	Gulf Power Co	FL	$305,662	$0	$0	$0	$305,662
52	642	Scholz	Gulf Power Co	FL	$0	$0	$0	$0	$0
53	667	Northside Generating Station	JEA	FL	$2,801,856	$0	$0	$0	$2,801,856
54	207	St Johns River Power Park	JEA	FL	$1,914,218	$0	$0	$0	$1,914,218
55	564	Stanton Energy Center	Orlando Utilities Comm	FL	$2,170,584	$0	$0	$0	$2,170,584
56	628	Crystal River	Progress Energy Florida Inc	FL	$298,912	$0	$0	$0	$298,912
57	136	Seminole	Seminole Electric Coop, Inc	FL	$3,038,220	$0	$0	$0	$3,038,220
58	645	Big Bend	Tampa Electric Co	FL	$41,617	$0	$0	$0	$41,617
59	7242	Polk	Tampa Electric Co	FL	$927,213	$0	$0	$0	$927,213
60	10672	Cedar Bay Generating Company LP	US Operating Services Company	FL	$0	$0	$0	$0	$0
61	50976	Indiantown Cogeneration LP	US Operating Services Company	FL	$0	$0	$0	$0	$0
62	753	Crisp Plant	Crisp County Power Comm	GA	$9,274	$0	$0	$0	$9,274
63	703	Bowen	Georgia Power Co	GA	$9,832,825	$0	$0	$0	$9,832,825
64	708	Hammond	Georgia Power Co	GA	$464,894	$0	$0	$0	$464,894
65	709	Harllee Branch	Georgia Power Co	GA	$1,258,233	$0	$0	$0	$1,258,233
66	710	Jack McDonough	Georgia Power Co	GA	$136,446	$0	$0	$0	$136,446
67	733	Kraft	Georgia Power Co	GA	$204,910	$0	$0	$0	$204,910
68	6124	McIntosh	Georgia Power Co	GA	$435,383	$0	$0	$0	$435,383
69	727	Mitchell	Georgia Power Co	GA	$0	$0	$0	$0	$0
70	6257	Scherer	Georgia Power Co	GA	$3,875,110	$0	$0	$0	$3,875,110
71	6052	Wansley	Georgia Power Co	GA	$2,629,932	$0	$0	$0	$2,629,932
72	728	Yates	Georgia Power Co	GA	$587,971	$0	$0	$0	$587,971
73	10673	AES Hawaii	AES Hawaii Inc	HI	$0	$0	$0	$0	$0
74	10604	Hawaiian Comm & Sugar Puunene Mill	Hawaiian Com & Sugar Co Ltd	HI	$717,537	$0	$0	$0	$717,537
75	1122	Ames Electric Services Power Plant	Ames City of	IA	$19,694	$0	$0	$0	$19,694
76	1167	Muscatine Plant #1	Board of Water Electric & Communications	IA	$6,110	$0	$0	$0	$6,110
77	1131	Streeter Station	Cedar Falls Utilities	IA	$3,384	$0	$0	$0	$3,384
78	1218	Fair Station	Central Iowa Power Cooperative	IA	$64,386	$0	$0	$0	$64,386

Exhibit J2
Cost for Hybrid C & D Without Land Treatment Sub-Option

Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
79	1217	Earl F Wisdom	Corn Belt Power Coop	IA	$0	$0	$0	$0	$0
80	1104	Burlington	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
81	1046	Dubuque	Interstate Power and Light Co	IA	$24,230	$0	$0	$0	$24,230
82	1047	Lansing	Interstate Power and Light Co	IA	$331,173	$0	$0	$0	$331,173
83	1048	Milton L Kapp	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
84	6254	Ottumwa	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
85	1073	Prairie Creek	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
86	1058	Sixth Street	Interstate Power and Light Co	IA	$36,969	$0	$0	$0	$36,969
87	1077	Sutherland	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
88	1091	George Neal North	MidAmerican Energy Co	IA	$2,904,636	$0	$0	$0	$2,904,636
89	7343	George Neal South	MidAmerican Energy Co	IA	$183,987	$0	$0	$0	$183,987
90	6664	Louisa	MidAmerican Energy Co	IA	$2,001,170	$0	$0	$0	$2,001,170
91	1081	Riverside	MidAmerican Energy Co	IA	$0	$0	$0	$0	$0
92	1082	Walter Scott Jr Energy Center	MidAmerican Energy Co	IA	$3,498,450	$0	$0	$0	$3,498,450
93	1175	Pella	Pella City of	IA	$0	$0	$0	$0	$0
94	861	Coffeen	Ameren Energy Generating Co	IL	$0	$0	$0	$0	$0
95	863	Hutsonville	Ameren Energy Generating Co	IL	$406,643	$0	$0	$0	$406,643
96	864	Meredosia	Ameren Energy Generating Co	IL	$901,035	$0	$0	$0	$901,035
97	6017	Newton	Ameren Energy Generating Co	IL	$1,180,436	$0	$0	$0	$1,180,436
98	6016	Duck Creek	Ameren Energy Resources Generating Co.	IL	$5,467,375	$0	$0	$0	$5,467,375
99	856	E D Edwards	Ameren Energy Resources Generating Co.	IL	$370,060	$0	$0	$0	$370,060
100	963	Dallman	City of Springfield	IL	$880,455	$0	$0	$0	$880,455
101	964	Lakeside	City of Springfield	IL	$0	$0	$0	$0	$0
102	876	Kincaid Generation LLC	Dominion Energy Services Co	IL	$0	$0	$0	$0	$0
103	889	Baldwin Energy Complex	Dynegy Midwest Generation Inc	IL	$2,970,179	$0	$0	$0	$2,970,179
104	891	Havana	Dynegy Midwest Generation Inc	IL	$1,354,744	$0	$0	$0	$1,354,744
105	892	Hennepin Power Station	Dynegy Midwest Generation Inc	IL	$220,279	$0	$0	$0	$220,279
106	897	Vermilion	Dynegy Midwest Generation Inc	IL	$142,123	$0	$0	$0	$142,123
107	898	Wood River	Dynegy Midwest Generation Inc	IL	$280,100	$0	$0	$0	$280,100
108	887	Joppa Steam	Electric Energy Inc	IL	$0	$0	$0	$0	$0
109	867	Crawford	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
110	886	Fisk Street	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
111	384	Joliet 29	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
112	874	Joliet 9	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
113	879	Powerton	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
114	883	Waukegan	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
115	884	Will County	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
116	976	Marion	Southern Illinois Power Coop	IL	$0	$0	$0	$0	$0
117	6238	Pearl Station	Soyland Power Coop Inc	IL	$174,527	$0	$0	$0	$174,527
118	55245	Tuscola Station	Trigen-Cinergy Sol-Tuscola LLC	IL	$261,353	$0	$0	$0	$261,353
119	6705	Warrick	AGC Division of APG Inc	IN	$4,532,740	$0	$0	$0	$4,532,740
120	992	CC Perry K	Citizens Thermal Energy	IN	$8,040	$0	$0	$0	$8,040

Exhibit J2 Cost for Hybrid C & D Without Land Treatment Sub-Option										
Plant Identity					Hybrid C & D					
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
121	6225	Jasper 2	City of Jasper	IN	$6,590	$0	$0	$0	$6,590
122	1032	Logansport	City of Logansport	IN	$11,793	$0	$0	$0	$11,793
123	1040	Whitewater Valley	City of Richmond	IN	$58,749	$0	$0	$0	$58,749
124	1024	Crawfordsville	Crawfordsville Elec, Lgt & Pwr	IN	$13,630	$0	$0	$0	$13,630
125	1001	Cayuga	Duke Energy Indiana Inc	IN	$4,299,084	$0	$0	$0	$4,299,084
126	1004	Edwardsport	Duke Energy Indiana Inc	IN	$312,616	$0	$0	$0	$312,616
127	6113	Gibson	Duke Energy Indiana Inc	IN	$5,515,408	$0	$0	$0	$5,515,408
128	1008	R Gallagher	Duke Energy Indiana Inc	IN	$961,213	$0	$0	$0	$961,213
129	1010	Wabash River	Duke Energy Indiana Inc	IN	$6,881,013	$0	$0	$0	$6,881,013
130	1043	Frank E Ratts	Hoosier Energy R E C, Inc	IN	$297,279	$0	$0	$0	$297,279
131	6213	Merom	Hoosier Energy R E C, Inc	IN	$38,577	$0	$0	$0	$38,577
132	6166	Rockport	Indiana Michigan Power Co	IN	$1,679,488	$0	$0	$0	$1,679,488
133	988	Tanners Creek	Indiana Michigan Power Co	IN	$2,037,635	$0	$0	$0	$2,037,635
134	983	Clifty Creek	Indiana-Kentucky Electric Corp	IN	$575,603	$0	$0	$0	$575,603
135	994	AES Petersburg	Indianapolis Power & Light Co	IN	$5,859	$0	$0	$0	$5,859
136	991	Eagle Valley	Indianapolis Power & Light Co	IN	$162,274	$0	$0	$0	$162,274
137	990	Harding Street	Indianapolis Power & Light Co	IN	$999,093	$0	$0	$0	$999,093
138	995	Bailly	Northern Indiana Pub Serv Co	IN	$592,246	$0	$0	$0	$592,246
139	997	Michigan City	Northern Indiana Pub Serv Co	IN	$187,560	$0	$0	$0	$187,560
140	6085	R M Schahfer	Northern Indiana Pub Serv Co	IN	$248,414	$0	$0	$0	$248,414
141	1037	Peru	Peru City of	IN	$17,710	$0	$0	$0	$17,710
142	6137	A B Brown	Southern Indiana Gas & Elec Co	IN	$1,604,311	$0	$0	$0	$1,604,311
143	1012	F B Culley	Southern Indiana Gas & Elec Co	IN	$423,003	$0	$0	$0	$423,003
144	981	State Line Energy	State Line Energy LLC	IN	$0	$0	$0	$0	$0
145	1239	Riverton	Empire District Electric Co	KS	$83,896	$0	$0	$0	$83,896
146	6064	Nearman Creek	Kansas City City of	KS	$332,023	$0	$0	$0	$332,023
147	1295	Quindaro	Kansas City City of	KS	$0	$0	$0	$0	$0
148	1241	La Cygne	Kansas City Power & Light Co	KS	$2,008,331	$0	$0	$0	$2,008,331
149	108	Holcomb	Sunflower Electric Power Corp	KS	$901,186	$0	$0	$0	$901,186
150	6068	Jeffrey Energy Center	Westar Energy Inc	KS	$4,932,501	$0	$0	$0	$4,932,501
151	1250	Lawrence Energy Center	Westar Energy Inc	KS	$12,262	$0	$0	$0	$12,262
152	1252	Tecumseh Energy Center	Westar Energy Inc	KS	$18,785	$0	$0	$0	$18,785
153	1374	Elmer Smith	City of Owensboro	KY	$0	$0	$0	$0	$0
154	6018	East Bend	Duke Energy Kentucky Inc	KY	$2,069,884	$0	$0	$0	$2,069,884
155	1384	Cooper	East Kentucky Power Coop, Inc	KY	$212,548	$0	$0	$0	$212,548
156	1385	Dale	East Kentucky Power Coop, Inc	KY	$908,405	$0	$0	$0	$908,405
157	6041	H L Spurlock	East Kentucky Power Coop, Inc	KY	$8,129,129	$0	$0	$0	$8,129,129
158	1372	Henderson I	Henderson City Utility Comm	KY	$10,878	$0	$0	$0	$10,878
159	1353	Big Sandy	Kentucky Power Co	KY	$5,686,904	$0	$0	$0	$5,686,904
160	1355	E W Brown	Kentucky Utilities Co	KY	$319,474	$0	$0	$0	$319,474
161	1356	Ghent	Kentucky Utilities Co	KY	$11,373,101	$0	$0	$0	$11,373,101
162	1357	Green River	Kentucky Utilities Co	KY	$349,271	$0	$0	$0	$349,271

Exhibit J2									
Cost for Hybrid C & D Without Land Treatment Sub-Option									
Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
163	1361	Tyrone	Kentucky Utilities Co	KY	$185,316	$0	$0	$0	$185,316
164	1363	Cane Run	Louisville Gas & Electric Co	KY	$1,725,911	$0	$0	$0	$1,725,911
165	1364	Mill Creek	Louisville Gas & Electric Co	KY	$5,251,934	$0	$0	$0	$5,251,934
166	6071	Trimble County	Louisville Gas & Electric Co	KY	$208,071	$0	$0	$0	$208,071
167	1378	Paradise	Tennessee Valley Authority	KY	$7,306,578	$0	$0	$0	$7,306,578
168	1379	Shawnee	Tennessee Valley Authority	KY	$623,905	$0	$0	$0	$623,905
169	6823	D B Wilson	Western Kentucky Energy Corp	KY	$6,137,559	$0	$0	$0	$6,137,559
170	1382	HMP&L Station Two Henderson	Western Kentucky Energy Corp	KY	$6,001,263	$0	$0	$0	$6,001,263
171	1381	Kenneth C Coleman	Western Kentucky Energy Corp	KY	$308,646	$0	$0	$0	$308,646
172	6639	R D Green	Western Kentucky Energy Corp	KY	$6,708,840	$0	$0	$0	$6,708,840
173	1383	Robert A Reid	Western Kentucky Energy Corp	KY	$36,022	$0	$0	$0	$36,022
174	51	Dolet Hills	Cleco Power LLC	LA	$1,253,675	$0	$0	$0	$1,253,675
175	6190	Rodemacher	Cleco Power LLC	LA	$0	$0	$0	$0	$0
176	1393	R S Nelson	Entergy Gulf States Louisiana LLC	LA	$0	$0	$0	$0	$0
177	6055	Big Cajun 2	Louisiana Generating LLC	LA	$140,032	$0	$0	$0	$140,032
178	1619	Brayton Point	Dominion Energy New England, LLC	MA	$0	$0	$0	$0	$0
179	1626	Salem Harbor	Dominion Energy New England, LLC	MA	$0	$0	$0	$0	$0
180	1606	Mount Tom	FirstLight Power Resources Services LLC	MA	$0	$0	$0	$0	$0
181	1613	Somerset Station	Somerset Power LLC	MA	$0	$0	$0	$0	$0
182	10678	AES Warrior Run Cogeneration Facility	AES WR Ltd Partnership	MD	$0	$0	$0	$0	$0
183	1570	R Paul Smith Power Station	Allegheny Energy Supply Co LLC	MD	$703,963	$0	$0	$0	$703,963
184	602	Brandon Shores	Constellation Power Source Gen	MD	$0	$0	$0	$0	$0
185	1552	C P Crane	Constellation Power Source Gen	MD	$0	$0	$0	$0	$0
186	1554	Herbert A Wagner	Constellation Power Source Gen	MD	$0	$0	$0	$0	$0
187	1571	Chalk Point LLC	Mirant Chalk Point LLC	MD	$692,449	$0	$0	$0	$692,449
188	1572	Dickerson	Mirant Mid-Atlantic LLC	MD	$155,066	$0	$0	$0	$155,066
189	1573	Morgantown Generating Plant	Mirant Mid-Atlantic LLC	MD	$99,080	$0	$0	$0	$99,080
190	10495	Rumford Cogeneration	NewPage Corporation	ME	$387,134	$0	$0	$0	$387,134
191	1825	J B Sims	City of Grand Haven	MI	$21,701	$0	$0	$0	$21,701
192	1830	James De Young	City of Holland	MI	$13,010	$0	$0	$0	$13,010
193	1843	Shiras	City of Marquette	MI	$10,877	$0	$0	$0	$10,877
194	1695	B C Cobb	Consumers Energy Co	MI	$0	$0	$0	$0	$0
195	1702	Dan E Karn	Consumers Energy Co	MI	$16,376	$0	$0	$0	$16,376
196	1720	J C Weadock	Consumers Energy Co	MI	$687,658	$0	$0	$0	$687,658
197	1710	J H Campbell	Consumers Energy Co	MI	$25,272	$0	$0	$0	$25,272
198	1723	J R Whiting	Consumers Energy Co	MI	$26,218	$0	$0	$0	$26,218
199	6034	Belle River	Detroit Edison Co	MI	$28,506	$0	$0	$0	$28,506
200	1731	Harbor Beach	Detroit Edison Co	MI	$9,211	$0	$0	$0	$9,211
201	1733	Monroe	Detroit Edison Co	MI	$5,283,883	$0	$0	$0	$5,283,883
202	1740	River Rouge	Detroit Edison Co	MI	$19,946	$0	$0	$0	$19,946

Exhibit J2
Cost for Hybrid C & D Without Land Treatment Sub-Option

Plant Identity					Hybrid C & D				
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203	1743	St Clair	Detroit Edison Co	MI	$25,720	$0	$0	$0	$25,720
204	1745	Trenton Channel	Detroit Edison Co	MI	$27,739	$0	$0	$0	$27,739
205	1831	Eckert Station	Lansing Board of Water and Light	MI	$0	$0	$0	$0	$0
206	1832	Erickson Station	Lansing Board of Water and Light	MI	$301,844	$0	$0	$0	$301,844
207	4259	Endicott Station	Michigan South Central Pwr Agy	MI	$20,262	$0	$0	$0	$20,262
208	50835	TES Filer City Station	TES Filer City Station LP	MI	$16,142	$0	$0	$0	$16,142
209	1771	Escanaba	Upper Peninsula Power Co	MI	$8,817	$0	$0	$0	$8,817
210	10148	White Pine Electric Power	White Pine Electric Power LLC	MI	$8,455	$0	$0	$0	$8,455
211	1769	Presque Isle	Wisconsin Electric Power Co	MI	$17,794	$0	$0	$0	$17,794
212	1866	Wyandotte	Wyandotte Municipal Serv Comm	MI	$14,085	$0	$0	$0	$14,085
213	1961	Austin Northeast	Austin City of	MN	$1,444	$0	$0	$0	$1,444
214	2018	Virginia	City of Virginia	MN	$6,604	$0	$0	$0	$6,604
215	1979	Hibbing	Hibbing Public Utilities Comm	MN	$3,226	$0	$0	$0	$3,226
216	1893	Clay Boswell	Minnesota Power Inc	MN	$2,520,246	$0	$0	$0	$2,520,246
217	1897	M L Hibbard	Minnesota Power Inc	MN	$0	$0	$0	$0	$0
218	10686	Rapids Energy Center	Minnesota Power Inc	MN	$0	$0	$0	$0	$0
219	1891	Syl Laskin	Minnesota Power Inc	MN	$177,369	$0	$0	$0	$177,369
220	10075	Taconite Harbor Energy Center	Minnesota Power Inc	MN	$39,078	$0	$0	$0	$39,078
221	2001	New Ulm	New Ulm Public Utilities Comm	MN	$8,275	$0	$0	$0	$8,275
222	1915	Allen S King	Northern States Power Co	MN	$13,271	$0	$0	$0	$13,271
223	1904	Black Dog	Northern States Power Co	MN	$183,365	$0	$0	$0	$183,365
224	1927	Riverside	Northern States Power Co	MN	$282,776	$0	$0	$0	$282,776
225	6090	Sherburne County	Northern States Power Co	MN	$15,989,117	$0	$0	$0	$15,989,117
226	1943	Hoot Lake	Otter Tail Power Co	MN	$8,406	$0	$0	$0	$8,406
227	2008	Silver Lake	Rochester Public Utilities	MN	$27,198	$0	$0	$0	$27,198
228	2022	Willmar	Willmar Municipal Utils Comm	MN	$8,555	$0	$0	$0	$8,555
229	2098	Lake Road	Aquila, Inc.	MO	$0	$0	$0	$0	$0
230	2094	Sibley	Aquila, Inc.	MO	$152,029	$0	$0	$0	$152,029
231	2167	New Madrid	Associated Electric Coop, Inc	MO	$2,584,292	$0	$0	$0	$2,584,292
232	2168	Thomas Hill	Associated Electric Coop, Inc	MO	$100,856	$0	$0	$0	$100,856
233	2169	Chamois	Central Electric Power Coop	MO	$191,069	$0	$0	$0	$191,069
234	2123	Columbia	City of Columbia	MO	$21,389	$0	$0	$0	$21,389
235	2144	Marshall	City of Marshall	MO	$19,977	$0	$0	$0	$19,977
236	6768	Sikeston Power Station	City of Sikeston	MO	$952,169	$0	$0	$0	$952,169
237	2161	James River Power Station	City Utilities of Springfield	MO	$87,141	$0	$0	$0	$87,141
238	6195	Southwest Power Station	City Utilities of Springfield	MO	$1,188,827	$0	$0	$0	$1,188,827
239	2076	Asbury	Empire District Electric Co	MO	$142,502	$0	$0	$0	$142,502
240	2132	Blue Valley	Independence City of	MO	$300,386	$0	$0	$0	$300,386
241	2171	Missouri City	Independence City of	MO	$41,286	$0	$0	$0	$41,286
242	2079	Hawthorn	Kansas City Power & Light Co	MO	$216,151	$0	$0	$0	$216,151
243	6065	Iatan	Kansas City Power & Light Co	MO	$316,796	$0	$0	$0	$316,796
244	2080	Montrose	Kansas City Power & Light Co	MO	$181,721	$0	$0	$0	$181,721

Exhibit J2 Cost for Hybrid C & D Without Land Treatment Sub-Option									
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245	2103	Labadie	Union Electric Co	MO	$570,739	$0	$0	$0	$570,739
246	2104	Meramec	Union Electric Co	MO	$840,898	$0	$0	$0	$840,898
247	6155	Rush Island	Union Electric Co	MO	$1,889,190	$0	$0	$0	$1,889,190
248	2107	Sioux	Union Electric Co	MO	$314,968	$0	$0	$0	$314,968
249	55076	Red Hills Generating Facility	Choctaw Generating LP	MS	$711,133	$0	$0	$0	$711,133
250	2062	Henderson	Greenwood Utilities Comm	MS	$13,538	$0	$0	$0	$13,538
251	2049	Jack Watson	Mississippi Power Co	MS	$337,017	$0	$0	$0	$337,017
252	6073	Victor J Daniel Jr	Mississippi Power Co	MS	$839,777	$0	$0	$0	$839,777
253	6061	R D Morrow	South Mississippi El Pwr Assn	MS	$1,805,579	$0	$0	$0	$1,805,579
254	10784	Colstrip Energy LP	Colstrip Energy LP	MT	$12,176	$0	$0	$0	$12,176
255	6089	Lewis & Clark	MDU Resources Group Inc	MT	$9,988	$0	$0	$0	$9,988
256	6076	Colstrip	PPL Montana LLC	MT	$20,205,971	$0	$0	$0	$20,205,971
257	2187	J E Corette Plant	PPL Montana LLC	MT	$0	$0	$0	$0	$0
258	55749	Hardin Generator Project	Rocky Mountain Power Inc	MT	$36,652	$0	$0	$0	$36,652
259	10381	Coastal Carolina Clean Power	Carlyle/Riverstone Renewable Energy	NC	$89,227	$0	$0	$0	$89,227
260	8042	Belews Creek	Duke Energy Carolinas, LLC	NC	$4,523,597	$0	$0	$0	$4,523,597
261	2720	Buck	Duke Energy Carolinas, LLC	NC	$204,494	$0	$0	$0	$204,494
262	2721	Cliffside	Duke Energy Carolinas, LLC	NC	$503,958	$0	$0	$0	$503,958
263	2723	Dan River	Duke Energy Carolinas, LLC	NC	$735,010	$0	$0	$0	$735,010
264	2718	G G Allen	Duke Energy Carolinas, LLC	NC	$691,909	$0	$0	$0	$691,909
265	2727	Marshall	Duke Energy Carolinas, LLC	NC	$4,013,475	$0	$0	$0	$4,013,475
266	2732	Riverbend	Duke Energy Carolinas, LLC	NC	$1,897,808	$0	$0	$0	$1,897,808
267	10384	Edgecombe Genco LLC	Edgecombe Operating Services LLC	NC	$0	$0	$0	$0	$0
268	10380	Elizabethtown Power LLC	North Carolina Power Holdings, LLC	NC	$35,244	$0	$0	$0	$35,244
269	10382	Lumberton	North Carolina Power Holdings, LLC	NC	$32,453	$0	$0	$0	$32,453
270	10379	Primary Energy Roxboro	Primary Energy of North Carolina LLC	NC	$66,095	$0	$0	$0	$66,095
271	10378	Primary Energy Southport	Primary Energy of North Carolina LLC	NC	$0	$0	$0	$0	$0
272	2706	Asheville	Progress Energy Carolinas Inc	NC	$317,017	$0	$0	$0	$317,017
273	2708	Cape Fear	Progress Energy Carolinas Inc	NC	$303,976	$0	$0	$0	$303,976
274	2713	L V Sutton	Progress Energy Carolinas Inc	NC	$381,594	$0	$0	$0	$381,594
275	2709	Lee	Progress Energy Carolinas Inc	NC	$419,097	$0	$0	$0	$419,097
276	6250	Mayo	Progress Energy Carolinas Inc	NC	$464,628	$0	$0	$0	$464,628
277	2712	Roxboro	Progress Energy Carolinas Inc	NC	$931,611	$0	$0	$0	$931,611
278	2716	W H Weatherspoon	Progress Energy Carolinas Inc	NC	$213,277	$0	$0	$0	$213,277
279	54035	Roanoke Valley Energy Facililty I	Westmoreland Partners	NC	$27,646	$0	$0	$0	$27,646
280	54755	Roanoke Valley Energy Facility II	Westmoreland Partners	NC	$78,881	$0	$0	$0	$78,881
281	6469	Antelope Valley	Basin Electric Power Coop	ND	$94,662	$0	$0	$0	$94,662
282	2817	Leland Olds	Basin Electric Power Coop	ND	$53,918	$0	$0	$0	$53,918
283	6030	Coal Creek	Great River Energy	ND	$39,260	$0	$0	$0	$39,260
284	2824	Stanton	Great River Energy	ND	$16,949	$0	$0	$0	$16,949

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285	2790	R M Heskett	MDU Resources Group Inc	ND	$23,654	$0	$0	$0	$23,654
286	2823	Milton R Young	Minnkota Power Coop, Inc	ND	$41,273	$0	$0	$0	$41,273
287	8222	Coyote	Otter Tail Power Co	ND	$37,114	$0	$0	$0	$37,114
288	2240	Lon Wright	Fremont City of	NE	$34,801	$0	$0	$0	$34,801
289	59	Platte	Grand Island City of	NE	$0	$0	$0	$0	$0
290	60	Whelan Energy Center	Hastings City of	NE	$680,197	$0	$0	$0	$680,197
291	6077	Gerald Gentleman	Nebraska Public Power District	NE	$2,763,721	$0	$0	$0	$2,763,721
292	2277	Sheldon	Nebraska Public Power District	NE	$248,751	$0	$0	$0	$248,751
293	6096	Nebraska City	Omaha Public Power District	NE	$334,933	$0	$0	$0	$334,933
294	2291	North Omaha	Omaha Public Power District	NE	$140,345	$0	$0	$0	$140,345
295	2364	Merrimack	Public Service Co of NH	NH	$38,236	$0	$0	$0	$38,236
296	2367	Schiller	Public Service Co of NH	NH	$0	$0	$0	$0	$0
297	2384	Deepwater	Conectiv Atlantic Generatn Inc	NJ	$0	$0	$0	$0	$0
298	2403	PSEG Hudson Generating Station	PSEG Fossil LLC	NJ	$0	$0	$0	$0	$0
299	2408	PSEG Mercer Generating Station	PSEG Fossil LLC	NJ	$0	$0	$0	$0	$0
300	2378	B L England	RC Cape May Holdings LLC	NJ	$0	$0	$0	$0	$0
301	10566	Chambers Cogeneration LP	US Operating Services Company	NJ	$0	$0	$0	$0	$0
302	10043	Logan Generating Company LP	US Operating Services Company	NJ	$1,582,552	$0	$0	$0	$1,582,552
303	2434	Howard Down	Vineland City of	NJ	$164,747	$0	$0	$0	$164,747
304	2442	Four Corners	Arizona Public Service Co	NM	$1,326,391	$0	$0	$0	$1,326,391
305	2451	San Juan	Public Service Co of NM	NM	$8,496,813	$0	$0	$0	$8,496,813
306	87	Escalante	Tri-State G & T Assn, Inc	NM	$2,363,818	$0	$0	$0	$2,363,818
307	2324	Reid Gardner	Nevada Power Co	NV	$1,227,499	$0	$0	$0	$1,227,499
308	8224	North Valmy	Sierra Pacific Power Co	NV	$4,100,706	$0	$0	$0	$4,100,706
309	2535	AES Cayuga	AES Cayuga LLC	NY	$0	$0	$0	$0	$0
310	2527	AES Greenidge LLC	AES Greenidge	NY	$0	$0	$0	$0	$0
311	6082	AES Somerset LLC	AES Somerset LLC	NY	$0	$0	$0	$0	$0
312	2526	AES Westover	AES Westover LLC	NY	$0	$0	$0	$0	$0
313	10464	Black River Generation	Black River Generation LLC	NY	$0	$0	$0	$0	$0
314	2554	Dunkirk Generating Plant	Dunkirk Power LLC	NY	$0	$0	$0	$0	$0
315	2480	Danskammer Generating Station	Dynegy Northeast Gen Inc	NY	$0	$0	$0	$0	$0
316	2682	S A Carlson	Jamestown Board of Public Util	NY	$0	$0	$0	$0	$0
317	2629	Lovett	Mirant New York Inc	NY	$0	$0	$0	$0	$0
318	50202	WPS Power Niagara	Niagara Generation LLC	NY	$0	$0	$0	$0	$0
319	2549	C R Huntley Generating Station	NRG Huntley Operations Inc	NY	$0	$0	$0	$0	$0
320	2642	Rochester 7	Rochester Gas & Electric Corp	NY	$0	$0	$0	$0	$0
321	50651	Trigen Syracuse Energy	Syracuse Energy Corp	NY	$0	$0	$0	$0	$0
322	7286	Richard Gorsuch	American Mun Power-Ohio, Inc	OH	$0	$0	$0	$0	$0
323	2828	Cardinal	Cardinal Operating Co	OH	$1,908,733	$0	$0	$0	$1,908,733

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324	2914	Dover	City of Dover	OH	$0	$0	$0	$0	$0
325	2917	Hamilton	City of Hamilton	OH	$0	$0	$0	$0	$0
326	2935	Orrville	City of Orrville	OH	$0	$0	$0	$0	$0
327	2936	Painesville	City of Painesville	OH	$0	$0	$0	$0	$0
328	2943	Shelby Municipal Light Plant	City of Shelby	OH	$0	$0	$0	$0	$0
329	2840	Conesville	Columbus Southern Power Co	OH	$4,096,257	$0	$0	$0	$4,096,257
330	2843	Picway	Columbus Southern Power Co	OH	$263,719	$0	$0	$0	$263,719
331	2850	J M Stuart	Dayton Power & Light Co	OH	$4,502,661	$0	$0	$0	$4,502,661
332	6031	Killen Station	Dayton Power & Light Co	OH	$5,089,636	$0	$0	$0	$5,089,636
333	2848	O H Hutchings	Dayton Power & Light Co	OH	$0	$0	$0	$0	$0
334	2832	Miami Fort	Duke Energy Ohio Inc	OH	$5,184,010	$0	$0	$0	$5,184,010
335	6019	W H Zimmer	Duke Energy Ohio Inc	OH	$0	$0	$0	$0	$0
336	2830	Walter C Beckjord	Duke Energy Ohio Inc	OH	$602,548	$0	$0	$0	$602,548
337	2835	Ashtabula	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
338	2878	Bay Shore	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
339	2837	Eastlake	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
340	2838	Lake Shore	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
341	2864	R E Burger	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
342	2866	W H Sammis	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
343	8102	General James M Gavin	Ohio Power Co	OH	$560,716	$0	$0	$0	$560,716
344	2872	Muskingum River	Ohio Power Co	OH	$1,639,338	$0	$0	$0	$1,639,338
345	2876	Kyger Creek	Ohio Valley Electric Corp	OH	$2,260,712	$0	$0	$0	$2,260,712
346	2836	Avon Lake	Orion Power Midwest LP	OH	$0	$0	$0	$0	$0
347	2861	Niles	Orion Power Midwest LP	OH	$0	$0	$0	$0	$0
348	10671	AES Shady Point LLC	AES Shady Point LLC	OK	$0	$0	$0	$0	$0
349	165	GRDA	Grand River Dam Authority	OK	$2,113,731	$0	$0	$0	$2,113,731
350	2952	Muskogee	Oklahoma Gas & Electric Co	OK	$0	$0	$0	$0	$0
351	6095	Sooner	Oklahoma Gas & Electric Co	OK	$0	$0	$0	$0	$0
352	2963	Northeastern	Public Service Co of Oklahoma	OK	$0	$0	$0	$0	$0
353	6772	Hugo	Western Farmers Elec Coop, Inc	OK	$5,176	$0	$0	$0	$5,176
354	6106	Boardman	Portland General Electric Co	OR	$804,138	$0	$0	$0	$804,138
355	10676	AES Beaver Valley Partners Beaver Valley	AES Beaver Valley	PA	$0	$0	$0	$0	$0
356	3178	Armstrong Power Station	Allegheny Energy Supply Co LLC	PA	$47,979	$0	$0	$0	$47,979
357	3179	Hatfields Ferry Power Station	Allegheny Energy Supply Co LLC	PA	$81,306	$0	$0	$0	$81,306
358	3181	Mitchell Power Station	Allegheny Energy Supply Co LLC	PA	$12,238	$0	$0	$0	$12,238
359	10641	Cambria Cogen	Cambria CoGen Co	PA	$575,691	$0	$0	$0	$575,691
360	54144	Piney Creek Project	Colmac Clarion Inc	PA	$131,965	$0	$0	$0	$131,965
361	10603	Ebensburg Power	Ebensburg Power Co	PA	$408,971	$0	$0	$0	$408,971
362	3159	Cromby Generating Station	Exelon Power	PA	$0	$0	$0	$0	$0
363	3161	Eddystone Generating Station	Exelon Power	PA	$0	$0	$0	$0	$0
364	6094	Bruce Mansfield	FirstEnergy Generation Corp	PA	$31,576,164	$0	$0	$0	$31,576,164

Exhibit J2
Cost for Hybrid C & D Without Land Treatment Sub-Option

Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
365	10113	John B Rich Memorial Power Station	Gilberton Power Co	PA	$531,011	$0	$0	$0	$531,011
366	10143	Colver Power Project	Inter-Power/AhlCon Partners, L.P.	PA	$0	$0	$0	$0	$0
367	3122	Homer City Station	Midwest Generations EME LLC	PA	$409,404	$0	$0	$0	$409,404
368	10343	Foster Wheeler Mt Carmel Cogen	Mount Carmel Cogen Inc	PA	$577,903	$0	$0	$0	$577,903
369	50039	Kline Township Cogen Facility	Northeastern Power Co	PA	$427,999	$0	$0	$0	$427,999
370	8226	Cheswick Power Plant	Orion Power Midwest LP	PA	$26,060	$0	$0	$0	$26,060
371	3098	Elrama Power Plant	Orion Power Midwest LP	PA	$0	$0	$0	$0	$0
372	3138	New Castle Plant	Orion Power Midwest LP	PA	$21,817	$0	$0	$0	$21,817
373	50776	Panther Creek Energy Facility	Panther Creek Partners	PA	$352,069	$0	$0	$0	$352,069
374	3140	PPL Brunner Island	PPL Brunner Island LLC	PA	$0	$0	$0	$0	$0
375	3149	PPL Montour	PPL Montour LLC	PA	$0	$0	$0	$0	$0
376	3113	Portland	Reliant Energy Mid-Atlantic PH LLC	PA	$18,795	$0	$0	$0	$18,795
377	3131	Shawville	Reliant Energy Mid-Atlantic PH LLC	PA	$260,051	$0	$0	$0	$260,051
378	3115	Titus	Reliant Energy Mid-Atlantic PH LLC	PA	$0	$0	$0	$0	$0
379	3130	Seward	Reliant Energy Seward LLC	PA	$2,028,597	$0	$0	$0	$2,028,597
380	3118	Conemaugh	Reliant Engy NE Management Co	PA	$1,147,480	$0	$0	$0	$1,147,480
381	3136	Keystone	Reliant Engy NE Management Co	PA	$138,956	$0	$0	$0	$138,956
382	54634	St Nicholas Cogen Project	Schuylkill Energy Resource Inc	PA	$1,265,354	$0	$0	$0	$1,265,354
383	3152	Sunbury Generation LP	Sunbury Generation LP	PA	$213,734	$0	$0	$0	$213,734
384	3176	Hunlock Power Station	UGI Development Co	PA	$53,837	$0	$0	$0	$53,837
385	50888	Northampton Generating Company LP	US Operating Services Company	PA	$185,536	$0	$0	$0	$185,536
386	50974	Scrubgrass Generating Company LP	US Operating Services Company	PA	$343,212	$0	$0	$0	$343,212
387	50879	Wheelabrator Frackville Energy	Wheelabrator Environmental Systems	PA	$519,929	$0	$0	$0	$519,929
388	50611	WPS Westwood Generation LLC	WPS Power Developement	PA	$501,426	$0	$0	$0	$501,426
389	3264	W S Lee	Duke Energy Carolinas, LLC	SC	$40,159	$0	$0	$0	$40,159
390	3251	H B Robinson	Progress Energy Carolinas Inc	SC	$310,021	$0	$0	$0	$310,021
391	7652	US DOE Savannah River Site (D Area)	Savannah River Nuclear Solutions LLC	SC	$0	$0	$0	$0	$0
392	3280	Canadys Steam	South Carolina Electric&Gas Co	SC	$454,979	$0	$0	$0	$454,979
393	7737	Cogen South	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0
394	7210	Cope	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0
395	3287	McMeekin	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0
396	3295	Urquhart	South Carolina Electric&Gas Co	SC	$140,198	$0	$0	$0	$140,198
397	3297	Wateree	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0
398	3298	Williams	South Carolina Genertg Co, Inc	SC	$0	$0	$0	$0	$0
399	130	Cross	South Carolina Pub Serv Auth	SC	$281,014	$0	$0	$0	$281,014
400	3317	Dolphus M Grainger	South Carolina Pub Serv Auth	SC	$58,811	$0	$0	$0	$58,811

Exhibit J2 Cost for Hybrid C & D Without Land Treatment Sub-Option										
Plant Identity					Hybrid C & D					
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
401	3319	Jefferies	South Carolina Pub Serv Auth	SC	$104,158	$0	$0	$0	$104,158
402	6249	Winyah	South Carolina Pub Serv Auth	SC	$405,228	$0	$0	$0	$405,228
403	3325	Ben French	Black Hills Power Inc	SD	$122,453	$0	$0	$0	$122,453
404	6098	Big Stone	Otter Tail Power Co	SD	$206,353	$0	$0	$0	$206,353
405	3393	Allen Steam Plant	Tennessee Valley Authority	TN	$11,407	$0	$0	$0	$11,407
406	3396	Bull Run	Tennessee Valley Authority	TN	$12,085	$0	$0	$0	$12,085
407	3399	Cumberland	Tennessee Valley Authority	TN	$0	$0	$0	$0	$0
408	3403	Gallatin	Tennessee Valley Authority	TN	$12,341	$0	$0	$0	$12,341
409	3405	John Sevier	Tennessee Valley Authority	TN	$8,750	$0	$0	$0	$8,750
410	3406	Johnsonville	Tennessee Valley Authority	TN	$10,024	$0	$0	$0	$10,024
411	3407	Kingston	Tennessee Valley Authority	TN	$2,926	$0	$0	$0	$2,926
412	7030	Twin Oaks Power One	Altura Power	TX	$173,085	$0	$0	$0	$173,085
413	6178	Coleto Creek	ANP-Coleto Creek	TX	$918,886	$0	$0	$0	$918,886
414	6179	Fayette Power Project	Lower Colorado River Authority	TX	$202,097	$0	$0	$0	$202,097
415	54972	Norit Americas Marshall Plant	Norit Americas Inc	TX	$2,577	$0	$0	$0	$2,577
416	298	Limestone	NRG Texas LLC	TX	$574,309	$0	$0	$0	$574,309
417	3470	W A Parish	NRG Texas LLC	TX	$63,690	$0	$0	$0	$63,690
418	127	Oklaunion	Public Service Co of Oklahoma	TX	$633,518	$0	$0	$0	$633,518
419	7097	J K Spruce	San Antonio City of	TX	$80,280	$0	$0	$0	$80,280
420	6181	J T Deely	San Antonio City of	TX	$43,290	$0	$0	$0	$43,290
421	6183	San Miguel	San Miguel Electric Coop, Inc	TX	$0	$0	$0	$0	$0
422	7902	Pirkey	Southwestern Electric Power Co	TX	$2,310,447	$0	$0	$0	$2,310,447
423	6139	Welsh	Southwestern Electric Power Co	TX	$50,825	$0	$0	$0	$50,825
424	6193	Harrington	Southwestern Public Service Co	TX	$0	$0	$0	$0	$0
425	6194	Tolk	Southwestern Public Service Co	TX	$0	$0	$0	$0	$0
426	6136	Gibbons Creek	Texas Municipal Power Agency	TX	$61,302	$0	$0	$0	$61,302
427	3497	Big Brown	TXU Generation Co LP	TX	$104,659	$0	$0	$0	$104,659
428	6146	Martin Lake	TXU Generation Co LP	TX	$395,342	$0	$0	$0	$395,342
429	6147	Monticello	TXU Generation Co LP	TX	$194,031	$0	$0	$0	$194,031
430	6648	Sandow No 4	TXU Generation Co LP	TX	$1,912,648	$0	$0	$0	$1,912,648
431	7790	Bonanza	Deseret Generation & Tran Coop	UT	$1,373,308	$0	$0	$0	$1,373,308
432	6481	Intermountain Power Project	Los Angeles City of	UT	$2,060,078	$0	$0	$0	$2,060,078
433	3644	Carbon	PacifiCorp	UT	$164,344	$0	$0	$0	$164,344
434	6165	Hunter	PacifiCorp	UT	$2,216,423	$0	$0	$0	$2,216,423
435	8069	Huntington	PacifiCorp	UT	$3,166,567	$0	$0	$0	$3,166,567
436	50951	Sunnyside Cogen Associates	Sunnyside Cogeneration Assoc	UT	$1,030,311	$0	$0	$0	$1,030,311
437	3775	Clinch River	Appalachian Power Co	VA	$0	$0	$0	$0	$0
438	3776	Glen Lyn	Appalachian Power Co	VA	$280,286	$0	$0	$0	$280,286
439	54304	Birchwood Power	Birchwood Power Partners LP	VA	$0	$0	$0	$0	$0
440	10071	Cogentrix Virginia Leasing Corporation	Cogentrix-Virginia Leas'g Corp	VA	$0	$0	$0	$0	$0
441	10377	James River Cogeneration	James River Cogeneration Co	VA	$0	$0	$0	$0	$0

Exhibit J2 Cost for Hybrid C & D Without Land Treatment Sub-Option									
Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
442	3788	Potomac River	Mirant Potomac River LLC	VA	$0	$0	$0	$0	$0
443	54081	Spruance Genco LLC	Spruance Operating Services LLC	VA	$0	$0	$0	$0	$0
444	10773	Altavista Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
445	3796	Bremo Bluff	Virginia Electric & Power Co	VA	$1,018,461	$0	$0	$0	$1,018,461
446	3803	Chesapeake	Virginia Electric & Power Co	VA	$439,125	$0	$0	$0	$439,125
447	3797	Chesterfield	Virginia Electric & Power Co	VA	$3,078,604	$0	$0	$0	$3,078,604
448	7213	Clover	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
449	10771	Hopewell Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
450	52007	Mecklenburg Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
451	10774	Southampton Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
452	3809	Yorktown	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
453	3845	Transalta Centralia Generation	TransAlta Centralia Gen LLC	WA	$0	$0	$0	$0	$0
454	4127	Menasha	City of Menasha	WI	$210,173	$0	$0	$0	$210,173
455	4140	Alma	Dairyland Power Coop	WI	$34,342	$0	$0	$0	$34,342
456	4143	Genoa	Dairyland Power Coop	WI	$0	$0	$0	$0	$0
457	4271	John P Madgett	Dairyland Power Coop	WI	$755,038	$0	$0	$0	$755,038
458	3992	Blount Street	Madison Gas & Electric Co	WI	$0	$0	$0	$0	$0
459	4125	Manitowoc	Manitowoc Public Utilities	WI	$378,986	$0	$0	$0	$378,986
460	4146	E J Stoneman Station	Mid-America Power LLC	WI	$154,741	$0	$0	$0	$154,741
461	3982	Bay Front	Northern States Power Co	WI	$0	$0	$0	$0	$0
462	7549	Milwaukee County	Wisconsin Electric Power Co	WI	$213,434	$0	$0	$0	$213,434
463	6170	Pleasant Prairie	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0
464	4041	South Oak Creek	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0
465	4042	Valley	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0
466	8023	Columbia	Wisconsin Power & Light Co	WI	$1,902,327	$0	$0	$0	$1,902,327
467	4050	Edgewater	Wisconsin Power & Light Co	WI	$10,829	$0	$0	$0	$10,829
468	4054	Nelson Dewey	Wisconsin Power & Light Co	WI	$0	$0	$0	$0	$0
469	4072	Pulliam	Wisconsin Public Service Corp	WI	$0	$0	$0	$0	$0
470	4078	Weston	Wisconsin Public Service Corp	WI	$0	$0	$0	$0	$0
471	3944	Harrison Power Station	Allegheny Energy Supply Co LLC	WV	$1,353,689	$0	$0	$0	$1,353,689
472	6004	Pleasants Power Station	Allegheny Energy Supply Co LLC	WV	$5,191,107	$0	$0	$0	$5,191,107
473	10151	Grant Town Power Plant	American Bituminous Power LP	WV	$712,495	$0	$0	$0	$712,495
474	3935	John E Amos	Appalachian Power Co	WV	$8,682,363	$0	$0	$0	$8,682,363
475	3936	Kanawha River	Appalachian Power Co	WV	$74,883	$0	$0	$0	$74,883
476	6264	Mountaineer	Appalachian Power Co	WV	$2,205,440	$0	$0	$0	$2,205,440
477	3938	Philip Sporn	Appalachian Power Co	WV	$2,980,904	$0	$0	$0	$2,980,904
478	3942	Albright	Monongahela Power Co	WV	$724,724	$0	$0	$0	$724,724
479	3943	Fort Martin Power Station	Monongahela Power Co	WV	$22,421	$0	$0	$0	$22,421
480	3945	Rivesville	Monongahela Power Co	WV	$398,109	$0	$0	$0	$398,109
481	3946	Willow Island	Monongahela Power Co	WV	$273,152	$0	$0	$0	$273,152
482	10743	Morgantown Energy Facility	Morgantown Energy Associates	WV	$525,644	$0	$0	$0	$525,644
483	3947	Kammer	Ohio Power Co	WV	$384,799	$0	$0	$0	$384,799

Exhibit J2 Cost for Hybrid C & D Without Land Treatment Sub-Option									
Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
484	3948	Mitchell	Ohio Power Co	WV	$24,891,903	$0	$0	$0	$24,891,903
485	3954	Mt Storm	Virginia Electric & Power Co	WV	$5,274,020	$0	$0	$0	$5,274,020
486	7537	North Branch	Virginia Electric & Power Co	WV	$1,997,621	$0	$0	$0	$1,997,621
487	6204	Laramie River Station	Basin Electric Power Coop	WY	$2,175,396	$0	$0	$0	$2,175,396
488	4150	Neil Simpson	Black Hills Power Inc	WY	$0	$0	$0	$0	$0
489	7504	Neil Simpson II	Black Hills Power Inc	WY	$694,687	$0	$0	$0	$694,687
490	4151	Osage	Black Hills Power Inc	WY	$157,298	$0	$0	$0	$157,298
491	55479	Wygen 1	Black Hills Power Inc	WY	$0	$0	$0	$0	$0
492	4158	Dave Johnston	PacifiCorp	WY	$186,078	$0	$0	$0	$186,078
493	8066	Jim Bridger	PacifiCorp	WY	$5,994,812	$0	$0	$0	$5,994,812
494	4162	Naughton	PacifiCorp	WY	$868,633	$0	$0	$0	$868,633
495	6101	Wyodak	PacifiCorp	WY	$340,716	$0	$0	$0	$340,716
			Total Costs:		$500,000,000	$0	$0	$0	$500,000,000

Exhibit J3 Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option														
Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
1	79	Aurora Energy LLC Chena	Aurora Energy LLC	AK	$591,115	$0	$0	$0	$591,115	$558,212	$0	$0	$0	$558,212
2	6288	Healy	Golden Valley Elec Assn Inc	AK	$413,908	$0	$0	$0	$413,908	$390,869	$0	$0	$0	$390,869
3	56	Charles R Lowman	Alabama Electric Coop Inc	AL	$259,869	$548,026	$0	$2,480,418	$3,288,313	$245,404	$0	$0	$2,480,418	$2,725,822
4	3	Barry	Alabama Power Co	AL	$4,378,685	$0	$0	$21,199,709	$25,578,394	$4,134,958	$0	$0	$21,199,709	$25,334,667
5	26	E C Gaston	Alabama Power Co	AL	$413,334	$0	$0	$0	$413,334	$390,327	$0	$0	$0	$390,327
6	7	Gadsden	Alabama Power Co	AL	$286,057	$0	$0	$2,555,356	$2,841,412	$270,134	$0	$0	$2,555,356	$2,825,490
7	8	Gorgas	Alabama Power Co	AL	$5,528,503	$0	$0	$22,848,326	$28,376,829	$5,220,774	$0	$0	$22,848,326	$28,069,100
8	10	Greene County	Alabama Power Co	AL	$5,692,168	$0	$0	$15,879,174	$21,571,342	$5,375,329	$0	$0	$15,879,174	$21,254,504
9	6002	James H Miller Jr	Alabama Power Co	AL	$2,347,384	$0	$0	$4,608,632	$6,956,016	$2,216,723	$0	$0	$4,608,632	$6,825,356
10	50407	Mobile Energy Services LLC	DTE Energy Services	AL	$12,105	$49,358	$0	$0	$61,463	$11,431	$0	$0	$0	$11,431
11	47	Colbert	Tennessee Valley Authority	AL	$779,441	$2,049	$0	$2,188,164	$2,969,653	$736,055	$0	$0	$2,188,164	$2,924,219
12	50	Widows Creek	Tennessee Valley Authority	AL	$2,414,692	$512	$0	$63,906,370	$66,321,573	$2,280,285	$0	$0	$63,906,370	$66,186,654
13	6641	Independence	Entergy Arkansas Inc	AR	$2,599,094	$0	$0	$0	$2,599,094	$2,454,422	$0	$0	$0	$2,454,422
14	6009	White Bluff	Entergy Arkansas Inc	AR	$3,239,418	$0	$0	$0	$3,239,418	$3,059,105	$0	$0	$0	$3,059,105
15	6138	Flint Creek	Southwestern Electric Power Co	AR	$446,835	$0	$0	$1,453,780	$1,900,615	$421,963	$0	$0	$1,453,780	$1,875,743
16	160	Apache Station	Arizona Electric Pwr Coop Inc	AZ	$5,390,167	$0	$0	$2,472,925	$7,863,092	$5,090,139	$0	$0	$2,472,925	$7,563,064
17	113	Cholla	Arizona Public Service Co	AZ	$1,615,591	$0	$0	$22,331,260	$23,946,851	$1,525,664	$0	$0	$22,331,260	$23,856,923
18	6177	Coronado	Salt River Project	AZ	$3,530,886	$0	$0	$4,263,922	$7,794,807	$3,334,349	$0	$0	$4,263,922	$7,598,271
19	4941	Navajo	Salt River Project	AZ	$16,621,306	$0	$0	$0	$16,621,306	$15,696,128	$0	$0	$0	$15,696,128
20	126	H Wilson Sundt Generating Station	Tucson Electric Power Co	AZ	$130,706	$33,291	$0	$0	$163,997	$123,431	$0	$0	$0	$123,431
21	8223	Springerville	Tucson Electric Power Co	AZ	$12,531,134	$0	$0	$0	$12,531,134	$11,833,624	$0	$0	$0	$11,833,624
22	10002	ACE Cogeneration Facility	ACE Cogeneration Co	CA	$0	$2,049	$0	$0	$2,049	$0	$0	$0	$0	$0
23	10640	Stockton Cogen	Air Products Energy Enterprise	CA	$1,266,176	$0	$0	$0	$1,266,176	$1,195,698	$0	$0	$0	$1,195,698

Exhibit J3
Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
24	54238	Port of Stockton District Energy Fac	FPL Energy Operating Servs Inc	CA	$537,621	$0	$0	$0	$537,621	$507,696	$0	$0	$0	$507,696
25	54626	Mt Poso Cogeneration	Mt Poso Cogeneration Co	CA	$566,514	$0	$0	$0	$566,514	$534,981	$0	$0	$0	$534,981
26	10768	Rio Bravo Jasmin	Rio Bravo Jasmin	CA	$326,459	$0	$0	$0	$326,459	$308,288	$0	$0	$0	$308,288
27	10769	Rio Bravo Poso	Rio Bravo Poso	CA	$319,852	$0	$0	$0	$319,852	$302,048	$0	$0	$0	$302,048
28	462	W N Clark	Aquila, Inc.	CO	$0	$106,947	$0	$0	$106,947	$0	$0	$0	$0	$0
29	10003	Colorado Energy Nations Company	Colorado Energy Nations Company LLLP	CO	$0	$133,647	$0	$0	$133,647	$0	$0	$0	$0	$0
30	492	Martin Drake	Colorado Springs City of	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	8219	Ray D Nixon	Colorado Springs City of	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	6761	Rawhide	Platte River Power Authority	CO	$268,977	$0	$0	$427,142	$696,118	$254,005	$0	$0	$427,142	$681,147
33	465	Arapahoe	Public Service Co of Colorado	CO	$0	$193,602	$0	$0	$193,602	$0	$0	$0	$0	$0
34	468	Cameo	Public Service Co of Colorado	CO	$0	$171,517	$0	$0	$171,517	$0	$0	$0	$0	$0
35	469	Cherokee	Public Service Co of Colorado	CO	$0	$1,449,452	$0	$0	$1,449,452	$0	$0	$0	$0	$0
36	470	Comanche	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	525	Hayden	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
38	6248	Pawnee	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
39	477	Valmont	Public Service Co of Colorado	CO	$0	$19,975	$0	$0	$19,975	$0	$0	$0	$0	$0
40	6021	Craig	Tri-State G & T Assn, Inc	CO	$0	$2,116,302	$0	$0	$2,116,302	$0	$0	$0	$0	$0
41	527	Nucla	Tri-State G & T Assn, Inc	CO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	10675	AES Thames	AES Thames LLC	CT	$0	$764,061	$0	$0	$764,061	$0	$0	$0	$0	$0
43	568	Bridgeport Station	PSEG Power Connecticut LLC	CT	$0	$118,312	$0	$0	$118,312	$0	$0	$0	$0	$0
44	593	Edge Moor	Conectiv Delmarva Gen Inc	DE	$0	$382,082	$0	$0	$382,082	$0	$0	$0	$0	$0
45	594	Indian River Generating	Indian River Operations Inc	DE	$2,069,032	$0	$0	$0	$2,069,032	$1,953,865	$0	$0	$0	$1,953,865

Exhibit J3
Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
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		Station												
46	10030	NRG Energy Center Dover	NRG Energy Center Dover LLC	DE	$303,134	$0	$0	$0	$303,134	$286,261	$0	$0	$0	$286,261
47	10333	Central Power & Lime	Central Power & Lime Inc	FL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
48	676	C D McIntosh Jr	City of Lakeland	FL	$966,487	$0	$0	$0	$966,487	$912,690	$0	$0	$0	$912,690
49	663	Deerhaven Generating Station	Gainesville Regional Utilities	FL	$67,978	$0	$0	$0	$67,978	$64,194	$0	$0	$0	$64,194
50	641	Crist	Gulf Power Co	FL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	643	Lansing Smith	Gulf Power Co	FL	$318,500	$0	$0	$5,268,079	$5,586,579	$300,771	$0	$0	$5,268,079	$5,568,850
52	642	Scholz	Gulf Power Co	FL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
53	667	Northside Generating Station	JEA	FL	$2,919,534	$0	$0	$0	$2,919,534	$2,757,027	$0	$0	$0	$2,757,027
54	207	St Johns River Power Park	JEA	FL	$1,994,615	$0	$0	$0	$1,994,615	$1,883,591	$0	$0	$0	$1,883,591
55	564	Stanton Energy Center	Orlando Utilities Comm	FL	$2,261,748	$0	$0	$0	$2,261,748	$2,135,854	$0	$0	$0	$2,135,854
56	628	Crystal River	Progress Energy Florida Inc	FL	$311,466	$0	$0	$0	$311,466	$294,129	$0	$0	$0	$294,129
57	136	Seminole	Seminole Electric Coop, Inc	FL	$3,165,825	$5,122	$0	$0	$3,170,947	$2,989,608	$0	$0	$0	$2,989,608
58	645	Big Bend	Tampa Electric Co	FL	$43,365	$0	$0	$277,267	$320,632	$40,951	$0	$0	$277,267	$318,219
59	7242	Polk	Tampa Electric Co	FL	$966,156	$0	$0	$0	$966,156	$912,377	$0	$0	$0	$912,377
60	10672	Cedar Bay Generating Company LP	US Operating Services Company	FL	$0	$1,229,217	$0	$0	$1,229,217	$0	$0	$0	$0	$0
61	50976	Indiantown Cogeneration LP	US Operating Services Company	FL	$0	$1,049,956	$0	$0	$1,049,956	$0	$0	$0	$0	$0
62	753	Crisp Plant	Crisp County Power Comm	GA	$9,664	$563	$0	$0	$10,227	$9,126	$0	$0	$0	$9,126
63	703	Bowen	Georgia Power Co	GA	$10,245,803	$0	$0	$6,991,633	$17,237,436	$9,675,500	$0	$0	$6,991,633	$16,667,132
64	708	Hammond	Georgia Power Co	GA	$484,420	$0	$0	$0	$484,420	$457,456	$0	$0	$0	$457,456
65	709	Harllee Branch	Georgia Power Co	GA	$1,311,079	$0	$0	$31,196,320	$32,507,399	$1,238,102	$0	$0	$31,196,320	$32,434,422
66	710	Jack McDonough	Georgia Power Co	GA	$142,177	$0	$0	$0	$142,177	$134,263	$0	$0	$0	$134,263
67	733	Kraft	Georgia Power Co	GA	$213,517	$204,870	$0	$749,371	$1,167,757	$201,632	$0	$0	$749,371	$951,003
68	6124	McIntosh	Georgia Power Co	GA	$453,669	$0	$0	$1,124,057	$1,577,725	$428,417	$0	$0	$1,124,057	$1,552,473
69	727	Mitchell	Georgia Power Co	GA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
70	6257	Scherer	Georgia Power Co	GA	$4,037,865	$0	$0	$35,265,405	$39,303,270	$3,813,108	$0	$0	$35,265,405	$39,078,514
71	6052	Wansley	Georgia Power Co	GA	$2,740,389	$0	$0	$40,218,748	$42,959,138	$2,587,853	$0	$0	$40,218,748	$42,806,602
72	728	Yates	Georgia Power Co	GA	$612,666	$0	$0	$0	$612,666	$578,563	$0	$0	$0	$578,563

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Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
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73	10673	AES Hawaii	AES Hawaii Inc	HI	$0	$263,770	$0	$0	$263,770	$0	$0	$0	$0	$0
74	10604	Hawaiian Comm & Sugar Puunene Mill	Hawaiian Com & Sugar Co Ltd	HI	$747,673	$0	$0	$0	$747,673	$706,056	$0	$0	$0	$706,056
75	1122	Ames Electric Services Power Plant	Ames City of	IA	$20,521	$0	$0	$0	$20,521	$19,379	$0	$0	$0	$19,379
76	1167	Muscatine Plant #1	Board of Water Electric & Communications	IA	$6,366	$0	$0	$0	$6,366	$6,012	$0	$0	$0	$6,012
77	1131	Streeter Station	Cedar Falls Utilities	IA	$3,526	$0	$0	$0	$3,526	$3,330	$0	$0	$0	$3,330
78	1218	Fair Station	Central Iowa Power Cooperative	IA	$67,091	$0	$0	$0	$67,091	$63,356	$0	$0	$0	$63,356
79	1217	Earl F Wisdom	Corn Belt Power Coop	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
80	1104	Burlington	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
81	1046	Dubuque	Interstate Power and Light Co	IA	$25,247	$0	$0	$0	$25,247	$23,842	$0	$0	$0	$23,842
82	1047	Lansing	Interstate Power and Light Co	IA	$345,083	$23,048	$0	$1,798,491	$2,166,621	$325,875	$0	$0	$1,798,491	$2,124,365
83	1048	Milton L Kapp	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
84	6254	Ottumwa	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
85	1073	Prairie Creek	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
86	1058	Sixth Street	Interstate Power and Light Co	IA	$38,522	$0	$0	$0	$38,522	$36,378	$0	$0	$0	$36,378
87	1077	Sutherland	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
88	1091	George Neal North	MidAmerican Energy Co	IA	$3,026,631	$0	$0	$3,761,843	$6,788,474	$2,858,162	$0	$0	$3,761,843	$6,620,005
89	7343	George Neal South	MidAmerican Energy Co	IA	$191,715	$0	$0	$0	$191,715	$181,043	$0	$0	$0	$181,043
90	6664	Louisa	MidAmerican Energy Co	IA	$2,085,220	$0	$0	$1,723,554	$3,808,773	$1,969,152	$0	$0	$1,723,554	$3,692,705
91	1081	Riverside	MidAmerican Energy Co	IA	$0	$94,240	$0	$0	$94,240	$0	$0	$0	$0	$0
92	1082	Walter Scott Jr Energy Center	MidAmerican Energy Co	IA	$3,645,385	$0	$0	$7,830,928	$11,476,314	$3,442,475	$0	$0	$7,830,928	$11,273,403
93	1175	Pella	Pella City of	IA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
94	861	Coffeen	Ameren Energy	IL	$0	$491,687	$0	$0	$491,687	$0	$0	$0	$0	$0

Exhibit J3
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			Generating Co											
95	863	Hutsonville	Ameren Energy Generating Co	IL	$423,723	$0	$0	$2,323,050	$2,746,773	$400,137	$0	$0	$2,323,050	$2,723,188
96	864	Meredosia	Ameren Energy Generating Co	IL	$938,878	$0	$0	$3,596,981	$4,535,860	$886,618	$0	$0	$3,596,981	$4,483,600
97	6017	Newton	Ameren Energy Generating Co	IL	$1,230,014	$0	$0	$8,168,145	$9,398,160	$1,161,549	$0	$0	$8,168,145	$9,329,694
98	6016	Duck Creek	Ameren Energy Resources Generating Co.	IL	$5,697,004	$0	$0	$13,863,366	$19,560,370	$5,379,897	$0	$0	$13,863,366	$19,243,263
99	856	E D Edwards	Ameren Energy Resources Generating Co.	IL	$385,602	$537,783	$0	$3,896,730	$4,820,115	$364,139	$0	$0	$3,896,730	$4,260,869
100	963	Dallman	City of Springfield	IL	$917,434	$0	$0	$5,402,966	$6,320,400	$866,367	$0	$0	$5,402,966	$6,269,333
101	964	Lakeside	City of Springfield	IL	$0	$58,961	$0	$0	$58,961	$0	$0	$0	$0	$0
102	876	Kincaid Generation LLC	Dominion Energy Services Co	IL	$0	$407,178	$0	$0	$407,178	$0	$0	$0	$0	$0
103	889	Baldwin Energy Complex	Dynegy Midwest Generation Inc	IL	$3,094,926	$0	$0	$8,692,705	$11,787,632	$2,922,656	$0	$0	$8,692,705	$11,615,361
104	891	Havana	Dynegy Midwest Generation Inc	IL	$1,411,644	$0	$0	$6,444,592	$7,856,235	$1,333,068	$0	$0	$6,444,592	$7,777,660
105	892	Hennepin Power Station	Dynegy Midwest Generation Inc	IL	$229,530	$0	$0	$1,558,692	$1,788,222	$216,754	$0	$0	$1,558,692	$1,775,446
106	897	Vermilion	Dynegy Midwest Generation Inc	IL	$148,092	$0	$0	$1,026,638	$1,174,731	$139,849	$0	$0	$1,026,638	$1,166,487
107	898	Wood River	Dynegy Midwest Generation Inc	IL	$291,864	$0	$0	$1,064,107	$1,355,971	$275,618	$0	$0	$1,064,107	$1,339,725
108	887	Joppa Steam	Electric Energy Inc	IL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
109	867	Crawford	Midwest Generations EME LLC	IL	$0	$97,313	$0	$0	$97,313	$0	$0	$0	$0	$0
110	886	Fisk Street	Midwest Generations EME LLC	IL	$0	$46,608	$0	$0	$46,608	$0	$0	$0	$0	$0
111	384	Joliet 29	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
112	874	Joliet 9	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
113	879	Powerton	Midwest Generations EME LLC	IL	$0	$649,436	$0	$0	$649,436	$0	$0	$0	$0	$0

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114	883	Waukegan	Midwest Generations EME LLC	IL	$0	$329,328	$0	$0	$329,328	$0	$0	$0	$0	$0
115	884	Will County	Midwest Generations EME LLC	IL	$0	$491,687	$0	$0	$491,687	$0	$0	$0	$0	$0
116	976	Marion	Southern Illinois Power Coop	IL	$0	$2,573,162	$0	$0	$2,573,162	$0	$0	$0	$0	$0
117	6238	Pearl Station	Soyland Power Coop Inc	IL	$181,857	$0	$0	$0	$181,857	$171,734	$0	$0	$0	$171,734
118	55245	Tuscola Station	Trigen-Cinergy Sol-Tuscola LLC	IL	$272,329	$0	$0	$0	$272,329	$257,171	$0	$0	$0	$257,171
119	6705	Warrick	AGC Division of APG Inc	IN	$4,723,116	$0	$0	$18,127,288	$22,850,403	$4,460,217	$0	$0	$18,127,288	$22,587,504
120	992	CC Perry K	Citizens Thermal Energy	IN	$8,378	$60,488	$0	$0	$68,865	$7,911	$0	$0	$0	$7,911
121	6225	Jasper 2	City of Jasper	IN	$6,866	$6,377	$0	$0	$13,243	$6,484	$0	$0	$0	$6,484
122	1032	Logansport	City of Logansport	IN	$12,288	$33,798	$0	$0	$46,086	$11,604	$0	$0	$0	$11,604
123	1040	Whitewater Valley	City of Richmond	IN	$61,216	$0	$0	$0	$61,216	$57,809	$0	$0	$0	$57,809
124	1024	Crawfordsville	Crawfordsville Elec, Lgt & Pwr	IN	$14,202	$10,382	$0	$0	$24,584	$13,412	$0	$0	$0	$13,412
125	1001	Cayuga	Duke Energy Indiana Inc	IN	$4,479,646	$0	$0	$15,804,237	$20,283,883	$4,230,299	$0	$0	$15,804,237	$20,034,536
126	1004	Edwardsport	Duke Energy Indiana Inc	IN	$325,746	$0	$0	$861,777	$1,187,523	$307,614	$0	$0	$861,777	$1,169,391
127	6113	Gibson	Duke Energy Indiana Inc	IN	$5,747,055	$0	$0	$67,278,540	$73,025,595	$5,427,162	$0	$0	$67,278,540	$72,705,702
128	1008	R Gallagher	Duke Energy Indiana Inc	IN	$1,001,584	$0	$0	$9,412,101	$10,413,685	$945,834	$0	$0	$9,412,101	$10,357,935
129	1010	Wabash River	Duke Energy Indiana Inc	IN	$7,170,015	$0	$0	$14,395,419	$21,565,435	$6,770,916	$0	$0	$14,395,419	$21,166,336
130	1043	Frank E Ratts	Hoosier Energy R E C, Inc	IN	$309,765	$0	$0	$2,982,497	$3,292,262	$292,523	$0	$0	$2,982,497	$3,275,020
131	6213	Merom	Hoosier Energy R E C, Inc	IN	$40,197	$0	$0	$0	$40,197	$37,960	$0	$0	$0	$37,960
132	6166	Rockport	Indiana Michigan Power Co	IN	$1,750,027	$0	$0	$884,258	$2,634,285	$1,652,617	$0	$0	$884,258	$2,536,875
133	988	Tanners Creek	Indiana Michigan Power Co	IN	$2,123,216	$0	$0	$10,536,158	$12,659,374	$2,005,033	$0	$0	$10,536,158	$12,541,191
134	983	Clifty Creek	Indiana-Kentucky Electric Corp	IN	$599,778	$6,658	$0	$1,626,135	$2,232,572	$566,393	$0	$0	$1,626,135	$2,192,528
135	994	AES Petersburg	Indianapolis Power	IN	$6,105	$3,568,315	$0	$0	$3,574,420	$5,765	$0	$0	$0	$5,765

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			& Light Co											
136	991	Eagle Valley	Indianapolis Power & Light Co	IN	$169,089	$0	$0	$0	$169,089	$159,677	$0	$0	$0	$159,677
137	990	Harding Street	Indianapolis Power & Light Co	IN	$1,041,055	$0	$0	$13,181,438	$14,222,493	$983,108	$0	$0	$13,181,438	$14,164,546
138	995	Bailly	Northern Indiana Pub Serv Co	IN	$617,121	$93,216	$0	$0	$710,336	$582,771	$0	$0	$0	$582,771
139	997	Michigan City	Northern Indiana Pub Serv Co	IN	$195,438	$0	$0	$0	$195,438	$184,559	$0	$0	$0	$184,559
140	6085	R M Schahfer	Northern Indiana Pub Serv Co	IN	$258,847	$0	$0	$187,343	$446,190	$244,439	$0	$0	$187,343	$431,782
141	1037	Peru	Peru City of	IN	$18,454	$9,665	$0	$0	$28,118	$17,426	$0	$0	$0	$17,426
142	6137	A B Brown	Southern Indiana Gas & Elec Co	IN	$1,671,692	$0	$0	$12,420,826	$14,092,518	$1,578,642	$0	$0	$12,420,826	$13,999,468
143	1012	F B Culley	Southern Indiana Gas & Elec Co	IN	$440,769	$581,830	$0	$2,667,761	$3,690,360	$416,235	$0	$0	$2,667,761	$3,083,996
144	981	State Line Energy	State Line Energy LLC	IN	$0	$102,435	$0	$0	$102,435	$0	$0	$0	$0	$0
145	1239	Riverton	Empire District Electric Co	KS	$87,419	$0	$0	$0	$87,419	$82,553	$0	$0	$0	$82,553
146	6064	Nearman Creek	Kansas City City of	KS	$345,968	$33,803	$0	$764,359	$1,144,130	$326,711	$0	$0	$764,359	$1,091,069
147	1295	Quindaro	Kansas City City of	KS	$0	$205,894	$0	$0	$205,894	$0	$0	$0	$0	$0
148	1241	La Cygne	Kansas City Power & Light Co	KS	$2,092,681	$0	$0	$0	$2,092,681	$1,976,197	$0	$0	$0	$1,976,197
149	108	Holcomb	Sunflower Electric Power Corp	KS	$939,036	$0	$0	$0	$939,036	$886,767	$0	$0	$0	$886,767
150	6068	Jeffrey Energy Center	Westar Energy Inc	KS	$5,139,666	$0	$0	$13,795,922	$18,935,588	$4,853,581	$0	$0	$13,795,922	$18,649,503
151	1250	Lawrence Energy Center	Westar Energy Inc	KS	$12,777	$0	$0	$0	$12,777	$12,066	$0	$0	$0	$12,066
152	1252	Tecumseh Energy Center	Westar Energy Inc	KS	$19,574	$0	$0	$0	$19,574	$18,484	$0	$0	$0	$18,484
153	1374	Elmer Smith	City of Owensboro	KY	$0	$989,520	$0	$0	$989,520	$0	$0	$0	$0	$0
154	6018	East Bend	Duke Energy Kentucky Inc	KY	$2,156,819	$0	$0	$12,956,627	$15,113,446	$2,036,766	$0	$0	$12,956,627	$14,993,393
155	1384	Cooper	East Kentucky Power Coop, Inc	KY	$221,475	$0	$0	$0	$221,475	$209,147	$0	$0	$0	$209,147
156	1385	Dale	East Kentucky Power Coop, Inc	KY	$946,558	$512	$0	$4,496,227	$5,443,297	$893,870	$0	$0	$4,496,227	$5,390,097
157	6041	H L Spurlock	East Kentucky Power Coop, Inc	KY	$8,470,552	$0	$0	$322,230	$8,792,782	$7,999,063	$0	$0	$322,230	$8,321,292
158	1372	Henderson I	Henderson City Utility Comm	KY	$11,335	$0	$0	$0	$11,335	$10,704	$0	$0	$0	$10,704

Exhibit J3
Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
159	1353	Big Sandy	Kentucky Power Co	KY	$5,925,754	$0	$0	$22,353,741	$28,279,495	$5,595,914	$0	$0	$22,353,741	$27,949,655
160	1355	E W Brown	Kentucky Utilities Co	KY	$332,892	$0	$0	$10,528,664	$10,861,556	$314,362	$0	$0	$10,528,664	$10,843,027
161	1356	Ghent	Kentucky Utilities Co	KY	$11,850,771	$0	$0	$47,562,585	$59,413,357	$11,191,131	$0	$0	$47,562,585	$58,753,717
162	1357	Green River	Kentucky Utilities Co	KY	$363,941	$0	$0	$2,293,076	$2,657,016	$343,683	$0	$0	$2,293,076	$2,636,759
163	1361	Tyrone	Kentucky Utilities Co	KY	$193,099	$0	$0	$1,416,311	$1,609,410	$182,351	$0	$0	$1,416,311	$1,598,662
164	1363	Cane Run	Louisville Gas & Electric Co	KY	$1,798,400	$0	$0	$2,780,167	$4,578,567	$1,698,297	$0	$0	$2,780,167	$4,478,464
165	1364	Mill Creek	Louisville Gas & Electric Co	KY	$5,472,515	$3,735,796	$0	$4,848,431	$14,056,743	$5,167,903	$0	$0	$4,848,431	$10,016,334
166	6071	Trimble County	Louisville Gas & Electric Co	KY	$216,810	$0	$0	$13,720,985	$13,937,795	$204,742	$0	$0	$13,720,985	$13,925,727
167	1378	Paradise	Tennessee Valley Authority	KY	$7,613,454	$16,390	$0	$41,792,428	$49,422,272	$7,189,673	$0	$0	$41,792,428	$48,982,101
168	1379	Shawnee	Tennessee Valley Authority	KY	$650,109	$5,122	$0	$4,578,658	$5,233,889	$613,923	$0	$0	$4,578,658	$5,192,580
169	6823	D B Wilson	Western Kentucky Energy Corp	KY	$6,395,337	$0	$0	$0	$6,395,337	$6,039,359	$0	$0	$0	$6,039,359
170	1382	HMP&L Station Two Henderson	Western Kentucky Energy Corp	KY	$6,253,316	$0	$0	$921,726	$7,175,043	$5,905,243	$0	$0	$921,726	$6,826,969
171	1381	Kenneth C Coleman	Western Kentucky Energy Corp	KY	$321,609	$0	$0	$0	$321,609	$303,708	$0	$0	$0	$303,708
172	6639	R D Green	Western Kentucky Energy Corp	KY	$6,990,611	$0	$0	$1,633,629	$8,624,240	$6,601,499	$0	$0	$1,633,629	$8,235,128
173	1383	Robert A Reid	Western Kentucky Energy Corp	KY	$37,535	$0	$0	$0	$37,535	$35,446	$0	$0	$0	$35,446
174	51	Dolet Hills	Cleco Power LLC	LA	$1,306,329	$0	$0	$3,889,236	$5,195,565	$1,233,616	$0	$0	$3,889,236	$5,122,852
175	6190	Rodemacher	Cleco Power LLC	LA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
176	1393	R S Nelson	Entergy Gulf States Louisiana LLC	LA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
177	6055	Big Cajun 2	Louisiana Generating LLC	LA	$145,914	$0	$0	$10,446,234	$10,592,147	$137,792	$0	$0	$10,446,234	$10,584,025
178	1619	Brayton Point	Dominion Energy New England, LLC	MA	$0	$291,939	$0	$0	$291,939	$0	$0	$0	$0	$0
179	1626	Salem Harbor	Dominion Energy New England, LLC	MA	$0	$360,570	$0	$0	$360,570	$0	$0	$0	$0	$0
180	1606	Mount Tom	FirstLight Power Resources Services LLC	MA	$0	$164,408	$0	$0	$164,408	$0	$0	$0	$0	$0
181	1613	Somerset Station	Somerset Power	MA	$0	$153,908	$0	$0	$153,908	$0	$0	$0	$0	$0

Exhibit J3
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			LLC											
182	10678	AES Warrior Run Cogeneration Facility	AES WR Ltd Partnership	MD	$0	$1,933,969	$0	$0	$1,933,969	$0	$0	$0	$0	$0
183	1570	R Paul Smith Power Station	Allegheny Energy Supply Co LLC	MD	$733,529	$0	$0	$1,880,922	$2,614,451	$692,699	$0	$0	$1,880,922	$2,573,621
184	602	Brandon Shores	Constellation Power Source Gen	MD	$0	$624,852	$0	$0	$624,852	$0	$0	$0	$0	$0
185	1552	C P Crane	Constellation Power Source Gen	MD	$0	$471,200	$0	$0	$471,200	$0	$0	$0	$0	$0
186	1554	Herbert A Wagner	Constellation Power Source Gen	MD	$0	$1,008,983	$0	$0	$1,008,983	$0	$0	$0	$0	$0
187	1571	Chalk Point LLC	Mirant Chalk Point LLC	MD	$721,532	$0	$0	$0	$721,532	$681,370	$0	$0	$0	$681,370
188	1572	Dickerson	Mirant Mid-Atlantic LLC	MD	$161,578	$0	$0	$0	$161,578	$152,585	$0	$0	$0	$152,585
189	1573	Morgantown Generating Plant	Mirant Mid-Atlantic LLC	MD	$103,241	$0	$0	$0	$103,241	$97,495	$0	$0	$0	$97,495
190	10495	Rumford Cogeneration	NewPage Corporation	ME	$403,394	$169,017	$0	$0	$572,411	$380,940	$0	$0	$0	$380,940
191	1825	J B Sims	City of Grand Haven	MI	$22,612	$0	$0	$0	$22,612	$21,353	$0	$0	$0	$21,353
192	1830	James De Young	City of Holland	MI	$13,556	$0	$0	$0	$13,556	$12,802	$0	$0	$0	$12,802
193	1843	Shiras	City of Marquette	MI	$11,334	$0	$0	$0	$11,334	$10,703	$0	$0	$0	$10,703
194	1695	B C Cobb	Consumers Energy Co	MI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
195	1702	Dan E Karn	Consumers Energy Co	MI	$17,064	$0	$0	$8,153,158	$8,170,222	$16,114	$0	$0	$8,153,158	$8,169,272
196	1720	J C Weadock	Consumers Energy Co	MI	$716,539	$0	$0	$5,238,104	$5,954,644	$676,655	$0	$0	$5,238,104	$5,914,759
197	1710	J H Campbell	Consumers Energy Co	MI	$26,334	$0	$0	$0	$26,334	$24,868	$0	$0	$0	$24,868
198	1723	J R Whiting	Consumers Energy Co	MI	$27,319	$0	$0	$254,786	$282,105	$25,798	$0	$0	$254,786	$280,585
199	6034	Belle River	Detroit Edison Co	MI	$29,704	$0	$0	$0	$29,704	$28,050	$0	$0	$0	$28,050
200	1731	Harbor Beach	Detroit Edison Co	MI	$9,597	$0	$0	$0	$9,597	$9,063	$0	$0	$0	$9,063
201	1733	Monroe	Detroit Edison Co	MI	$5,505,806	$0	$0	$36,119,688	$41,625,494	$5,199,341	$0	$0	$36,119,688	$41,319,029
202	1740	River Rouge	Detroit Edison Co	MI	$20,784	$0	$0	$0	$20,784	$19,627	$0	$0	$0	$19,627
203	1743	St Clair	Detroit Edison Co	MI	$26,800	$0	$0	$0	$26,800	$25,308	$0	$0	$0	$25,308
204	1745	Trenton Channel	Detroit Edison Co	MI	$28,904	$0	$0	$0	$28,904	$27,295	$0	$0	$0	$27,295
205	1831	Eckert Station	Lansing Board of Water and Light	MI	$0	$41,998	$0	$0	$41,998	$0	$0	$0	$0	$0

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206	1832	Erickson Station	Lansing Board of Water and Light	MI	$314,522	$32,267	$0	$382,179	$728,968	$297,015	$0	$0	$382,179	$679,194
207	4259	Endicott Station	Michigan South Central Pwr Agy	MI	$21,113	$0	$0	$0	$21,113	$19,938	$0	$0	$0	$19,938
208	50835	TES Filer City Station	TES Filer City Station LP	MI	$16,820	$0	$0	$0	$16,820	$15,884	$0	$0	$0	$15,884
209	1771	Escanaba	Upper Peninsula Power Co	MI	$9,188	$51,776	$0	$0	$60,963	$8,676	$0	$0	$0	$8,676
210	10148	White Pine Electric Power	White Pine Electric Power LLC	MI	$8,810	$34,188	$0	$0	$42,998	$8,320	$0	$0	$0	$8,320
211	1769	Presque Isle	Wisconsin Electric Power Co	MI	$18,541	$0	$0	$0	$18,541	$17,509	$0	$0	$0	$17,509
212	1866	Wyandotte	Wyandotte Municipal Serv Comm	MI	$14,677	$0	$0	$0	$14,677	$13,860	$0	$0	$0	$13,860
213	1961	Austin Northeast	Austin City of	MN	$1,504	$0	$0	$0	$1,504	$1,421	$0	$0	$0	$1,421
214	2018	Virginia	City of Virginia	MN	$6,881	$0	$0	$0	$6,881	$6,498	$0	$0	$0	$6,498
215	1979	Hibbing	Hibbing Public Utilities Comm	MN	$3,362	$0	$0	$0	$3,362	$3,175	$0	$0	$0	$3,175
216	1893	Clay Boswell	Minnesota Power Inc	MN	$2,626,096	$0	$0	$21,072,316	$23,698,412	$2,479,922	$0	$0	$21,072,316	$23,552,238
217	1897	M L Hibbard	Minnesota Power Inc	MN	$0	$13,050	$0	$0	$13,050	$0	$0	$0	$0	$0
218	10686	Rapids Energy Center	Minnesota Power Inc	MN	$0	$11,396	$0	$0	$11,396	$0	$0	$0	$0	$0
219	1891	Syl Laskin	Minnesota Power Inc	MN	$184,819	$0	$0	$1,513,730	$1,698,548	$174,531	$0	$0	$1,513,730	$1,688,261
220	10075	Taconite Harbor Energy Center	Minnesota Power Inc	MN	$40,719	$0	$0	$0	$40,719	$38,453	$0	$0	$0	$38,453
221	2001	New Ulm	New Ulm Public Utilities Comm	MN	$8,623	$0	$0	$0	$8,623	$8,143	$0	$0	$0	$8,143
222	1915	Allen S King	Northern States Power Co	MN	$13,829	$0	$0	$0	$13,829	$13,059	$0	$0	$0	$13,059
223	1904	Black Dog	Northern States Power Co	MN	$191,066	$0	$0	$359,698	$550,764	$180,431	$0	$0	$359,698	$540,129
224	1927	Riverside	Northern States Power Co	MN	$294,653	$0	$0	$502,079	$796,731	$278,252	$0	$0	$502,079	$780,330
225	6090	Sherburne County	Northern States Power Co	MN	$16,660,660	$0	$0	$37,543,493	$54,204,154	$15,733,291	$0	$0	$37,543,493	$53,276,785
226	1943	Hoot Lake	Otter Tail Power Co	MN	$8,759	$0	$0	$0	$8,759	$8,271	$0	$0	$0	$8,271
227	2008	Silver Lake	Rochester Public Utilities	MN	$28,341	$0	$0	$0	$28,341	$26,763	$0	$0	$0	$26,763
228	2022	Willmar	Willmar Municipal	MN	$8,914	$0	$0	$0	$8,914	$8,418	$0	$0	$0	$8,418

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			Utils Comm											
229	2098	Lake Road	Aquila, Inc.	MO	$0	$82,972	$0	$0	$82,972	$0	$0	$0	$0	$0
230	2094	Sibley	Aquila, Inc.	MO	$158,415	$0	$0	$0	$158,415	$149,597	$0	$0	$0	$149,597
231	2167	New Madrid	Associated Electric Coop, Inc	MO	$2,692,832	$0	$0	$8,183,133	$10,875,965	$2,542,943	$0	$0	$8,183,133	$10,726,076
232	2168	Thomas Hill	Associated Electric Coop, Inc	MO	$105,092	$0	$0	$0	$105,092	$99,243	$0	$0	$0	$99,243
233	2169	Chamois	Central Electric Power Coop	MO	$199,093	$0	$0	$0	$199,093	$188,011	$0	$0	$0	$188,011
234	2123	Columbia	City of Columbia	MO	$22,287	$16,507	$0	$0	$38,795	$21,047	$0	$0	$0	$21,047
235	2144	Marshall	City of Marshall	MO	$20,817	$12,763	$0	$0	$33,580	$19,658	$0	$0	$0	$19,658
236	6768	Sikeston Power Station	City of Sikeston	MO	$992,160	$0	$0	$846,789	$1,838,950	$936,935	$0	$0	$846,789	$1,783,724
237	2161	James River Power Station	City Utilities of Springfield	MO	$90,801	$0	$0	$0	$90,801	$85,747	$0	$0	$0	$85,747
238	6195	Southwest Power Station	City Utilities of Springfield	MO	$1,238,757	$0	$0	$0	$1,238,757	$1,169,805	$0	$0	$0	$1,169,805
239	2076	Asbury	Empire District Electric Co	MO	$148,487	$0	$0	$4,009,136	$4,157,623	$140,222	$0	$0	$4,009,136	$4,149,357
240	2132	Blue Valley	Independence City of	MO	$313,003	$0	$0	$2,229,379	$2,542,382	$295,580	$0	$0	$2,229,379	$2,524,959
241	2171	Missouri City	Independence City of	MO	$43,020	$37,138	$0	$0	$80,158	$40,625	$0	$0	$0	$40,625
242	2079	Hawthorn	Kansas City Power & Light Co	MO	$225,229	$574,147	$0	$0	$799,376	$212,692	$0	$0	$0	$212,692
243	6065	Iatan	Kansas City Power & Light Co	MO	$330,101	$0	$0	$1,228,969	$1,559,070	$311,727	$0	$0	$1,228,969	$1,540,696
244	2080	Montrose	Kansas City Power & Light Co	MO	$189,353	$0	$0	$0	$189,353	$178,813	$0	$0	$0	$178,813
245	2103	Labadie	Union Electric Co	MO	$594,710	$225,357	$0	$18,734,278	$19,554,344	$561,607	$0	$0	$18,734,278	$19,295,885
246	2104	Meramec	Union Electric Co	MO	$876,216	$0	$0	$8,318,020	$9,194,235	$827,444	$0	$0	$8,318,020	$9,145,463
247	6155	Rush Island	Union Electric Co	MO	$1,968,536	$256,087	$0	$7,193,963	$9,418,586	$1,858,963	$0	$0	$7,193,963	$9,052,926
248	2107	Sioux	Union Electric Co	MO	$328,197	$0	$0	$7,643,585	$7,971,782	$309,929	$0	$0	$7,643,585	$7,953,514
249	55076	Red Hills Generating Facility	Choctaw Generating LP	MS	$741,001	$0	$0	$0	$741,001	$699,755	$0	$0	$0	$699,755
250	2062	Henderson	Greenwood Utilities Comm	MS	$14,106	$8,707	$0	$0	$22,813	$13,321	$0	$0	$0	$13,321
251	2049	Jack Watson	Mississippi Power Co	MS	$351,171	$0	$0	$2,930,041	$3,281,212	$331,624	$0	$0	$2,930,041	$3,261,666
252	6073	Victor J Daniel Jr	Mississippi Power Co	MS	$875,047	$0	$0	$0	$875,047	$826,340	$0	$0	$0	$826,340
253	6061	R D Morrow	South Mississippi	MS	$1,881,414	$0	$0	$0	$1,881,414	$1,776,690	$0	$0	$0	$1,776,690

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			El Pwr Assn											
254	10784	Colstrip Energy LP	Colstrip Energy LP	MT	$12,687	$0	$0	$0	$12,687	$11,981	$0	$0	$0	$11,981
255	6089	Lewis & Clark	MDU Resources Group Inc	MT	$10,408	$0	$0	$0	$10,408	$9,828	$0	$0	$0	$9,828
256	6076	Colstrip	PPL Montana LLC	MT	$21,054,622	$0	$0	$72,209,402	$93,264,024	$19,882,676	$0	$0	$72,209,402	$92,092,077
257	2187	J E Corette Plant	PPL Montana LLC	MT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
258	55749	Hardin Generator Project	Rocky Mountain Power Inc	MT	$38,192	$0	$0	$0	$38,192	$36,066	$0	$0	$0	$36,066
259	10381	Coastal Carolina Clean Power	Carlyle/Riverstone Renewable Energy	NC	$92,974	$59,684	$0	$0	$152,658	$87,799	$0	$0	$0	$87,799
260	8042	Belews Creek	Duke Energy Carolinas, LLC	NC	$4,713,588	$0	$0	$3,102,396	$7,815,985	$4,451,220	$0	$0	$3,102,396	$7,553,616
261	2720	Buck	Duke Energy Carolinas, LLC	NC	$213,083	$0	$0	$9,134,834	$9,347,917	$201,222	$0	$0	$9,134,834	$9,336,056
262	2721	Cliffside	Duke Energy Carolinas, LLC	NC	$525,124	$0	$0	$7,261,406	$7,786,530	$495,894	$0	$0	$7,261,406	$7,757,301
263	2723	Dan River	Duke Energy Carolinas, LLC	NC	$765,880	$0	$0	$2,135,708	$2,901,588	$723,250	$0	$0	$2,135,708	$2,858,957
264	2718	G G Allen	Duke Energy Carolinas, LLC	NC	$720,969	$0	$0	$10,745,982	$11,466,951	$680,838	$0	$0	$10,745,982	$11,426,820
265	2727	Marshall	Duke Energy Carolinas, LLC	NC	$4,182,041	$0	$0	$2,510,393	$6,692,434	$3,949,260	$0	$0	$2,510,393	$6,459,653
266	2732	Riverbend	Duke Energy Carolinas, LLC	NC	$1,977,516	$0	$0	$6,976,645	$8,954,162	$1,867,444	$0	$0	$6,976,645	$8,844,089
267	10384	Edgecombe Genco LLC	Edgecombe Operating Services LLC	NC	$0	$363,643	$0	$0	$363,643	$0	$0	$0	$0	$0
268	10380	Elizabethtown Power LLC	North Carolina Power Holdings, LLC	NC	$36,724	$4,266	$0	$0	$40,990	$34,680	$0	$0	$0	$34,680
269	10382	Lumberton	North Carolina Power Holdings, LLC	NC	$33,816	$1,588	$0	$0	$35,404	$31,934	$0	$0	$0	$31,934
270	10379	Primary Energy Roxboro	Primary Energy of North Carolina LLC	NC	$68,871	$39,156	$0	$0	$108,027	$65,038	$0	$0	$0	$65,038
271	10378	Primary Energy Southport	Primary Energy of North Carolina LLC	NC	$0	$117,800	$0	$0	$117,800	$0	$0	$0	$0	$0
272	2706	Asheville	Progress Energy Carolinas Inc	NC	$330,332	$35,852	$0	$7,943,334	$8,309,518	$311,945	$0	$0	$7,943,334	$8,255,279
273	2708	Cape Fear	Progress Energy Carolinas Inc	NC	$316,743	$0	$0	$7,591,130	$7,907,873	$299,113	$0	$0	$7,591,130	$7,890,242

Exhibit J3
Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
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274	2713	L V Sutton	Progress Energy Carolinas Inc	NC	$397,621	$0	$0	$12,439,561	$12,837,181	$375,488	$0	$0	$12,439,561	$12,815,049
275	2709	Lee	Progress Energy Carolinas Inc	NC	$436,699	$0	$0	$7,950,828	$8,387,527	$412,392	$0	$0	$7,950,828	$8,363,219
276	6250	Mayo	Progress Energy Carolinas Inc	NC	$484,142	$0	$0	$15,946,618	$16,430,760	$457,194	$0	$0	$15,946,618	$16,403,811
277	2712	Roxboro	Progress Energy Carolinas Inc	NC	$970,739	$0	$0	$3,469,588	$4,440,327	$916,705	$0	$0	$3,469,588	$4,386,294
278	2716	W H Weatherspoon	Progress Energy Carolinas Inc	NC	$222,235	$0	$0	$3,522,044	$3,744,279	$209,865	$0	$0	$3,522,044	$3,731,909
279	54035	Roanoke Valley Energy Facililty I	Westmoreland Partners	NC	$28,807	$666,338	$0	$0	$695,145	$27,204	$0	$0	$0	$27,204
280	54755	Roanoke Valley Energy Facility II	Westmoreland Partners	NC	$82,194	$91,628	$0	$0	$173,822	$77,619	$0	$0	$0	$77,619
281	6469	Antelope Valley	Basin Electric Power Coop	ND	$98,638	$0	$0	$0	$98,638	$93,148	$0	$0	$0	$93,148
282	2817	Leland Olds	Basin Electric Power Coop	ND	$56,183	$0	$0	$14,597,750	$14,653,932	$53,056	$0	$0	$14,597,750	$14,650,805
283	6030	Coal Creek	Great River Energy	ND	$40,909	$0	$0	$0	$40,909	$38,632	$0	$0	$0	$38,632
284	2824	Stanton	Great River Energy	ND	$17,661	$0	$0	$0	$17,661	$16,678	$0	$0	$0	$16,678
285	2790	R M Heskett	MDU Resources Group Inc	ND	$24,647	$14,853	$0	$0	$39,500	$23,275	$0	$0	$0	$23,275
286	2823	Milton R Young	Minnkota Power Coop, Inc	ND	$43,007	$263,770	$0	$10,491,196	$10,797,972	$40,613	$0	$0	$10,491,196	$10,531,809
287	8222	Coyote	Otter Tail Power Co	ND	$38,673	$0	$0	$0	$38,673	$36,520	$0	$0	$0	$36,520
288	2240	Lon Wright	Fremont City of	NE	$36,263	$58,900	$0	$0	$95,163	$34,244	$0	$0	$0	$34,244
289	59	Platte	Grand Island City of	NE	$0	$29,706	$0	$0	$29,706	$0	$0	$0	$0	$0
290	60	Whelan Energy Center	Hastings City of	NE	$708,766	$0	$0	$0	$708,766	$669,314	$0	$0	$0	$669,314
291	6077	Gerald Gentleman	Nebraska Public Power District	NE	$2,879,798	$0	$0	$0	$2,879,798	$2,719,502	$0	$0	$0	$2,719,502
292	2277	Sheldon	Nebraska Public Power District	NE	$259,199	$0	$0	$0	$259,199	$244,771	$0	$0	$0	$244,771
293	6096	Nebraska City	Omaha Public Power District	NE	$349,000	$0	$0	$0	$349,000	$329,574	$0	$0	$0	$329,574
294	2291	North Omaha	Omaha Public Power District	NE	$146,240	$0	$0	$0	$146,240	$138,100	$0	$0	$0	$138,100
295	2364	Merrimack	Public Service Co of NH	NH	$39,842	$0	$0	$0	$39,842	$37,624	$0	$0	$0	$37,624
296	2367	Schiller	Public Service Co	NH	$0	$457,371	$0	$0	$457,371	$0	$0	$0	$0	$0

Exhibit J3
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			of NH											
297	2384	Deepwater	Conectiv Atlantic Generatn Inc	NJ	$0	$34,828	$0	$0	$34,828	$0	$0	$0	$0	$0
298	2403	PSEG Hudson Generating Station	PSEG Fossil LLC	NJ	$0	$806,674	$0	$0	$806,674	$0	$0	$0	$0	$0
299	2408	PSEG Mercer Generating Station	PSEG Fossil LLC	NJ	$0	$406,154	$0	$0	$406,154	$0	$0	$0	$0	$0
300	2378	B L England	RC Cape May Holdings LLC	NJ	$0	$26,121	$0	$0	$26,121	$0	$0	$0	$0	$0
301	10566	Chambers Cogeneration LP	US Operating Services Company	NJ	$0	$829,722	$0	$0	$829,722	$0	$0	$0	$0	$0
302	10043	Logan Generating Company LP	US Operating Services Company	NJ	$1,649,019	$624,852	$0	$0	$2,273,871	$1,557,231	$0	$0	$0	$1,557,231
303	2434	Howard Down	Vineland City of	NJ	$171,666	$0	$0	$0	$171,666	$162,111	$0	$0	$0	$162,111
304	2442	Four Corners	Arizona Public Service Co	NM	$1,382,099	$4,968,087	$0	$37,573,468	$43,923,654	$1,305,168	$0	$0	$37,573,468	$38,878,637
305	2451	San Juan	Public Service Co of NM	NM	$8,853,679	$5,562,208	$0	$0	$14,415,888	$8,360,864	$0	$0	$0	$8,360,864
306	87	Escalante	Tri-State G & T Assn, Inc	NM	$2,463,098	$0	$0	$1,176,513	$3,639,611	$2,325,997	$0	$0	$1,176,513	$3,502,509
307	2324	Reid Gardner	Nevada Power Co	NV	$1,279,054	$0	$0	$0	$1,279,054	$1,207,859	$0	$0	$0	$1,207,859
308	8224	North Valmy	Sierra Pacific Power Co	NV	$4,272,935	$0	$0	$0	$4,272,935	$4,035,094	$0	$0	$0	$4,035,094
309	2535	AES Cayuga	AES Cayuga LLC	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
310	2527	AES Greenidge LLC	AES Greenidge	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
311	6082	AES Somerset LLC	AES Somerset LLC	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
312	2526	AES Westover	AES Westover LLC	NY	$0	$212,962	$0	$0	$212,962	$0	$0	$0	$0	$0
313	10464	Black River Generation	Black River Generation LLC	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
314	2554	Dunkirk Generating Plant	Dunkirk Power LLC	NY	$0	$267,355	$0	$0	$267,355	$0	$0	$0	$0	$0
315	2480	Danskammer Generating Station	Dynegy Northeast Gen Inc	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
316	2682	S A Carlson	Jamestown Board of Public Util	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
317	2629	Lovett	Mirant New York Inc	NY	$0	$547,002	$0	$0	$547,002	$0	$0	$0	$0	$0

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318	50202	WPS Power Niagara	Niagara Generation LLC	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
319	2549	C R Huntley Generating Station	NRG Huntley Operations Inc	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
320	2642	Rochester 7	Rochester Gas & Electric Corp	NY	$0	$125,687	$0	$0	$125,687	$0	$0	$0	$0	$0
321	50651	Trigen Syracuse Energy	Syracuse Energy Corp	NY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
322	7286	Richard Gorsuch	American Mun Power-Ohio, Inc	OH	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
323	2828	Cardinal	Cardinal Operating Co	OH	$1,988,900	$0	$0	$36,749,160	$38,738,060	$1,878,193	$0	$0	$36,749,160	$38,627,354
324	2914	Dover	City of Dover	OH	$0	$14,689	$0	$0	$14,689	$0	$0	$0	$0	$0
325	2917	Hamilton	City of Hamilton	OH	$0	$157,750	$0	$0	$157,750	$0	$0	$0	$0	$0
326	2935	Orrville	City of Orrville	OH	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
327	2936	Painesville	City of Painesville	OH	$0	$48,646	$0	$0	$48,646	$0	$0	$0	$0	$0
328	2943	Shelby Municipal Light Plant	City of Shelby	OH	$0	$22,295	$0	$0	$22,295	$0	$0	$0	$0	$0
329	2840	Conesville	Columbus Southern Power Co	OH	$4,268,300	$0	$0	$37,003,946	$41,272,246	$4,030,717	$0	$0	$37,003,946	$41,034,663
330	2843	Picway	Columbus Southern Power Co	OH	$274,795	$0	$0	$794,333	$1,069,128	$259,499	$0	$0	$794,333	$1,053,832
331	2850	J M Stuart	Dayton Power & Light Co	OH	$4,691,773	$0	$0	$48,956,416	$53,648,189	$4,430,618	$0	$0	$48,956,416	$53,387,034
332	6031	Killen Station	Dayton Power & Light Co	OH	$5,303,401	$0	$0	$18,929,115	$24,232,515	$5,008,202	$0	$0	$18,929,115	$23,937,316
333	2848	O H Hutchings	Dayton Power & Light Co	OH	$0	$409,739	$0	$0	$409,739	$0	$0	$0	$0	$0
334	2832	Miami Fort	Duke Energy Ohio Inc	OH	$5,401,738	$0	$0	$16,808,394	$22,210,133	$5,101,066	$0	$0	$16,808,394	$21,909,460
335	6019	W H Zimmer	Duke Energy Ohio Inc	OH	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
336	2830	Walter C Beckjord	Duke Energy Ohio Inc	OH	$627,855	$0	$0	$5,747,677	$6,375,531	$592,907	$0	$0	$5,747,677	$6,340,583
337	2835	Ashtabula	FirstEnergy Generation Corp	OH	$0	$61,973	$0	$0	$61,973	$0	$0	$0	$0	$0
338	2878	Bay Shore	FirstEnergy Generation Corp	OH	$0	$263,770	$0	$0	$263,770	$0	$0	$0	$0	$0
339	2837	Eastlake	FirstEnergy Generation Corp	OH	$0	$649,436	$0	$0	$649,436	$0	$0	$0	$0	$0
340	2838	Lake Shore	FirstEnergy	OH	$0	$126,507	$0	$0	$126,507	$0	$0	$0	$0	$0

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			Generation Corp											
341	2864	R E Burger	FirstEnergy Generation Corp	OH	$0	$318,060	$0	$0	$318,060	$0	$0	$0	$0	$0
342	2866	W H Sammis	FirstEnergy Generation Corp	OH	$0	$2,664,841	$0	$0	$2,664,841	$0	$0	$0	$0	$0
343	8102	General James M Gavin	Ohio Power Co	OH	$584,266	$0	$0	$6,796,796	$7,381,062	$551,744	$0	$0	$6,796,796	$7,348,540
344	2872	Muskingum River	Ohio Power Co	OH	$1,708,190	$0	$0	$10,745,982	$12,454,172	$1,613,109	$0	$0	$10,745,982	$12,359,091
345	2876	Kyger Creek	Ohio Valley Electric Corp	OH	$2,355,662	$0	$0	$17,347,942	$19,703,603	$2,224,541	$0	$0	$17,347,942	$19,572,482
346	2836	Avon Lake	Orion Power Midwest LP	OH	$0	$798,991	$0	$0	$798,991	$0	$0	$0	$0	$0
347	2861	Niles	Orion Power Midwest LP	OH	$0	$289,378	$0	$0	$289,378	$0	$0	$0	$0	$0
348	10671	AES Shady Point LLC	AES Shady Point LLC	OK	$0	$2,163,422	$0	$0	$2,163,422	$0	$0	$0	$0	$0
349	165	GRDA	Grand River Dam Authority	OK	$2,202,508	$0	$0	$0	$2,202,508	$2,079,912	$0	$0	$0	$2,079,912
350	2952	Muskogee	Oklahoma Gas & Electric Co	OK	$0	$263,770	$0	$0	$263,770	$0	$0	$0	$0	$0
351	6095	Sooner	Oklahoma Gas & Electric Co	OK	$0	$376,448	$0	$0	$376,448	$0	$0	$0	$0	$0
352	2963	Northeastern	Public Service Co of Oklahoma	OK	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
353	6772	Hugo	Western Farmers Elec Coop, Inc	OK	$5,393	$0	$0	$1,240,959	$1,246,352	$5,093	$0	$0	$1,240,959	$1,246,052
354	6106	Boardman	Portland General Electric Co	OR	$837,912	$0	$0	$0	$837,912	$791,272	$0	$0	$0	$791,272
355	10676	AES Beaver Valley Partners Beaver Valley	AES Beaver Valley	PA	$0	$892,719	$0	$0	$892,719	$0	$0	$0	$0	$0
356	3178	Armstrong Power Station	Allegheny Energy Supply Co LLC	PA	$49,994	$0	$0	$0	$49,994	$47,212	$0	$0	$0	$47,212
357	3179	Hatfields Ferry Power Station	Allegheny Energy Supply Co LLC	PA	$84,721	$446,616	$0	$0	$531,336	$80,005	$0	$0	$0	$80,005
358	3181	Mitchell Power Station	Allegheny Energy Supply Co LLC	PA	$12,752	$989,008	$0	$0	$1,001,759	$12,042	$0	$0	$0	$12,042
359	10641	Cambria Cogen	Cambria CoGen Co	PA	$599,870	$0	$0	$0	$599,870	$566,480	$0	$0	$0	$566,480
360	54144	Piney Creek Project	Colmac Clarion Inc	PA	$137,508	$0	$0	$0	$137,508	$129,854	$0	$0	$0	$129,854
361	10603	Ebensburg Power	Ebensburg Power Co	PA	$426,147	$0	$0	$0	$426,147	$402,427	$0	$0	$0	$402,427

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362	3159	Cromby Generating Station	Exelon Power	PA	$0	$153,140	$0	$0	$153,140	$0	$0	$0	$0	$0
363	3161	Eddystone Generating Station	Exelon Power	PA	$0	$548,538	$0	$0	$548,538	$0	$0	$0	$0	$0
364	6094	Bruce Mansfield	FirstEnergy Generation Corp	PA	$32,902,363	$0	$0	$77,852,166	$110,754,529	$31,070,945	$0	$0	$77,852,166	$108,923,112
365	10113	John B Rich Memorial Power Station	Gilberton Power Co	PA	$553,314	$0	$0	$0	$553,314	$522,515	$0	$0	$0	$522,515
366	10143	Colver Power Project	Inter-Power/AhlCon Partners, L.P.	PA	$0	$139,823	$0	$0	$139,823	$0	$0	$0	$0	$0
367	3122	Homer City Station	Midwest Generations EME LLC	PA	$426,599	$0	$0	$0	$426,599	$402,854	$0	$0	$0	$402,854
368	10343	Foster Wheeler Mt Carmel Cogen	Mount Carmel Cogen Inc	PA	$602,175	$0	$0	$0	$602,175	$568,656	$0	$0	$0	$568,656
369	50039	Kline Township Cogen Facility	Northeastern Power Co	PA	$445,975	$0	$0	$0	$445,975	$421,151	$0	$0	$0	$421,151
370	8226	Cheswick Power Plant	Orion Power Midwest LP	PA	$27,155	$0	$0	$0	$27,155	$25,643	$0	$0	$0	$25,643
371	3098	Elrama Power Plant	Orion Power Midwest LP	PA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
372	3138	New Castle Plant	Orion Power Midwest LP	PA	$22,733	$0	$0	$0	$22,733	$21,468	$0	$0	$0	$21,468
373	50776	Panther Creek Energy Facility	Panther Creek Partners	PA	$366,856	$0	$0	$0	$366,856	$346,436	$0	$0	$0	$346,436
374	3140	PPL Brunner Island	PPL Brunner Island LLC	PA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
375	3149	PPL Montour	PPL Montour LLC	PA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
376	3113	Portland	Reliant Energy Mid-Atlantic PH LLC	PA	$19,584	$0	$0	$0	$19,584	$18,494	$0	$0	$0	$18,494
377	3131	Shawville	Reliant Energy Mid-Atlantic PH LLC	PA	$270,973	$0	$0	$0	$270,973	$255,890	$0	$0	$0	$255,890
378	3115	Titus	Reliant Energy Mid-Atlantic PH LLC	PA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
379	3130	Seward	Reliant Energy Seward LLC	PA	$2,113,798	$0	$0	$0	$2,113,798	$1,996,139	$0	$0	$0	$1,996,139

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380	3118	Conemaugh	Reliant Engy NE Management Co	PA	$1,195,674	$0	$0	$0	$1,195,674	$1,129,120	$0	$0	$0	$1,129,120
381	3136	Keystone	Reliant Engy NE Management Co	PA	$144,792	$0	$0	$0	$144,792	$136,733	$0	$0	$0	$136,733
382	54634	St Nicholas Cogen Project	Schuylkill Energy Resource Inc	PA	$1,318,498	$0	$0	$0	$1,318,498	$1,245,108	$0	$0	$0	$1,245,108
383	3152	Sunbury Generation LP	Sunbury Generation LP	PA	$222,711	$221,771	$0	$37,469	$481,951	$210,314	$0	$0	$37,469	$247,783
384	3176	Hunlock Power Station	UGI Development Co	PA	$56,098	$0	$0	$0	$56,098	$52,975	$0	$0	$0	$52,975
385	50888	Northampton Generating Company LP	US Operating Services Company	PA	$193,328	$1,562,130	$0	$0	$1,755,459	$182,567	$0	$0	$0	$182,567
386	50974	Scrubgrass Generating Company LP	US Operating Services Company	PA	$357,627	$0	$0	$0	$357,627	$337,720	$0	$0	$0	$337,720
387	50879	Wheelabrator Frackville Energy	Wheelabrator Environmental Systems	PA	$541,766	$0	$0	$0	$541,766	$511,610	$0	$0	$0	$511,610
388	50611	WPS Westwood Generation LLC	WPS Power Developement	PA	$522,486	$0	$0	$0	$522,486	$493,403	$0	$0	$0	$493,403
389	3264	W S Lee	Duke Energy Carolinas, LLC	SC	$41,846	$0	$0	$4,758,507	$4,800,353	$39,517	$0	$0	$4,758,507	$4,798,023
390	3251	H B Robinson	Progress Energy Carolinas Inc	SC	$323,042	$0	$0	$4,661,088	$4,984,131	$305,061	$0	$0	$4,661,088	$4,966,149
391	7652	US DOE Savannah River Site (D Area)	Savannah River Nuclear Solutions LLC	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
392	3280	Canadys Steam	South Carolina Electric&Gas Co	SC	$474,088	$0	$0	$7,576,142	$8,050,230	$447,699	$0	$0	$7,576,142	$8,023,841
393	7737	Cogen South	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
394	7210	Cope	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
395	3287	McMeekin	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
396	3295	Urquhart	South Carolina Electric&Gas Co	SC	$146,086	$0	$0	$936,714	$1,082,800	$137,955	$0	$0	$936,714	$1,074,669
397	3297	Wateree	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
398	3298	Williams	South Carolina Genertg Co, Inc	SC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
399	130	Cross	South Carolina Pub Serv Auth	SC	$292,817	$95,777	$0	$816,815	$1,205,408	$276,518	$0	$0	$816,815	$1,093,333

Exhibit J3
Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
400	3317	Dolphus M Grainger	South Carolina Pub Serv Auth	SC	$61,281	$275,550	$0	$524,560	$861,390	$57,870	$0	$0	$524,560	$582,430
401	3319	Jefferies	South Carolina Pub Serv Auth	SC	$108,532	$0	$0	$2,615,305	$2,723,837	$102,491	$0	$0	$2,615,305	$2,717,796
402	6249	Winyah	South Carolina Pub Serv Auth	SC	$422,248	$196,521	$0	$670,687	$1,289,456	$398,745	$0	$0	$670,687	$1,069,432
403	3325	Ben French	Black Hills Power Inc	SD	$127,596	$33,051	$0	$0	$160,647	$120,494	$0	$0	$0	$120,494
404	6098	Big Stone	Otter Tail Power Co	SD	$215,020	$0	$0	$0	$215,020	$203,051	$0	$0	$0	$203,051
405	3393	Allen Steam Plant	Tennessee Valley Authority	TN	$11,886	$0	$0	$2,967,510	$2,979,396	$11,225	$0	$0	$2,967,510	$2,978,734
406	3396	Bull Run	Tennessee Valley Authority	TN	$12,593	$24,584	$0	$1,678,591	$1,715,768	$11,892	$0	$0	$1,678,591	$1,690,483
407	3399	Cumberland	Tennessee Valley Authority	TN	$0	$102	$0	$0	$102	$0	$0	$0	$0	$0
408	3403	Gallatin	Tennessee Valley Authority	TN	$12,860	$1,024	$0	$13,526,149	$13,540,033	$12,144	$0	$0	$13,526,149	$13,538,293
409	3405	John Sevier	Tennessee Valley Authority	TN	$9,118	$36,364	$0	$749,371	$794,853	$8,610	$0	$0	$749,371	$757,981
410	3406	Johnsonville	Tennessee Valley Authority	TN	$10,445	$1,144,196	$0	$4,024,123	$5,178,765	$9,864	$0	$0	$4,024,123	$4,033,987
411	3407	Kingston	Tennessee Valley Authority	TN	$3,049	$0	$0	$24,422,005	$24,425,054	$2,879	$0	$0	$24,422,005	$24,424,884
412	7030	Twin Oaks Power One	Altura Power	TX	$180,354	$0	$0	$0	$180,354	$170,315	$0	$0	$0	$170,315
413	6178	Coleto Creek	ANP-Coleto Creek	TX	$957,479	$0	$0	$4,758,507	$5,715,986	$904,183	$0	$0	$4,758,507	$5,662,690
414	6179	Fayette Power Project	Lower Colorado River Authority	TX	$210,585	$0	$0	$2,990,740	$3,201,325	$198,863	$0	$0	$2,990,740	$3,189,603
415	54972	Norit Americas Marshall Plant	Norit Americas Inc	TX	$2,685	$2,704	$0	$0	$5,389	$2,536	$0	$0	$0	$2,536
416	298	Limestone	NRG Texas LLC	TX	$598,430	$0	$0	$0	$598,430	$565,120	$0	$0	$0	$565,120
417	3470	W A Parish	NRG Texas LLC	TX	$66,365	$0	$0	$0	$66,365	$62,671	$0	$0	$0	$62,671
418	127	Oklaunion	Public Service Co of Oklahoma	TX	$660,126	$0	$0	$2,922,547	$3,582,673	$623,382	$0	$0	$2,922,547	$3,545,929
419	7097	J K Spruce	San Antonio City of	TX	$83,652	$185,919	$0	$0	$269,571	$78,995	$0	$0	$0	$78,995
420	6181	J T Deely	San Antonio City of	TX	$45,108	$0	$0	$0	$45,108	$42,597	$0	$0	$0	$42,597
421	6183	San Miguel	San Miguel Electric Coop, Inc	TX	$0	$6,543,021	$0	$0	$6,543,021	$0	$0	$0	$0	$0
422	7902	Pirkey	Southwestern Electric Power Co	TX	$2,407,485	$0	$0	$8,992,454	$11,399,939	$2,273,479	$0	$0	$8,992,454	$11,265,933
423	6139	Welsh	Southwestern Electric Power Co	TX	$52,960	$0	$0	$0	$52,960	$50,012	$0	$0	$0	$50,012
424	6193	Harrington	Southwestern	TX	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Exhibit J3
Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
			Public Service Co											
425	6194	Tolk	Southwestern Public Service Co	TX	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
426	6136	Gibbons Creek	Texas Municipal Power Agency	TX	$63,877	$0	$0	$0	$63,877	$60,321	$0	$0	$0	$60,321
427	3497	Big Brown	TXU Generation Co LP	TX	$109,055	$0	$0	$0	$109,055	$102,985	$0	$0	$0	$102,985
428	6146	Martin Lake	TXU Generation Co LP	TX	$411,947	$0	$0	$0	$411,947	$389,017	$0	$0	$0	$389,017
429	6147	Monticello	TXU Generation Co LP	TX	$202,180	$0	$0	$0	$202,180	$190,926	$0	$0	$0	$190,926
430	6648	Sandow No 4	TXU Generation Co LP	TX	$1,992,979	$0	$0	$23,560,228	$25,553,207	$1,882,045	$0	$0	$23,560,228	$25,442,274
431	7790	Bonanza	Deseret Generation & Tran Coop	UT	$1,430,987	$0	$0	$0	$1,430,987	$1,351,335	$0	$0	$0	$1,351,335
432	6481	Intermountain Power Project	Los Angeles City of	UT	$2,146,602	$0	$0	$7,246,419	$9,393,020	$2,027,117	$0	$0	$7,246,419	$9,273,536
433	3644	Carbon	PacifiCorp	UT	$171,246	$0	$0	$0	$171,246	$161,714	$0	$0	$0	$161,714
434	6165	Hunter	PacifiCorp	UT	$2,309,513	$0	$0	$0	$2,309,513	$2,180,961	$0	$0	$0	$2,180,961
435	8069	Huntington	PacifiCorp	UT	$3,299,563	$0	$0	$0	$3,299,563	$3,115,902	$0	$0	$0	$3,115,902
436	50951	Sunnyside Cogen Associates	Sunnyside Cogeneration Assoc	UT	$1,073,584	$0	$0	$0	$1,073,584	$1,013,826	$0	$0	$0	$1,013,826
437	3775	Clinch River	Appalachian Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
438	3776	Glen Lyn	Appalachian Power Co	VA	$292,058	$0	$0	$434,635	$726,693	$275,801	$0	$0	$434,635	$710,437
439	54304	Birchwood Power	Birchwood Power Partners LP	VA	$0	$604,365	$0	$0	$604,365	$0	$0	$0	$0	$0
440	10071	Cogentrix Virginia Leasing Corporation	Cogentrix-Virginia Leas'g Corp	VA	$0	$215,113	$0	$0	$215,113	$0	$0	$0	$0	$0
441	10377	James River Cogeneration	James River Cogeneration Co	VA	$0	$235,600	$0	$0	$235,600	$0	$0	$0	$0	$0
442	3788	Potomac River	Mirant Potomac River LLC	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
443	54081	Spruance Genco LLC	Spruance Operating Services LLC	VA	$0	$809,235	$0	$0	$809,235	$0	$0	$0	$0	$0
444	10773	Altavista Power Station	Virginia Electric & Power Co	VA	$0	$101,661	$0	$0	$101,661	$0	$0	$0	$0	$0
445	3796	Bremo Bluff	Virginia Electric & Power Co	VA	$1,061,237	$0	$0	$6,369,655	$7,430,891	$1,002,166	$0	$0	$6,369,655	$7,371,820
446	3803	Chesapeake	Virginia Electric &	VA	$457,568	$1,307,068	$0	$2,607,812	$4,372,448	$432,099	$0	$0	$2,607,812	$3,039,911

Exhibit J3
Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
			Power Co											
447	3797	Chesterfield	Virginia Electric & Power Co	VA	$3,207,906	$0	$0	$24,174,713	$27,382,618	$3,029,347	$0	$0	$24,174,713	$27,204,059
448	7213	Clover	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
449	10771	Hopewell Power Station	Virginia Electric & Power Co	VA	$0	$72,104	$0	$0	$72,104	$0	$0	$0	$0	$0
450	52007	Mecklenburg Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
451	10774	Southampton Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
452	3809	Yorktown	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
453	3845	Transalta Centralia Generation	TransAlta Centralia Gen LLC	WA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
454	4127	Menasha	City of Menasha	WI	$219,000	$0	$0	$0	$219,000	$206,810	$0	$0	$0	$206,810
455	4140	Alma	Dairyland Power Coop	WI	$35,784	$0	$0	$0	$35,784	$33,792	$0	$0	$0	$33,792
456	4143	Genoa	Dairyland Power Coop	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
457	4271	John P Madgett	Dairyland Power Coop	WI	$786,749	$0	$0	$0	$786,749	$742,957	$0	$0	$0	$742,957
458	3992	Blount Street	Madison Gas & Electric Co	WI	$0	$2,561	$0	$0	$2,561	$0	$0	$0	$0	$0
459	4125	Manitowoc	Manitowoc Public Utilities	WI	$394,903	$0	$0	$0	$394,903	$372,922	$0	$0	$0	$372,922
460	4146	E J Stoneman Station	Mid-America Power LLC	WI	$161,240	$0	$0	$0	$161,240	$152,265	$0	$0	$0	$152,265
461	3982	Bay Front	Northern States Power Co	WI	$0	$44,457	$0	$0	$44,457	$0	$0	$0	$0	$0
462	7549	Milwaukee County	Wisconsin Electric Power Co	WI	$222,398	$0	$0	$0	$222,398	$210,019	$0	$0	$0	$210,019
463	6170	Pleasant Prairie	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
464	4041	South Oak Creek	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
465	4042	Valley	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
466	8023	Columbia	Wisconsin Power & Light Co	WI	$1,982,225	$0	$0	$824,308	$2,806,533	$1,871,890	$0	$0	$824,308	$2,696,198
467	4050	Edgewater	Wisconsin Power & Light Co	WI	$11,284	$0	$0	$0	$11,284	$10,656	$0	$0	$0	$10,656

Exhibit J3
Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option

Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
468	4054	Nelson Dewey	Wisconsin Power & Light Co	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
469	4072	Pulliam	Wisconsin Public Service Corp	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
470	4078	Weston	Wisconsin Public Service Corp	WI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
471	3944	Harrison Power Station	Allegheny Energy Supply Co LLC	WV	$1,410,544	$0	$0	$0	$1,410,544	$1,332,030	$0	$0	$0	$1,332,030
472	6004	Pleasants Power Station	Allegheny Energy Supply Co LLC	WV	$5,409,133	$0	$0	$0	$5,409,133	$5,108,049	$0	$0	$0	$5,108,049
473	10151	Grant Town Power Plant	American Bituminous Power LP	WV	$742,420	$0	$0	$0	$742,420	$701,095	$0	$0	$0	$701,095
474	3935	John E Amos	Appalachian Power Co	WV	$9,047,022	$0	$0	$29,367,854	$38,414,877	$8,543,445	$0	$0	$29,367,854	$37,911,300
475	3936	Kanawha River	Appalachian Power Co	WV	$78,028	$0	$0	$119,899	$197,927	$73,685	$0	$0	$119,899	$193,584
476	6264	Mountaineer	Appalachian Power Co	WV	$2,298,069	$0	$0	$711,903	$3,009,972	$2,170,153	$0	$0	$711,903	$2,882,056
477	3938	Philip Sporn	Appalachian Power Co	WV	$3,106,102	$0	$0	$10,273,878	$13,379,981	$2,933,210	$0	$0	$10,273,878	$13,207,088
478	3942	Albright	Monongahela Power Co	WV	$755,162	$0	$0	$0	$755,162	$713,128	$0	$0	$0	$713,128
479	3943	Fort Martin Power Station	Monongahela Power Co	WV	$23,363	$1,046,371	$0	$0	$1,069,734	$22,062	$0	$0	$0	$22,062
480	3945	Rivesville	Monongahela Power Co	WV	$414,830	$0	$0	$0	$414,830	$391,740	$0	$0	$0	$391,740
481	3946	Willow Island	Monongahela Power Co	WV	$284,624	$0	$0	$0	$284,624	$268,781	$0	$0	$0	$268,781
482	10743	Morgantown Energy Facility	Morgantown Energy Associates	WV	$547,721	$0	$0	$0	$547,721	$517,234	$0	$0	$0	$517,234
483	3947	Kammer	Ohio Power Co	WV	$400,961	$0	$0	$3,649,437	$4,050,398	$378,643	$0	$0	$3,649,437	$4,028,080
484	3948	Mitchell	Ohio Power Co	WV	$25,937,363	$0	$0	$23,035,668	$48,973,031	$24,493,632	$0	$0	$23,035,668	$47,529,301
485	3954	Mt Storm	Virginia Electric & Power Co	WV	$5,495,529	$2,117,327	$0	$0	$7,612,856	$5,189,636	$0	$0	$0	$5,189,636
486	7537	North Branch	Virginia Electric & Power Co	WV	$2,081,521	$0	$0	$0	$2,081,521	$1,965,659	$0	$0	$0	$1,965,659
487	6204	Laramie River Station	Basin Electric Power Coop	WY	$2,266,763	$0	$0	$5,927,526	$8,194,288	$2,140,590	$0	$0	$5,927,526	$8,068,115
488	4150	Neil Simpson	Black Hills Power Inc	WY	$0	$34,654	$0	$0	$34,654	$0	$0	$0	$0	$0
489	7504	Neil Simpson II	Black Hills Power Inc	WY	$723,864	$0	$0	$0	$723,864	$683,572	$0	$0	$0	$683,572

Exhibit J3 Cost for Subtitle C haz waste and Subtitle D Version 1 With Land Treatment Dewatering Sub-Option														
Plant Identity					Subtitle C haz waste					Subtitle D Version 1				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
490	4151	Osage	Black Hills Power Inc	WY	$163,905	$0	$0	$0	$163,905	$154,782	$0	$0	$0	$154,782
491	55479	Wygen 1	Black Hills Power Inc	WY	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
492	4158	Dave Johnston	PacifiCorp	WY	$193,893	$0	$0	$1,273,931	$1,467,824	$183,100	$0	$0	$1,273,931	$1,457,031
493	8066	Jim Bridger	PacifiCorp	WY	$6,246,594	$0	$0	$11,540,315	$17,786,909	$5,898,895	$0	$0	$11,540,315	$17,439,210
494	4162	Naughton	PacifiCorp	WY	$905,116	$0	$0	$12,739,309	$13,644,425	$854,735	$0	$0	$12,739,309	$13,594,044
495	6101	Wyodak	PacifiCorp	WY	$355,027	$988,496	$0	$2,098,239	$3,441,761	$335,265	$0	$0	$2,098,239	$2,433,504
			Total Costs:		$521,000,000	$77,000,000	$0	$1,676,000,000	$2,274,000,000	$492,000,000	$0	$0	$1,676,000,000	$2,168,000,000

Exhibit J4 Cost Hybrid C & D With Land Treatment Dewatering Sub-Option										
Plant Identity					Hybrid C & D					
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
1	79	Aurora Energy LLC Chena	Aurora Energy LLC	AK	$567,289	$0	$0	$0	$567,289
2	6288	Healy	Golden Valley Elec Assn Inc	AK	$397,225	$0	$0	$0	$397,225
3	56	Charles R Lowman	Alabama Electric Coop Inc	AL	$249,394	$0	$0	$2,480,418	$2,729,813
4	3	Barry	Alabama Power Co	AL	$4,202,193	$0	$0	$21,199,709	$25,401,902
5	26	E C Gaston	Alabama Power Co	AL	$396,674	$0	$0	$0	$396,674
6	7	Gadsden	Alabama Power Co	AL	$274,527	$0	$0	$2,555,356	$2,829,882
7	8	Gorgas	Alabama Power Co	AL	$5,305,665	$0	$0	$22,848,326	$28,153,991
8	10	Greene County	Alabama Power Co	AL	$5,462,733	$0	$0	$15,879,174	$21,341,907
9	6002	James H Miller Jr	Alabama Power Co	AL	$2,252,768	$0	$0	$4,608,632	$6,861,400
10	50407	Mobile Energy Services LLC	DTE Energy Services	AL	$11,617	$0	$0	$0	$11,617
11	47	Colbert	Tennessee Valley Authority	AL	$748,024	$0	$0	$2,188,164	$2,936,187
12	50	Widows Creek	Tennessee Valley Authority	AL	$2,317,362	$0	$0	$63,906,370	$66,223,732
13	6641	Independence	Entergy Arkansas Inc	AR	$2,494,332	$0	$0	$0	$2,494,332
14	6009	White Bluff	Entergy Arkansas Inc	AR	$3,108,847	$0	$0	$0	$3,108,847
15	6138	Flint Creek	Southwestern Electric Power Co	AR	$428,824	$0	$0	$1,453,780	$1,882,604
16	160	Apache Station	Arizona Electric Pwr Coop Inc	AZ	$5,172,905	$0	$0	$2,472,925	$7,645,830
17	113	Cholla	Arizona Public Service Co	AZ	$1,550,471	$0	$0	$22,331,260	$23,881,731
18	6177	Coronado	Salt River Project	AZ	$3,388,566	$0	$0	$4,263,922	$7,652,488
19	4941	Navajo	Salt River Project	AZ	$15,951,350	$0	$0	$0	$15,951,350
20	126	H Wilson Sundt Generating Station	Tucson Electric Power Co	AZ	$125,438	$0	$0	$0	$125,438
21	8223	Springerville	Tucson Electric Power Co	AZ	$12,026,040	$0	$0	$0	$12,026,040
22	10002	ACE Cogeneration Facility	ACE Cogeneration Co	CA	$0	$0	$0	$0	$0
23	10640	Stockton Cogen	Air Products Energy Enterprise	CA	$1,215,140	$0	$0	$0	$1,215,140
24	54238	Port of Stockton District Energy Fac	FPL Energy Operating Servs Inc	CA	$515,951	$0	$0	$0	$515,951
25	54626	Mt Poso Cogeneration	Mt Poso Cogeneration Co	CA	$543,680	$0	$0	$0	$543,680
26	10768	Rio Bravo Jasmin	Rio Bravo Jasmin	CA	$313,301	$0	$0	$0	$313,301
27	10769	Rio Bravo Poso	Rio Bravo Poso	CA	$306,959	$0	$0	$0	$306,959
28	462	W N Clark	Aquila, Inc.	CO	$0	$0	$0	$0	$0
29	10003	Colorado Energy Nations Company	Colorado Energy Nations Company LLLP	CO	$0	$0	$0	$0	$0
30	492	Martin Drake	Colorado Springs City of	CO	$0	$0	$0	$0	$0
31	8219	Ray D Nixon	Colorado Springs City of	CO	$0	$0	$0	$0	$0
32	6761	Rawhide	Platte River Power Authority	CO	$258,135	$0	$0	$427,142	$685,277
33	465	Arapahoe	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
34	468	Cameo	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
35	469	Cherokee	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
36	470	Comanche	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
37	525	Hayden	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0

Exhibit J4
Cost Hybrid C & D With Land Treatment Dewatering Sub-Option

Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
38	6248	Pawnee	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
39	477	Valmont	Public Service Co of Colorado	CO	$0	$0	$0	$0	$0
40	6021	Craig	Tri-State G & T Assn, Inc	CO	$0	$0	$0	$0	$0
41	527	Nucla	Tri-State G & T Assn, Inc	CO	$0	$0	$0	$0	$0
42	10675	AES Thames	AES Thames LLC	CT	$0	$0	$0	$0	$0
43	568	Bridgeport Station	PSEG Power Connecticut LLC	CT	$0	$0	$0	$0	$0
44	593	Edge Moor	Conectiv Delmarva Gen Inc	DE	$0	$0	$0	$0	$0
45	594	Indian River Generating Station	Indian River Operations Inc	DE	$1,985,635	$0	$0	$0	$1,985,635
46	10030	NRG Energy Center Dover	NRG Energy Center Dover LLC	DE	$290,916	$0	$0	$0	$290,916
47	10333	Central Power & Lime	Central Power & Lime Inc	FL	$0	$0	$0	$0	$0
48	676	C D McIntosh Jr	City of Lakeland	FL	$927,531	$0	$0	$0	$927,531
49	663	Deerhaven Generating Station	Gainesville Regional Utilities	FL	$65,238	$0	$0	$0	$65,238
50	641	Crist	Gulf Power Co	FL	$0	$0	$0	$0	$0
51	643	Lansing Smith	Gulf Power Co	FL	$305,662	$0	$0	$5,268,079	$5,573,741
52	642	Scholz	Gulf Power Co	FL	$0	$0	$0	$0	$0
53	667	Northside Generating Station	JEA	FL	$2,801,856	$0	$0	$0	$2,801,856
54	207	St Johns River Power Park	JEA	FL	$1,914,218	$0	$0	$0	$1,914,218
55	564	Stanton Energy Center	Orlando Utilities Comm	FL	$2,170,584	$0	$0	$0	$2,170,584
56	628	Crystal River	Progress Energy Florida Inc	FL	$298,912	$0	$0	$0	$298,912
57	136	Seminole	Seminole Electric Coop, Inc	FL	$3,038,220	$0	$0	$0	$3,038,220
58	645	Big Bend	Tampa Electric Co	FL	$41,617	$0	$0	$277,267	$318,885
59	7242	Polk	Tampa Electric Co	FL	$927,213	$0	$0	$0	$927,213
60	10672	Cedar Bay Generating Company LP	US Operating Services Company	FL	$0	$0	$0	$0	$0
61	50976	Indiantown Cogeneration LP	US Operating Services Company	FL	$0	$0	$0	$0	$0
62	753	Crisp Plant	Crisp County Power Comm	GA	$9,274	$0	$0	$0	$9,274
63	703	Bowen	Georgia Power Co	GA	$9,832,825	$0	$0	$6,991,633	$16,824,457
64	708	Hammond	Georgia Power Co	GA	$464,894	$0	$0	$0	$464,894
65	709	Harllee Branch	Georgia Power Co	GA	$1,258,233	$0	$0	$31,196,320	$32,454,553
66	710	Jack McDonough	Georgia Power Co	GA	$136,446	$0	$0	$0	$136,446
67	733	Kraft	Georgia Power Co	GA	$204,910	$0	$0	$749,371	$954,281
68	6124	McIntosh	Georgia Power Co	GA	$435,383	$0	$0	$1,124,057	$1,559,439
69	727	Mitchell	Georgia Power Co	GA	$0	$0	$0	$0	$0
70	6257	Scherer	Georgia Power Co	GA	$3,875,110	$0	$0	$35,265,405	$39,140,516
71	6052	Wansley	Georgia Power Co	GA	$2,629,932	$0	$0	$40,218,748	$42,848,680
72	728	Yates	Georgia Power Co	GA	$587,971	$0	$0	$0	$587,971
73	10673	AES Hawaii	AES Hawaii Inc	HI	$0	$0	$0	$0	$0
74	10604	Hawaiian Comm & Sugar Puunene Mill	Hawaiian Com & Sugar Co Ltd	HI	$717,537	$0	$0	$0	$717,537
75	1122	Ames Electric Services Power Plant	Ames City of	IA	$19,694	$0	$0	$0	$19,694
76	1167	Muscatine Plant #1	Board of Water Electric & Communications	IA	$6,110	$0	$0	$0	$6,110

Exhibit J4
Cost Hybrid C & D With Land Treatment Dewatering Sub-Option

Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
77	1131	Streeter Station	Cedar Falls Utilities	IA	$3,384	$0	$0	$0	$3,384
78	1218	Fair Station	Central Iowa Power Cooperative	IA	$64,386	$0	$0	$0	$64,386
79	1217	Earl F Wisdom	Corn Belt Power Coop	IA	$0	$0	$0	$0	$0
80	1104	Burlington	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
81	1046	Dubuque	Interstate Power and Light Co	IA	$24,230	$0	$0	$0	$24,230
82	1047	Lansing	Interstate Power and Light Co	IA	$331,173	$0	$0	$1,798,491	$2,129,664
83	1048	Milton L Kapp	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
84	6254	Ottumwa	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
85	1073	Prairie Creek	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
86	1058	Sixth Street	Interstate Power and Light Co	IA	$36,969	$0	$0	$0	$36,969
87	1077	Sutherland	Interstate Power and Light Co	IA	$0	$0	$0	$0	$0
88	1091	George Neal North	MidAmerican Energy Co	IA	$2,904,636	$0	$0	$3,761,843	$6,666,479
89	7343	George Neal South	MidAmerican Energy Co	IA	$183,987	$0	$0	$0	$183,987
90	6664	Louisa	MidAmerican Energy Co	IA	$2,001,170	$0	$0	$1,723,554	$3,724,724
91	1081	Riverside	MidAmerican Energy Co	IA	$0	$0	$0	$0	$0
92	1082	Walter Scott Jr Energy Center	MidAmerican Energy Co	IA	$3,498,450	$0	$0	$7,830,928	$11,329,379
93	1175	Pella	Pella City of	IA	$0	$0	$0	$0	$0
94	861	Coffeen	Ameren Energy Generating Co	IL	$0	$0	$0	$0	$0
95	863	Hutsonville	Ameren Energy Generating Co	IL	$406,643	$0	$0	$2,323,050	$2,729,694
96	864	Meredosia	Ameren Energy Generating Co	IL	$901,035	$0	$0	$3,596,981	$4,498,016
97	6017	Newton	Ameren Energy Generating Co	IL	$1,180,436	$0	$0	$8,168,145	$9,348,581
98	6016	Duck Creek	Ameren Energy Resources Generating Co.	IL	$5,467,375	$0	$0	$13,863,366	$19,330,741
99	856	E D Edwards	Ameren Energy Resources Generating Co.	IL	$370,060	$0	$0	$3,896,730	$4,266,790
100	963	Dallman	City of Springfield	IL	$880,455	$0	$0	$5,402,966	$6,283,420
101	964	Lakeside	City of Springfield	IL	$0	$0	$0	$0	$0
102	876	Kincaid Generation LLC	Dominion Energy Services Co	IL	$0	$0	$0	$0	$0
103	889	Baldwin Energy Complex	Dynegy Midwest Generation Inc	IL	$2,970,179	$0	$0	$8,692,705	$11,662,884
104	891	Havana	Dynegy Midwest Generation Inc	IL	$1,354,744	$0	$0	$6,444,592	$7,799,336
105	892	Hennepin Power Station	Dynegy Midwest Generation Inc	IL	$220,279	$0	$0	$1,558,692	$1,778,971
106	897	Vermilion	Dynegy Midwest Generation Inc	IL	$142,123	$0	$0	$1,026,638	$1,168,761
107	898	Wood River	Dynegy Midwest Generation Inc	IL	$280,100	$0	$0	$1,064,107	$1,344,207
108	887	Joppa Steam	Electric Energy Inc	IL	$0	$0	$0	$0	$0
109	867	Crawford	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
110	886	Fisk Street	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
111	384	Joliet 29	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
112	874	Joliet 9	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
113	879	Powerton	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
114	883	Waukegan	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
115	884	Will County	Midwest Generations EME LLC	IL	$0	$0	$0	$0	$0
116	976	Marion	Southern Illinois Power Coop	IL	$0	$0	$0	$0	$0
117	6238	Pearl Station	Soyland Power Coop Inc	IL	$174,527	$0	$0	$0	$174,527
118	55245	Tuscola Station	Trigen-Cinergy Sol-Tuscola LLC	IL	$261,353	$0	$0	$0	$261,353

Exhibit J4
Cost Hybrid C & D With Land Treatment Dewatering Sub-Option

Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
119	6705	Warrick	AGC Division of APG Inc	IN	$4,532,740	$0	$0	$18,127,288	$22,660,028
120	992	CC Perry K	Citizens Thermal Energy	IN	$8,040	$0	$0	$0	$8,040
121	6225	Jasper 2	City of Jasper	IN	$6,590	$0	$0	$0	$6,590
122	1032	Logansport	City of Logansport	IN	$11,793	$0	$0	$0	$11,793
123	1040	Whitewater Valley	City of Richmond	IN	$58,749	$0	$0	$0	$58,749
124	1024	Crawfordsville	Crawfordsville Elec, Lgt & Pwr	IN	$13,630	$0	$0	$0	$13,630
125	1001	Cayuga	Duke Energy Indiana Inc	IN	$4,299,084	$0	$0	$15,804,237	$20,103,322
126	1004	Edwardsport	Duke Energy Indiana Inc	IN	$312,616	$0	$0	$861,777	$1,174,393
127	6113	Gibson	Duke Energy Indiana Inc	IN	$5,515,408	$0	$0	$67,278,540	$72,793,948
128	1008	R Gallagher	Duke Energy Indiana Inc	IN	$961,213	$0	$0	$9,412,101	$10,373,314
129	1010	Wabash River	Duke Energy Indiana Inc	IN	$6,881,013	$0	$0	$14,395,419	$21,276,432
130	1043	Frank E Ratts	Hoosier Energy R E C, Inc	IN	$297,279	$0	$0	$2,982,497	$3,279,776
131	6213	Merom	Hoosier Energy R E C, Inc	IN	$38,577	$0	$0	$0	$38,577
132	6166	Rockport	Indiana Michigan Power Co	IN	$1,679,488	$0	$0	$884,258	$2,563,746
133	988	Tanners Creek	Indiana Michigan Power Co	IN	$2,037,635	$0	$0	$10,536,158	$12,573,793
134	983	Clifty Creek	Indiana-Kentucky Electric Corp	IN	$575,603	$0	$0	$1,626,135	$2,201,738
135	994	AES Petersburg	Indianapolis Power & Light Co	IN	$5,859	$0	$0	$0	$5,859
136	991	Eagle Valley	Indianapolis Power & Light Co	IN	$162,274	$0	$0	$0	$162,274
137	990	Harding Street	Indianapolis Power & Light Co	IN	$999,093	$0	$0	$13,181,438	$14,180,531
138	995	Bailly	Northern Indiana Pub Serv Co	IN	$592,246	$0	$0	$0	$592,246
139	997	Michigan City	Northern Indiana Pub Serv Co	IN	$187,560	$0	$0	$0	$187,560
140	6085	R M Schahfer	Northern Indiana Pub Serv Co	IN	$248,414	$0	$0	$187,343	$435,756
141	1037	Peru	Peru City of	IN	$17,710	$0	$0	$0	$17,710
142	6137	A B Brown	Southern Indiana Gas & Elec Co	IN	$1,604,311	$0	$0	$12,420,826	$14,025,137
143	1012	F B Culley	Southern Indiana Gas & Elec Co	IN	$423,003	$0	$0	$2,667,761	$3,090,764
144	981	State Line Energy	State Line Energy LLC	IN	$0	$0	$0	$0	$0
145	1239	Riverton	Empire District Electric Co	KS	$83,896	$0	$0	$0	$83,896
146	6064	Nearman Creek	Kansas City City of	KS	$332,023	$0	$0	$764,359	$1,096,382
147	1295	Quindaro	Kansas City City of	KS	$0	$0	$0	$0	$0
148	1241	La Cygne	Kansas City Power & Light Co	KS	$2,008,331	$0	$0	$0	$2,008,331
149	108	Holcomb	Sunflower Electric Power Corp	KS	$901,186	$0	$0	$0	$901,186
150	6068	Jeffrey Energy Center	Westar Energy Inc	KS	$4,932,501	$0	$0	$13,795,922	$18,728,423
151	1250	Lawrence Energy Center	Westar Energy Inc	KS	$12,262	$0	$0	$0	$12,262
152	1252	Tecumseh Energy Center	Westar Energy Inc	KS	$18,785	$0	$0	$0	$18,785
153	1374	Elmer Smith	City of Owensboro	KY	$0	$0	$0	$0	$0
154	6018	East Bend	Duke Energy Kentucky Inc	KY	$2,069,884	$0	$0	$12,956,627	$15,026,511
155	1384	Cooper	East Kentucky Power Coop, Inc	KY	$212,548	$0	$0	$0	$212,548
156	1385	Dale	East Kentucky Power Coop, Inc	KY	$908,405	$0	$0	$4,496,227	$5,404,631
157	6041	H L Spurlock	East Kentucky Power Coop, Inc	KY	$8,129,129	$0	$0	$322,230	$8,451,358
158	1372	Henderson I	Henderson City Utility Comm	KY	$10,878	$0	$0	$0	$10,878
159	1353	Big Sandy	Kentucky Power Co	KY	$5,686,904	$0	$0	$22,353,741	$28,040,645
160	1355	E W Brown	Kentucky Utilities Co	KY	$319,474	$0	$0	$10,528,664	$10,848,138

Exhibit J4 Cost Hybrid C & D With Land Treatment Dewatering Sub-Option									
Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
161	1356	Ghent	Kentucky Utilities Co	KY	$11,373,101	$0	$0	$47,562,585	$58,935,686
162	1357	Green River	Kentucky Utilities Co	KY	$349,271	$0	$0	$2,293,076	$2,642,347
163	1361	Tyrone	Kentucky Utilities Co	KY	$185,316	$0	$0	$1,416,311	$1,601,627
164	1363	Cane Run	Louisville Gas & Electric Co	KY	$1,725,911	$0	$0	$2,780,167	$4,506,078
165	1364	Mill Creek	Louisville Gas & Electric Co	KY	$5,251,934	$0	$0	$4,848,431	$10,100,365
166	6071	Trimble County	Louisville Gas & Electric Co	KY	$208,071	$0	$0	$13,720,985	$13,929,056
167	1378	Paradise	Tennessee Valley Authority	KY	$7,306,578	$0	$0	$41,792,428	$49,099,006
168	1379	Shawnee	Tennessee Valley Authority	KY	$623,905	$0	$0	$4,578,658	$5,202,563
169	6823	D B Wilson	Western Kentucky Energy Corp	KY	$6,137,559	$0	$0	$0	$6,137,559
170	1382	HMP&L Station Two Henderson	Western Kentucky Energy Corp	KY	$6,001,263	$0	$0	$921,726	$6,922,990
171	1381	Kenneth C Coleman	Western Kentucky Energy Corp	KY	$308,646	$0	$0	$0	$308,646
172	6639	R D Green	Western Kentucky Energy Corp	KY	$6,708,840	$0	$0	$1,633,629	$8,342,469
173	1383	Robert A Reid	Western Kentucky Energy Corp	KY	$36,022	$0	$0	$0	$36,022
174	51	Dolet Hills	Cleco Power LLC	LA	$1,253,675	$0	$0	$3,889,236	$5,142,911
175	6190	Rodemacher	Cleco Power LLC	LA	$0	$0	$0	$0	$0
176	1393	R S Nelson	Entergy Gulf States Louisiana LLC	LA	$0	$0	$0	$0	$0
177	6055	Big Cajun 2	Louisiana Generating LLC	LA	$140,032	$0	$0	$10,446,234	$10,586,266
178	1619	Brayton Point	Dominion Energy New England, LLC	MA	$0	$0	$0	$0	$0
179	1626	Salem Harbor	Dominion Energy New England, LLC	MA	$0	$0	$0	$0	$0
180	1606	Mount Tom	FirstLight Power Resources Services LLC	MA	$0	$0	$0	$0	$0
181	1613	Somerset Station	Somerset Power LLC	MA	$0	$0	$0	$0	$0
182	10678	AES Warrior Run Cogeneration Facility	AES WR Ltd Partnership	MD	$0	$0	$0	$0	$0
183	1570	R Paul Smith Power Station	Allegheny Energy Supply Co LLC	MD	$703,963	$0	$0	$1,880,922	$2,584,884
184	602	Brandon Shores	Constellation Power Source Gen	MD	$0	$0	$0	$0	$0
185	1552	C P Crane	Constellation Power Source Gen	MD	$0	$0	$0	$0	$0
186	1554	Herbert A Wagner	Constellation Power Source Gen	MD	$0	$0	$0	$0	$0
187	1571	Chalk Point LLC	Mirant Chalk Point LLC	MD	$692,449	$0	$0	$0	$692,449
188	1572	Dickerson	Mirant Mid-Atlantic LLC	MD	$155,066	$0	$0	$0	$155,066
189	1573	Morgantown Generating Plant	Mirant Mid-Atlantic LLC	MD	$99,080	$0	$0	$0	$99,080
190	10495	Rumford Cogeneration	NewPage Corporation	ME	$387,134	$0	$0	$0	$387,134
191	1825	J B Sims	City of Grand Haven	MI	$21,701	$0	$0	$0	$21,701
192	1830	James De Young	City of Holland	MI	$13,010	$0	$0	$0	$13,010
193	1843	Shiras	City of Marquette	MI	$10,877	$0	$0	$0	$10,877
194	1695	B C Cobb	Consumers Energy Co	MI	$0	$0	$0	$0	$0
195	1702	Dan E Karn	Consumers Energy Co	MI	$16,376	$0	$0	$8,153,158	$8,169,534
196	1720	J C Weadock	Consumers Energy Co	MI	$687,658	$0	$0	$5,238,104	$5,925,762
197	1710	J H Campbell	Consumers Energy Co	MI	$25,272	$0	$0	$0	$25,272
198	1723	J R Whiting	Consumers Energy Co	MI	$26,218	$0	$0	$254,786	$281,004
199	6034	Belle River	Detroit Edison Co	MI	$28,506	$0	$0	$0	$28,506
200	1731	Harbor Beach	Detroit Edison Co	MI	$9,211	$0	$0	$0	$9,211

Exhibit J4
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Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
201	1733	Monroe	Detroit Edison Co	MI	$5,283,883	$0	$0	$36,119,688	$41,403,571
202	1740	River Rouge	Detroit Edison Co	MI	$19,946	$0	$0	$0	$19,946
203	1743	St Clair	Detroit Edison Co	MI	$25,720	$0	$0	$0	$25,720
204	1745	Trenton Channel	Detroit Edison Co	MI	$27,739	$0	$0	$0	$27,739
205	1831	Eckert Station	Lansing Board of Water and Light	MI	$0	$0	$0	$0	$0
206	1832	Erickson Station	Lansing Board of Water and Light	MI	$301,844	$0	$0	$382,179	$684,024
207	4259	Endicott Station	Michigan South Central Pwr Agy	MI	$20,262	$0	$0	$0	$20,262
208	50835	TES Filer City Station	TES Filer City Station LP	MI	$16,142	$0	$0	$0	$16,142
209	1771	Escanaba	Upper Peninsula Power Co	MI	$8,817	$0	$0	$0	$8,817
210	10148	White Pine Electric Power	White Pine Electric Power LLC	MI	$8,455	$0	$0	$0	$8,455
211	1769	Presque Isle	Wisconsin Electric Power Co	MI	$17,794	$0	$0	$0	$17,794
212	1866	Wyandotte	Wyandotte Municipal Serv Comm	MI	$14,085	$0	$0	$0	$14,085
213	1961	Austin Northeast	Austin City of	MN	$1,444	$0	$0	$0	$1,444
214	2018	Virginia	City of Virginia	MN	$6,604	$0	$0	$0	$6,604
215	1979	Hibbing	Hibbing Public Utilities Comm	MN	$3,226	$0	$0	$0	$3,226
216	1893	Clay Boswell	Minnesota Power Inc	MN	$2,520,246	$0	$0	$21,072,316	$23,592,562
217	1897	M L Hibbard	Minnesota Power Inc	MN	$0	$0	$0	$0	$0
218	10686	Rapids Energy Center	Minnesota Power Inc	MN	$0	$0	$0	$0	$0
219	1891	Syl Laskin	Minnesota Power Inc	MN	$177,369	$0	$0	$1,513,730	$1,691,099
220	10075	Taconite Harbor Energy Center	Minnesota Power Inc	MN	$39,078	$0	$0	$0	$39,078
221	2001	New Ulm	New Ulm Public Utilities Comm	MN	$8,275	$0	$0	$0	$8,275
222	1915	Allen S King	Northern States Power Co	MN	$13,271	$0	$0	$0	$13,271
223	1904	Black Dog	Northern States Power Co	MN	$183,365	$0	$0	$359,698	$543,063
224	1927	Riverside	Northern States Power Co	MN	$282,776	$0	$0	$502,079	$784,855
225	6090	Sherburne County	Northern States Power Co	MN	$15,989,117	$0	$0	$37,543,493	$53,532,611
226	1943	Hoot Lake	Otter Tail Power Co	MN	$8,406	$0	$0	$0	$8,406
227	2008	Silver Lake	Rochester Public Utilities	MN	$27,198	$0	$0	$0	$27,198
228	2022	Willmar	Willmar Municipal Utils Comm	MN	$8,555	$0	$0	$0	$8,555
229	2098	Lake Road	Aquila, Inc.	MO	$0	$0	$0	$0	$0
230	2094	Sibley	Aquila, Inc.	MO	$152,029	$0	$0	$0	$152,029
231	2167	New Madrid	Associated Electric Coop, Inc	MO	$2,584,292	$0	$0	$8,183,133	$10,767,424
232	2168	Thomas Hill	Associated Electric Coop, Inc	MO	$100,856	$0	$0	$0	$100,856
233	2169	Chamois	Central Electric Power Coop	MO	$191,069	$0	$0	$0	$191,069
234	2123	Columbia	City of Columbia	MO	$21,389	$0	$0	$0	$21,389
235	2144	Marshall	City of Marshall	MO	$19,977	$0	$0	$0	$19,977
236	6768	Sikeston Power Station	City of Sikeston	MO	$952,169	$0	$0	$846,789	$1,798,959
237	2161	James River Power Station	City Utilities of Springfield	MO	$87,141	$0	$0	$0	$87,141
238	6195	Southwest Power Station	City Utilities of Springfield	MO	$1,188,827	$0	$0	$0	$1,188,827
239	2076	Asbury	Empire District Electric Co	MO	$142,502	$0	$0	$4,009,136	$4,151,637
240	2132	Blue Valley	Independence City of	MO	$300,386	$0	$0	$2,229,379	$2,529,765
241	2171	Missouri City	Independence City of	MO	$41,286	$0	$0	$0	$41,286
242	2079	Hawthorn	Kansas City Power & Light Co	MO	$216,151	$0	$0	$0	$216,151

Exhibit J4 Cost Hybrid C & D With Land Treatment Dewatering Sub-Option									
Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
243	6065	Iatan	Kansas City Power & Light Co	MO	$316,796	$0	$0	$1,228,969	$1,545,765
244	2080	Montrose	Kansas City Power & Light Co	MO	$181,721	$0	$0	$0	$181,721
245	2103	Labadie	Union Electric Co	MO	$570,739	$0	$0	$18,734,278	$19,305,017
246	2104	Meramec	Union Electric Co	MO	$840,898	$0	$0	$8,318,020	$9,158,918
247	6155	Rush Island	Union Electric Co	MO	$1,889,190	$0	$0	$7,193,963	$9,083,153
248	2107	Sioux	Union Electric Co	MO	$314,968	$0	$0	$7,643,585	$7,958,554
249	55076	Red Hills Generating Facility	Choctaw Generating LP	MS	$711,133	$0	$0	$0	$711,133
250	2062	Henderson	Greenwood Utilities Comm	MS	$13,538	$0	$0	$0	$13,538
251	2049	Jack Watson	Mississippi Power Co	MS	$337,017	$0	$0	$2,930,041	$3,267,058
252	6073	Victor J Daniel Jr	Mississippi Power Co	MS	$839,777	$0	$0	$0	$839,777
253	6061	R D Morrow	South Mississippi El Pwr Assn	MS	$1,805,579	$0	$0	$0	$1,805,579
254	10784	Colstrip Energy LP	Colstrip Energy LP	MT	$12,176	$0	$0	$0	$12,176
255	6089	Lewis & Clark	MDU Resources Group Inc	MT	$9,988	$0	$0	$0	$9,988
256	6076	Colstrip	PPL Montana LLC	MT	$20,205,971	$0	$0	$72,209,402	$92,415,373
257	2187	J E Corette Plant	PPL Montana LLC	MT	$0	$0	$0	$0	$0
258	55749	Hardin Generator Project	Rocky Mountain Power Inc	MT	$36,652	$0	$0	$0	$36,652
259	10381	Coastal Carolina Clean Power	Carlyle/Riverstone Renewable Energy	NC	$89,227	$0	$0	$0	$89,227
260	8042	Belews Creek	Duke Energy Carolinas, LLC	NC	$4,523,597	$0	$0	$3,102,396	$7,625,994
261	2720	Buck	Duke Energy Carolinas, LLC	NC	$204,494	$0	$0	$9,134,834	$9,339,328
262	2721	Cliffside	Duke Energy Carolinas, LLC	NC	$503,958	$0	$0	$7,261,406	$7,765,364
263	2723	Dan River	Duke Energy Carolinas, LLC	NC	$735,010	$0	$0	$2,135,708	$2,870,717
264	2718	G G Allen	Duke Energy Carolinas, LLC	NC	$691,909	$0	$0	$10,745,982	$11,437,891
265	2727	Marshall	Duke Energy Carolinas, LLC	NC	$4,013,475	$0	$0	$2,510,393	$6,523,868
266	2732	Riverbend	Duke Energy Carolinas, LLC	NC	$1,897,808	$0	$0	$6,976,645	$8,874,454
267	10384	Edgecombe Genco LLC	Edgecombe Operating Services LLC	NC	$0	$0	$0	$0	$0
268	10380	Elizabethtown Power LLC	North Carolina Power Holdings, LLC	NC	$35,244	$0	$0	$0	$35,244
269	10382	Lumberton	North Carolina Power Holdings, LLC	NC	$32,453	$0	$0	$0	$32,453
270	10379	Primary Energy Roxboro	Primary Energy of North Carolina LLC	NC	$66,095	$0	$0	$0	$66,095
271	10378	Primary Energy Southport	Primary Energy of North Carolina LLC	NC	$0	$0	$0	$0	$0
272	2706	Asheville	Progress Energy Carolinas Inc	NC	$317,017	$0	$0	$7,943,334	$8,260,351
273	2708	Cape Fear	Progress Energy Carolinas Inc	NC	$303,976	$0	$0	$7,591,130	$7,895,106
274	2713	L V Sutton	Progress Energy Carolinas Inc	NC	$381,594	$0	$0	$12,439,561	$12,821,154
275	2709	Lee	Progress Energy Carolinas Inc	NC	$419,097	$0	$0	$7,950,828	$8,369,925
276	6250	Mayo	Progress Energy Carolinas Inc	NC	$464,628	$0	$0	$15,946,618	$16,411,245
277	2712	Roxboro	Progress Energy Carolinas Inc	NC	$931,611	$0	$0	$3,469,588	$4,401,199
278	2716	W H Weatherspoon	Progress Energy Carolinas Inc	NC	$213,277	$0	$0	$3,522,044	$3,735,322
279	54035	Roanoke Valley Energy Facililty I	Westmoreland Partners	NC	$27,646	$0	$0	$0	$27,646
280	54755	Roanoke Valley Energy Facility II	Westmoreland Partners	NC	$78,881	$0	$0	$0	$78,881
281	6469	Antelope Valley	Basin Electric Power Coop	ND	$94,662	$0	$0	$0	$94,662
282	2817	Leland Olds	Basin Electric Power Coop	ND	$53,918	$0	$0	$14,597,750	$14,651,668

Exhibit J4 Cost Hybrid C & D With Land Treatment Dewatering Sub-Option									
Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
283	6030	Coal Creek	Great River Energy	ND	$39,260	$0	$0	$0	$39,260
284	2824	Stanton	Great River Energy	ND	$16,949	$0	$0	$0	$16,949
285	2790	R M Heskett	MDU Resources Group Inc	ND	$23,654	$0	$0	$0	$23,654
286	2823	Milton R Young	Minnkota Power Coop, Inc	ND	$41,273	$0	$0	$10,491,196	$10,532,469
287	8222	Coyote	Otter Tail Power Co	ND	$37,114	$0	$0	$0	$37,114
288	2240	Lon Wright	Fremont City of	NE	$34,801	$0	$0	$0	$34,801
289	59	Platte	Grand Island City of	NE	$0	$0	$0	$0	$0
290	60	Whelan Energy Center	Hastings City of	NE	$680,197	$0	$0	$0	$680,197
291	6077	Gerald Gentleman	Nebraska Public Power District	NE	$2,763,721	$0	$0	$0	$2,763,721
292	2277	Sheldon	Nebraska Public Power District	NE	$248,751	$0	$0	$0	$248,751
293	6096	Nebraska City	Omaha Public Power District	NE	$334,933	$0	$0	$0	$334,933
294	2291	North Omaha	Omaha Public Power District	NE	$140,345	$0	$0	$0	$140,345
295	2364	Merrimack	Public Service Co of NH	NH	$38,236	$0	$0	$0	$38,236
296	2367	Schiller	Public Service Co of NH	NH	$0	$0	$0	$0	$0
297	2384	Deepwater	Conectiv Atlantic Generatn Inc	NJ	$0	$0	$0	$0	$0
298	2403	PSEG Hudson Generating Station	PSEG Fossil LLC	NJ	$0	$0	$0	$0	$0
299	2408	PSEG Mercer Generating Station	PSEG Fossil LLC	NJ	$0	$0	$0	$0	$0
300	2378	B L England	RC Cape May Holdings LLC	NJ	$0	$0	$0	$0	$0
301	10566	Chambers Cogeneration LP	US Operating Services Company	NJ	$0	$0	$0	$0	$0
302	10043	Logan Generating Company LP	US Operating Services Company	NJ	$1,582,552	$0	$0	$0	$1,582,552
303	2434	Howard Down	Vineland City of	NJ	$164,747	$0	$0	$0	$164,747
304	2442	Four Corners	Arizona Public Service Co	NM	$1,326,391	$0	$0	$37,573,468	$38,899,859
305	2451	San Juan	Public Service Co of NM	NM	$8,496,813	$0	$0	$0	$8,496,813
306	87	Escalante	Tri-State G & T Assn, Inc	NM	$2,363,818	$0	$0	$1,176,513	$3,540,330
307	2324	Reid Gardner	Nevada Power Co	NV	$1,227,499	$0	$0	$0	$1,227,499
308	8224	North Valmy	Sierra Pacific Power Co	NV	$4,100,706	$0	$0	$0	$4,100,706
309	2535	AES Cayuga	AES Cayuga LLC	NY	$0	$0	$0	$0	$0
310	2527	AES Greenidge LLC	AES Greenidge	NY	$0	$0	$0	$0	$0
311	6082	AES Somerset LLC	AES Somerset LLC	NY	$0	$0	$0	$0	$0
312	2526	AES Westover	AES Westover LLC	NY	$0	$0	$0	$0	$0
313	10464	Black River Generation	Black River Generation LLC	NY	$0	$0	$0	$0	$0
314	2554	Dunkirk Generating Plant	Dunkirk Power LLC	NY	$0	$0	$0	$0	$0
315	2480	Danskammer Generating Station	Dynegy Northeast Gen Inc	NY	$0	$0	$0	$0	$0
316	2682	S A Carlson	Jamestown Board of Public Util	NY	$0	$0	$0	$0	$0
317	2629	Lovett	Mirant New York Inc	NY	$0	$0	$0	$0	$0
318	50202	WPS Power Niagara	Niagara Generation LLC	NY	$0	$0	$0	$0	$0
319	2549	C R Huntley Generating Station	NRG Huntley Operations Inc	NY	$0	$0	$0	$0	$0
320	2642	Rochester 7	Rochester Gas & Electric Corp	NY	$0	$0	$0	$0	$0
321	50651	Trigen Syracuse Energy	Syracuse Energy Corp	NY	$0	$0	$0	$0	$0

Exhibit J4 Cost Hybrid C & D With Land Treatment Dewatering Sub-Option									
Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
322	7286	Richard Gorsuch	American Mun Power-Ohio, Inc	OH	$0	$0	$0	$0	$0
323	2828	Cardinal	Cardinal Operating Co	OH	$1,908,733	$0	$0	$36,749,160	$38,657,893
324	2914	Dover	City of Dover	OH	$0	$0	$0	$0	$0
325	2917	Hamilton	City of Hamilton	OH	$0	$0	$0	$0	$0
326	2935	Orrville	City of Orrville	OH	$0	$0	$0	$0	$0
327	2936	Painesville	City of Painesville	OH	$0	$0	$0	$0	$0
328	2943	Shelby Municipal Light Plant	City of Shelby	OH	$0	$0	$0	$0	$0
329	2840	Conesville	Columbus Southern Power Co	OH	$4,096,257	$0	$0	$37,003,946	$41,100,203
330	2843	Picway	Columbus Southern Power Co	OH	$263,719	$0	$0	$794,333	$1,058,052
331	2850	J M Stuart	Dayton Power & Light Co	OH	$4,502,661	$0	$0	$48,956,416	$53,459,077
332	6031	Killen Station	Dayton Power & Light Co	OH	$5,089,636	$0	$0	$18,929,115	$24,018,751
333	2848	O H Hutchings	Dayton Power & Light Co	OH	$0	$0	$0	$0	$0
334	2832	Miami Fort	Duke Energy Ohio Inc	OH	$5,184,010	$0	$0	$16,808,394	$21,992,404
335	6019	W H Zimmer	Duke Energy Ohio Inc	OH	$0	$0	$0	$0	$0
336	2830	Walter C Beckjord	Duke Energy Ohio Inc	OH	$602,548	$0	$0	$5,747,677	$6,350,224
337	2835	Ashtabula	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
338	2878	Bay Shore	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
339	2837	Eastlake	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
340	2838	Lake Shore	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
341	2864	R E Burger	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
342	2866	W H Sammis	FirstEnergy Generation Corp	OH	$0	$0	$0	$0	$0
343	8102	General James M Gavin	Ohio Power Co	OH	$560,716	$0	$0	$6,796,796	$7,357,512
344	2872	Muskingum River	Ohio Power Co	OH	$1,639,338	$0	$0	$10,745,982	$12,385,320
345	2876	Kyger Creek	Ohio Valley Electric Corp	OH	$2,260,712	$0	$0	$17,347,942	$19,608,653
346	2836	Avon Lake	Orion Power Midwest LP	OH	$0	$0	$0	$0	$0
347	2861	Niles	Orion Power Midwest LP	OH	$0	$0	$0	$0	$0
348	10671	AES Shady Point LLC	AES Shady Point LLC	OK	$0	$0	$0	$0	$0
349	165	GRDA	Grand River Dam Authority	OK	$2,113,731	$0	$0	$0	$2,113,731
350	2952	Muskogee	Oklahoma Gas & Electric Co	OK	$0	$0	$0	$0	$0
351	6095	Sooner	Oklahoma Gas & Electric Co	OK	$0	$0	$0	$0	$0
352	2963	Northeastern	Public Service Co of Oklahoma	OK	$0	$0	$0	$0	$0
353	6772	Hugo	Western Farmers Elec Coop, Inc	OK	$5,176	$0	$0	$1,240,959	$1,246,134
354	6106	Boardman	Portland General Electric Co	OR	$804,138	$0	$0	$0	$804,138
355	10676	AES Beaver Valley Partners Beaver Valley	AES Beaver Valley	PA	$0	$0	$0	$0	$0
356	3178	Armstrong Power Station	Allegheny Energy Supply Co LLC	PA	$47,979	$0	$0	$0	$47,979
357	3179	Hatfields Ferry Power Station	Allegheny Energy Supply Co LLC	PA	$81,306	$0	$0	$0	$81,306
358	3181	Mitchell Power Station	Allegheny Energy Supply Co LLC	PA	$12,238	$0	$0	$0	$12,238
359	10641	Cambria Cogen	Cambria CoGen Co	PA	$575,691	$0	$0	$0	$575,691
360	54144	Piney Creek Project	Colmac Clarion Inc	PA	$131,965	$0	$0	$0	$131,965
361	10603	Ebensburg Power	Ebensburg Power Co	PA	$408,971	$0	$0	$0	$408,971
362	3159	Cromby Generating Station	Exelon Power	PA	$0	$0	$0	$0	$0

Exhibit J4
Cost Hybrid C & D With Land Treatment Dewatering Sub-Option

Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
363	3161	Eddystone Generating Station	Exelon Power	PA	$0	$0	$0	$0	$0
364	6094	Bruce Mansfield	FirstEnergy Generation Corp	PA	$31,576,164	$0	$0	$77,852,166	$109,428,330
365	10113	John B Rich Memorial Power Station	Gilberton Power Co	PA	$531,011	$0	$0	$0	$531,011
366	10143	Colver Power Project	Inter-Power/AhlCon Partners, L.P.	PA	$0	$0	$0	$0	$0
367	3122	Homer City Station	Midwest Generations EME LLC	PA	$409,404	$0	$0	$0	$409,404
368	10343	Foster Wheeler Mt Carmel Cogen	Mount Carmel Cogen Inc	PA	$577,903	$0	$0	$0	$577,903
369	50039	Kline Township Cogen Facility	Northeastern Power Co	PA	$427,999	$0	$0	$0	$427,999
370	8226	Cheswick Power Plant	Orion Power Midwest LP	PA	$26,060	$0	$0	$0	$26,060
371	3098	Elrama Power Plant	Orion Power Midwest LP	PA	$0	$0	$0	$0	$0
372	3138	New Castle Plant	Orion Power Midwest LP	PA	$21,817	$0	$0	$0	$21,817
373	50776	Panther Creek Energy Facility	Panther Creek Partners	PA	$352,069	$0	$0	$0	$352,069
374	3140	PPL Brunner Island	PPL Brunner Island LLC	PA	$0	$0	$0	$0	$0
375	3149	PPL Montour	PPL Montour LLC	PA	$0	$0	$0	$0	$0
376	3113	Portland	Reliant Energy Mid-Atlantic PH LLC	PA	$18,795	$0	$0	$0	$18,795
377	3131	Shawville	Reliant Energy Mid-Atlantic PH LLC	PA	$260,051	$0	$0	$0	$260,051
378	3115	Titus	Reliant Energy Mid-Atlantic PH LLC	PA	$0	$0	$0	$0	$0
379	3130	Seward	Reliant Energy Seward LLC	PA	$2,028,597	$0	$0	$0	$2,028,597
380	3118	Conemaugh	Reliant Engy NE Management Co	PA	$1,147,480	$0	$0	$0	$1,147,480
381	3136	Keystone	Reliant Engy NE Management Co	PA	$138,956	$0	$0	$0	$138,956
382	54634	St Nicholas Cogen Project	Schuylkill Energy Resource Inc	PA	$1,265,354	$0	$0	$0	$1,265,354
383	3152	Sunbury Generation LP	Sunbury Generation LP	PA	$213,734	$0	$0	$37,469	$251,203
384	3176	Hunlock Power Station	UGI Development Co	PA	$53,837	$0	$0	$0	$53,837
385	50888	Northampton Generating Company LP	US Operating Services Company	PA	$185,536	$0	$0	$0	$185,536
386	50974	Scrubgrass Generating Company LP	US Operating Services Company	PA	$343,212	$0	$0	$0	$343,212
387	50879	Wheelabrator Frackville Energy	Wheelabrator Environmental Systems	PA	$519,929	$0	$0	$0	$519,929
388	50611	WPS Westwood Generation LLC	WPS Power Developement	PA	$501,426	$0	$0	$0	$501,426
389	3264	W S Lee	Duke Energy Carolinas, LLC	SC	$40,159	$0	$0	$4,758,507	$4,798,666
390	3251	H B Robinson	Progress Energy Carolinas Inc	SC	$310,021	$0	$0	$4,661,088	$4,971,110
391	7652	US DOE Savannah River Site (D Area)	Savannah River Nuclear Solutions LLC	SC	$0	$0	$0	$0	$0
392	3280	Canadys Steam	South Carolina Electric&Gas Co	SC	$454,979	$0	$0	$7,576,142	$8,031,121
393	7737	Cogen South	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0
394	7210	Cope	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0
395	3287	McMeekin	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0
396	3295	Urquhart	South Carolina Electric&Gas Co	SC	$140,198	$0	$0	$936,714	$1,076,912
397	3297	Wateree	South Carolina Electric&Gas Co	SC	$0	$0	$0	$0	$0
398	3298	Williams	South Carolina Genertg Co, Inc	SC	$0	$0	$0	$0	$0

Exhibit J4
Cost Hybrid C & D With Land Treatment Dewatering Sub-Option

Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
399	130	Cross	South Carolina Pub Serv Auth	SC	$281,014	$0	$0	$816,815	$1,097,829
400	3317	Dolphus M Grainger	South Carolina Pub Serv Auth	SC	$58,811	$0	$0	$524,560	$583,371
401	3319	Jefferies	South Carolina Pub Serv Auth	SC	$104,158	$0	$0	$2,615,305	$2,719,463
402	6249	Winyah	South Carolina Pub Serv Auth	SC	$405,228	$0	$0	$670,687	$1,075,915
403	3325	Ben French	Black Hills Power Inc	SD	$122,453	$0	$0	$0	$122,453
404	6098	Big Stone	Otter Tail Power Co	SD	$206,353	$0	$0	$0	$206,353
405	3393	Allen Steam Plant	Tennessee Valley Authority	TN	$11,407	$0	$0	$2,967,510	$2,978,917
406	3396	Bull Run	Tennessee Valley Authority	TN	$12,085	$0	$0	$1,678,591	$1,690,676
407	3399	Cumberland	Tennessee Valley Authority	TN	$0	$0	$0	$0	$0
408	3403	Gallatin	Tennessee Valley Authority	TN	$12,341	$0	$0	$13,526,149	$13,538,490
409	3405	John Sevier	Tennessee Valley Authority	TN	$8,750	$0	$0	$749,371	$758,121
410	3406	Johnsonville	Tennessee Valley Authority	TN	$10,024	$0	$0	$4,024,123	$4,034,147
411	3407	Kingston	Tennessee Valley Authority	TN	$2,926	$0	$0	$24,422,005	$24,424,931
412	7030	Twin Oaks Power One	Altura Power	TX	$173,085	$0	$0	$0	$173,085
413	6178	Coleto Creek	ANP-Coleto Creek	TX	$918,886	$0	$0	$4,758,507	$5,677,392
414	6179	Fayette Power Project	Lower Colorado River Authority	TX	$202,097	$0	$0	$2,990,740	$3,192,837
415	54972	Norit Americas Marshall Plant	Norit Americas Inc	TX	$2,577	$0	$0	$0	$2,577
416	298	Limestone	NRG Texas LLC	TX	$574,309	$0	$0	$0	$574,309
417	3470	W A Parish	NRG Texas LLC	TX	$63,690	$0	$0	$0	$63,690
418	127	Oklaunion	Public Service Co of Oklahoma	TX	$633,518	$0	$0	$2,922,547	$3,556,066
419	7097	J K Spruce	San Antonio City of	TX	$80,280	$0	$0	$0	$80,280
420	6181	J T Deely	San Antonio City of	TX	$43,290	$0	$0	$0	$43,290
421	6183	San Miguel	San Miguel Electric Coop, Inc	TX	$0	$0	$0	$0	$0
422	7902	Pirkey	Southwestern Electric Power Co	TX	$2,310,447	$0	$0	$8,992,454	$11,302,900
423	6139	Welsh	Southwestern Electric Power Co	TX	$50,825	$0	$0	$0	$50,825
424	6193	Harrington	Southwestern Public Service Co	TX	$0	$0	$0	$0	$0
425	6194	Tolk	Southwestern Public Service Co	TX	$0	$0	$0	$0	$0
426	6136	Gibbons Creek	Texas Municipal Power Agency	TX	$61,302	$0	$0	$0	$61,302
427	3497	Big Brown	TXU Generation Co LP	TX	$104,659	$0	$0	$0	$104,659
428	6146	Martin Lake	TXU Generation Co LP	TX	$395,342	$0	$0	$0	$395,342
429	6147	Monticello	TXU Generation Co LP	TX	$194,031	$0	$0	$0	$194,031
430	6648	Sandow No 4	TXU Generation Co LP	TX	$1,912,648	$0	$0	$23,560,228	$25,472,876
431	7790	Bonanza	Deseret Generation & Tran Coop	UT	$1,373,308	$0	$0	$0	$1,373,308
432	6481	Intermountain Power Project	Los Angeles City of	UT	$2,060,078	$0	$0	$7,246,419	$9,306,497
433	3644	Carbon	PacifiCorp	UT	$164,344	$0	$0	$0	$164,344
434	6165	Hunter	PacifiCorp	UT	$2,216,423	$0	$0	$0	$2,216,423
435	8069	Huntington	PacifiCorp	UT	$3,166,567	$0	$0	$0	$3,166,567
436	50951	Sunnyside Cogen Associates	Sunnyside Cogeneration Assoc	UT	$1,030,311	$0	$0	$0	$1,030,311
437	3775	Clinch River	Appalachian Power Co	VA	$0	$0	$0	$0	$0
438	3776	Glen Lyn	Appalachian Power Co	VA	$280,286	$0	$0	$434,635	$714,921
439	54304	Birchwood Power	Birchwood Power Partners LP	VA	$0	$0	$0	$0	$0
440	10071	Cogentrix Virginia Leasing	Cogentrix-Virginia Leas'g Corp	VA	$0	$0	$0	$0	$0

Exhibit J4 Cost Hybrid C & D With Land Treatment Dewatering Sub-Option									
Plant Identity					Hybrid C & D				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
		Corporation							
441	10377	James River Cogeneration	James River Cogeneration Co	VA	$0	$0	$0	$0	$0
442	3788	Potomac River	Mirant Potomac River LLC	VA	$0	$0	$0	$0	$0
443	54081	Spruance Genco LLC	Spruance Operating Services LLC	VA	$0	$0	$0	$0	$0
444	10773	Altavista Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
445	3796	Bremo Bluff	Virginia Electric & Power Co	VA	$1,018,461	$0	$0	$6,369,655	$7,388,116
446	3803	Chesapeake	Virginia Electric & Power Co	VA	$439,125	$0	$0	$2,607,812	$3,046,937
447	3797	Chesterfield	Virginia Electric & Power Co	VA	$3,078,604	$0	$0	$24,174,713	$27,253,317
448	7213	Clover	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
449	10771	Hopewell Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
450	52007	Mecklenburg Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
451	10774	Southampton Power Station	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
452	3809	Yorktown	Virginia Electric & Power Co	VA	$0	$0	$0	$0	$0
453	3845	Transalta Centralia Generation	TransAlta Centralia Gen LLC	WA	$0	$0	$0	$0	$0
454	4127	Menasha	City of Menasha	WI	$210,173	$0	$0	$0	$210,173
455	4140	Alma	Dairyland Power Coop	WI	$34,342	$0	$0	$0	$34,342
456	4143	Genoa	Dairyland Power Coop	WI	$0	$0	$0	$0	$0
457	4271	John P Madgett	Dairyland Power Coop	WI	$755,038	$0	$0	$0	$755,038
458	3992	Blount Street	Madison Gas & Electric Co	WI	$0	$0	$0	$0	$0
459	4125	Manitowoc	Manitowoc Public Utilities	WI	$378,986	$0	$0	$0	$378,986
460	4146	E J Stoneman Station	Mid-America Power LLC	WI	$154,741	$0	$0	$0	$154,741
461	3982	Bay Front	Northern States Power Co	WI	$0	$0	$0	$0	$0
462	7549	Milwaukee County	Wisconsin Electric Power Co	WI	$213,434	$0	$0	$0	$213,434
463	6170	Pleasant Prairie	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0
464	4041	South Oak Creek	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0
465	4042	Valley	Wisconsin Electric Power Co	WI	$0	$0	$0	$0	$0
466	8023	Columbia	Wisconsin Power & Light Co	WI	$1,902,327	$0	$0	$824,308	$2,726,635
467	4050	Edgewater	Wisconsin Power & Light Co	WI	$10,829	$0	$0	$0	$10,829
468	4054	Nelson Dewey	Wisconsin Power & Light Co	WI	$0	$0	$0	$0	$0
469	4072	Pulliam	Wisconsin Public Service Corp	WI	$0	$0	$0	$0	$0
470	4078	Weston	Wisconsin Public Service Corp	WI	$0	$0	$0	$0	$0
471	3944	Harrison Power Station	Allegheny Energy Supply Co LLC	WV	$1,353,689	$0	$0	$0	$1,353,689
472	6004	Pleasants Power Station	Allegheny Energy Supply Co LLC	WV	$5,191,107	$0	$0	$0	$5,191,107
473	10151	Grant Town Power Plant	American Bituminous Power LP	WV	$712,495	$0	$0	$0	$712,495
474	3935	John E Amos	Appalachian Power Co	WV	$8,682,363	$0	$0	$29,367,854	$38,050,218
475	3936	Kanawha River	Appalachian Power Co	WV	$74,883	$0	$0	$119,899	$194,782
476	6264	Mountaineer	Appalachian Power Co	WV	$2,205,440	$0	$0	$711,903	$2,917,343
477	3938	Philip Sporn	Appalachian Power Co	WV	$2,980,904	$0	$0	$10,273,878	$13,254,783
478	3942	Albright	Monongahela Power Co	WV	$724,724	$0	$0	$0	$724,724
479	3943	Fort Martin Power Station	Monongahela Power Co	WV	$22,421	$0	$0	$0	$22,421
480	3945	Rivesville	Monongahela Power Co	WV	$398,109	$0	$0	$0	$398,109
481	3946	Willow Island	Monongahela Power Co	WV	$273,152	$0	$0	$0	$273,152

Exhibit J4 Cost Hybrid C & D With Land Treatment Dewatering Sub-Option									
Plant Identity					**Hybrid C & D**				
Item	Plant code	Plant name	Onwer entity name	State	Engineering controls + ancillary costs	Offsite disposal cost	Lost CCR sales revenue from reduced beneficial use	Land disposal treatment	Total cost
482	10743	Morgantown Energy Facility	Morgantown Energy Associates	WV	$525,644	$0	$0	$0	$525,644
483	3947	Kammer	Ohio Power Co	WV	$384,799	$0	$0	$3,649,437	$4,034,237
484	3948	Mitchell	Ohio Power Co	WV	$24,891,903	$0	$0	$23,035,668	$47,927,571
485	3954	Mt Storm	Virginia Electric & Power Co	WV	$5,274,020	$0	$0	$0	$5,274,020
486	7537	North Branch	Virginia Electric & Power Co	WV	$1,997,621	$0	$0	$0	$1,997,621
487	6204	Laramie River Station	Basin Electric Power Coop	WY	$2,175,396	$0	$0	$5,927,526	$8,102,922
488	4150	Neil Simpson	Black Hills Power Inc	WY	$0	$0	$0	$0	$0
489	7504	Neil Simpson II	Black Hills Power Inc	WY	$694,687	$0	$0	$0	$694,687
490	4151	Osage	Black Hills Power Inc	WY	$157,298	$0	$0	$0	$157,298
491	55479	Wygen 1	Black Hills Power Inc	WY	$0	$0	$0	$0	$0
492	4158	Dave Johnston	PacifiCorp	WY	$186,078	$0	$0	$1,273,931	$1,460,009
493	8066	Jim Bridger	PacifiCorp	WY	$5,994,812	$0	$0	$11,540,315	$17,535,127
494	4162	Naughton	PacifiCorp	WY	$868,633	$0	$0	$12,739,309	$13,607,943
495	6101	Wyodak	PacifiCorp	WY	$340,716	$0	$0	$2,098,239	$2,438,956
			Total Costs:		$500,000,000	$0	$0	$1,676,000,000	$2,176,000,000

Exhibit J5 Entity-by-Entity Aggregation of Regulatory Cost Estimates Without Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Owner Entity Name	State	Owner Entity Size/Type	Total cost	Total cost	Total cost
1	American Mun Power-Ohio, Inc	OH	Non-Small City	$0	$0	$0
2	Ames City of	IA	Non-Small City	$34,278	$32,370	$32,896
3	City of Columbia	MO	Non-Small City	$12,103	$11,429	$11,615
4	City of Hamilton	OH	Non-Small City	$174,036	$0	$0
5	City of Lakeland	FL	Non-Small City	$904,687	$854,330	$868,221
6	City of Owensboro	KY	Non-Small City	$1,091,682	$0	$0
7	City of Springfield	IL	Non-Small City	$973,971	$919,757	$934,713
8	City Utilities of Springfield	MO	Non-Small City	$263,643	$248,968	$253,017
9	Colorado Springs City of	CO	Non-Small City	$50,716	$47,893	$48,672
10	Gainesville Regional Utilities	FL	Non-Small City	$40,467	$38,214	$38,836
11	Independence City of	MO	Non-Small City	$210,984	$199,240	$202,480
12	JEA	FL	Non-Small City	$3,752,681	$3,543,798	$3,601,421
13	Kansas City City of	KS	Non-Small City	$459,205	$183,919	$186,910
14	Lansing Board of Water and Light	MI	Non-Small City	$259,265	$167,462	$170,185
15	Los Angeles City of	UT	Non-Small City	$3,319,457	$3,134,689	$3,185,660
16	Niagara Generation LLC	NY	Non-Small City	$0	$0	$0
17	Orlando Utilities Comm	FL	Non-Small City	$2,087,553	$1,971,355	$2,003,410
18	Rochester Public Utilities	MN	Non-Small City	$28,921	$27,312	$27,756
19	San Antonio City of	TX	Non-Small City	$305,215	$94,529	$96,066
20	Sunnyside Cogeneration Assoc	UT	Non-Small City	$748,254	$706,605	$718,094
21	Syracuse Energy Corp	NY	Non-Small City	$0	$0	$0
22	Tampa Electric Co	FL	Non-Small City	$2,638,384	$2,491,526	$2,532,038
23	Tucson Electric Power Co	AZ	Non-Small City	$13,140,618	$12,374,498	$12,575,709
24	Vineland City of	NJ	Non-Small City	$106,480	$100,553	$102,188
25	AES Corp - AES Beaver Valley	PA	Non-Small Company	$984,887	$0	$0
26	AES Corp - AES Cayuga LLC	NY	Non-Small Company	$0	$0	$0
27	AES Corp - AES Greenidge	NY	Non-Small Company	$0	$0	$0
28	AES Corp - AES Hawaii Inc	HI	Non-Small Company	$291,002	$0	$0
29	AES Corp - AES Shady Point LLC	OK	Non-Small Company	$2,386,784	$0	$0
30	AES Corp - AES Somerset LLC	NY	Non-Small Company	$0	$0	$0
31	AES Corp - AES Thames LLC	CT	Non-Small Company	$842,946	$0	$0
32	AES Corp - AES Westover LLC	NY	Non-Small Company	$234,949	$0	$0
33	AES Corp - AES WR Ltd Partnership	MD	Non-Small Company	$2,133,640	$0	$0
34	AGC Division of APG Inc	IN	Non-Small Company	$2,768,651	$2,614,542	$2,657,055
35	Air Products Energy Enterprise	CA	Non-Small Company	$930,217	$878,439	$892,722
36	Alabama Power Co	AL	Non-Small Company	$12,151,470	$11,475,093	$11,661,680
37	Allegheny Energy Supply Co LLC	MD 1X	Non-Small Company	$12,807,816	$10,599,222	$10,771,567
38	Altura Power	TX	Non-Small Company	$164,304	$155,158	$157,681
39	Ameren Energy Generating Co	IL	Non-Small Company	$3,752,843	$2,471,414	$2,511,599
40	Ameren Energy Resources Generating Co.	IL	Non-Small Company	$6,565,541	$6,200,089	$6,300,903
41	American Bituminous Power LP	WV	Non-Small Company	$0	$0	$0
42	American Electric Power Co - Appalachian Power Co	VA 2x	Non-Small Company	$6,707,647	$6,334,285	$6,437,282
43	American Electric Power Co - Columbus Southern Power Co	OH	Non-Small Company	$4,311,077	$4,071,113	$4,137,310
44	American Electric Power Co - Indiana Michigan Power Co	IN	Non-Small Company	$3,813,134	$3,600,886	$3,659,437
45	American Electric Power Co - Kentucky Power Co	KY	Non-Small Company	$8,826,470	$8,335,169	$8,470,700

Exhibit J5 Entity-by-Entity Aggregation of Regulatory Cost Estimates Without Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	**Owner Entity Name**	**State**	**Owner Entity Size/Type**	**Total cost**	**Total cost**	**Total cost**
46	American Electric Power Co - Ohio Power Co	OH 2X	Non-Small Company	$22,975,214	$21,696,363	$22,049,149
47	American Electric Power Co - Public Service Co of Oklahoma	OK 1X	Non-Small Company	$566,034	$534,527	$543,219
48	American Electric Power Co - Southwestern Electric Power Co	AR 1X	Non-Small Company	$2,580,620	$2,436,977	$2,476,603
49	ANP-Coleto Creek	TX	Non-Small Company	$539,710	$509,668	$517,956
50	Aquila, Inc.	CO 1X	Non-Small Company	$206,443	$108,509	$110,273
51	Arizona Public Service Co	AZ 1X	Non-Small Company	$9,521,977	$3,816,034	$3,878,083
52	Babcox & Wicox & ESI Inc - Ebensburg Power Co	PA	Non-Small Company	$244,735	$231,112	$234,870
53	Birchwood Power Partners LP	VA	Non-Small Company	$666,763	$0	$0
54	Black Hills Power Inc	WY	Non-Small Company	$785,319	$741,607	$753,665
55	Black River Generation LLC	NY	Non-Small Company	$0	$0	$0
56	Cambria CoGen Co	PA	Non-Small Company	$344,604	$325,423	$330,714
57	Cardinal Operating Co	OH	Non-Small Company	$1,610,035	$1,520,417	$1,545,139
58	Carlyle/Riverstone Renewable Energy	NC	Non-Small Company	$57,773	$54,557	$55,444
59	Central Power & Lime Inc	FL	Non-Small Company	$0	$0	$0
60	Choctaw Generating LP	MS	Non-Small Company	$687,944	$649,651	$660,215
61	Citizens Thermal Energy	IN	Non-Small Company	$8,559	$8,082	$8,214
62	Cleco Power LLC	LA	Non-Small Company	$328,187	$309,920	$314,959
63	Cogentrix Energy - Cogentrix-Virginia Leas'g Corp	VA	Non-Small Company	$237,322	$0	$0
64	Cogentrix Energy - James River Cogeneration Co	VA	Non-Small Company	$0	$0	$0
65	Cogentrix Energy - Morgantown Energy Associates	WV	Non-Small Company	$0	$0	$0
66	Colmac Clarion Inc	PA	Non-Small Company	$78,988	$74,591	$75,804
67	Conectiv Atlantic Generatn Inc	NJ	Non-Small Company	$38,424	$0	$0
68	Conectiv Delmarva Gen Inc	DE	Non-Small Company	$421,530	$0	$0
69	Constellation Energy - Inter-Power/AhlCon Partners, L.P.	PA	Non-Small Company	$463,897	$292,402	$297,157
70	Constellation Energy - Panther Creek Partners	PA	Non-Small Company	$210,696	$198,969	$202,204
71	Constellation Energy - Rio Bravo Jasmin	CA	Non-Small Company	$279,661	$264,094	$268,389
72	Constellation Energy - Rio Bravo Poso	CA	Non-Small Company	$274,001	$258,749	$262,957
73	Constellation Energy (ACE Cogeneration Co)	CA	Non-Small Company	$1,261,547	$1,189,192	$1,208,529
74	Constellation Power Source Gen	MD	Non-Small Company	$2,322,368	$0	$0
75	Consumers Energy Co	MI	Non-Small Company	$458,464	$432,945	$439,985
76	Detroit Edison Co	MI	Non-Small Company	$3,187,106	$3,009,705	$3,058,643
77	Dominion Energy New England, LLC	MA	Non-Small Company	$719,878	$0	$0
78	Dominion Energy Services Co	IL	Non-Small Company	$449,217	$0	$0
79	DPL Inc - Dayton Power & Light Co	OH	Non-Small Company	$7,742,648	$6,884,794	$6,996,742
80	DTE Energy Services	AL	Non-Small Company	$6,887	$6,504	$6,609
81	Duke Energy Carolinas, LLC	NC	Non-Small Company	$15,533,471	$14,668,844	$14,907,361
82	Duke Energy Indiana Inc	IN	Non-Small Company	$12,642,911	$11,939,179	$12,133,312
83	Duke Energy Kentucky Inc	KY	Non-Small Company	$8,265,645	$7,805,561	$7,932,481
84	Duke Energy Ohio Inc	OH	Non-Small Company	$6,092,056	$5,752,959	$5,846,503
85	Dynegy Midwest Generation Inc	IL	Non-Small Company	$5,085,684	$4,802,604	$4,880,695
86	Dynegy Northeast Gen Inc	NY	Non-Small Company	$0	$0	$0
87	Electric Energy Inc	IL	Non-Small Company	$0	$0	$0
88	Empire District Electric Co	KS 1X	Non-Small Company	$145,652	$137,545	$139,781
89	Energy East Corporation - Rochester Gas & Electric Corp	NY	Non-Small Company	$138,664	$0	$0
90	Entergy Arkansas Inc	AR	Non-Small Company	$6,372,087	$6,017,403	$6,115,247
91	Entergy Gulf States Louisiana LLC	LA	Non-Small Company	$0	$0	$0
92	EON USA LLC - Kentucky Utilities Co	KY	Non-Small Company	$26,083,163	$24,631,317	$25,031,826

Exhibit J5 Entity-by-Entity Aggregation of Regulatory Cost Estimates Without Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Owner Entity Name	State	Owner Entity Size/Type	Total cost	Total cost	Total cost
93	Exelon Power	PA	Non-Small Company	$774,123	$0	$0
94	FirstEnergy Generation Corp	OH 6x	Non-Small Company	$23,085,525	$17,545,067	$17,830,353
95	FirstLight Power Resources Services LLC	MA	Non-Small Company	$181,382	$0	$0
96	FPL Energy Operating Servs Inc	CA	Non-Small Company	$499,944	$472,116	$479,793
97	Georgia Power Co	GA	Non-Small Company	$20,907,063	$19,529,890	$19,847,449
98	Gilberton Power Co	PA	Non-Small Company	$317,771	$300,083	$304,962
99	Gulf Power Co	FL	Non-Small Company	$178,849	$168,894	$171,640
100	Hawaiian Com & Sugar Co Ltd	HI	Non-Small Company	$778,484	$735,152	$747,106
101	Hoosier Energy R E C, Inc	IN	Non-Small Company	$853,223	$805,730	$818,832
102	Indiana-Kentucky Electric Corp	IN	Non-Small Company	$553,012	$515,294	$523,672
103	Indianapolis Power & Light Co	IN	Non-Small Company	$5,147,636	$1,143,510	$1,162,103
104	Integrys Energy Group - Mid-America Power LLC	WI	Non-Small Company	$96,363	$90,999	$92,479
105	Integrys Energy Group - Upper Peninsula Power Co	MI	Non-Small Company	$5,261	$4,968	$5,049
106	Integrys Energy Group - WPS Power Developement	PA	Non-Small Company	$300,032	$283,331	$287,939
107	Interstate Power and Light Co	IA	Non-Small Company	$419,383	$372,027	$378,076
108	Kansas City Power & Light Co	KS 1X	Non-Small Company	$3,764,123	$2,956,437	$3,004,509
109	Louisville Gas & Electric Co	KY	Non-Small Company	$15,356,050	$10,609,213	$10,781,721
110	Madison Gas & Electric Co	WI	Non-Small Company	$2,825	$0	$0
111	MDU Resources Group Inc	ND 1X	Non-Small Company	$108,428	$86,918	$88,332
112	MidAmerican Energy Co	IA	Non-Small Company	$9,420,842	$8,798,275	$8,941,336
113	Midwest Generations EME LLC	IL 7X	Non-Small Company	$2,026,147	$231,457	$235,221
114	Minnesota Power Inc	MN	Non-Small Company	$1,106,096	$1,044,529	$1,061,513
115	Mirant - Chalk Point LLC	MD	Non-Small Company	$964,088	$910,425	$925,229
116	Mirant - Mid-Atlantic LLC	MD	Non-Small Company	$285,721	$269,817	$274,204
117	Mirant - New York Inc	NY	Non-Small Company	$603,477	$0	$0
118	Mirant - Potomac River LLC	VA	Non-Small Company	$0	$0	$0
119	Mississippi Power Co	MS	Non-Small Company	$908,915	$858,322	$872,279
120	Monongahela Power Co	WV	Non-Small Company	$2,183,552	$971,864	$987,667
121	Mt Poso Cogeneration Co	CA	Non-Small Company	$526,894	$497,566	$505,657
122	Nevada Power Co	NV	Non-Small Company	$1,265,986	$1,195,518	$1,214,958
123	NewPage Corporation	ME	Non-Small Company	$554,652	$347,691	$353,344
124	Norit Americas Inc	TX	Non-Small Company	$1,515	$1,431	$1,454
125	North Carolina Power Holdings, LLC	NC	Non-Small Company	$38,536	$36,391	$36,983
126	Northern Indiana Pub Serv Co	IN	Non-Small Company	$1,116,121	$956,880	$972,439
127	Northern States Power Co	MN 4X	Non-Small Company	$12,994,302	$12,271,011	$12,470,539
128	NRG Energy - Dunkirk Power LLC	NY	Non-Small Company	$294,958	$0	$0
129	NRG Energy - Energy Center Dover LLC	DE	Non-Small Company	$260,629	$246,122	$250,124
130	NRG Energy - Huntley Operations Inc	NY	Non-Small Company	$0	$0	$0
131	NRG Energy - Indian River Operations Inc	DE	Non-Small Company	$2,357,005	$2,225,809	$2,262,001
132	NRG Energy - Louisiana Generating LLC	LA	Non-Small Company	$2,994	$2,828	$2,874
133	NRG Energy - Reliant Energy Mid-Atlantic PH LLC	PA	Non-Small Company	$166,855	$157,567	$160,129
134	NRG Energy - Reliant Energy Seward LLC	PA	Non-Small Company	$2,504,468	$2,365,064	$2,403,520
135	NRG Energy - Reliant Engy NE Management Co	PA	Non-Small Company	$1,599,652	$1,510,612	$1,535,174
136	NRG Energy - Texas LLC	TX	Non-Small Company	$831,388	$785,111	$797,877
137	Ohio Valley Electric Corp	OH	Non-Small Company	$2,221,158	$2,097,524	$2,131,630
138	Oklahoma Gas & Electric Co	OK	Non-Small Company	$706,316	$0	$0
139	Orion Power Midwest LP	OH 2X	Non-Small Company	$1,229,345	$27,015	$27,454

Exhibit J5 Entity-by-Entity Aggregation of Regulatory Cost Estimates Without Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	**Owner Entity Name**	**State**	**Owner Entity Size/Type**	**Total cost**	**Total cost**	**Total cost**
140	Otter Tail Power Co	MN 1X	Non-Small Company	$483,394	$456,487	$463,910
141	PacifiCorp	UT 3X	Non-Small Company	$14,871,789	$13,014,143	$13,225,755
142	Portland General Electric Co	OR	Non-Small Company	$840,356	$793,580	$806,484
143	PPL - Brunner Island LLC	PA	Non-Small Company	$0	$0	$0
144	PPL - Montana LLC	MT	Non-Small Company	$20,681,687	$19,530,499	$19,848,068
145	PPL - Montour LLC	PA	Non-Small Company	$0	$0	$0
146	Primary Energy of North Carolina LLC	NC	Non-Small Company	$171,520	$39,244	$39,882
147	Progress Energy Carolinas Inc	NC 7X	Non-Small Company	$2,610,247	$2,427,603	$2,467,076
148	Progress Energy Florida Inc	FL	Non-Small Company	$218,090	$205,950	$209,299
149	PSEG Fossil LLC	NJ	Non-Small Company	$1,338,046	$0	$0
150	PSEG Power Connecticut LLC	CT	Non-Small Company	$130,527	$0	$0
151	Public Service Co of Colorado	CO	Non-Small Company	$1,930,592	$101,201	$102,847
152	Public Service Co of NH	NH	Non-Small Company	$529,786	$23,791	$24,178
153	Public Service Co of NM	NM	Non-Small Company	$9,567,948	$9,035,375	$9,182,292
154	RC Cape May Holdings LLC	NJ	Non-Small Company	$28,818	$0	$0
155	Rocky Mountain Power Inc	MT	Non-Small Company	$21,549	$20,350	$20,681
156	Savannah River Nuclear Solutions LLC	SC	Non-Small Company	$0	$0	$0
157	Sierra Pacific Power Co	NV	Non-Small Company	$3,357,996	$3,171,083	$3,222,645
158	South Carolina Electric&Gas Co	SC	Non-Small Company	$645,019	$609,116	$619,020
159	South Carolina Genertg Co, Inc	SC	Non-Small Company	$0	$0	$0
160	Southern Indiana Gas & Elec Co	IN	Non-Small Company	$2,569,352	$1,820,165	$1,849,761
161	Southwestern Public Service Co	TX	Non-Small Company	$0	$0	$0
162	State Line Energy LLC	IN	Non-Small Company	$113,011	$0	$0
163	Suez Energy - Colorado Energy Nations Company LLP	CO	Non-Small Company	$11,548	$10,905	$11,082
164	Suez Energy - Northeastern Power Co	PA	Non-Small Company	$256,117	$241,861	$245,793
165	Sunbury Generation LP	PA	Non-Small Company	$591,395	$327,427	$332,751
166	Sunflower Electric Power Corp	KS	Non-Small Company	$724,194	$683,884	$695,004
167	TransAlta Centralia Gen LLC	WA	Non-Small Company	$590,163	$557,313	$566,375
168	Trigen-Cinergy Sol-Tuscola LLC	IL	Non-Small Company	$178,873	$168,917	$171,664
169	Tri-State G & T Assn, Inc	NM 1X	Non-Small Company	$5,043,780	$2,558,194	$2,599,790
170	TXU Generation Co LP	TX	Non-Small Company	$2,652,086	$2,504,465	$2,545,188
171	UGI Development Co	PA	Non-Small Company	$32,217	$30,424	$30,918
172	Union Electric Co	MO	Non-Small Company	$2,788,710	$2,131,900	$2,166,565
173	US Operating Services Company	NJ 2X	Non-Small Company	$7,800,142	$1,848,535	$1,878,593
174	Virginia Electric & Power Co	VA 9X	Non-Small Company	$15,253,483	$10,836,785	$11,012,992
175	Westar Energy Inc	KS	Non-Small Company	$3,218,661	$3,039,503	$3,088,926
176	Western Kentucky Energy Corp	KY	Non-Small Company	$29,773,066	$28,115,832	$28,573,000
177	Wheelabrator Environmental Systems	PA	Non-Small Company	$311,135	$293,816	$298,594
178	Wisconsin Electric Power Co	MI 1X	Non-Small Company	$156,927	$148,192	$150,602
179	Wisconsin Power & Light Co	WI	Non-Small Company	$1,320,595	$1,247,088	$1,267,365
180	Wisconsin Public Service Corp	WI	Non-Small Company	$1,130,018	$1,067,119	$1,084,470
181	Alabama Electric Coop Inc	AL	Non-Small Coop	$812,443	$196,268	$199,459
182	Arizona Electric Pwr Coop Inc	AZ	Non-Small Coop	$5,864,619	$5,538,182	$5,628,233
183	Associated Electric Coop, Inc	MO	Non-Small Coop	$1,717,107	$1,621,529	$1,647,895
184	Basin Electric Power Coop	ND 2X	Non-Small Coop	$3,068,631	$2,897,824	$2,944,944
185	Dairyland Power Coop	WI	Non-Small Coop	$568,689	$537,034	$545,767
186	Deseret Generation & Tran Coop	UT	Non-Small Coop	$1,516,780	$1,432,352	$1,455,643

Exhibit J5 Entity-by-Entity Aggregation of Regulatory Cost Estimates Without Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Owner Entity Name	State	Owner Entity Size/Type	Total cost	Total cost	Total cost
187	East Kentucky Power Coop, Inc	KY	Non-Small Coop	$15,136,957	$14,293,867	$14,526,288
188	Great River Energy	ND	Non-Small Coop	$307,877	$290,740	$295,468
189	Minnkota Power Coop, Inc	ND	Non-Small Coop	$422,012	$123,717	$125,729
190	Seminole Electric Coop, Inc	FL	Non-Small Coop	$6,640,176	$6,265,233	$6,367,107
191	South Mississippi El Pwr Assn	MS	Non-Small Coop	$1,455,406	$1,374,395	$1,396,743
192	Western Farmers Elec Coop, Inc	OK	Non-Small Coop	$2,673	$2,524	$2,565
193	Tennessee Valley Authority	AL 2X	Non-Small Federal	$23,405,899	$20,821,259	$21,159,816
194	Grand River Dam Authority	OK	Non-Small State	$1,644,175	$1,552,657	$1,577,904
195	Lower Colorado River Authority	TX	Non-Small State	$118,018	$111,449	$113,261
196	Nebraska Public Power District	NE	Non-Small State	$3,215,099	$3,036,140	$3,085,508
197	Omaha Public Power District	NE	Non-Small State	$480,458	$453,714	$461,092
198	Platte River Power Authority	CO	Non-Small State	$178,898	$168,940	$171,687
199	Salt River Project	AZ	Non-Small State	$21,959,751	$20,737,423	$21,074,617
200	South Carolina Pub Serv Auth	SC	Non-Small State	$1,691,340	$1,005,593	$1,021,944
201	Austin City of	MN	Small City	$1,704	$1,610	$1,636
202	Board of Water Electric & Communications	IA	Small City	$6,329	$5,976	$6,074
203	Cedar Falls Utilities	IA	Small City	$18,757	$17,713	$18,001
204	City of Dover	OH	Small City	$0	$0	$0
205	City of Grand Haven	MI	Small City	$12,927	$12,207	$12,406
206	City of Holland	MI	Small City	$7,752	$7,321	$7,440
207	City of Jasper	IN	Small City	$4,532	$4,280	$4,350
208	City of Logansport	IN	Small City	$9,531	$9,000	$9,147
209	City of Marquette	MI	Small City	$6,488	$6,127	$6,227
210	City of Marshall	MO	Small City	$11,115	$10,496	$10,667
211	City of Menasha	WI	Small City	$139,941	$132,151	$134,300
212	City of Orrville	OH	Small City	$0	$0	$0
213	City of Painesville	OH	Small City	$0	$0	$0
214	City of Richmond	IN	Small City	$50,069	$47,282	$48,051
215	City of Shelby	OH	Small City	$0	$0	$0
216	City of Sikeston	MO	Small City	$269,678	$254,668	$258,808
217	City of Virginia	MN	Small City	$7,908	$7,468	$7,590
218	Crawfordsville Elec, Lgt & Pwr	IN	Small City	$9,340	$8,820	$8,963
219	Fremont City of	NE	Small City	$102,079	$35,033	$35,603
220	Grand Island City of	NE	Small City	$32,773	$0	$0
221	Greenwood Utilities Comm	MS	Small City	$7,283	$6,878	$6,990
222	Hastings City of	NE	Small City	$714,491	$674,721	$685,692
223	Henderson City Utility Comm	KY	Small City	$11,434	$10,797	$10,973
224	Hibbing Public Utilities Comm	MN	Small City	$3,733	$3,525	$3,582
225	Jamestown Board of Public Util	NY	Small City	$0	$0	$0
226	Manitowoc Public Utilities	WI	Small City	$282,912	$267,164	$271,508
227	Michigan South Central Pwr Agy	MI	Small City	$12,068	$11,396	$11,582
228	New Ulm Public Utilities Comm	MN	Small City	$9,259	$8,744	$8,886
229	Pella City of	IA	Small City	$13,255	$12,517	$12,721
230	Peru City of	IN	Small City	$11,995	$11,327	$11,511
231	Somerset Power LLC	MA	Small City	$169,798	$0	$0
232	Texas Municipal Power Agency	TX	Small City	$37,600	$35,507	$36,085
233	Willmar Municipal Utils Comm	MN	Small City	$10,446	$9,865	$10,025

Exhibit J5 Entity-by-Entity Aggregation of Regulatory Cost Estimates Without Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	**Owner Entity Name**	**State**	**Owner Entity Size/Type**	**Total cost**	**Total cost**	**Total cost**
234	Wyandotte Municipal Serv Comm	MI	Small City	$8,392	$7,925	$8,054
235	Aurora Energy LLC	AK	Small Company	$536,747	$506,871	$515,113
236	Colstrip Energy LP	MT	Small Company	$7,158	$6,760	$6,870
237	Edgecombe Operating Services LLC	NC	Small Company	$401,188	$0	$0
238	Golden Valley Elec Assn Inc	AK	Small Company	$337,045	$318,284	$323,460
239	Mount Carmel Cogen Inc	PA	Small Company	$345,901	$326,647	$331,959
240	Schuylkill Energy Resource Inc	PA	Small Company	$757,588	$715,419	$727,052
241	Spruance Operating Services LLC	VA	Small Company	$892,784	$0	$0
242	TES Filer City Station LP	MI	Small Company	$9,623	$9,087	$9,235
243	Westmoreland Partners	NC	Small Company	$800,156	$61,403	$62,402
244	White Pine Electric Power LLC	MI	Small Company	$5,045	$4,764	$4,842
245	Central Electric Power Coop	MO	Small Coop	$73,153	$69,081	$70,204
246	Central Iowa Power Cooperative	IA	Small Coop	$101,262	$95,626	$97,180
247	Corn Belt Power Coop	IA	Small Coop	$13,292	$12,553	$12,757
248	San Miguel Electric Coop, Inc	TX	Small Coop	$7,218,552	$0	$0
249	Southern Illinois Power Coop	IL	Small Coop	$2,838,826	$0	$0
250	Soyland Power Coop Inc	IL	Small Coop	$110,907	$104,733	$106,436
251	Crisp County Power Comm	GA	Small County	$4,385	$4,141	$4,209
	SUBTOTALS BY SIZE/TYPE CATEGORIES:		**COLUMN TOTALS =**	**$598,000,000**	**$492,000,000**	**$500,000,000**
		1	Non-Small City	$30,603,000	$27,148,000	$27,590,000
		2	Non-Small Company	$460,753,000	$378,535,000	$384,690,000
		3	Non-Small Coop	$37,513,000	$34,574,000	$35,136,000
		4	Non-Small Federal	$23,406,000	$20,821,000	$21,160,000
		5	Non-Small State	$29,288,000	$27,066,000	$27,506,000
		6	Small City	$1,984,000	$1,621,000	$1,647,000
		7	Small Company	$4,093,000	$1,949,000	$1,981,000
		8	Small Coop	$10,356,000	$282,000	$287,000
		9	Small County	$4,000	$4,000	$4,000

Exhibit J6 Entity-by-Entity Aggreation of Regulatory Costs With Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Owner Entity Name	State	Owner Entity Size/Type	Total cost	Total cost	Total cost
1	American Mun Power-Ohio, Inc	OH	Non-Small City	$0	$0	$0
2	Ames City of	IA	Non-Small City	$34,278	$32,370	$32,896
3	City of Columbia	MO	Non-Small City	$12,103	$11,429	$11,615
4	City of Hamilton	OH	Non-Small City	$174,036	$0	$0
5	City of Lakeland	FL	Non-Small City	$904,687	$854,330	$868,221
6	City of Owensboro	KY	Non-Small City	$1,091,682	$0	$0
7	City of Springfield	IL	Non-Small City	$6,376,936	$6,322,723	$6,337,678
8	City Utilities of Springfield	MO	Non-Small City	$263,643	$248,968	$253,017
9	Colorado Springs City of	CO	Non-Small City	$50,716	$47,893	$48,672
10	Gainesville Regional Utilities	FL	Non-Small City	$40,467	$38,214	$38,836
11	Independence City of	MO	Non-Small City	$2,440,363	$2,428,619	$2,431,859
12	JEA	FL	Non-Small City	$3,752,681	$3,543,798	$3,601,421
13	Kansas City City of	KS	Non-Small City	$1,223,564	$948,278	$951,269
14	Lansing Board of Water and Light	MI	Non-Small City	$641,444	$549,641	$552,364
15	Los Angeles City of	UT	Non-Small City	$10,565,876	$10,381,108	$10,432,078
16	Niagara Generation LLC	NY	Non-Small City	$0	$0	$0
17	Orlando Utilities Comm	FL	Non-Small City	$2,087,553	$1,971,355	$2,003,410
18	Rochester Public Utilities	MN	Non-Small City	$28,921	$27,312	$27,756
19	San Antonio City of	TX	Non-Small City	$305,215	$94,529	$96,066
20	Sunnyside Cogeneration Assoc	UT	Non-Small City	$748,254	$706,605	$718,094
21	Syracuse Energy Corp	NY	Non-Small City	$0	$0	$0
22	Tampa Electric Co	FL	Non-Small City	$2,915,651	$2,768,793	$2,809,306
23	Tucson Electric Power Co	AZ	Non-Small City	$13,140,618	$12,374,498	$12,575,709
24	Vineland City of	NJ	Non-Small City	$106,480	$100,553	$102,188
25	AES Corp - AES Beaver Valley	PA	Non-Small Company	$984,887	$0	$0
26	AES Corp - AES Cayuga LLC	NY	Non-Small Company	$0	$0	$0
27	AES Corp - AES Greenidge	NY	Non-Small Company	$0	$0	$0
28	AES Corp - AES Hawaii Inc	HI	Non-Small Company	$291,002	$0	$0
29	AES Corp - AES Shady Point LLC	OK	Non-Small Company	$2,386,784	$0	$0
30	AES Corp - AES Somerset LLC	NY	Non-Small Company	$0	$0	$0
31	AES Corp - AES Thames LLC	CT	Non-Small Company	$842,946	$0	$0
32	AES Corp - AES Westover LLC	NY	Non-Small Company	$234,949	$0	$0
33	AES Corp - AES WR Ltd Partnership	MD	Non-Small Company	$2,133,640	$0	$0
34	AGC Division of APG Inc	IN	Non-Small Company	$20,895,939	$20,741,829	$20,784,342
35	Air Products Energy Enterprise	CA	Non-Small Company	$930,217	$878,439	$892,722
36	Alabama Power Co	AL	Non-Small Company	$79,242,667	$78,566,290	$78,752,877
37	Allegheny Energy Supply Co LLC	MD 1X	Non-Small Company	$14,688,738	$12,480,143	$12,652,488
38	Altura Power	TX	Non-Small Company	$164,304	$155,158	$157,681
39	Ameren Energy Generating Co	IL	Non-Small Company	$17,841,020	$16,559,591	$16,599,777
40	Ameren Energy Resources Generating Co.	IL	Non-Small Company	$24,325,637	$23,960,185	$24,060,999
41	American Bituminous Power LP	WV	Non-Small Company	$0	$0	$0
42	American Electric Power Co - Appalachian Power Co	VA 2x	Non-Small Company	$47,615,817	$47,242,455	$47,345,451
43	American Electric Power Co - Columbus Southern Power Co	OH	Non-Small Company	$42,109,357	$41,869,393	$41,935,590
44	American Electric Power Co - Indiana Michigan Power Co	IN	Non-Small Company	$15,233,550	$15,021,302	$15,079,853
45	American Electric Power Co - Kentucky Power Co	KY	Non-Small Company	$31,180,210	$30,688,910	$30,824,441

Exhibit J6 Entity-by-Entity Aggreation of Regulatory Costs With Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Owner Entity Name	State	Owner Entity Size/Type	Total cost	Total cost	Total cost
46	American Electric Power Co - Ohio Power Co	OH 2X	Non-Small Company	$67,203,098	$65,924,247	$66,277,033
47	American Electric Power Co - Public Service Co of Oklahoma	OK 1X	Non-Small Company	$3,488,581	$3,457,074	$3,465,766
48	American Electric Power Co - Southwestern Electric Power Co	AR 1X	Non-Small Company	$13,026,854	$12,883,211	$12,922,836
49	ANP-Coleto Creek	TX	Non-Small Company	$5,298,216	$5,268,175	$5,276,462
50	Aquila, Inc.	CO 1X	Non-Small Company	$206,443	$108,509	$110,273
51	Arizona Public Service Co	AZ 1X	Non-Small Company	$69,426,705	$63,720,762	$63,782,811
52	Babcox & Wicox & ESI Inc - Ebensburg Power Co	PA	Non-Small Company	$244,735	$231,112	$234,870
53	Birchwood Power Partners LP	VA	Non-Small Company	$666,763	$0	$0
54	Black Hills Power Inc	WY	Non-Small Company	$785,319	$741,607	$753,665
55	Black River Generation LLC	NY	Non-Small Company	$0	$0	$0
56	Cambria CoGen Co	PA	Non-Small Company	$344,604	$325,423	$330,714
57	Cardinal Operating Co	OH	Non-Small Company	$38,359,195	$38,269,577	$38,294,299
58	Carlyle/Riverstone Renewable Energy	NC	Non-Small Company	$57,773	$54,557	$55,444
59	Central Power & Lime Inc	FL	Non-Small Company	$0	$0	$0
60	Choctaw Generating LP	MS	Non-Small Company	$687,944	$649,651	$660,215
61	Citizens Thermal Energy	IN	Non-Small Company	$8,559	$8,082	$8,214
62	Cleco Power LLC	LA	Non-Small Company	$4,217,424	$4,199,156	$4,204,195
63	Cogentrix Energy - Cogentrix-Virginia Leas'g Corp	VA	Non-Small Company	$237,322	$0	$0
64	Cogentrix Energy - James River Cogeneration Co	VA	Non-Small Company	$0	$0	$0
65	Cogentrix Energy - Morgantown Energy Associates	WV	Non-Small Company	$0	$0	$0
66	Colmac Clarion Inc	PA	Non-Small Company	$78,988	$74,591	$75,804
67	Conectiv Atlantic Generatn Inc	NJ	Non-Small Company	$38,424	$0	$0
68	Conectiv Delmarva Gen Inc	DE	Non-Small Company	$421,530	$0	$0
69	Constellation Energy - Inter-Power/AhlCon Partners, L.P.	PA	Non-Small Company	$463,897	$292,402	$297,157
70	Constellation Energy - Panther Creek Partners	PA	Non-Small Company	$210,696	$198,969	$202,204
71	Constellation Energy - Rio Bravo Jasmin	CA	Non-Small Company	$279,661	$264,094	$268,389
72	Constellation Energy - Rio Bravo Poso	CA	Non-Small Company	$274,001	$258,749	$262,957
73	Constellation Energy (ACE Cogeneration Co)	CA	Non-Small Company	$1,261,547	$1,189,192	$1,208,529
74	Constellation Power Source Gen	MD	Non-Small Company	$2,322,368	$0	$0
75	Consumers Energy Co	MI	Non-Small Company	$14,104,513	$14,078,993	$14,086,033
76	Detroit Edison Co	MI	Non-Small Company	$39,306,795	$39,129,393	$39,178,332
77	Dominion Energy New England, LLC	MA	Non-Small Company	$719,878	$0	$0
78	Dominion Energy Services Co	IL	Non-Small Company	$449,217	$0	$0
79	DPL Inc - Dayton Power & Light Co	OH	Non-Small Company	$75,628,178	$74,770,325	$74,882,273
80	DTE Energy Services	AL	Non-Small Company	$6,887	$6,504	$6,609
81	Duke Energy Carolinas, LLC	NC	Non-Small Company	$62,159,342	$61,294,715	$61,533,233
82	Duke Energy Indiana Inc	IN	Non-Small Company	$120,394,986	$119,691,254	$119,885,387
83	Duke Energy Kentucky Inc	KY	Non-Small Company	$21,222,272	$20,762,188	$20,889,108
84	Duke Energy Ohio Inc	OH	Non-Small Company	$28,648,127	$28,309,030	$28,402,574
85	Dynegy Midwest Generation Inc	IL	Non-Small Company	$23,872,418	$23,589,338	$23,667,429
86	Dynegy Northeast Gen Inc	NY	Non-Small Company	$0	$0	$0
87	Electric Energy Inc	IL	Non-Small Company	$0	$0	$0
88	Empire District Electric Co	KS 1X	Non-Small Company	$4,154,787	$4,146,680	$4,148,917
89	Energy East Corporation - Rochester Gas & Electric Corp	NY	Non-Small Company	$138,664	$0	$0
90	Entergy Arkansas Inc	AR	Non-Small Company	$6,372,087	$6,017,403	$6,115,247
91	Entergy Gulf States Louisiana LLC	LA	Non-Small Company	$0	$0	$0
92	EON USA LLC - Kentucky Utilities Co	KY	Non-Small Company	$87,883,800	$86,431,954	$86,832,463

Exhibit J6 Entity-by-Entity Aggreation of Regulatory Costs With Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Owner Entity Name	State	Owner Entity Size/Type	Total cost	Total cost	Total cost
93	Exelon Power	PA	Non-Small Company	$774,123	$0	$0
94	FirstEnergy Generation Corp	OH 6x	Non-Small Company	$100,937,692	$95,397,234	$95,682,519
95	FirstLight Power Resources Services LLC	MA	Non-Small Company	$181,382	$0	$0
96	FPL Energy Operating Servs Inc	CA	Non-Small Company	$499,944	$472,116	$479,793
97	Georgia Power Co	GA	Non-Small Company	$136,452,598	$135,075,424	$135,392,984
98	Gilberton Power Co	PA	Non-Small Company	$317,771	$300,083	$304,962
99	Gulf Power Co	FL	Non-Small Company	$5,446,928	$5,436,973	$5,439,719
100	Hawaiian Com & Sugar Co Ltd	HI	Non-Small Company	$778,484	$735,152	$747,106
101	Hoosier Energy R E C, Inc	IN	Non-Small Company	$3,835,720	$3,788,228	$3,801,329
102	Indiana-Kentucky Electric Corp	IN	Non-Small Company	$2,179,148	$2,141,429	$2,149,808
103	Indianapolis Power & Light Co	IN	Non-Small Company	$18,329,074	$14,324,948	$14,343,542
104	Integrys Energy Group - Mid-America Power LLC	WI	Non-Small Company	$96,363	$90,999	$92,479
105	Integrys Energy Group - Upper Peninsula Power Co	MI	Non-Small Company	$5,261	$4,968	$5,049
106	Integrys Energy Group - WPS Power Developement	PA	Non-Small Company	$300,032	$283,331	$287,939
107	Interstate Power and Light Co	IA	Non-Small Company	$2,217,873	$2,170,518	$2,176,567
108	Kansas City Power & Light Co	KS 1X	Non-Small Company	$4,993,092	$4,185,406	$4,233,478
109	Louisville Gas & Electric Co	KY	Non-Small Company	$36,705,633	$31,958,797	$32,131,304
110	Madison Gas & Electric Co	WI	Non-Small Company	$2,825	$0	$0
111	MDU Resources Group Inc	ND 1X	Non-Small Company	$108,428	$86,918	$88,332
112	MidAmerican Energy Co	IA	Non-Small Company	$22,737,167	$22,114,600	$22,257,661
113	Midwest Generations EME LLC	IL 7X	Non-Small Company	$2,026,147	$231,457	$235,221
114	Minnesota Power Inc	MN	Non-Small Company	$23,692,142	$23,630,574	$23,647,559
115	Mirant - Chalk Point LLC	MD	Non-Small Company	$964,088	$910,425	$925,229
116	Mirant - Mid-Atlantic LLC	MD	Non-Small Company	$285,721	$269,817	$274,204
117	Mirant - New York Inc	NY	Non-Small Company	$603,477	$0	$0
118	Mirant - Potomac River LLC	VA	Non-Small Company	$0	$0	$0
119	Mississippi Power Co	MS	Non-Small Company	$3,838,956	$3,788,363	$3,802,320
120	Monongahela Power Co	WV	Non-Small Company	$2,183,552	$971,864	$987,667
121	Mt Poso Cogeneration Co	CA	Non-Small Company	$526,894	$497,566	$505,657
122	Nevada Power Co	NV	Non-Small Company	$1,265,986	$1,195,518	$1,214,958
123	NewPage Corporation	ME	Non-Small Company	$554,652	$347,691	$353,344
124	Norit Americas Inc	TX	Non-Small Company	$1,515	$1,431	$1,454
125	North Carolina Power Holdings, LLC	NC	Non-Small Company	$38,536	$36,391	$36,983
126	Northern Indiana Pub Serv Co	IN	Non-Small Company	$1,303,464	$1,144,223	$1,159,782
127	Northern States Power Co	MN 4X	Non-Small Company	$51,399,572	$50,676,281	$50,875,810
128	NRG Energy - Dunkirk Power LLC	NY	Non-Small Company	$294,958	$0	$0
129	NRG Energy - Energy Center Dover LLC	DE	Non-Small Company	$260,629	$246,122	$250,124
130	NRG Energy - Huntley Operations Inc	NY	Non-Small Company	$0	$0	$0
131	NRG Energy - Indian River Operations Inc	DE	Non-Small Company	$2,357,005	$2,225,809	$2,262,001
132	NRG Energy - Louisiana Generating LLC	LA	Non-Small Company	$10,449,228	$10,449,061	$10,449,107
133	NRG Energy - Reliant Energy Mid-Atlantic PH LLC	PA	Non-Small Company	$166,855	$157,567	$160,129
134	NRG Energy - Reliant Energy Seward LLC	PA	Non-Small Company	$2,504,468	$2,365,064	$2,403,520
135	NRG Energy - Reliant Engy NE Management Co	PA	Non-Small Company	$1,599,652	$1,510,612	$1,535,174
136	NRG Energy - Texas LLC	TX	Non-Small Company	$831,388	$785,111	$797,877
137	Ohio Valley Electric Corp	OH	Non-Small Company	$19,569,100	$19,445,465	$19,479,571
138	Oklahoma Gas & Electric Co	OK	Non-Small Company	$706,316	$0	$0
139	Orion Power Midwest LP	OH 2X	Non-Small Company	$1,229,345	$27,015	$27,454

Exhibit J6
Entity-by-Entity Aggreation of Regulatory Costs With Land Treatment Dewatering Sub-Option

				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Owner Entity Name	State	Owner Entity Size/Type	Total cost	Total cost	Total cost
140	Otter Tail Power Co	MN 1X	Non-Small Company	$483,394	$456,487	$463,910
141	PacifiCorp	UT 3X	Non-Small Company	$42,523,584	$40,665,937	$40,877,550
142	Portland General Electric Co	OR	Non-Small Company	$840,356	$793,580	$806,484
143	PPL - Brunner Island LLC	PA	Non-Small Company	$0	$0	$0
144	PPL - Montana LLC	MT	Non-Small Company	$92,891,089	$91,739,901	$92,057,470
145	PPL - Montour LLC	PA	Non-Small Company	$0	$0	$0
146	Primary Energy of North Carolina LLC	NC	Non-Small Company	$171,520	$39,244	$39,882
147	Progress Energy Carolinas Inc	NC 7X	Non-Small Company	$66,134,438	$65,951,793	$65,991,267
148	Progress Energy Florida Inc	FL	Non-Small Company	$218,090	$205,950	$209,299
149	PSEG Fossil LLC	NJ	Non-Small Company	$1,338,046	$0	$0
150	PSEG Power Connecticut LLC	CT	Non-Small Company	$130,527	$0	$0
151	Public Service Co of Colorado	CO	Non-Small Company	$1,930,592	$101,201	$102,847
152	Public Service Co of NH	NH	Non-Small Company	$529,786	$23,791	$24,178
153	Public Service Co of NM	NM	Non-Small Company	$9,567,948	$9,035,375	$9,182,292
154	RC Cape May Holdings LLC	NJ	Non-Small Company	$28,818	$0	$0
155	Rocky Mountain Power Inc	MT	Non-Small Company	$21,549	$20,350	$20,681
156	Savannah River Nuclear Solutions LLC	SC	Non-Small Company	$0	$0	$0
157	Sierra Pacific Power Co	NV	Non-Small Company	$3,357,996	$3,171,083	$3,222,645
158	South Carolina Electric&Gas Co	SC	Non-Small Company	$9,157,875	$9,121,972	$9,131,876
159	South Carolina Genertg Co, Inc	SC	Non-Small Company	$0	$0	$0
160	Southern Indiana Gas & Elec Co	IN	Non-Small Company	$17,657,939	$16,908,753	$16,938,349
161	Southwestern Public Service Co	TX	Non-Small Company	$0	$0	$0
162	State Line Energy LLC	IN	Non-Small Company	$113,011	$0	$0
163	Suez Energy - Colorado Energy Nations Company LLP	CO	Non-Small Company	$11,548	$10,905	$11,082
164	Suez Energy - Northeastern Power Co	PA	Non-Small Company	$256,117	$241,861	$245,793
165	Sunbury Generation LP	PA	Non-Small Company	$628,864	$364,896	$370,220
166	Sunflower Electric Power Corp	KS	Non-Small Company	$724,194	$683,884	$695,004
167	TransAlta Centralia Gen LLC	WA	Non-Small Company	$590,163	$557,313	$566,375
168	Trigen-Cinergy Sol-Tuscola LLC	IL	Non-Small Company	$178,873	$168,917	$171,664
169	Tri-State G & T Assn, Inc	NM 1X	Non-Small Company	$6,220,293	$3,734,706	$3,776,303
170	TXU Generation Co LP	TX	Non-Small Company	$26,212,314	$26,064,693	$26,105,416
171	UGI Development Co	PA	Non-Small Company	$32,217	$30,424	$30,918
172	Union Electric Co	MO	Non-Small Company	$44,678,557	$44,021,746	$44,056,411
173	US Operating Services Company	NJ 2X	Non-Small Company	$7,800,142	$1,848,535	$1,878,593
174	Virginia Electric & Power Co	VA 9X	Non-Small Company	$48,405,661	$43,988,963	$44,165,171
175	Westar Energy Inc	KS	Non-Small Company	$17,014,583	$16,835,426	$16,884,848
176	Western Kentucky Energy Corp	KY	Non-Small Company	$32,328,421	$30,671,187	$31,128,355
177	Wheelabrator Environmental Systems	PA	Non-Small Company	$311,135	$293,816	$298,594
178	Wisconsin Electric Power Co	MI 1X	Non-Small Company	$156,927	$148,192	$150,602
179	Wisconsin Power & Light Co	WI	Non-Small Company	$2,144,903	$2,071,396	$2,091,674
180	Wisconsin Public Service Corp	WI	Non-Small Company	$1,130,018	$1,067,119	$1,084,470
181	Alabama Electric Coop Inc	AL	Non-Small Coop	$3,292,862	$2,676,686	$2,679,878
182	Arizona Electric Pwr Coop Inc	AZ	Non-Small Coop	$8,337,544	$8,011,106	$8,101,158
183	Associated Electric Coop, Inc	MO	Non-Small Coop	$9,900,240	$9,804,662	$9,831,028
184	Basin Electric Power Coop	ND 2X	Non-Small Coop	$23,593,906	$23,423,100	$23,470,219
185	Dairyland Power Coop	WI	Non-Small Coop	$568,689	$537,034	$545,767
186	Deseret Generation & Tran Coop	UT	Non-Small Coop	$1,516,780	$1,432,352	$1,455,643

Exhibit J6 Entity-by-Entity Aggreation of Regulatory Costs With Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	**Owner Entity Name**	**State**	**Owner Entity Size/Type**	**Total cost**	**Total cost**	**Total cost**
187	East Kentucky Power Coop, Inc	KY	Non-Small Coop	$19,955,413	$19,112,323	$19,344,744
188	Great River Energy	ND	Non-Small Coop	$307,877	$290,740	$295,468
189	Minnkota Power Coop, Inc	ND	Non-Small Coop	$10,913,207	$10,614,913	$10,616,925
190	Seminole Electric Coop, Inc	FL	Non-Small Coop	$6,640,176	$6,265,233	$6,367,107
191	South Mississippi El Pwr Assn	MS	Non-Small Coop	$1,455,406	$1,374,395	$1,396,743
192	Western Farmers Elec Coop, Inc	OK	Non-Small Coop	$1,243,631	$1,243,482	$1,243,523
193	Tennessee Valley Authority	AL 2X	Non-Small Federal	$183,239,267	$180,654,627	$180,993,184
194	Grand River Dam Authority	OK	Non-Small State	$1,644,175	$1,552,657	$1,577,904
195	Lower Colorado River Authority	TX	Non-Small State	$3,108,758	$3,102,189	$3,104,001
196	Nebraska Public Power District	NE	Non-Small State	$3,215,099	$3,036,140	$3,085,508
197	Omaha Public Power District	NE	Non-Small State	$480,458	$453,714	$461,092
198	Platte River Power Authority	CO	Non-Small State	$606,039	$596,081	$598,828
199	Salt River Project	AZ	Non-Small State	$26,223,673	$25,001,345	$25,338,539
200	South Carolina Pub Serv Auth	SC	Non-Small State	$6,318,706	$5,632,959	$5,649,310
201	Austin City of	MN	Small City	$1,704	$1,610	$1,636
202	Board of Water Electric & Communications	IA	Small City	$6,329	$5,976	$6,074
203	Cedar Falls Utilities	IA	Small City	$18,757	$17,713	$18,001
204	City of Dover	OH	Small City	$0	$0	$0
205	City of Grand Haven	MI	Small City	$12,927	$12,207	$12,406
206	City of Holland	MI	Small City	$7,752	$7,321	$7,440
207	City of Jasper	IN	Small City	$4,532	$4,280	$4,350
208	City of Logansport	IN	Small City	$9,531	$9,000	$9,147
209	City of Marquette	MI	Small City	$6,488	$6,127	$6,227
210	City of Marshall	MO	Small City	$11,115	$10,496	$10,667
211	City of Menasha	WI	Small City	$139,941	$132,151	$134,300
212	City of Orrville	OH	Small City	$0	$0	$0
213	City of Painesville	OH	Small City	$0	$0	$0
214	City of Richmond	IN	Small City	$50,069	$47,282	$48,051
215	City of Shelby	OH	Small City	$0	$0	$0
216	City of Sikeston	MO	Small City	$1,116,468	$1,101,457	$1,105,598
217	City of Virginia	MN	Small City	$7,908	$7,468	$7,590
218	Crawfordsville Elec, Lgt & Pwr	IN	Small City	$9,340	$8,820	$8,963
219	Fremont City of	NE	Small City	$102,079	$35,033	$35,603
220	Grand Island City of	NE	Small City	$32,773	$0	$0
221	Greenwood Utilities Comm	MS	Small City	$7,283	$6,878	$6,990
222	Hastings City of	NE	Small City	$714,491	$674,721	$685,692
223	Henderson City Utility Comm	KY	Small City	$11,434	$10,797	$10,973
224	Hibbing Public Utilities Comm	MN	Small City	$3,733	$3,525	$3,582
225	Jamestown Board of Public Util	NY	Small City	$0	$0	$0
226	Manitowoc Public Utilities	WI	Small City	$282,912	$267,164	$271,508
227	Michigan South Central Pwr Agy	MI	Small City	$12,068	$11,396	$11,582
228	New Ulm Public Utilities Comm	MN	Small City	$9,259	$8,744	$8,886
229	Pella City of	IA	Small City	$13,255	$12,517	$12,721
230	Peru City of	IN	Small City	$11,995	$11,327	$11,511
231	Somerset Power LLC	MA	Small City	$169,798	$0	$0
232	Texas Municipal Power Agency	TX	Small City	$37,600	$35,507	$36,085
233	Willmar Municipal Utils Comm	MN	Small City	$10,446	$9,865	$10,025

Exhibit J6 Entity-by-Entity Aggreation of Regulatory Costs With Land Treatment Dewatering Sub-Option						
				Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Owner Entity Name	State	Owner Entity Size/Type	Total cost	Total cost	Total cost
234	Wyandotte Municipal Serv Comm	MI	Small City	$8,392	$7,925	$8,054
235	Aurora Energy LLC	AK	Small Company	$536,747	$506,871	$515,113
236	Colstrip Energy LP	MT	Small Company	$7,158	$6,760	$6,870
237	Edgecombe Operating Services LLC	NC	Small Company	$401,188	$0	$0
238	Golden Valley Elec Assn Inc	AK	Small Company	$337,045	$318,284	$323,460
239	Mount Carmel Cogen Inc	PA	Small Company	$345,901	$326,647	$331,959
240	Schuylkill Energy Resource Inc	PA	Small Company	$757,588	$715,419	$727,052
241	Spruance Operating Services LLC	VA	Small Company	$892,784	$0	$0
242	TES Filer City Station LP	MI	Small Company	$9,623	$9,087	$9,235
243	Westmoreland Partners	NC	Small Company	$800,156	$61,403	$62,402
244	White Pine Electric Power LLC	MI	Small Company	$5,045	$4,764	$4,842
245	Central Electric Power Coop	MO	Small Coop	$73,153	$69,081	$70,204
246	Central Iowa Power Cooperative	IA	Small Coop	$101,262	$95,626	$97,180
247	Corn Belt Power Coop	IA	Small Coop	$13,292	$12,553	$12,757
248	San Miguel Electric Coop, Inc	TX	Small Coop	$7,218,552	$0	$0
249	Southern Illinois Power Coop	IL	Small Coop	$2,838,826	$0	$0
250	Soyland Power Coop Inc	IL	Small Coop	$110,907	$104,733	$106,436
251	Crisp County Power Comm	GA	Small County	$4,385	$4,141	$4,209
	SUBTOTALS BY SIZE/TYPE CATEGORIES:		**COLUMN TOTALS =**	**$2,274,000,000**	**$2,168,000,000**	**$2,176,000,000**
		1	Non-Small City	$46,905,000	$43,451,000	$43,892,000
		2	Non-Small Company	$1,897,249,000	$1,815,031,000	$1,821,186,000
		3	Non-Small Coop	$87,726,000	$84,786,000	$85,348,000
		4	Non-Small Federal	$183,239,000	$180,655,000	$180,993,000
		5	Non-Small State	$41,597,000	$39,375,000	$39,815,000
		6	Small City	$2,830,000	$2,467,000	$2,494,000
		7	Small Company	$4,093,000	$1,949,000	$1,981,000
		8	Small Coop	$10,356,000	$282,000	$287,000
		9	Small County	$4,000	$4,000	$4,000

Appendix K
Appendices Supporting the Regulatory Benefits Evaluation

Appendix K1 – Facility Data

Exhibits E2 and E4 within Attachment E of U.S. EPA (2009b) provided information on liners for all facilities where onsite disposal of coal combustion residuals (CCRs) occur. The plants identified in this appendix therefore do not include facilities sending CCRs offsite for disposal. Additionally, several facilities appear twice in this appendix. As mentioned in the text, this is due to the fact that many facilities operate multiple waste management units (WMUs). While the riskiest units were chosen for the purposes of this analysis, all units were reported here to allow for duplication of EPA's results. In interpreting the data below, note that the column entitled "WMU Type" should be interpreted as follows:

1 = Unlined Landfill
2 = Clay-Lined Landfill
3 = Composite-Lined Landfill
4 = Unlined Surface Impoundment
5 = Clay-Lined Surface Impoundment
6 = Composite-Lined Surface Impoundment

Table A.1 – Facility Liner Types

Utility Code	State	WMU Type	Plant Code
8245	NE	1	60
986	AK	1	79
24211	AZ	1	126
21554	FL	1	136
7490	OK	1	165
54888	TX	1	298
14610	FL	1	564
9332	DE	1	594
6455	FL	1	628
6909	FL	1	663
9617	FL	1	667
10623	FL	1	676
9417	IA	1	1046
9417	IA	1	1058
554	IA	1	1122
3203	IA	1	1131
14645	IA	1	1175
4363	IA	1	1217
3258	IA	1	1218
8449	KY	1	1372
20546	KY	1	1381
20546	KY	1	1383
5580	KY	1	1384
12628	MD	1	1571
12653	MD	1	1572
12653	MD	1	1573
3242	MO	1	2169
6779	NE	1	2240
14127	NE	1	2291
Utility Code	**State**	**WMU Type**	**Plant Code**
13407	NV	1	2324
19856	NJ	1	2434
15473	NM	1	2451
12796	WV	1	3942
12796	WV	1	3945
12796	WV	1	3946
20860	WI	1	4072
11571	WI	1	4125
12298	WI	1	4127
12435	WI	1	4146
19545	WY	1	4151
4716	WI	1	4271
16572	AZ	1	4941
23279	WV	1	6004
814	AR	1	6009
17568	MS	1	6061
13337	NE	1	6077
14127	NE	1	6096
14232	SD	1	6098
15248	OR	1	6106
18715	TX	1	6136
17698	TX	1	6139
19323	TX	1	6147
16604	TX	1	6181
17833	MO	1	6195
40307	IL	1	6238
7353	AK	1	6288
814	AR	1	6641
20546	KY	1	6823
54891	TX	1	7030
16604	TX	1	7097
Utility Code	**State**	**WMU Type**	**Plant Code**
12341	IA	1	7343
19545	WY	1	7504
19876	WV	1	7537
20847	WI	1	7549
24211	AZ	1	8223

17166	NV	1	8224
52	CA	1	10002
7860	DE	1	10030
14932	NJ	1	10043
54784	ME	1	10495
8286	HI	1	10604
16061	CA	1	10768
16002	CA	1	10769
6811	CA	1	54238
13060	CA	1	54626
19145	IL	1	55245
9617	FL	2	207
9273	IN	2	991
3599	IN	2	992
9273	IN	2	994
13756	IN	2	995
13756	IN	2	997
4508	IN	2	1024
11142	IN	2	1032
14839	IN	2	1037
15989	IN	2	1040
13143	IA	2	1167
12647	MN	2	1897
14232	MN	2	1943
1009	MN	2	1961
8543	MN	2	1979
Utility Code	**State**	**WMU Type**	**Plant Code**
13488	MN	2	2001
16181	MN	2	2008
19883	MN	2	2018
20737	MN	2	2022
13337	NE	2	2277

19545	SD	2	3325
54888	TX	2	3470
19876	WV	2	3954
12686	MS	2	6073
19323	TX	2	6146
9667	IN	2	6225
12647	MN	2	10075
12647	MN	2	10686
195	AL	3	26
18315	KS	3	108
770	CO	3	462
15466	CO	3	465
15466	CO	3	468
15466	CO	3	477
3989	CO	3	492
15466	CO	3	525
30151	CO	3	527
7801	FL	3	641
7801	FL	3	642
7140	GA	3	708
7140	GA	3	710
7140	GA	3	727
7140	GA	3	728
4538	GA	3	753
12384	IL	3	874
17828	IL	3	964
Utility Code	**State**	**WMU Type**	**Plant Code**
5860	KS	3	1239
10000	KS	3	1241
22500	KS	3	1250
22500	KS	3	1252
4254	MI	3	1695

4254	MI	3	1710
5109	MI	3	1731
5109	MI	3	1740
5109	MI	3	1743
5109	MI	3	1745
20847	MI	3	1769
19578	MI	3	1771
7483	MI	3	1825
8723	MI	3	1830
11701	MI	3	1843
21048	MI	3	1866
13781	MN	3	1915
7651	MS	3	2062
10000	MO	3	2079
10000	MO	3	2080
770	MO	3	2094
4045	MO	3	2123
11732	MO	3	2144
17833	MO	3	2161
924	MO	3	2168
9231	MO	3	2171
15472	NH	3	2364
5511	NY	3	2480
25	NY	3	2527
22125	NY	3	2535
13168	NY	3	2549
Utility Code	**State**	**WMU Type**	**Plant Code**
13579	NY	3	2554
16183	NY	3	2642
9645	NY	3	2682
12199	ND	3	2790
7570	ND	3	2824

14165	OH	3	2861
6526	OH	3	2878
5336	OH	3	2914
14194	OH	3	2935
14381	OH	3	2936
17043	OH	3	2943
15474	OK	3	2963
17235	PA	3	3113
15873	PA	3	3118
12384	PA	3	3122
15998	PA	3	3130
17235	PA	3	3131
15873	PA	3	3136
14165	PA	3	3138
19391	PA	3	3176
23279	PA	3	3178
23279	PA	3	3179
23279	PA	3	3181
17539	SC	3	3287
17554	SC	3	3298
18642	TN	3	3399
19323	TX	3	3497
14354	UT	3	3644
733	VA	3	3775
12588	VA	3	3788
19876	VA	3	3809
Utility Code	**State**	**WMU Type**	**Plant Code**
19099	WA	3	3845
12796	WV	3	3943
23279	WV	3	3944
13781	WI	3	3982
20856	WI	3	4050

4716	WI	3	4140
4716	WI	3	4143
19545	WY	3	4150
12807	MI	3	4259
3542	OH	3	6019
7570	ND	3	6030
5109	MI	3	6034
22129	NY	3	6082
12199	MT	3	6089
14354	UT	3	6165
9267	IN	3	6213
15466	CO	3	6248
1307	ND	3	6469
17539	SC	3	7210
19876	VA	3	7213
18454	FL	3	7242
40577	OH	3	7286
56190	SC	3	7652
17539	SC	3	7737
40230	UT	3	7790
14354	UT	3	8069
3989	CO	3	8219
14232	ND	3	8222
14165	PA	3	8226
19173	CO	3	10003
7199	PA	3	10113
Utility Code	**State**	**WMU Type**	**Plant Code**
9379	PA	3	10143
1951	MI	3	10148
563	WV	3	10151
49889	PA	3	10343
54708	NC	3	10379

13695	NC	3	10380
54889	NC	3	10381
13695	NC	3	10382
1746	NY	3	10464
5670	PA	3	10603
353	CA	3	10640
2884	PA	3	10641
14932	FL	3	10672
12949	WV	3	10743
19876	VA	3	10771
19876	VA	3	10773
19876	VA	3	10774
4217	MT	3	10784
13833	PA	3	50039
55807	NY	3	50202
34672	AL	3	50407
21025	PA	3	50611
19194	NY	3	50651
14432	PA	3	50776
18414	MI	3	50835
20541	PA	3	50879
14932	PA	3	50888
21734	UT	3	50951
14932	PA	3	50974
14932	FL	3	50976
19876	VA	3	52007
Utility Code	**State**	**WMU Type**	**Plant Code**
55808	NC	3	54035
4129	PA	3	54144
16793	PA	3	54634
55808	NC	3	54755
35120	TX	3	54972

3593	MS	3	55076
19545	WY	3	55479
16233	MT	3	55749
195	AL	4	3
195	AL	4	7
195	AL	4	8
195	AL	4	10
18642	AL	4	47
18642	AL	4	50
189	AL	4	56
30151	NM	4	87
803	AZ	4	113
15474	TX	4	127
17543	SC	4	130
796	AZ	4	160
7140	GA	4	703
7140	GA	4	709
7140	GA	4	733
49756	IL	4	856
520	IL	4	864
5517	IL	4	889
5517	IL	4	892
5517	IL	4	897
17828	IL	4	963
9269	IN	4	983
9324	IN	4	988
Utility Code	**State**	**WMU Type**	**Plant Code**
15470	IN	4	1001
15470	IN	4	1004
15470	IN	4	1008
17633	IN	4	1012
9267	IN	4	1043

9417	IA	4	1047
12341	IA	4	1082
12341	IA	4	1091
23279	MD	4	1570
4254	MI	4	1720
5109	MI	4	1733
56155	MI	4	1832
12647	MN	4	1891
12647	MN	4	1893
13781	MN	4	1904
13781	MN	4	1927
12686	MS	4	2049
5416	NC	4	2723
5416	NC	4	2727
5416	NC	4	2732
3006	OH	4	2828
3542	OH	4	2830
3542	OH	4	2832
4062	OH	4	2840
4062	OH	4	2843
4922	OH	4	2850
14006	OH	4	2872
14015	OH	4	2876
22001	PA	4	3152
3046	SC	4	3251
5416	SC	4	3264
Utility Code	**State**	**WMU Type**	**Plant Code**
17539	SC	4	3280
17539	SC	4	3295
17543	SC	4	3317
17543	SC	4	3319
18642	TN	4	3393

18642	TN	4	3396
18642	TN	4	3403
18642	TN	4	3405
18642	TN	4	3406
18642	TN	4	3407
733	VA	4	3776
19876	VA	4	3796
19876	VA	4	3797
19876	VA	4	3803
733	WV	4	3935
733	WV	4	3938
195	AL	4	6002
49756	IL	4	6016
520	IL	4	6017
4922	OH	4	6031
7140	GA	4	6052
15298	MT	4	6076
13756	IN	4	6085
6526	PA	4	6094
14354	WY	4	6101
15470	IN	4	6113
7140	GA	4	6124
17633	IN	4	6137
17698	AR	4	6138
9324	IN	4	6166
16572	AZ	4	6177
Utility Code	**State**	**WMU Type**	**Plant Code**
54865	TX	4	6178
11269	TX	4	6179
1307	WY	4	6204
17543	SC	4	6249
7140	GA	4	6257

19323	TX	4	6648
12341	IA	4	6664
261	IN	4	6705
15143	CO	4	6761
17698	TX	4	7902
20856	WI	4	8023
5416	NC	4	8042
14354	WY	4	8066
14006	OH	4	8102
3265	LA	5	51
7801	FL	5	643
18454	FL	5	645
520	IL	5	863
5517	IL	5	891
5517	IL	5	898
9273	IN	5	990
15470	IN	5	1010
22053	KY	5	1353
10171	KY	5	1355
10171	KY	5	1356
10171	KY	5	1357
10171	KY	5	1361
11249	KY	5	1363
11249	KY	5	1364
18642	KY	5	1378
18642	KY	5	1379
Utility Code	**State**	**WMU Type**	**Plant Code**
20546	KY	5	1382
5580	KY	5	1385
4254	MI	5	1702
4254	MI	5	1723
5860	MO	5	2076

19436	MO	5	2103
19436	MO	5	2104
19436	MO	5	2107
9231	MO	5	2132
924	MO	5	2167
803	NM	5	2442
3046	NC	5	2706
3046	NC	5	2708
3046	NC	5	2709
3046	NC	5	2712
3046	NC	5	2713
3046	NC	5	2716
5416	NC	5	2718
5416	NC	5	2720
5416	NC	5	2721
1307	ND	5	2817
Utility Code	**State**	**WMU Type**	**Plant Code**
12658	ND	5	2823
733	WV	5	3936

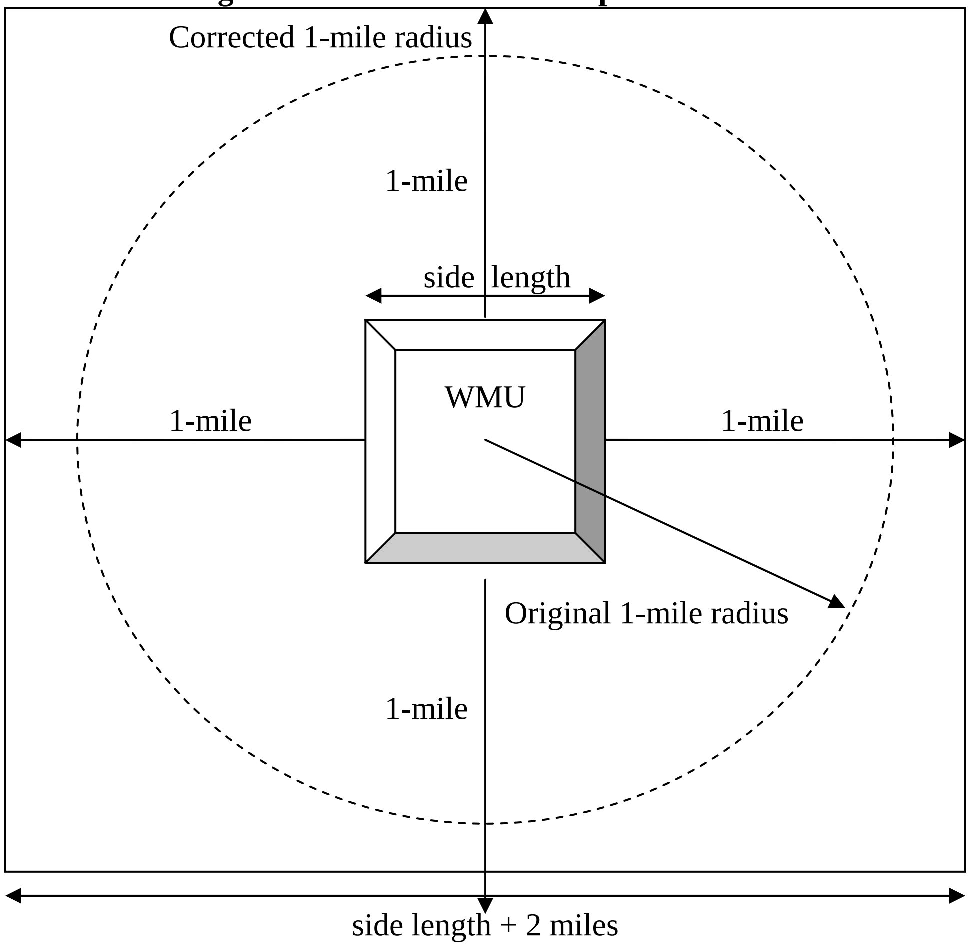
14006	WV	5	3947
14006	WV	5	3948
14354	WY	5	4158
14354	WY	5	4162
55729	KY	5	6018
5580	KY	5	6041
11252	LA	5	6055
9996	KS	5	6064
10000	MO	5	6065
22500	KS	5	6068
11249	KY	5	6071
13781	MN	5	6090
19436	MO	5	6155
3046	NC	5	6250
733	WV	5	6264
11208	UT	5	6481
20546	KY	5	6639
17177	MO	5	6768
20447	OK	5	6772

Appendix K2– WMU Area Data

Attachment B-2 of U.S. EPA (2009a) reports landfill and surface impoundment sizes from a 1995 EPRI survey. These sizes (in acres) can be seen in Attachments C-1 and C-2 of this appendix for landfills and surface impoundments, respectively. For landfills, the area in acres was first converted to square miles using a conversion factor of 0.001562 mi^2/acre. Taking the square root,[8] the length of the side of the WMU was then calculated. As seen in Figure C.1 below, the side of the 1-mile radius was calculated by adding 2 miles to the side length of the WMU, and then squaring that total side length. Averaging these areas and dividing by Pi miles, EPA arrived at a landfill population adjustment factor of 1.81.

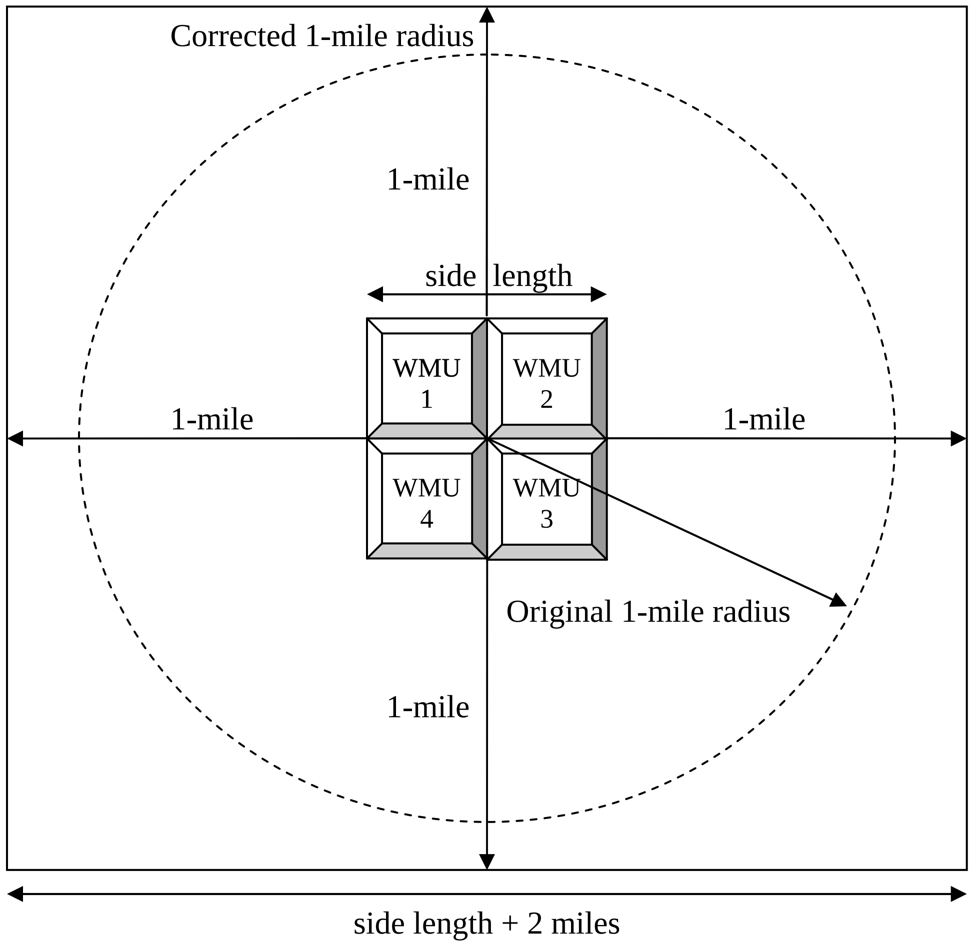
[8] For these calculations, it is assumed that all WMUs are perfect squares. This assumption is consistent with those made in U.S. EPA (2009a).

Figure C.1 – Landfill Area Representation



For surface impoundments, additional analysis was necessary. In a recent survey of CCW surface impoundments, EPA received responses indicating that there are 584 surface impoundments that dispose of at least some CCW. Since EPA estimates that there are 158 facilities that dispose of CCW in surface impoundments, this equates to approximately 3.70 surface impoundments per facility. To account for the 1-mile exposure areas of all impoundments, EPA multiplied the area of each surface impoundment in attachment C-2 by 3.70 before taking the steps outlined above for landfills. In taking this step, the simplifying assumption was that multiple surface impoundments would typically be adjacent in such a way as to form a square, thus allowing the side length to be found by taking the square root. As illustrated in Figure C.2 below, if there were four surface impoundments, they would be aligned as in a block. After accounting for the multiple waste management units and performing all of the calculations discussed for landfills above, the surface impoundment population adjustment factor was estimated to be 2.56.

Figure C.2 – Surface Impoundment Area Representation



Attachment C-1 – Landfill Area Data

Fac. ID	WMU	Acres
42	LF	176
3000	LF	18
7	LF	85
57	LF	27
198	LF	54
81	LF	10
32	LF	85
168	LF	315
14	LF	4.61
15	LF	3.4
41	LF	106
2700	LF	96
143	LF	25.24
144	LF	25.77
339	LF	246
223	LF	26
338	LF	35
263	lf	11.7739066
292	LF	596
139	LF	22
29	LF	70
30	LF	220
89	LF	9
101	LF	434
250	LF	300
251	LF	100

Fac. ID	WMU	Acres
157	LF	12
264	LF	320
265	LF	30
266	LF	30
267	LF	230
268	LF	60
178	LF	22
6	LF	40
24	LF	14
13	LF	45
290	LF	206
246	LF	109
11	LF	21.3
49	LF	12
113	LF	174
289	LF	25
196	LF	23
191	LF	40
213	LF	17
214	LF	61
215	LF	121
135	LF	255
137	LF	99
244	LF	100
329	LF	85
211	LF	79

Fac. ID	WMU	Acres
112	LF	20
87	LF	58
65	LF	8
118	LF	247
40	LF	72
193	LF	40
256	LF	280
255	LF	70
225	LF	339
257	LF	120
258	LF	241
121	LF	200
298	LF	51
106	LF	155
109	LF	825
110	LF	22
111	LF	30
103	LF	37
104	LF	20
52	LF	105
53	LF	38
232	LF	110
152	LF	290
184	LF	65
39	LF	80
100	LF	80

Fac. ID	WMU	Acres
208	LF	70
72	LF	250
26	LF	400
291	LF	212
212	LF	60
73	LF	125
134	LF	900
70	LF	36
51	LF	36
93	LF	200
284	LF	150
20	LF	17
66	LF	27
180	LF	309
17	LF	13
142	LF	69
96	LF	41.2
155	LF	250
243	LF	26
242	LF	300
67	LF	15
140	LF	33
116	LF	292
85	LF	200
95	LF	112.5
239	LF	55
153	LF	125
187	LF	48
318	LF	96
209	LF	68
23	LF	9
3	LF	45
4	LF	130
154	LF	57
158	lf	128.624166
117	LF	312
2000	LF	4
177	LF	540
3900	LF	61
207	LF	39
8	LF	16.4
287	lf	49.20163084
189	lf	28.68322214
123	LF	14
54	LF	60
241	LF	18
71	LF	68

Attachment C-2 – Surface Impoundment Area Data

Fac. ID	WMU	Acres
293	SI	85
159	SI	140
2	SI	107
301	SI	63
167	SI	512
186	SI	241
138	SI	115
176	SI	23.1
235	SI	90
296	SI	41
161	SI	60
126	SI	123
325	SI	280
107	SI	171
163	SI	82
190	si	314.6135409
94	SI	200
272	SI	24.5
294	SI	75
303	SI	295
151	SI	115
179	SI	417
234	SI	72
245	SI	66
276	SI	145
313	SI	33
314	SI	84
114	SI	151
130	SI	10
183	SI	82
195	SI	190
192	si	35.73857178
182	SI	39
237	SI	210
283	SI	60
304	SI	341
Fac. ID	WMU	Acres
136	SI	300
327	SI	875
280	SI	250
281	SI	283
282	SI	1500
147	SI	36
279	SI	480
169	SI	30
203	SI	56
204	SI	324
205	SI	203
330	SI	300
274	SI	150
194	si	151.0232271
224	SI	105
226	SI	180
115	SI	267
125	SI	88
129	SI	6
202	SI	73
220	SI	100
300	SI	200
259	SI	140
262	SI	125
120	SI	100
122	SI	10
297	SI	57
309	SI	105
306	SI	91
275	SI	63.1
254	SI	
311	SI	41
312	SI	275
206	si	59.87027428
231	SI	162
64	SI	15
260	SI	10.7
261	SI	38
240	SI	35
63	SI	30

Fac. ID	WMU	Acres
233	SI	340
171	SI	30
172	SI	65
175	SI	61.1
131	SI	
27	SI	400
92	SI	150
228	SI	11
229	SI	19.4
230	SI	290.8
146	SI	85
316	SI	200
156	si	156.6901408
77	SI	56
326	SI	170
84	SI	80
165	SI	143
247	SI	36
248	SI	109
188	SI	45
199	SI	490
317	SI	180
68	SI	75
69	SI	115
148	SI	5.5
149	SI	5
150	SI	7.75
55	SI	43
288	si	20.03879417
236	SI	26
238	SI	41
324	SI	120
124	SI	
200	SI	330
201	SI	43
181	SI	140
320	SI	110
321	SI	222
277	SI	60
197	SI	4.7

Appendix K3– Population Data

EPA has developed estimates of the population within 1 mile of a power plant potentially exposed to coal combustion residuals (CCRs). These estimates are only for "on-site" CCR management at or very near the power plant; it does not include CCR management more than 1 mile away, or "off-site." EPA started by obtaining a GIS data source. This latitude/longitude data was supplied by an Excel spreadsheet entitled "eGRID2007 Version 1.1 Plant File (Year 2005 Data)."[9] EPA sorted this data set to obtain a list of coal-fired power plants that matched the 495 identified in Appendix B of U.S. EPA (2009b). A few power plants that were present in the U.S. EPA (2009b) list were not in the eGRID list,so EPA added those to the final list. Since this handful of power plants was not in eGRID, their latitude/longitude data could not be obtained, and populations were extrapolated as described in Section 2.

The population risk assessment relied on estimates of household locations in the vicinity of coal-fired power plants (and the associated individuals residing in those households). Population data were obtained from a "synthetic population" data set.[10] The synthetic population database represents each household (and individual) within the contiguous United States. Households are located using a dasymetric algorithm based on demographic information from the 2000 U.S. census and LandScan population estimates (Bhaduri et al. 2007). The LandScan dataset provides population estimates at a much finer resolution (90 m grid) than typical census blocks. The LandScan data take into account the landuse/landcover distribution and are calibrated so that the populations of their grid cells, when summarized at the block group level, match census counts. Within the synthetic population dataset, households are placed randomly within each LandScan grid cell. The approach maintains counts of synthetic households and individuals so that aggregate census data at the block group level remain accurate. For the population assessment, coal-fired power plant facility locations were superimposed onto the synthetic population data. The locations of households (and potential individual receptors) within one mile of each coal-fired power plant facility are based on this overlay.

The risk assessment approach also requires information about the water source for households in the population. Specifically, individuals must be categorized as groundwater users or non-groundwater users in order to assign to them the appropriate exposure pathways and risks (i.e., only groundwater users may be exposed via contact with contaminated groundwater). The 1990 Census provides the required water usage information (U.S. Census Bureau, 1990). If a household documented in the Census specifies "individual well" as their water source, then it is assumed that the associated potential receptors are groundwater users. The ratio of

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[9] "The Emissions & Generation Resource Integrated Database for 2007 (eGRID 2007) Technical Support Document," September 2008. http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html#download

[10] This was developed to support infectious disease models for the Modeling of Infectious Disease Agents Study (MIDAS), funded by the National Institutes of Health (see http://www.midasmodels.org).

households using groundwater reflected in the 1990 Census data at the block group level were applied to the synthetic population data (which are based on the 2000 Census) in order to categorize users for this risk assessment. Note that the 1990 Census information is the best and most recent currently available source of drinking water information, because the 2000 Census did not collect house-hold water source data.

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
3	22	16	6	5	5	0
7	2902	2030	872	8	5	3
8	48	37	11	27	24	3
10	30	24	6	9	7	2
26	35	27	8	4	4	0
47	48	32	16	6	6	0
50	114	83	31	44	29	15
51	7	7	0	0	0	0
56	17	8	9	5	2	3
59	28	22	6	16	11	5
60	17	13	4	5	5	0
79	0	0	0	0	0	0
87	0	0	0	0	0	0
108	0	0	0	0	0	0
113	0	0	0	0	0	0
126	3150	2055	1095	118	91	27
127	1	1	0	0	0	0
130	16	11	5	16	11	5
136	22	14	8	22	14	8
160	18	16	2	13	11	2
165	36	31	5	0	0	0
207	12	12	0	12	12	0
298	6	5	1	2	1	1
384	903	619	284	165	110	55
462	0	0	0	0	0	0
465	8768	6107	2661	90	57	33
468	14	10	4	10	6	4
469	291	231	60	47	40	7

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
470	10	7	3	0	0	0
477	1044	802	242	240	195	45
492	4778	3681	1097	62	45	17
525	19	13	6	10	7	3
527	98	77	21	16	13	3
564	18	16	2	4	4	0
568	0	0	0	0	0	0
593	0	0	0	0	0	0
594	56	39	17	54	37	17
602	2483	1852	631	157	118	39
628	3	3	0	1	1	0
641	253	188	65	0	0	0
642	43	31	12	16	14	2
643	18	14	4	18	14	4
645	155	138	17	0	0	0
663	172	134	38	49	38	11
676	44	29	15	2	2	0
703	303	180	123	50	28	22
708	94	76	18	54	44	10
709	632	512	120	367	287	80
710	3086	2464	622	0	0	0
727	122	79	43	42	31	11
728	164	111	53	141	95	46
733	1000	737	263	6	6	0
753	130	102	28	30	24	6
856	145	116	29	85	71	14
861	9	7	2	7	5	2
863	27	23	4	10	8	2
864	709	546	163	184	137	47
867	22924	14163	8761	15	4	11
874	1080	734	346	167	108	59
876	11	10	1	4	4	0
879	286	195	91	171	112	59

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
883	604	454	150	17	12	5
884	217	162	55	143	106	37
886	45295	30442	14853	54	38	16
887	284	194	90	76	54	22
889	12	9	3	6	4	2
891	523	389	134	138	106	32
892	0	0	0	0	0	0
897	28	19	9	28	19	9
898	7	7	0	1	1	0
963	1896	1492	404	17	13	4
964	1896	1492	404	17	13	4
976	160	123	37	8	6	2
981	13108	8702	4406	37	26	11
983	177	122	55	3	3	0
988	1314	964	350	77	53	24
990	514	348	166	465	306	159
991	346	257	89	78	54	24
992	3219	2325	894	0	0	0
994	242	176	66	44	27	17
995	0	0	0	0	0	0
997	4482	2918	1564	42	25	17
1001	6	5	1	2	2	0
1004	423	296	127	56	41	15
1008	3593	2541	1052	64	38	26
1010	69	54	15	40	30	10
1012	35	23	12	4	2	2
1024	9096	6426	2670	293	230	63
1032	7747	5319	2428	435	315	120
1037	5033	3779	1254	207	155	52
1040	3067	2265	802	215	173	42
1043	108	83	25	10	7	3
1046	10745	7635	3110	23	17	6
1047	84	56	28	66	47	19

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
1048	924	700	224	4	4	0
1058	8817	6405	2412	14	7	7
1073	356	277	79	61	48	13
1077	27	24	3	0	0	0
1081	959	669	290	282	208	74
1082	8	3	5	8	3	5
1091	3	3	0	1	1	0
1104	96	70	26	75	57	18
1122	7045	5606	1439	19	17	2
1131	8407	6596	1811	29	21	8
1167	881	589	292	16	14	2
1175	18	11	7	16	9	7
1217	36	24	12	21	11	10
1218	277	193	84	259	182	77
1239	854	576	278	282	179	103
1241	1	1	0	0	0	0
1250	70	53	17	18	15	3
1252	442	321	121	2	2	0
1295	3025	2203	822	0	0	0
1353	91	70	21	89	68	21
1355	155	120	35	47	34	13
1356	77	53	24	11	10	1
1357	48	37	11	3	2	1
1361	102	84	18	13	10	3
1363	1051	762	289	64	50	14
1364	2023	1397	626	45	31	14
1372	5417	4020	1397	10	8	2
1374	1085	837	248	16	10	6
1378	0	0	0	0	0	0
1379	8	6	2	0	0	0
1381	5	4	1	0	0	0
1382	13	8	5	3	2	1
1383	9	6	3	3	2	1

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
1384	429	339	90	110	87	23
1385	135	105	30	38	32	6
1393	254	169	85	38	26	12
1552	549	375	174	26	16	10
1554	2713	2024	689	57	46	11
1570	2224	1696	528	363	282	81
1571	12	10	2	9	8	1
1572	33	20	13	28	18	10
1573	650	415	235	195	126	69
1606	177	147	30	2	2	0
1613	8381	6617	1764	36	28	8
1619	2141	1665	476	29	19	10
1626	10305	7479	2826	20	15	5
1695	1038	650	388	22	19	3
1702	50	36	14	0	0	0
1710	321	220	101	306	211	95
1720	50	36	14	0	0	0
1723	204	153	51	81	56	25
1731	1963	1382	581	181	119	62
1733	0	0	0	0	0	0
1740	3074	2001	1073	0	0	0
1743	764	613	151	12	9	3
1745	2116	1620	496	0	0	0
1769	2475	1880	595	35	25	10
1771	275	224	51	259	210	49
1825	2663	1999	664	20	16	4
1830	8307	5357	2950	488	322	166
1831	12850	8837	4013	34	26	8
1832	94	68	26	48	38	10
1843	3893	3090	803	104	72	32
1866	8527	6473	2054	0	0	0
1891	12	12	0	5	5	0
1893	41	26	15	20	11	9

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
1897	3278	2507	771	14	7	7
1904	3164	2369	795	34	29	5
1915	1651	1192	459	132	96	36
1927	11333	7104	4229	23	17	6
1943	2115	1535	580	707	498	209
1961	519	384	135	266	194	72
1979	6497	4939	1558	16	11	5
2008	14772	11167	3605	345	251	94
2018	7345	5698	1647	0	0	0
2022	132	99	33	98	71	27
2049	1470	1083	387	66	46	20
2062	0	0	0	0	0	0
2076	13	7	6	0	0	0
2079	0	0	0	0	0	0
2080	1	1	0	0	0	0
2094	382	261	121	46	31	15
2098	510	324	186	0	0	0
2103	0	0	0	0	0	0
2104	282	201	81	4	2	2
2107	6	4	2	6	4	2
2123	6612	4902	1710	46	28	18
2132	1226	858	368	20	15	5
2144	6333	4482	1851	29	25	4
2161	1257	958	299	525	416	109
2167	0	0	0	0	0	0
2168	0	0	0	0	0	0
2169	234	157	77	38	28	10
2171	256	170	86	5	4	1
2187	947	688	259	132	91	41
2240	4108	3048	1060	104	72	32
2277	10	9	1	4	4	0
2291	8644	5876	2768	19	13	6
2324	14	10	4	0	0	0

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
2364	1583	1214	369	101	68	33
2367	3497	2668	829	151	112	39
2378	521	381	140	511	373	138
2384	746	576	170	14	11	3
2403	22440	16630	5810	1	1	0
2408	685	508	177	0	0	0
2434	11249	7199	4050	149	102	47
2442	4	2	2	0	0	0
2451	0	0	0	0	0	0
2480	555	394	161	193	143	50
2526	7132	5215	1917	95	65	30
2527	467	298	169	296	181	115
2535	36	24	12	32	22	10
2549	281	225	56	0	0	0
2554	2970	2112	858	14	9	5
2629	1556	1132	424	968	687	281
2642	4531	3513	1018	0	0	0
2682	18088	12893	5195	18	14	4
2706	1599	1210	389	204	150	54
2708	56	38	18	30	18	12
2709	157	111	46	79	57	22
2712	108	90	18	108	90	18
2713	7	6	1	7	6	1
2716	318	187	131	30	21	9
2718	616	467	149	489	371	118
2720	27	24	3	20	17	3
2721	146	107	39	96	71	25
2723	522	431	91	16	13	3
2727	362	284	78	318	246	72
2732	198	160	38	198	160	38
2790	176	122	54	47	31	16
2817	2	2	0	0	0	0
2823	0	0	0	0	0	0

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
2824	28	15	13	9	5	4
2828	342	252	90	24	17	7
2830	204	140	64	39	29	10
2832	13	9	4	0	0	0
2835	247	198	49	2	1	1
2836	2914	2163	751	0	0	0
2837	3773	2852	921	3	3	0
2838	16280	9760	6520	22	14	8
2840	423	335	88	423	335	88
2843	10	10	0	10	10	0
2848	828	584	244	264	184	80
2850	55	40	15	15	12	3
2861	3285	2402	883	133	91	42
2864	1436	1104	332	117	82	35
2866	359	274	85	93	70	23
2872	90	62	28	56	40	16
2876	210	158	52	21	18	3
2878	717	499	218	30	24	6
2914	6349	4643	1706	230	182	48
2917	12408	8075	4333	6	6	0
2935	4559	3179	1380	423	308	115
2936	10918	7304	3614	45	34	11
2943	8071	5786	2285	576	418	158
2952	40	28	12	0	0	0
2963	411	289	122	7	6	1
3098	849	657	192	139	103	36
3113	170	136	34	168	134	34
3115	177	146	31	38	30	8
3118	754	576	178	48	41	7
3122	52	43	9	52	43	9
3130	952	737	215	56	48	8
3131	134	93	41	38	26	12
3136	94	60	34	73	45	28

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
3138	958	747	211	124	90	34
3140	201	146	55	177	128	49
3149	69	50	19	63	44	19
3152	1938	1538	400	666	550	116
3159	1435	1037	398	395	289	106
3161	1027	733	294	0	0	0
3176	356	267	89	339	253	86
3178	376	277	99	199	145	54
3179	787	659	128	7	7	0
3181	448	328	120	63	47	16
3251	629	465	164	322	230	92
3264	155	113	42	94	69	25
3280	143	104	39	138	100	38
3287	655	438	217	123	88	35
3295	855	560	295	80	54	26
3297	9	6	3	5	3	2
3298	0	0	0	0	0	0
3317	2082	1499	583	5	3	2
3319	199	139	60	199	139	60
3325	1726	1299	427	14	11	3
3393	0	0	0	0	0	0
3396	582	435	147	19	10	9
3399	144	100	44	72	50	22
3403	204	139	65	12	9	3
3405	232	166	66	122	86	36
3406	360	292	68	10	7	3
3407	518	388	130	47	37	10
3470	46	34	12	37	27	10
3497	0	0	0	0	0	0
3644	1	1	0	1	1	0
3775	63	48	15	38	31	7
3776	255	198	57	189	144	45
3788	13051	11266	1785	0	0	0

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
3796	168	136	32	140	114	26
3797	33	31	2	22	20	2
3803	1480	924	556	38	19	19
3809	327	255	72	36	30	6
3845	19	16	3	17	14	3
3935	1475	1084	391	275	195	80
3936	1260	912	348	80	59	21
3938	841	589	252	95	79	16
3942	327	251	76	227	170	57
3943	161	129	32	7	7	0
3944	1512	1106	406	84	61	23
3945	1383	1082	301	13	9	4
3946	71	53	18	30	24	6
3947	360	269	91	16	15	1
3948	40	28	12	4	3	1
3954	18	12	6	12	8	4
3982	3316	2405	911	311	233	78
3992	15756	13707	2049	0	0	0
4041	75	67	8	23	21	2
4042	14490	9202	5288	24	16	8
4050	5745	4168	1577	562	378	184
4054	556	392	164	116	83	33
4072	412	265	147	0	0	0
4078	403	281	122	323	225	98
4125	8281	5865	2416	67	48	19
4140	220	173	47	52	43	9
4143	200	151	49	120	85	35
4146	1066	755	311	221	155	66
4150	708	467	241	253	155	98
4151	0	0	0	0	0	0
4158	0	0	0	0	0	0
4162	0	0	0	0	0	0
4259	936	614	322	362	235	127

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
4271	119	90	29	24	19	5
4941	0	0	0	0	0	0
6002	332	263	69	0	0	0
6004	94	68	26	41	30	11
6009	19	11	8	7	4	3
6016	32	22	10	32	22	10
6017	5	3	2	5	3	2
6018	38	24	14	27	18	9
6019	305	199	106	61	39	22
6021	9	6	3	9	6	3
6030	0	0	0	0	0	0
6031	54	33	21	54	33	21
6034	180	148	32	16	12	4
6041	78	48	30	20	13	7
6052	6	5	1	4	3	1
6055	46	36	10	8	8	0
6061	20	14	6	8	6	2
6064	100	79	21	0	0	0
6065	0	0	0	0	0	0
6068	7	7	0	2	2	0
6071	49	37	12	10	9	1
6073	316	215	101	173	119	54
6076	1379	925	454	6	5	1
6077	7	5	2	7	5	2
6082	79	60	19	7	3	4
6085	38	31	7	38	31	7
6089	114	88	26	98	73	25
6090	0	0	0	0	0	0
6094	330	235	95	233	160	73
6095	5	2	3	0	0	0
6096	2	2	0	0	0	0
6098	7	7	0	2	2	0
6101	7	7	0	2	2	0

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
6106	0	0	0	0	0	0
6113	0	0	0	0	0	0
6124	8	8	0	2	2	0
6136	5	5	0	3	3	0
6137	97	82	15	73	62	11
6138	141	110	31	59	44	15
6139	40	26	14	23	15	8
6146	1	1	0	0	0	0
6147	0	0	0	0	0	0
6155	3	2	1	3	2	1
6165	0	0	0	0	0	0
6166	19	16	3	2	2	0
6170	169	126	43	111	83	28
6177	0	0	0	0	0	0
6178	49	38	11	47	36	11
6179	1	1	0	1	1	0
6181	22	9	13	12	7	5
6183	0	0	0	0	0	0
6190	0	0	0	0	0	0
6193	24	19	5	24	19	5
6194	0	0	0	0	0	0
6195	373	282	91	175	128	47
6204	1	1	0	1	1	0
6204	1	1	0	1	1	0
6213	0	0	0	0	0	0
6225	2298	1681	617	27	18	9
6238	23	21	2	2	2	0
6248	25	14	11	20	11	9
6249	113	78	35	66	47	19
6250	33	23	10	33	23	10
6254	33	23	10	18	13	5
6257	2	2	0	2	2	0
6264	146	117	29	13	13	0

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
6288	0	0	0	0	0	0
6469	0	0	0	0	0	0
6481	0	0	0	0	0	0
6639	6	4	2	0	0	0
6641	9	7	2	0	0	0
6648	2	2	0	1	1	0
6664	258	181	77	220	157	63
6705	14	14	0	0	0	0
6761	6	6	0	2	2	0
6768	2487	1701	786	32	28	4
6772	0	0	0	0	0	0
7030	6	6	0	3	3	0
7097	26	13	13	14	9	5
7210	0	0	0	0	0	0
7213	41	29	12	26	20	6
7242	4	4	0	3	3	0
7286	136	102	34	38	31	7
7343	1	1	0	1	1	0
7504	20	18	2	2	2	0
7537	114	86	28	13	10	3
7549	6825	5403	1422	12	9	3
7652	0	0	0	0	0	0
7737	943	686	257	0	0	0
7790	0	0	0	0	0	0
7902	2	2	0	0	0	0
8023	121	81	40	121	81	40
8042	94	67	27	87	63	24
8066	0	0	0	0	0	0
8069	3	3	0	0	0	0
8102	300	220	80	56	45	11
8219	0	0	0	0	0	0
8222	3	2	1	0	0	0
8223	0	0	0	0	0	0

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
8224	0	0	0	0	0	0
8226	6015	4627	1388	100	75	25
10002	744	515	229	0	0	0
10003	5322	4129	1193	309	250	59
10030	3779	2729	1050	179	130	49
10043	102	70	32	15	10	5
10071	1832	1365	467	8	8	0
10075	35	29	6	33	27	6
10113	417	319	98	24	19	5
10143	816	647	169	108	84	24
10148	0	0	0	0	0	0
10151	706	524	182	139	100	39
10333	71	57	14	40	34	6
10343	1003	772	231	3	2	1
10377	380	250	130	6	4	2
10378	693	562	131	73	60	13
10379	1634	1223	411	698	532	166
10380	429	317	112	8	7	1
10382	383	246	137	79	47	32
10384	997	661	336	292	199	93
10464	810	462	348	22	12	10
10495	0	0	0	0	0	0
10566	1214	900	314	274	189	85
10603	162	120	42	44	30	14
10640	1658	939	719	171	98	73
10641	1359	975	384	469	341	128
10671	23	15	8	5	3	2
10672	6	4	2	5	3	2
10673	0	0	0	0	0	0
10675	2178	1626	552	1112	828	284
10676	59	45	14	27	19	8
10678	779	602	177	391	301	90
10743	13379	11257	2122	24	18	6

Plant ID	Total Population	Adults	Children	All Private Well Users	Private Well Adults	Private Well Children
10773	1968	1480	488	58	51	7
10774	60	52	8	22	20	2
10784	0	0	0	0	0	0
50039	254	202	52	64	53	11
50202	4294	3121	1173	6	6	0
50611	166	135	31	50	40	10
50651	7948	5782	2166	0	0	0
50776	126	108	18	0	0	0
50835	793	620	173	198	154	44
50879	387	298	89	62	46	16
50888	4044	2967	1077	277	189	88
50951	681	487	194	29	19	10
50974	48	40	8	48	40	8
50976	230	135	95	58	37	21
52007	302	229	73	229	173	56
54035	1051	806	245	13	11	2
54081	1837	1245	592	18	10	8
54144	10	7	3	4	4	0
54238	2599	1670	929	0	0	0
54304	136	99	37	100	75	25
54626	15	11	4	12	9	3
54634	120	93	27	11	5	6
54755	1051	806	245	13	11	2
55076	43	31	12	3	3	0
55245	20	18	2	12	11	1
55479	20	18	2	2	2	0
TOTAL	**715,855**	**515,200**	**200,655**	**34,533**	**25,208**	**9,325**

*Note: The list of plants here is the full list of plants from U.S. EPA (2009b), and thus includes populations near facilities that dispose of CCR off-site only.

Appendix K4– Cancer Calculations

A.1 – Yearly Risk Increments

EPA estimates lifetime cancer risk (Risk) from groundwater ingestion by multiplying a cancer slope factor (CSF) by a Lifetime Average Daily Dose (LADD).

$$Risk = CSF \times LADD$$

LADD is calculated using drinking water concentration (C), ingestion rate (IR), years of exposure duration (ED), exposure frequency (EF), body weight (BW), and an averaging time (AT). Substituting the LADD equation in, this can be restated as:

$$Risk = CSF \times \frac{C \times IR \times ED \times EF}{BW \times AT}$$

However, for this assessment EPA needed the increment of lifetime cancer risk (iRisk) associated with one year of exposure. This incremental cancer risk can be expressed as the CSF times the incremental lifetime average daily dose (iLADD). As seen below, this is easily done by dividing both sides by exposure duration.

$$\frac{Risk}{ED} = \frac{CSF \times \frac{C \times IR \times ED \times EF}{BW \times AT}}{ED}$$

Thus, as stated in Section 3, incremental lifetime risk is simply total risk divided by exposure duration, or:

$$YearlyRisk = \frac{Risk}{ED}$$

A.2 – NRC (2001) Cancer Slope Factor Derivation

The National Research Council published the report Arsenic in Drinking Water: 2001 Update (NRC, 2001) which reviewed the available toxicological, epidemiological, and risk assessment literature on the health effects of inorganic arsenic, building upon the NRC's prior report Arsenic in Drinking Water (NRC, 1999). This report, developed by an eminent committee of scientists with expertise in arsenic toxicology and risk assessment provides a scientifically sound and transparent assessment of cancer risks from inorganic arsenic. The "Overall Conclusions" from the Executive Summary of NRC (2001) are as follows:

> *There is a sound database on the carcinogenic effects of arsenic in humans that is adequate for the purposes of a risk assessment. The subcommittee concludes that arsenic-induced internal (lung and bladder) cancers should continue to be the principal focus of arsenic risk assessment for regulatory decision making, as discussed and as recommended in the 1999 NRC report. The human data from southwestern Taiwan used by EPA in its risk assessment[in support of an arsenic Maximum Contaminant Limit in drinking water] remain the most appropriate for determining quantitative lifetime cancer risk estimates. Human data from more recent studies cited in this report, especially those from Chile, provide additional support for the risk assessment. In view of new data from southwestern Taiwan, the subcommittee recommends using an external comparison population, rather than high- and low-exposure groups within the exposed population, when analyzing the earlier studies from southwestern Taiwan. The observed data should be analyzed, using a model that is biologically plausible and provides a reasonable statistical fit to the data. For the southwestern Taiwanese cancer data, this model is the additive Poisson model with a linear term used for dose. The available data on the mode of action of arsenic do not indicate what form of extrapolation (linear or nonlinear) should be used below arsenic concentrations at which cancers have been observed in human studies. As discussed previously, there are no experimental data to indicate the concentration at which any theoretical threshold might exist. Therefore, the curve should be extrapolated linearly from the ED01 to determine risk estimates for the potential concentrations of concern (3, 5, 10, and 20 μg/l)[concentrations used for characterization purposes; NRC did not make risk management recommendations]. The choice for the shape of the dose-response curve below the ED01 is, in part, a policy decision. It should be noted, however, that the Taiwanese and other human studies include data on exposures at arsenic concentrations relatively close to some U.S. exposures. Consequently, the extrapolation is over only a relatively small range of arsenic concentrations. The uncertainly associated with the assumptions in the analyses was discussed earlier."*

More recently, the EPA Science Advisory Board provided advice on the assessment of risks of inorganic arsenic (EPA-SAB-07-008, Advisory on EPA's Assessments of Carcinogenic Effects of Organic and Inorganic Arsenic: A Report of the US EPA Science Advisory Board, June 2007) that reinforces the conclusions of NRC (2001). The SAB advised:

> *[T]he Taiwanese database remains the most appropriate choice for EPA's use in deriving the cancer unit risk for iAs [inorganic arsenic]".* Regarding dose response modeling the SAB report stated that *"the final recommendation of NRC (2001) to base*

current risk assessments on a linear dose response model that includes the SW Taiwan population as a comparison group, seems to be the most appropriate approach".

EPA is now working to issue a final IRIS risk assessment for inorganic arsenic based on a reimplementation of the statistical modeling of the Taiwanese data as used in NRC (2001) and addressing the suggestions of the SAB (2007) for adjunct analyses to further examine effects of assumptions and variability in some parameters used to derive the risk estimates.

Note that the NRC specifically advised that cancer risks for arsenic be assessed using data on the internal cancers (lung and bladder) resulting from arsenic exposure. Older assessments, including the cancer slope factor currently (as of Jan 2010) in EPA's IRIS database, developed arsenic risk estimates based on skin cancer incidence, as data on skin cancer risks were available prior to the availability of quantitative data for internal cancers. Note that arsenic risk estimates based on skin cancer are lower than the risk estimates based on internal cancer developed by NRC (2001) and that (nonmelanoma) skin cancer is a health endpoint associated with lower fatality risk than the internal cancers induced by arsenic. Thus, the skin cancer based risk assessments no longer represent the current state of the science for health risk assessment for arsenic.

The cancer risk estimates presented in NRC (2001) Table ES-1 for consumption of drinking water with specified arsenic concentrations provide information that is scientifically equivalent to estimates of cancer slope factors (CSFs). The NRC's recommended risk models provide estimates that consumption of drinking water containing 10 µg/L arsenic is associated with the site specific cancer risks below. (Note that the same CSF values, other than small differences due to rounding error, would be obtained starting with any of the water concentrations presented in the NRC table.)

Table A.1 – Theoretical Maximum Likelihood Estimates of Excess Lifetime Risk of Lung Cancer and Bladder Cancer for US Populations (Incidence per 10,000 people)

As conc. µg /L	F Bladder	M Bladder	F Lung	M Lung
10	12	23	18	14

The equivalent CSFs can be calculated as follows:

Using the exposure factors for US populations applied in NRC (2001), consumption of 10 µg/L arsenic in drinking water results in a daily exposure of (10 µg/L) x (1 L/d) x (1 mg/1000 µg) x (1/70 kg) = 0.000143 mg/kg-d of inorganic arsenic. As the NRC risk estimates are linear (proportional to dose) for these exposures, equivalent CSF values come from the equation:

$$Risk = CSF \times dose$$

As an example, applying this equation to bladder cancers in females:

$$12 \times 10^{-4} = CSF \times 0.000143 \text{ mg/kg-d}$$

$$CSF = 8.4 \text{ per mg/kg-d}$$

Thus the CSF estimates resulting from Table A.1 are:

Table A.2 – Arsenic Cancer Slope Factors for Lung Cancer and Bladder Cancer in US Populations (per mg/kg-d)

F Bladder	M Bladder	F Lung	M Lung
8	16	13	10

As these are maximum likelihood estimates, it is appropriate to add risks across the two sites resulting in combined CSFs for lung and bladder cancer of 21 and 26 per mg/kg-d in females and males respectively. In consideration of EPA's science policy goal that CSF values represent reasonable upper bound estimates of risk, and as the source of the differences between the male and female CSFs derived from the Taiwan data has not been determined, the CSF for males may appropriately be used in this risk characterization. Note, however, that combined cancer risk values for males and for females are closely similar.

Appendix K5– Sensitivity Analyses

In the main document, EPA made several assumptions which could affect the number of cancers or the benefits quantified. This appendix provides information on three different sensitivity analyses performed by EPA.

Section F.1 examines cancer risks under an assumption of 100% arsenic V.

Section F.2 examines cancer risks with the female cancer slope factor from NRC (2001).

Section F.3 examines the benefits under an alternative value for non-fatal cancers.

Section F.4 examines the alternate assumption of an alternate fraction of CCRs generated per ton of coal burned.

F.1 – Alternative Arsenic Speciation

EPA estimated cancer risks using an assumption that all arsenic in CCR is speciated as arsenic III. While Turner (1981) suggests most would be, arsenic speciated as arsenic V could decrease potential risks due to increased sorption. While there is likely some mix of arsenic species present in CCRs destined for disposal, this mix cannot be ascertained without site-specific data. Thus, EPA assumed 100% arsenic III speciation.

As an alternative, EPA assumed 100% arsenic V speciation. Not only did arsenic V result in lower peak risks, but it also resulted in a longer time until peak risks arrived. As seen in Tables F.1 and F.2 below, this combination of factors would affect the number of cancers expected. Cancer risks decrease noticeably when 100% arsenic V was assumed. This is due to the nature of arsenic transport in the environment. Using the proportions of co-managed to conventionally managed CCRs, the best estimate decreased from 2,509 cancers to 99 cancers, or an approximately 96% decrease.

Table F.1 – Cancers from the Disposal of Ash Only With 100% Arsenic V Speciation

WMU	Adult	Child	Totals
Unlined Landfills	0	0	0
Clay-Lined Landfills	0	0	0
Unlined Surface Impoundments	11	10	21
Clay-Lined Surface Impoundments	1	1	2
Totals	12	10	**22**

Table F.2 – Cancers from the Disposal of Ash and Coal Refuse With 100% Arsenic V Speciation

WMU	Adult	Child	Totals
Unlined Landfills	0	0	0
Clay-Lined Landfills	0	0	0
Unlined Surface Impoundments	75	52	127
Clay-Lined Surface Impoundments	5	4	10
Totals	80	57	**137**

F.2 – Alternative Cancer Slope Factor

As discussed in the main body, EPA used a cancer slope factor based on male cancers in NRC (2001) consistent with EPA policy. However, the cancer slope factor based on female cancers was lower. The difference in cancers using the 21 $mg/kg/d^{-1}$ cancer slope factor for females can be seen in tables F.3 and F.4 below.

Table F.3 – Cancers from the Disposal of CCRs Only
Estimating a CSF from NRC (2001)

WMU	Adult	Child	Totals
Unlined Landfills	1	1	2
Clay-Lined Landfills	1	1	2
Unlined Surface Impoundments	281	227	508
Clay-Lined Surface Impoundments	66	49	115
Totals	349	278	**628**

Table F.4 – Cancers from the Disposal of CCRs and Coal Refuse
Estimating a CSF from NRC (2001)

WMU	Adult	Child	Totals
Unlined Landfills	1	1	2
Clay-Lined Landfills	1	0	1
Unlined Surface Impoundments	1,370	944	2,314
Clay-Lined Surface Impoundments	246	176	422
Totals	1,618	1,121	**2,740**

Using the percent of co-managed versus conventionally managed CCRs, the best estimate would decrease from 2,509 cancers to 2,026 cancers. However, while the number of cancers that occur would decrease by 19%, the monetary value of those cancers would decrease by less. This occurs because the ratio of lung to bladder cancers flips from 38%:62% in males to 60%:40% in females. Since fatal cancers are valued higher than non-fatal cancers, and lung cancers are much more often fatal than bladder cancers, the average female cancer would obtain a higher value, partially offsetting the lower number of cancers.

F.3 – Alternative Cancer Monetization Value

EPA used an estimate from Magat et al. (1996) for estimating the value of avoided non-fatal cancers. An alternative valuation found in the literature can be derived from Viscusi et al. (1991). There the mean estimate for the value of chronic bronchitis was $587,500. Chronic bronchitis costs may be a relatively close valuation for living with lung or bladder cancer due to its chronic nature. EPA updated this value to 2008 dollars using the consumer price index and factoring in an income elasticity of 0.43 based on Kleckner and Neumann (1999). This results in the updated value of chronic bronchitis of approximately $831,000. As seen in Table F.5 below, this leads to a decrease of Subtitle C benefits from $3,316 million to $2,664 million or $970 million to $790 million under a 3% and 7% discount rate, respectively. This equates to a 19% to 20% decrease in total groundwater benefits.

Table F.5 – Groundwater Remediation Benefits

Groundwater Benefits (in millions)	Subtitle C	Subtitle D	Subtitle D’
@ 3%	$2,664	$1,053	$527
@ 7%	$790	$302	$151

F.4 – Alternative CCR Generation Rate

This section provides an alternative projection of the CCRs generated assuming that the ratio of CCRs generated per ton of coal burned would increase over time. Table F.6 below projects the ratio of CCRs generated per ton of coal burned based on a linear trend over time.

Table F.6 – Forecasted Ratio of CCRs Generated per Ton of Coal Burned

Year	CCRs	Year	CCRs	Year	CCRs	Year	CCRs
2012	0.133	**2025**	0.151	**2038**	0.168	**2051**	0.185
2013	0.135	**2026**	0.152	**2039**	0.169	**2052**	0.187
2014	0.136	**2027**	0.153	**2040**	0.171	**2053**	0.188
2015	0.137	**2028**	0.155	**2041**	0.172	**2054**	0.189
2016	0.139	**2029**	0.156	**2042**	0.173	**2055**	0.191
2017	0.140	**2030**	0.157	**2043**	0.175	**2056**	0.192
2018	0.141	**2031**	0.159	**2044**	0.176	**2057**	0.193
2019	0.143	**2032**	0.160	**2045**	0.177	**2058**	0.195
2020	0.144	**2033**	0.161	**2046**	0.179	**2059**	0.196
2021	0.145	**2034**	0.163	**2047**	0.180	**2060**	0.197
2022	0.147	**2035**	0.164	**2048**	0.181	**2061**	0.199
2023	0.148	**2036**	0.165	**2049**	0.183		
2024	0.149	**2037**	0.167	**2050**	0.184		

Given these ratios, EPA was able to project the annual quantities of CCR generated in each year from the tons of coal burned. Table F.7 below presents these estimates of CCR generation after taking into account the recent increasing trend in the ratio of tons CCR generated to tons coal combustion. For example, in year 2035 the projection in Table 25 of the main document yields a value of 153 million tons CCR generation whereas the growing trend leads to 191 million tons of CCR generation in Table F.7.

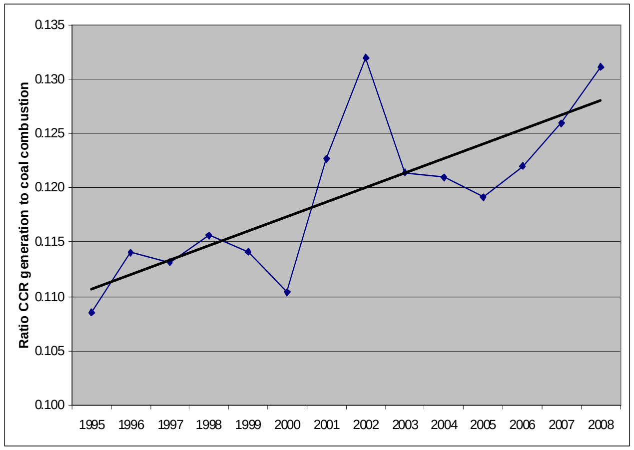
Table F.7 – Forecasted Quantities of CCRs Generated (Short Tons)

Year	CCRs	Year	CCRs	Year	CCRs	Year	CCRs
2012	137,158,617	**2025**	166,823,095	**2038**	199,213,700	**2051**	234,330,427
2013	139,343,714	**2026**	169,217,895	**2039**	201,818,200	**2052**	237,144,631
2014	141,544,943	**2027**	171,628,825	**2040**	204,438,833	**2053**	239,974,964
2015	143,762,302	**2028**	174,055,887	**2041**	207,075,596	**2054**	242,821,430
2016	145,995,792	**2029**	176,499,078	**2042**	209,728,490	**2055**	245,684,025
2017	148,245,413	**2030**	178,958,402	**2043**	212,397,515	**2056**	248,562,753
2018	150,511,166	**2031**	181,433,855	**2044**	215,082,671	**2057**	251,457,610
2019	152,793,048	**2032**	183,925,441	**2045**	217,783,957	**2058**	254,368,599
2020	155,091,063	**2033**	186,433,156	**2046**	220,501,376	**2059**	257,295,718
2021	157,405,207	**2034**	188,957,003	**2047**	223,234,924	**2060**	260,238,970
2022	159,735,483	**2035**	191,496,981	**2048**	225,984,604	**2061**	263,198,350
2023	162,081,889	**2036**	194,053,090	**2049**	228,750,413		
2024	164,444,427	**2037**	196,625,329	**2050**	231,532,356		

Increase in Ratio of CCR Generation to Coal Combustion by Electric Utility Plants

A. Historical Data Regression for Ratio Generation:to:Combustion:

		A	B	C	D (B+C)	E (A/D)
Item	Year	Electric utility CCR generation tons (source: ACAA)	Electric utility coal usage tons (source: DOE-EIA)	Independent power producers (tons)	Electric power sector (tons)	Ratio CCR to coal
1	1995	92,000,000	829,007,000	18,847,000	847,854,000	0.109
2	1996	102,000,000	874,681,000	19,719,000	894,400,000	0.114
3	1997	104,000,000	900,361,000	18,648,000	919,009,000	0.113
4	1998	108,000,000	910,867,000	23,259,000	934,126,000	0.116
5	1999	107,000,000	894,120,000	43,768,000	937,888,000	0.114
6	2000	108,500,000	859,335,000	123,378,000	982,713,000	0.110
7	2001	117,930,542	806,269,000	155,254,000	961,523,000	0.123
8	2002	128,703,572	767,803,000	207,448,000	975,251,000	0.132
9	2003	121,744,571	757,384,000	245,652,000	###########	0.121
10	2004	122,465,119	772,224,000	240,235,000	###########	0.121
11	2005	123,126,093	761,349,000	272,218,000	###########	0.119
12	2006	124,795,124	753,390,000	269,412,000	###########	0.122
13	2007	131,127,693	764,765,000	276,581,000	###########	0.126
14	2008	136,073,107	761,549,000	276,189,000	###########	0.131



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.774621
R Square	0.600037
Adjusted R Square	0.566707
Standard Error	0.00473
Observations	14

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.000402828	0.000403	18.00280702	0.001141
Residual	12	0.00026851	2.24E-05		
Total	13	0.000671338			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	-2.543974	0.62770488	-4.052818	0.00160221
X Variable 1	0.001331	0.000313617	4.242971	0.001141434

B. Future Projection of CCR Generation:

		F	G (F/0.131)	I
Item	Year	Regression trend line	Ratio trendline multiplier 2008=0.131	Tons CCR generation based on constant ratio
1	1995	0.111		
2	1996	0.112		
3	1997	0.113		
4	1998	0.115		
5	1999	0.116		
6	2000	0.117		
7	2001	0.119		
8	2002	0.120		
9	2003	0.121		
10	2004	0.123		
11	2005	0.124		
12	2006	0.125		
13	2007	0.127		
14	2008	0.128		
15	2009	0.129		
16	2010	0.131		
17	2011	0.132		
18	2012	0.133	1.018	134,764,862
19	2013	0.135	1.028	135,558,881
20	2014	0.136	1.038	136,352,901
21	2015	0.137	1.048	137,146,920
22	2016	0.139	1.058	137,940,940
23	2017	0.140	1.069	138,734,959
24	2018	0.141	1.079	139,528,979
25	2019	0.143	1.089	140,322,998
26	2020	0.144	1.099	141,117,018
27	2021	0.145	1.109	141,911,037
28	2022	0.147	1.119	142,705,057
29	2023	0.148	1.129	143,499,076
30	2024	0.149	1.140	144,293,096
31	2025	0.151	1.150	145,087,115
32	2026	0.152	1.160	145,881,135
33	2027	0.153	1.170	146,675,154
34	2028	0.155	1.180	147,469,174
35	2029	0.156	1.190	148,263,193
36	2030	0.157	1.201	149,057,213
37	2031	0.159	1.211	149,851,232
38	2032	0.160	1.221	150,645,252
39	2033	0.161	1.231	151,439,271
40	2034	0.163	1.241	152,233,291
41	2035	0.164	1.251	153,027,310
42	2036	0.165	1.262	153,821,330
43	2037	0.167	1.272	154,615,349
44	2038	0.168	1.282	155,409,369
45	2039	0.169	1.292	156,203,388
46	2040	0.171	1.302	156,997,408
47	2041	0.172	1.312	157,791,427
48	2042	0.173	1.322	158,585,447
49	2043	0.175	1.333	159,379,466
50	2044	0.176	1.343	160,173,486
51	2045	0.177	1.353	160,967,505
52	2046	0.179	1.363	161,761,525
53	2047	0.180	1.373	162,555,544
54	2048	0.181	1.383	163,349,564
55	2049	0.183	1.394	164,143,583
56	2050	0.184	1.404	164,937,603
57	2051	0.185	1.414	165,731,622
58	2052	0.187	1.424	166,525,642
59	2053	0.188	1.434	167,319,661
60	2054	0.189	1.444	168,113,681
61	2055	0.191	1.455	168,907,700
62	2056	0.192	1.465	169,701,720
63	2057	0.193	1.475	170,495,739
64	2058	0.195	1.485	171,289,759
65	2059	0.196	1.495	172,083,778
66	2060	0.197	1.505	172,877,798

Appendix K6– Distributions

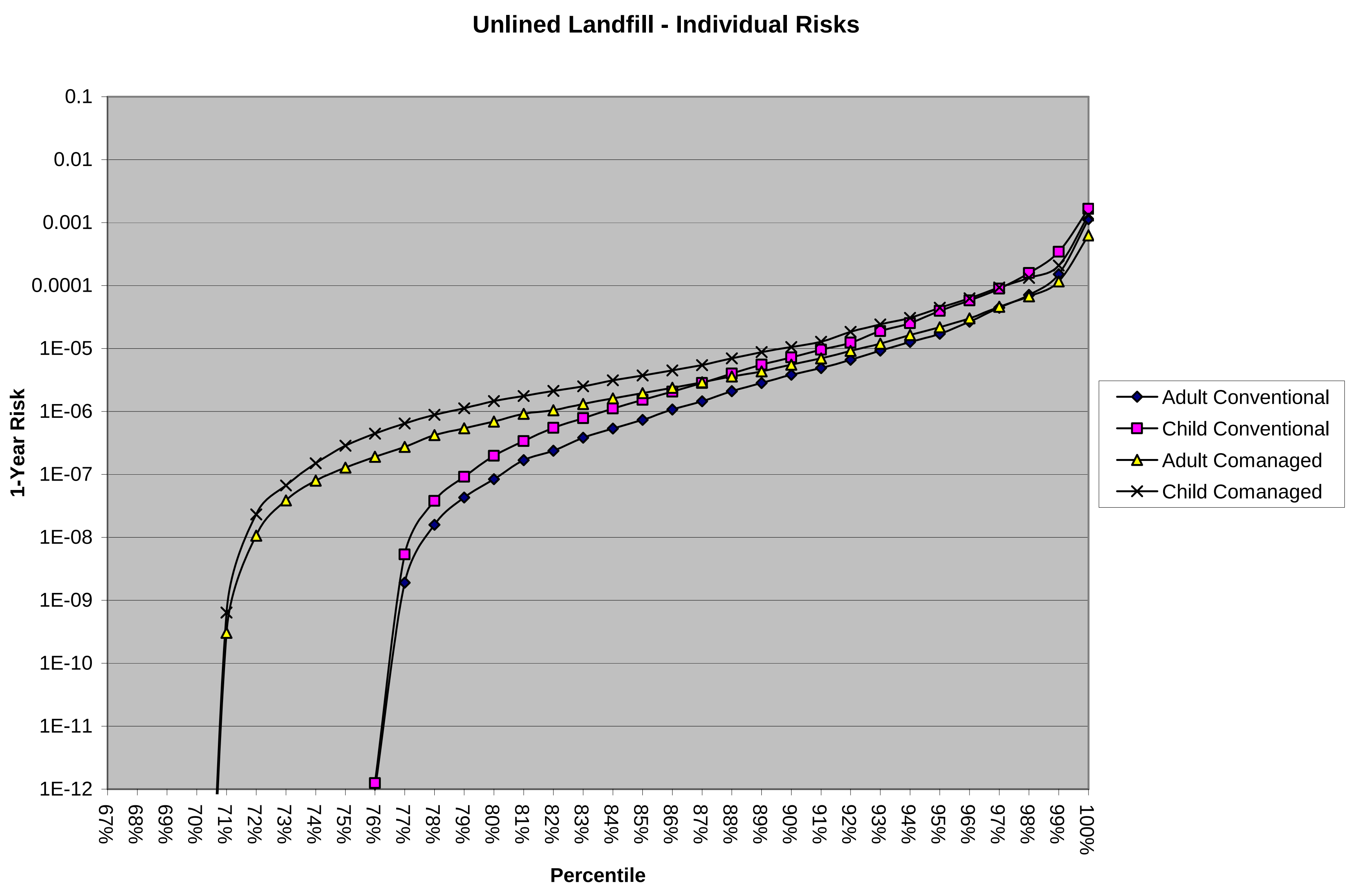
EPA used inputs and outputs from model iterations in U.S. EPA (2009) to calculate population risks as discussed in section 3. This was done using the equation:

$$\frac{\sum \frac{RISKn \times WELLREACH}{EDn}}{n}$$

To allow for increased transparency, EPA has included the graphical distributions of individual 1-year cancer risks in Figures E.1 through E.4 below. These risks can be thought of as the intermediate outputs of the equation above before averaging, or:

$$\frac{RISKn \times WELLREACH}{EDn}$$

No intermediate results are reported for the first 67% of risks because these were zeros as a result of interception by surface waterbodies.


Unlined Landfill - Individual Risks
1-Year Risk
0.1
0.01
0.001
0.0001
1E-05
1E-06
1E-07
1E-08
1E-09
1E-10
1E-11
1E-12
67%
68%
69%
70%
71%
72%
73%
74%
75%
76%
77%
78%
79%
80%
81%
82%
83%
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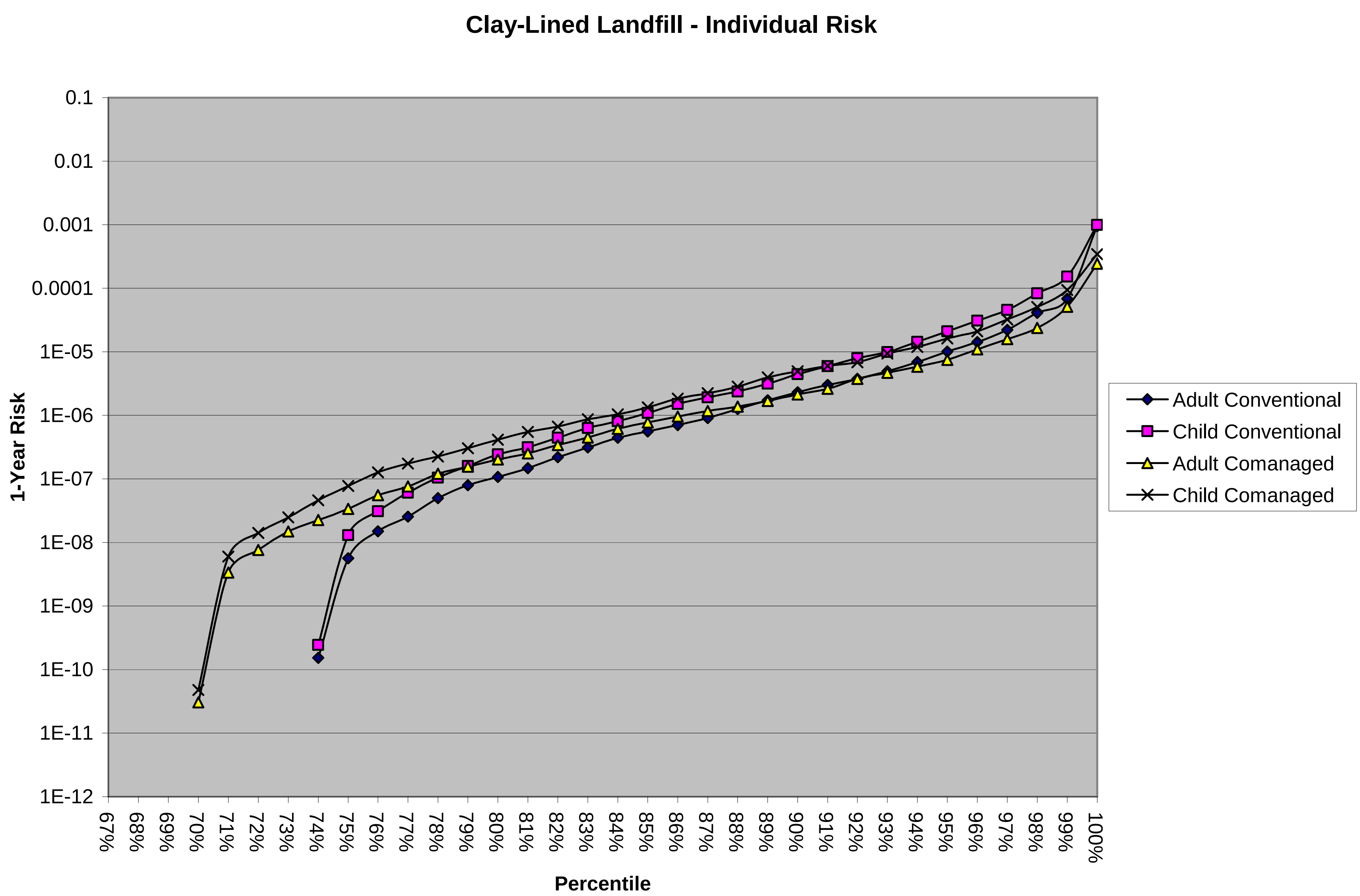
87%
88%
89%
90%
91%
92%
93%
94%
95%
96%
97%
98%
99%
100%
Percentile
Adult Conventional
Child Conventional
Adult Comanaged
Child Comanaged


Clay-Lined Landfill - Individual Risk
1-Year Risk
0.1
0.01
0.001
0.0001
1E-05
1E-06
1E-07
1E-08
1E-09
1E-10
1E-11
1E-12
67%
68%
69%
70%
71%
72%
73%
74%
75%
76%
77%
78%
79%
80%
81%
82%
83%
84%
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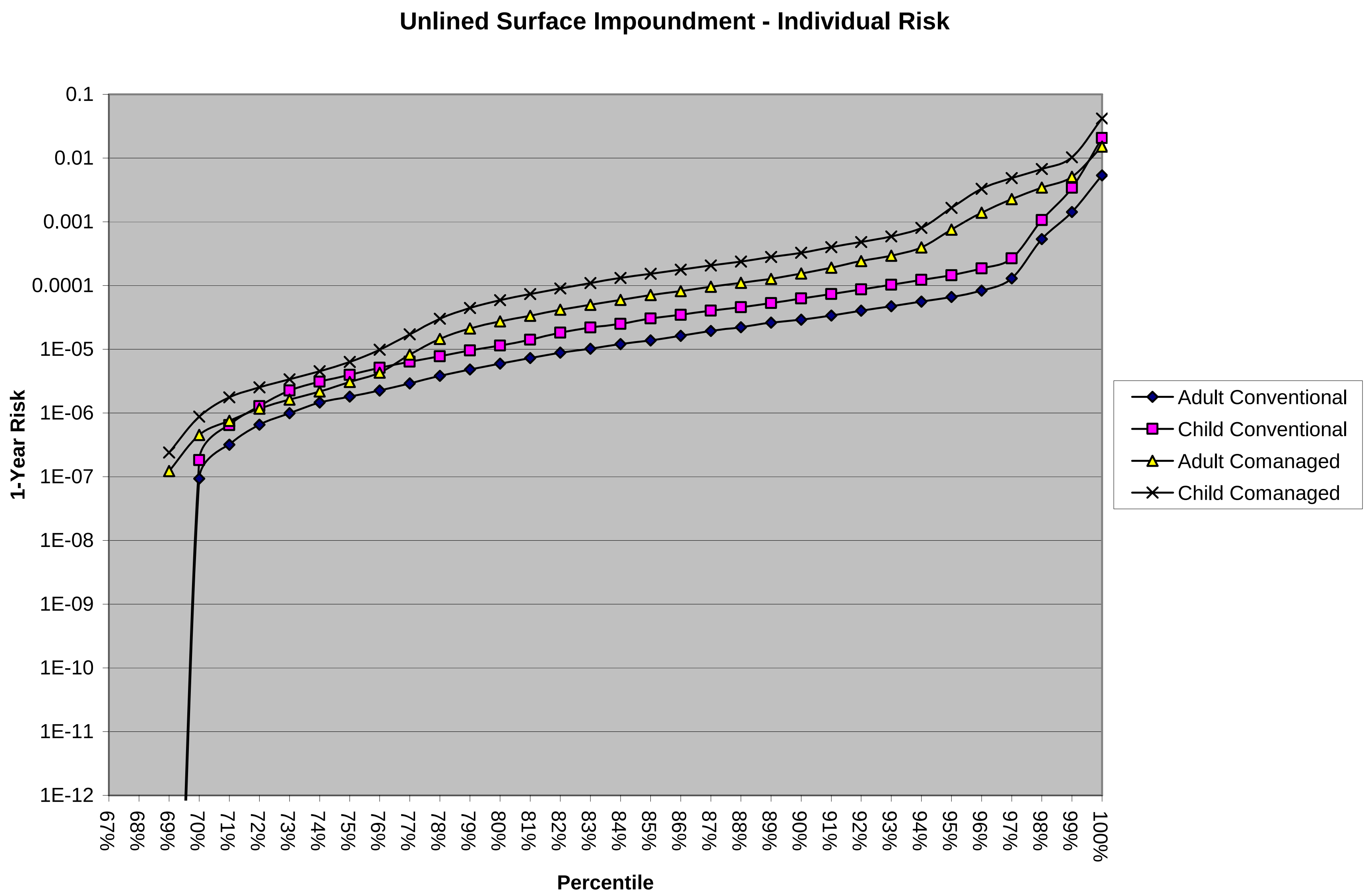
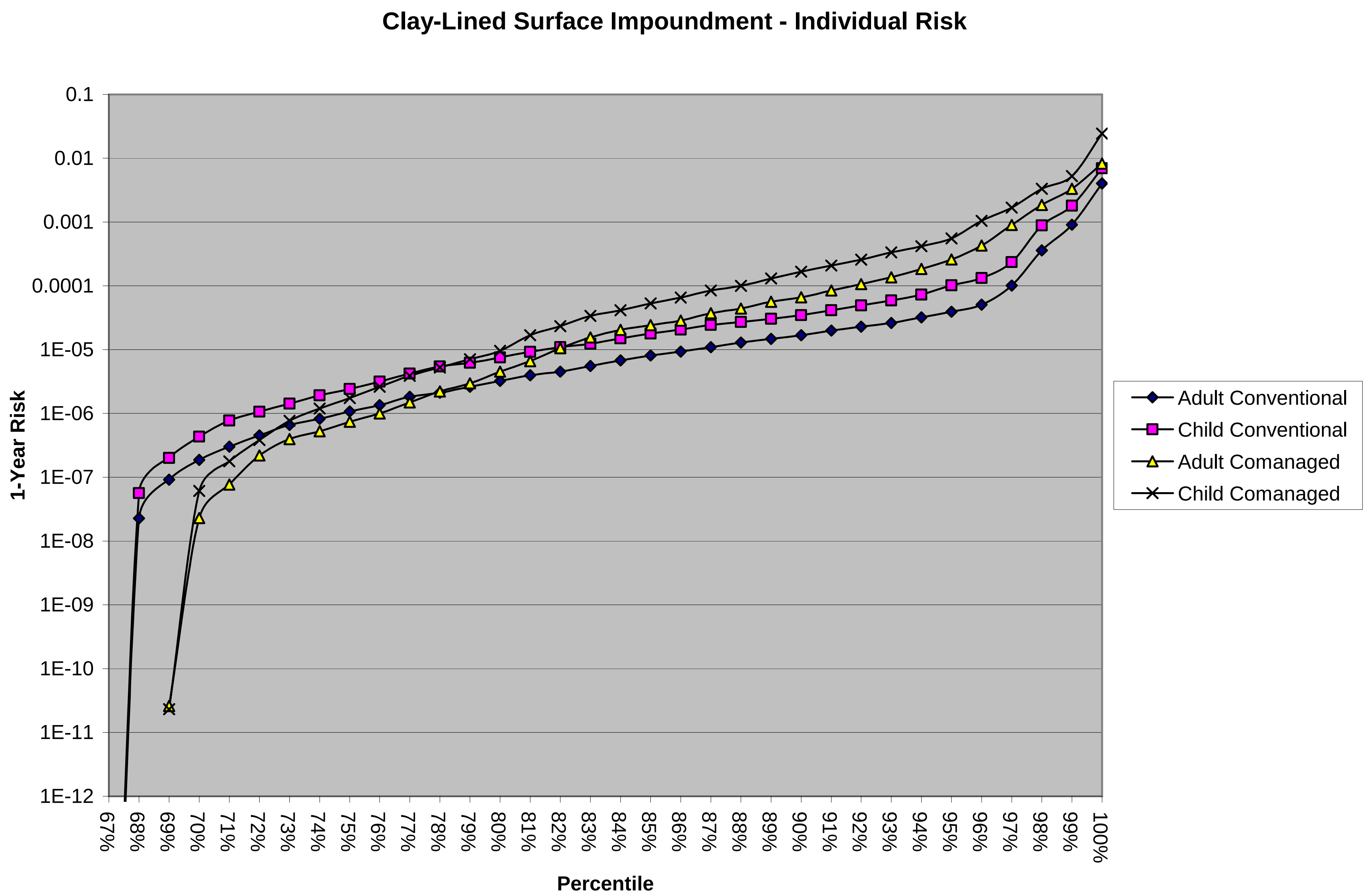
86%
87%
88%
89%
90%
91%
92%
93%
94%
95%
96%
97%
98%
99%
100%
Percentile
Adult Conventional
Child Conventional
Adult Comanaged
Child Comanaged



Unlined Surface Impoundment - Individual Risk
0.1
0.01
0.001
0.0001
1E-05
1E-06
1E-07
1E-08
1E-09
1E-10
1E-11
1E-12
1-Year Risk
67%
68%
69%
70%
71%
72%
73%
74%
75%
76%
77%
78%
79%
80%
81%
82%
83%
84%
85%
86%
87%
88%
89%
90%
91%
92%
93%
94%
95%
96%
97%
98%
99%
100%
Percentile
Adult Conventional
Child Conventional
Adult Comanaged
Child Comanaged



Clay-Lined Surface Impoundment - Individual Risk
1-Year Risk
0.1
0.01
0.001
0.0001
1E-05
1E-06
1E-07
1E-08
1E-09
1E-10
1E-11
1E-12
67%
68%
69%
70%
71%
72%
73%
74%
75%
76%
77%
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79%
80%
81%
82%
83%
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85%
86%
87%
88%
89%
90%
91%
92%
93%
94%
95%
96%
97%
98%
99%
100%
Percentile
Adult Conventional
Child Conventional
Adult Comanaged
Child Comanaged

Appendix K7– Cancer Profiles

H.1 – Nominal and Discounted Cancers

Table H.1 presents the number of bladder and lung cancers expected in each year of the analysis as well as the discounted, monetized value of those cancers.

Table H.1 – Best Estimate Nominal and Discounted Cancers

Year	Nominal Cancers		Discounted Monetized Value	
	Bladder	Lung	at 3%	at 7%
2015	1.87	1.14	$16,551,850	$11,951,827
2016	2.20	1.34	$19,068,867	$13,254,413
2017	2.54	1.54	$21,505,326	$14,388,981
2018	2.88	1.75	$23,863,745	$15,369,912
2019	3.23	1.97	$26,145,918	$16,210,098
2020	3.59	2.19	$28,361,477	$16,926,202
2021	3.95	2.41	$30,508,486	$17,526,705
2022	4.32	2.63	$32,588,026	$18,021,320
2023	4.70	2.86	$34,601,190	$18,419,105
2024	5.08	3.09	$36,552,707	$18,730,354
2025	5.47	3.33	$38,440,446	$18,961,112
2026	5.86	3.57	$40,265,515	$19,118,666
2027	6.26	3.81	$42,028,912	$19,209,736
2028	6.67	4.06	$43,731,684	$19,240,590
2029	7.08	4.31	$45,374,753	$19,216,991
2030	7.50	4.56	$46,963,745	$19,146,209
2031	7.92	4.82	$48,495,268	$19,031,296
2032	8.35	5.09	$49,970,126	$18,876,801
2033	8.79	5.35	$51,389,172	$18,686,954
2034	9.23	5.62	$52,758,546	$18,467,524
2035	9.68	5.89	$54,074,112	$18,220,245

2036	10.14	6.17	$55,336,609	$17,948,425
2037	10.60	6.45	$56,552,372	$17,656,866
2038	11.07	6.74	$57,716,955	$17,346,633
2039	11.54	7.02	$58,836,820	$17,021,977
2040	12.02	7.32	$59,913,046	$16,685,193
2041	12.51	7.61	$60,940,563	$16,336,739
2042	13.00	7.92	$61,926,162	$15,980,197
2043	13.50	8.22	$62,870,842	$15,617,314
2044	14.01	8.53	$63,769,094	$15,248,124
2045	14.53	8.84	$64,627,789	$14,875,604
2046	15.05	9.16	$65,448,006	$14,501,099
2047	15.58	9.48	$66,230,343	$14,125,723
2048	16.11	9.81	$66,975,679	$13,750,549
Year	**Nominal Cancers**		**Discounted Monetized Value**	
	Bladder	**Lung**	**at 3%**	**at 7%**
2049	16.66	10.14	$67,684,643	$13,376,494
2050	17.21	10.47	$68,357,916	$13,004,398
2051	17.77	10.81	$68,997,546	$12,635,266
2052	18.33	11.16	$69,603,699	$12,269,657
2053	18.91	11.51	$70,177,223	$11,908,187
2054	19.49	11.86	$70,718,944	$11,551,400
2055	20.08	12.22	$71,229,674	$11,199,773
2056	20.68	12.59	$71,710,207	$10,853,722
2057	21.29	12.96	$72,161,318	$10,513,605
2058	21.90	13.33	$72,583,770	$10,179,729
2059	22.52	13.71	$72,978,307	$9,852,354
2060	23.16	14.10	$73,345,658	$9,531,696
2061	23.80	14.49	$73,686,536	$9,217,932
2062	24.45	14.88	$74,001,640	$8,911,203
2063	25.10	15.28	$74,291,654	$8,611,616
2064	25.77	15.69	$74,557,246	$8,319,249
2065	26.45	16.10	$74,799,071	$8,034,154

2066	27.13	16.52	$75,017,771	$7,756,358
2067	27.83	16.94	$75,213,972	$7,485,864
2068	28.53	17.37	$75,388,288	$7,222,658
2069	29.24	17.80	$75,541,319	$6,966,707
2070	29.96	18.24	$75,673,654	$6,717,961
2071	30.70	18.68	$75,785,866	$6,476,358
2072	31.44	19.14	$75,878,518	$6,241,821
2073	32.19	19.59	$75,952,161	$6,014,264
2074	32.95	20.06	$76,007,332	$5,793,590
2075	33.72	20.53	$76,044,558	$5,579,694
2076	34.50	21.00	$76,064,355	$5,372,462
2077	35.29	21.48	$76,067,226	$5,171,777
2078	36.10	21.97	$76,053,663	$4,977,512
2079	36.91	22.47	$76,024,149	$4,789,540
2080	37.73	22.97	$75,979,154	$4,607,727
2081	38.57	23.47	$75,919,141	$4,431,938
2082	39.41	23.99	$75,844,558	$4,262,034
2083	40.27	24.51	$75,755,847	$4,097,875
2084	41.13	25.04	$75,653,439	$3,939,321
2085	42.01	25.57	$75,537,755	$3,786,230
2086	42.90	26.11	$75,409,207	$3,638,459
2087	43.80	26.66	$75,268,196	$3,495,866
2088	44.71	27.22	$75,115,117	$3,358,311
2089	45.64	27.78	$74,950,355	$3,225,652
2090	46.57	28.35	$74,774,285	$3,097,750
Total	**1,560**	**949**	**$4,696,189,090**	**$884,547,648**

H.2 – Cancer Profiles Under Regulatory Options

In comparing regulatory options, it was necessary for EPA to account for groundwater monitoring and remediation over time, as these are likely to eliminate cancers as they occur. Here, it is assumed that facilities with groundwater monitoring will be able to switch nearby residents to municipal water immediately to avoid the cancers. However, even at sites where adequate groundwater monitoring is not available, the contamination will eventually be discovered, and at that point residents would be placed on municipal water. Since the first percentile time to peak numbers for unlined surface impoundments is 6 years, it is assumed that no contamination from facilities without groundwater monitoring would be discovered before year 2018. At that time, facilities would steadily find contamination until all contamination is detected by year 2090.

Table H.2 – Profile of Realized Cancers

Year	Baseline	Subtitle D'	Subtitle D
2015	88%	70%	52%
2016	88%	70%	52%
2017	88%	70%	52%
2018	87%	69%	51%
2019	86%	68%	51%
2020	85%	67%	50%
2021	84%	66%	49%
2022	82%	65%	49%
2023	81%	65%	48%
2024	80%	64%	47%
2025	79%	63%	46%
2026	78%	62%	46%
2027	76%	61%	45%
2028	75%	60%	44%
2029	74%	59%	44%
2030	73%	58%	43%
2031	72%	57%	42%
2032	70%	56%	41%
2033	69%	55%	41%
2034	68%	54%	40%
2035	67%	53%	39%
2036	65%	52%	39%
2037	64%	51%	38%
2038	63%	50%	37%
2039	62%	49%	36%
2040	61%	48%	36%
2041	59%	47%	35%
2042	58%	46%	34%
2043	57%	45%	34%
2044	56%	44%	33%
2045	55%	43%	32%
2046	53%	42%	31%
2047	52%	41%	31%
2048	51%	40%	30%
2049	50%	39%	29%
Year	Baseline	Subtitle D'	Subtitle D
2050	48%	39%	29%
2051	47%	38%	28%
2052	46%	37%	27%
2053	45%	36%	26%
2054	44%	35%	26%
2055	42%	34%	25%
2056	41%	33%	24%
2057	40%	32%	24%
2058	39%	31%	23%
2059	38%	30%	22%
2060	36%	29%	21%
2061	35%	28%	21%
2062	34%	27%	20%
2063	33%	26%	19%
2064	32%	25%	19%
2065	30%	24%	18%
2066	29%	23%	17%
2067	28%	22%	16%
2068	27%	21%	16%
2069	25%	20%	15%
2070	24%	19%	14%
2071	23%	18%	14%
2072	22%	17%	13%
2073	21%	16%	12%
2074	19%	15%	11%
2075	18%	14%	11%

2076	17%	13%	10%
2077	16%	13%	9%
2078	15%	12%	9%
2079	13%	11%	8%
2080	12%	10%	7%
2081	11%	9%	6%
2082	10%	8%	6%
2083	8%	7%	5%
2084	7%	6%	4%
2085	6%	5%	4%
2086	5%	4%	3%
2087	4%	3%	2%
2088	2%	2%	1%
2089	1%	1%	1%
2090	0%	0%	0%

Applying the percents in these cancer profiles to the numbers in Table H.2 above, EPA derived the following cancer valuations under the baseline and two Subtitle D options. Subtitle C cancer values are not shown in Table H.3 below because federally enforced groundwater monitoring requirements would lead to residents being placed on municipal groundwater or bottled water to prevent all cancers.

Table H.3 – Net Present Benefits Under the Baseline and Various Regulatory Options

Year	Baseline		Subtitle D Prime		Subtitle D	
	at 3%	at 7%	at 3%	at 7%	at 3%	at 7%
2015	$14,646,778	$10,576,205	$11,636,839	$8,402,776	$8,626,899	$6,229,346
2016	$16,874,094	$11,728,867	$13,406,437	$9,318,564	$9,938,780	$6,908,260
2017	$19,030,123	$12,732,850	$15,119,398	$10,116,226	$11,208,673	$7,499,602
2018	$20,827,819	$13,414,565	$16,547,665	$10,657,848	$12,267,510	$7,901,130
2019	$22,502,716	$13,951,365	$17,878,367	$11,084,334	$13,254,018	$8,217,303
2020	$24,065,760	$14,362,507	$19,120,203	$11,410,986	$14,174,645	$8,459,465
2021	$25,517,755	$14,659,598	$20,273,810	$11,647,024	$15,029,865	$8,634,450
2022	$26,862,082	$14,854,848	$21,341,875	$11,802,150	$15,821,669	$8,749,452
2023	$28,102,085	$14,959,464	$22,327,055	$11,885,267	$16,552,026	$8,811,070
2024	$29,243,960	$14,985,203	$23,234,273	$11,905,716	$17,224,586	$8,826,230
2025	$30,288,271	$14,939,975	$24,063,976	$11,869,783	$17,839,682	$8,799,591
2026	$31,238,196	$14,832,360	$24,818,690	$11,784,283	$18,399,184	$8,736,206
2027	$32,096,776	$14,670,153	$25,500,830	$11,655,410	$18,904,884	$8,640,667
2028	$32,867,040	$14,460,482	$26,112,804	$11,488,827	$19,358,567	$8,517,172
2029	$33,551,877	$14,209,799	$26,656,905	$11,289,660	$19,761,933	$8,369,520
2030	$34,157,548	$13,925,370	$27,138,109	$11,063,681	$20,118,671	$8,201,992
2031	$34,683,593	$13,611,096	$27,556,052	$10,813,991	$20,428,510	$8,016,886
2032	$35,132,669	$13,271,778	$27,912,842	$10,544,403	$20,693,014	$7,817,029
2033	$35,507,425	$12,911,779	$28,210,585	$10,258,385	$20,913,744	$7,604,991
2034	$35,814,060	$12,536,301	$28,454,205	$9,960,068	$21,094,351	$7,383,836
2035	$36,051,621	$12,147,576	$28,642,947	$9,651,227	$21,234,273	$7,154,878
2036	$36,222,549	$11,748,781	$28,778,749	$9,334,385	$21,334,950	$6,919,989
2037	$36,332,845	$11,343,895	$28,866,379	$9,012,704	$21,399,913	$6,681,513
2038	$36,381,405	$10,934,307	$28,904,960	$8,687,287	$21,428,515	$6,440,267
2039	$36,374,085	$10,523,323	$28,899,144	$8,360,761	$21,424,203	$6,198,199
2040	$36,313,166	$10,112,859	$28,850,744	$8,034,648	$21,388,323	$5,956,437
2041	$36,197,223	$9,703,628	$28,758,628	$7,709,515	$21,320,033	$5,715,402
2042	$36,031,979	$9,298,140	$28,627,342	$7,387,355	$21,222,704	$5,476,571
2043	$35,819,527	$8,897,682	$28,458,549	$7,069,193	$21,097,571	$5,240,703
2044	$35,558,283	$8,502,506	$28,250,991	$6,755,226	$20,943,700	$5,007,945
2045	$35,253,685	$8,114,464	$28,008,989	$6,446,927	$20,764,292	$4,779,390

2046	$34,907,746	$7,734,394	$27,734,141	$6,144,962	$20,560,535	$4,555,530
2047	$34,522,176	$7,362,950	$27,427,806	$5,849,850	$20,333,436	$4,336,751
2048	$34,098,802	$7,000,709	$27,091,436	$5,562,051	$20,084,071	$4,123,392
2049	$33,639,281	$6,648,120	$26,726,348	$5,281,919	$19,813,414	$3,915,719
2050	$33,145,266	$6,305,550	$26,333,854	$5,009,748	$19,522,441	$3,713,946
2051	$32,619,024	$5,973,402	$25,915,755	$4,745,857	$19,212,486	$3,518,312
2052	$32,061,854	$5,651,825	$25,473,084	$4,490,365	$18,884,315	$3,328,904
2053	$31,475,353	$5,340,969	$25,007,111	$4,243,390	$18,538,868	$3,145,811
2054	$30,861,070	$5,040,920	$24,519,064	$4,005,002	$18,177,058	$2,969,084
2055	$30,220,504	$4,751,711	$24,010,136	$3,775,225	$17,799,767	$2,798,740
2056	$29,555,111	$4,473,324	$23,481,482	$3,554,047	$17,407,853	$2,634,771
2057	$28,866,299	$4,205,700	$22,934,222	$3,341,421	$17,002,145	$2,477,142
2058	$28,155,433	$3,948,743	$22,369,440	$3,137,269	$16,583,448	$2,325,795
2059	$27,423,835	$3,702,324	$21,788,187	$2,941,490	$16,152,539	$2,180,655
2060	$26,672,785	$3,466,284	$21,191,479	$2,753,956	$15,710,174	$2,041,629
2061	$25,903,524	$3,240,442	$20,580,302	$2,574,525	$15,257,081	$1,908,608
2062	$25,117,250	$3,024,594	$19,955,609	$2,403,034	$14,793,969	$1,781,475
2063	$24,315,124	$2,818,520	$19,318,322	$2,239,309	$14,321,520	$1,660,098
2064	$23,498,271	$2,621,985	$18,669,334	$2,083,162	$13,840,396	$1,544,340
Year	**Baseline**		**Subtitle D Prime**		**Subtitle D**	
	at 3%	**at 7%**	**at 3%**	**at 7%**	**at 3%**	**at 7%**
2065	$22,667,776	$2,434,742	$18,009,507	$1,934,398	$13,351,238	$1,434,054
2066	$21,824,691	$2,256,533	$17,339,677	$1,792,812	$12,854,664	$1,329,090
2067	$20,970,031	$2,087,096	$16,660,651	$1,658,194	$12,351,272	$1,229,292
2068	$20,104,777	$1,926,160	$15,973,209	$1,530,331	$11,841,641	$1,134,501
2069	$19,229,880	$1,773,452	$15,278,104	$1,409,005	$11,326,329	$1,044,557
2070	$18,346,254	$1,628,697	$14,576,066	$1,293,996	$10,805,877	$959,296
2071	$17,454,786	$1,491,616	$13,867,796	$1,185,087	$10,280,805	$878,557
2072	$16,556,329	$1,361,936	$13,153,973	$1,082,055	$9,751,618	$802,175
2073	$15,651,709	$1,239,379	$12,435,254	$984,684	$9,218,800	$729,990
2074	$14,741,721	$1,123,674	$11,712,270	$892,757	$8,682,820	$661,840
2075	$13,827,132	$1,014,552	$10,985,631	$806,060	$8,144,130	$597,567
2076	$12,908,683	$911,747	$10,255,925	$724,381	$7,603,167	$537,015
2077	$11,987,086	$814,997	$9,523,718	$647,513	$7,060,350	$480,030
2078	$11,063,030	$724,046	$8,789,557	$575,253	$6,516,084	$426,461
2079	$10,137,175	$638,644	$8,053,967	$507,402	$5,970,759	$376,159
2080	$9,210,160	$558,547	$7,317,455	$443,764	$5,424,751	$328,982
2081	$8,282,596	$483,514	$6,580,508	$384,151	$4,878,419	$284,788
2082	$7,355,075	$413,313	$5,843,594	$328,377	$4,332,113	$243,440
2083	$6,428,163	$347,720	$5,107,164	$276,263	$3,786,165	$204,806
2084	$5,502,406	$286,514	$4,371,652	$227,635	$3,240,897	$168,756
2085	$4,578,327	$229,483	$3,637,472	$182,323	$2,696,618	$135,164
2086	$3,656,428	$176,421	$2,905,026	$140,166	$2,153,623	$103,911

2087	$2,737,193	$127,130	$2,174,695	$101,005	$1,612,197	$74,879
2088	$1,821,084	$81,419	$1,446,848	$64,687	$1,072,612	$47,955
2089	$908,545	$39,101	$721,837	$31,066	$535,130	$23,030
2090	$0	$0	$0	$0	$0	$0
NPV	$1,824,556,743	$504,404,625	$1,449,607,012	$400,748,557	$1,074,657,282	$297,092,488

Appendix K8– VSL Adjustments

G.1 – Accounting for Cancer Cessation over Time

Bladder and lung cancers from ingestion of arsenic-contaminated groundwater are not expected to cause cancers immediately upon exposure.[11] Instead, there is likely to be a distribution of cancers into the future. In attempting to estimate the value of cancer cases avoided, EPA accounted for the future dates when these cancers would be expected using a cessation lag model. The data used to parameterize the cessation lag model for arsenic from drinking water and bladder cancer is derived from Table 5 of Chen and Gibb (2003). This data is shown in Table G.1 below for the smokers and non-smokers.

Table G.1 – Summary of Arsenic/Bladder Cancer Data from Chen and Gibb (2003) used to Model Cessation Lag

Years After Exposure Reduction from 50 to 10 ug/L	Estimated RR for Smokers	%MRRR for Smokers	Estimated RR for Non-Smokers	%MRRR for Non-Smokers
0	1.0360	0.0%	1.0396	0.0%
8	1.0141	60.80%	1.0096	75.69%
12	1.0065	81.85%	1.0087	77.89%
20	1.0044	87.82%	1.0098	75.26%
22	1.0050	86.25%	0.9989	102.77%
23	1.0012	96.74%	1.0000	100%
25	1.0000	100%	1.0000	100%
Always at 10 ug/L	1.0	NA	1.0	NA

RR = Relative Risk; **MRRR** = Maximum Relative Risk Reduction

$$\%MRRR_j = \frac{RR_0 - RR_j}{RR_0 - 1.0} \times 100$$

As was done in U.S. EPA (2005), a Weibull function was fit to the Chen and Gibb (2003) smoker and non-smoker data together. These data were not weighted to reflect smoking primarily because the results were so similar between the two groups and information on the proportion of smokers in the study group was not available. The form of the resulting Weibull function can be stated as

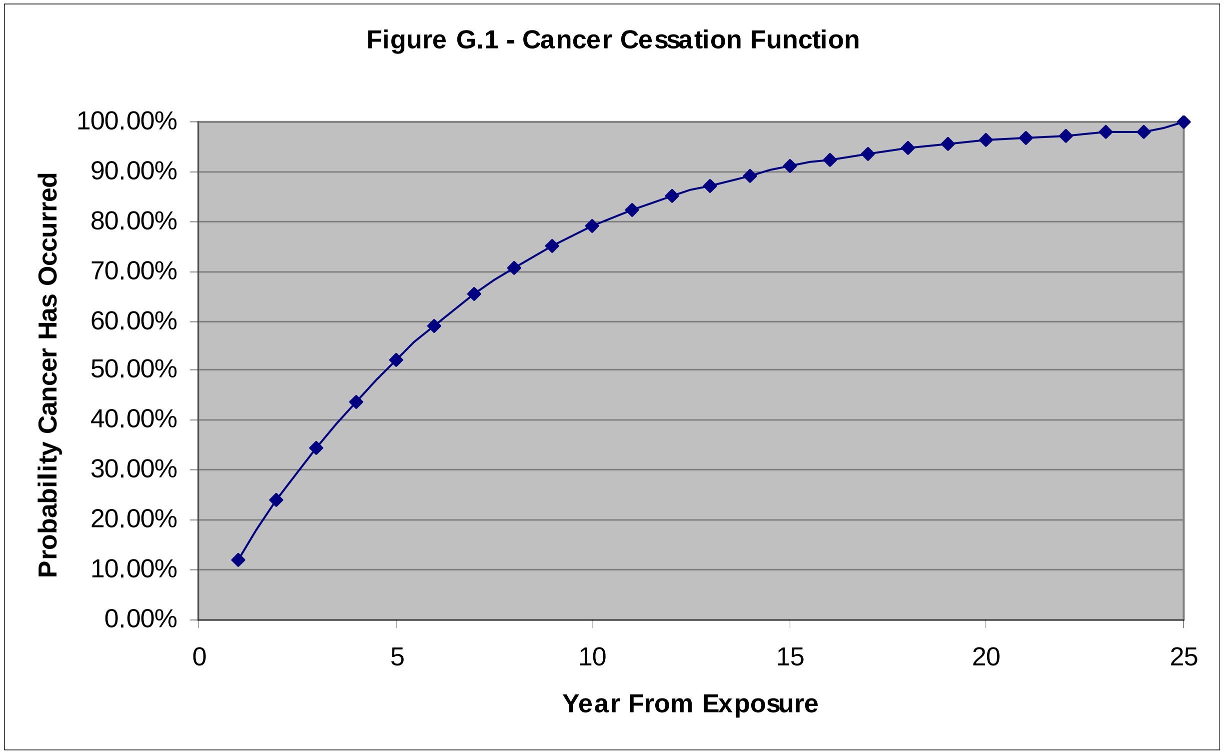
[11] EPA assumed that the lag for bladder and lung cancers from arsenic in drinking water is similar.

$$CF_j = 1 - e^{-\left(\frac{j}{r}\right)^q}$$

<u>where</u>:

j	=	the year;
q	=	1.079; and
r	=	6.635

The arsenic bladder cancer data did not provide ranges for either the RR or the years following arsenic exposure reduction, and therefore it was not possible to generate uncertainty sets of parameters for this cessation lag model. In this document, the Weibull function was truncated at year 25 for simplicity. (In other words, whatever fraction of cancers would have occurred between year 25 and infinity were moved up to year 25.) However, due to discounting and the low fraction of cancer cases remaining this truncation is unlikely to affect the overall results. The graphical depiction of this cancer cessation function can be seen in Figure G.1 below.



Using this Weibull cancer cessation function, EPA estimated the fraction of cancers expected in each year (i.e., the marginal reduction in cancers). Discounting and summing these marginal reductions at 3% and 7%, EPA estimated what fraction of a nominal cancer each real cancer would be worth at the time of exposure, as seen in Table G.2 below. Thus, applying a 3% discount rate, an exposure leading to cancer would be worth only about 83% of that cancer, and at 7%, it would be about 67%.

Table G.2 – Cessation Function

Year	% reductions realized	marginal reductions realized	VSL equivalent @3%	VSL equivalent @7%
1	12.17%	12.17%	0.118	0.114
2	23.98%	11.81%	0.111	0.103
3	34.60%	10.62%	0.097	0.087
4	43.97%	9.37%	0.083	0.071
5	52.14%	8.17%	0.071	0.058
6	59.23%	7.08%	0.059	0.047
7	65.34%	6.11%	0.050	0.038
8	70.59%	5.25%	0.041	0.031
9	75.08%	4.49%	0.034	0.024
10	78.92%	3.84%	0.029	0.020
11	82.19%	3.27%	0.024	0.016
12	84.97%	2.78%	0.020	0.012
13	87.33%	2.36%	0.016	0.010
14	89.34%	2.00%	0.013	0.008
15	91.03%	1.69%	0.011	0.006
16	92.46%	1.43%	0.009	0.005
17	93.67%	1.21%	0.007	0.004
18	94.69%	1.02%	0.006	0.003
19	95.55%	0.86%	0.005	0.002
20	96.27%	0.72%	0.004	0.002
21	96.88%	0.61%	0.003	0.001
22	97.39%	0.51%	0.003	0.001
23	97.82%	0.43%	0.002	0.001
24	98.18%	0.36%	0.002	0.001
25	100.00%	1.82%	0.009	0.003
		Discounted Fraction of VSL	**0.827**	**0.668**

G.2 – Adjusting the VSL for Income

In addition to accounting for the lag time in cancer cases, EPA also adjusted the VSL to account for income growth. This was done in four steps. First, EPA used CBO forecasts out until 2019, followed by a constant 2.2% real growth rate thereafter to predict GDP in future years. Second, populations were grown out under the same Census projections used in the main document until 2050, and then at a constant growth rate of 0.79% there after. Third, GDP was divided by population in each year to calculate GDP per capita. Finally, EPA used the GDP per capita in the following equation, with an income elasticity of 0.5 from Viscusi and Aldi (2003) to estimate the adjustments:

$$VAF_j = \left(1 + \frac{I_j - I_b}{I_b}\right)^e$$

<u>where</u>:

VAF = VSL adjustment factor
I = GDP per capita (in dollars)
e = 0.5 income elasticity
j = current year
b = base year (2009)

GDP, population, GDP per capita, and the final VSL adjustment factors are arrayed for each year below in Table G.3.

Table G.3 – VSL Adjustment Factors by Year

Year	Real GDP (billions)	Population (1000's)	Real GDP per capita (dollars)	VSL adjustment factor
2009	$11,363	307,006	$37,011.12	1.0000
2010	$11,557	310,233	$37,251.41	1.0032
2011	$11,963	313,232	$38,191.32	1.0158
2012	$12,558	316,266	$39,706.89	1.0358
2013	$13,123	319,330	$41,094.87	1.0537
2014	$13,516	322,423	$41,920.61	1.0643
2015	$13,876	325,540	$42,623.44	1.0731
2016	$14,220	328,678	$43,264.83	1.0812
2017	$14,552	331,833	$43,854.28	1.0885
2018	$14,878	335,005	$44,412.74	1.0954
2019	$15,205	338,190	$44,959.68	1.1022
2020	$15,539	341,387	$45,518.50	1.1090
2021	$15,881	344,592	$46,087.23	1.1159
2022	$16,231	347,803	$46,666.30	1.1229
2023	$16,588	351,018	$47,256.13	1.1300
2024	$16,953	354,235	$47,857.17	1.1371

2025	$17,326	357,452	$48,469.84	1.1444
2026	$17,707	360,667	$49,094.61	1.1517
2027	$18,096	363,880	$49,731.66	1.1592
2028	$18,494	367,090	$50,381.31	1.1667
2029	$18,901	370,298	$51,043.63	1.1744
2030	$19,317	373,504	$51,718.82	1.1821
2031	$19,742	376,708	$52,407.07	1.1900
2032	$20,176	379,912	$53,108.33	1.1979
2033	$20,620	383,117	$53,822.65	1.2059
2034	$21,074	386,323	$54,550.26	1.2140
2035	$21,538	389,531	$55,291.23	1.2223
Year	**Real GDP (billions)**	**Population (1000's)**	**Real GDP per capita (dollars)**	**VSL adjustment factor**
2036	$22,011	392,743	$56,045.50	1.2306
2037	$22,496	395,961	$56,813.00	1.2390
2038	$22,991	399,184	$57,594.08	1.2474
2039	$23,496	402,415	$58,388.56	1.2560
2040	$24,013	405,655	$59,196.49	1.2647
2041	$24,542	408,906	$60,017.82	1.2734
2042	$25,082	412,170	$60,852.47	1.2823
2043	$25,633	415,448	$61,700.52	1.2912
2044	$26,197	418,743	$62,561.74	1.3001
2045	$26,774	422,059	$63,435.75	1.3092
2046	$27,363	425,395	$64,322.92	1.3183
2047	$27,965	428,756	$65,222.71	1.3275
2048	$28,580	432,143	$66,135.17	1.3367
2049	$29,209	435,560	$67,059.89	1.3461
2050	$29,851	439,010	$67,996.62	1.3554
2051	$30,508	442,478	$68,947.86	1.3649
2052	$31,179	445,974	$69,912.40	1.3744
2053	$31,865	449,497	$70,890.44	1.3840
2054	$32,566	453,048	$71,882.16	1.3936
2055	$33,283	456,627	$72,887.76	1.4033
2056	$34,015	460,234	$73,907.42	1.4131
2057	$34,763	463,870	$74,941.35	1.4230
2058	$35,528	467,535	$75,989.74	1.4329

2059	$36,309	471,228	$77,052.79	1.4429
2060	$37,108	474,951	$78,130.72	1.4529
2061	$37,925	478,703	$79,223.73	1.4631
2062	$38,759	482,485	$80,332.03	1.4733
2063	$39,612	486,297	$81,455.83	1.4835
2064	$40,483	490,138	$82,595.36	1.4939
2065	$41,374	494,010	$83,750.83	1.5043
2066	$42,284	497,913	$84,922.46	1.5148
2067	$43,214	501,847	$86,110.48	1.5253
2068	$44,165	505,811	$87,315.12	1.5360
2069	$45,137	509,807	$88,536.61	1.5467
2070	$46,130	513,835	$89,775.19	1.5574
2071	$47,144	517,894	$91,031.10	1.5683
2072	$48,182	521,985	$92,304.58	1.5792
2073	$49,242	526,109	$93,595.87	1.5902
2074	$50,325	530,265	$94,905.23	1.6013
2075	$51,432	534,454	$96,232.91	1.6125
2076	$52,564	538,676	$97,579.15	1.6237
2077	$53,720	542,932	$98,944.24	1.6350
2078	$54,902	547,221	$100,328.42	1.6464
Year	**Real GDP (billions)**	**Population (1000's)**	**Real GDP per capita (dollars)**	**VSL adjustment factor**
2079	$56,110	551,544	$101,731.96	1.6579
2080	$57,344	555,901	$103,155.14	1.6695
2081	$58,606	560,293	$104,598.22	1.6811
2082	$59,895	564,719	$106,061.50	1.6928
2083	$61,213	569,181	$107,545.24	1.7046
2084	$62,559	573,677	$109,049.75	1.7165
2085	$63,936	578,209	$110,575.30	1.7285
2086	$65,342	582,777	$112,122.19	1.7405
2087	$66,780	587,381	$113,690.72	1.7527
2088	$68,249	592,021	$115,281.19	1.7649
2089	$69,750	596,698	$116,893.92	1.7772
2090	$71,285	601,412	$118,529.20	1.7896

Appendix K9– State Programs

In attempting to estimate the likelihood of early detection under baseline relative to the three alternative regulatory options, EPA examined the groundwater monitoring requirements in different states. First, EPA aggregated the tons disposed in each state (see "Tons" column). This was converted into a percent of the total U.S. tons disposed to represent facilities in that state (see "Percent" column). Exhibit D-1 and D-2 of U.S. EPA (2009b) contain data on whether or not a state has groundwater monitoring for landfills and surface impoundments, respectively. Roughly speaking, regarding groundwater monitoring, there are three levels of potential state regulatory stringency:

1. no monitoring requirements
2. monitoring requirements for newly constructed WMUs only
3. monitoring requirements for both new and existing WMUs

In columns "LF M" and "SI M" of Table I.1 below, a state in either category 2 or 3 (i.e., a state with any groundwater monitoring program) is noted with a 1, and a state without such a program is noted with a 0. Columns "LF (E)" and "SI (E)" correspond to only category 3 (i.e., the subset of states with groundwater monitoring for existing units). Multiplying the percent of U.S. tons in a state by that state's monitoring designation, the percent of U.S. tons monitored was determined.

LF = Landfills
SI = Surface Impoundments
M = State has some groundwater monitoring requirements (states in 2 or 3)
(E) = Subset of 'M' where monitoring is required for existing units (states in 3)
M% = Percent of facilities (by tons disposed) in 'M'
(E%) = Percent of facilities (by tons disposed) in '(E)'

Table I.1 –Tonnage and Monitoring Requirements by State

State	Tons	Percent	LF M	LF (E)	SI M	SI (E)	LF M%	LF (E%)	SI M%	SI (E%)
AK	46,179	0.03%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
AL	3,904,337	2.62%	1	1	0	0	2.62%	2.62%	0.00%	0.00%
AR	744,267	0.50%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
AZ	3,334,030	2.24%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
CA	159,927	0.11%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
CO	1,704,433	1.14%	1	1	1	0	1.14%	1.14%	1.14%	0.00%
CT	172,280	0.12%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
DE	251,205	0.17%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
FL	7,442,345	5.00%	1	0	1	0	5.00%	0.00%	5.00%	0.00%
GA	6,141,700	4.12%	1	1	0	0	4.12%	4.12%	0.00%	0.00%
HI	58,968	0.04%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
IA	1,136,289	0.76%	1	1	0	0	0.76%	0.76%	0.00%	0.00%
IL	3,958,748	2.66%	1	0	0	0	2.66%	0.00%	0.00%	0.00%
State	Tons	Percent	LF M	LF (E)	SI M	SI (E)	LF M%	LF (E%)	SI M%	SI (E%)
IN	9,123,845	6.12%	1	1	0	0	6.12%	6.12%	0.00%	0.00%
KS	1,495,099	1.00%	1	1	0	0	1.00%	1.00%	0.00%	0.00%
KY	9,881,567	6.63%	1	1	1	0	6.63%	6.63%	6.63%	0.00%
LA	1,614,800	1.08%	1	0	1	1	1.08%	0.00%	1.08%	1.08%
MA	363,150	0.24%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
MD	1,932,740	1.30%	1	1	0	0	1.30%	1.30%	0.00%	0.00%
ME	48,000	0.03%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
MI	2,369,673	1.59%	0	0	1	0	0.00%	0.00%	1.59%	0.00%
MN	1,525,979	1.02%	1	1	1	1	1.02%	1.02%	1.02%	1.02%
MO	2,679,742	1.80%	1	0	1	1	1.80%	0.00%	1.80%	1.80%
MS	1,229,400	0.83%	1	0	0	0	0.83%	0.00%	0.00%	0.00%
MT	1,830,624	1.23%	1	1	0	0	1.23%	1.23%	0.00%	0.00%
NC	5,681,531	3.81%	1	1	1	0	3.81%	3.81%	3.81%	0.00%
ND	3,038,100	2.04%	1	1	1	1	2.04%	2.04%	2.04%	2.04%
NE	614,473	0.41%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
NH	176,900	0.12%	0	0	0	0	0.00%	0.00%	0.00%	0.00%

NJ	735,214	0.49%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
NM	3,983,300	2.67%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
NV	391,500	0.26%	1	0	1	1	0.26%	0.00%	0.26%	0.26%
NY	1,645,792	1.10%	1	1	1	1	1.10%	1.10%	1.10%	1.10%
OH	11,967,446	8.03%	1	1	0	0	8.03%	8.03%	0.00%	0.00%
OK	1,490,800	1.00%	1	0	1	1	1.00%	0.00%	1.00%	1.00%
OR	99,900	0.07%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
PA	16,029,680	10.76%	1	1	1	0	10.76%	10.76%	10.76%	0.00%
SC	2,178,360	1.46%	1	1	1	1	1.46%	1.46%	1.46%	1.46%
SD	103,753	0.07%	0	0	0	0	0.00%	0.00%	0.00%	0.00%
TN	4,810,120	3.23%	1	1	0	0	3.23%	3.23%	0.00%	0.00%
TX	13,208,728	8.87%	1	0	0	0	8.87%	0.00%	0.00%	0.00%
UT	2,582,144	1.73%	1	1	1	1	1.73%	1.73%	1.73%	1.73%
VA	2,388,526	1.60%	1	1	0	0	1.60%	1.60%	0.00%	0.00%
WA	1,405,220	0.94%	1	1	0	0	0.94%	0.94%	0.00%	0.00%
WI	1,412,534	0.95%	1	0	1	0	0.95%	0.00%	0.95%	0.00%
WV	9,662,118	6.49%	1	0	1	0	6.49%	0.00%	6.49%	0.00%
WY	2,224,848	1.49%	1	1	0	0	1.49%	1.49%	0.00%	0.00%
Total	**148,980,314**	**100.00%**	**31**	**21**	**17**	**9**	**91%**	**62%**	**48%**	**12%**

Appendix K10– Remediation Costs

Table K.1 – Remediation Costs (Baseline Option)

Year	Nominal Costs @ 3%		Nominal Costs @ 7%		Discounted Costs	
	Early Detection	Late Detection	Early Detection	Late Detection	@ 3%	@ 7%
2015	$3,160,637		$2,870,746		$2,892,431	$2,343,384
2016	$3,160,637		$2,870,746		$2,808,185	$2,190,078
2017	$3,160,637		$2,870,746		$2,726,393	$2,046,802
2018	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$51,994,645	$32,797,979
2019	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$50,480,238	$30,652,316
2020	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$49,009,940	$28,647,025
2021	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$47,582,466	$26,772,920
2022	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$46,196,569	$25,021,421
2023	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$44,851,038	$23,384,505
2024	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$43,544,697	$21,854,678
2025	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$42,276,405	$20,424,933
2026	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$41,045,053	$19,088,722
2027	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$39,849,566	$17,839,927
2028	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$38,688,899	$16,672,829
2029	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$37,562,038	$15,582,083
2030	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$36,467,998	$14,562,695
2031	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$35,405,823	$13,609,995
2032	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$34,374,586	$12,719,622
2033	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$33,373,384	$11,887,497
2034	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$32,401,344	$11,109,810
2035	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$31,457,615	$10,383,000
2036	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$30,541,374	$9,703,738
2037	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$29,651,820	$9,068,914
2038	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$28,788,174	$8,475,621
2039	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$27,949,684	$7,921,141
2040	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$27,135,615	$7,402,936
2041	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$26,345,258	$6,918,631
2042	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$25,577,920	$6,466,011
2043	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$24,832,932	$6,043,001

Year	Nominal Costs @ 3%		Nominal Costs @ 7%		Discounted Costs	
	Early Detection	Late Detection	Early Detection	Late Detection	@ 3%	@ 7%
2044	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$24,109,643	$5,647,664
2045	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$23,407,420	$5,278,191
2046	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$22,725,651	$4,932,889
2047	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$22,063,739	$4,610,176
2048	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$21,421,105	$4,308,576
2049	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$20,797,190	$4,026,706
2050	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$20,191,446	$3,763,277
2051	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$19,603,346	$3,517,081
2052	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$19,032,375	$3,286,992
2053	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$18,478,034	$3,071,955
2054	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$17,939,838	$2,870,986
2055	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$17,417,319	$2,683,165
2056	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$16,910,018	$2,507,630
2057	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$16,417,494	$2,343,580
2058	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$15,939,314	$2,190,262
2059	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$15,475,062	$2,046,973
2060	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$15,024,332	$1,913,059
2061	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$14,586,730	$1,787,906
2062	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$14,161,874	$1,670,940
2063	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$13,749,392	$1,561,626
2064	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$13,348,925	$1,459,464
2065	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$12,960,121	$1,363,985
2066	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$12,582,642	$1,274,752
2067	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$12,216,157	$1,191,357
2068	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$11,860,347	$1,113,418
2069	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$11,514,900	$1,040,577
2070	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$11,179,514	$972,502
2071	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$10,853,897	$908,881
2072	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$10,537,764	$849,421
2073	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$10,230,839	$793,852
2074	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$9,932,854	$741,917
2075	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$9,643,547	$693,381
2076	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$9,362,667	$648,019

2077	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$9,089,968	$605,626
2078	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$8,825,212	$566,005
2079	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$8,568,167	$528,977
2080	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$8,318,609	$494,371
2081	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$8,076,319	$462,029
2082	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$7,841,086	$431,803
2083	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$7,612,705	$403,554
2084	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$7,390,976	$377,153
2085	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$7,175,705	$352,480
2086	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$6,966,704	$329,420
2087	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$6,763,790	$307,869
2088	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$6,566,786	$287,728
2089	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$6,375,521	$268,905
2090	$3,160,637	$58,923,688.10	$2,870,746	$46,350,176.33	$6,189,826	$251,313
				Net Present Value	**$1,587,248,958**	**$504,330,608**

Table K.2 – Remediation Costs (Subtitle D Prime Option)

Year	Nominal Costs @ 3%		Nominal Costs @ 7%		Discounted Costs	
	Early Detection	Late Detection	Early Detection	Late Detection	@ 3%	@ 7%
2015	$5,283,026		$4,798,470		$4,834,717	$3,916,981
2016	$5,283,026		$4,798,470		$4,693,900	$3,660,730
2017	$5,283,026		$4,798,470		$4,557,185	$3,421,243
2018	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$42,403,000	$26,966,949
2019	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$41,167,961	$25,202,756
2020	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$39,968,895	$23,553,978
2021	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$38,804,752	$22,013,063
2022	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$37,674,516	$20,572,957
2023	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$36,577,200	$19,227,062
2024	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$35,511,845	$17,969,217
2025	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$34,477,520	$16,793,661
2026	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$33,473,320	$15,695,010
2027	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$32,498,369	$14,668,234
2028	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$31,551,814	$13,708,630
2029	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$30,632,830	$12,811,803
2030	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$29,740,611	$11,973,648
2031	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$28,874,380	$11,190,325
2032	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$28,033,378	$10,458,248
2033	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$27,216,872	$9,774,063
2034	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$26,424,148	$9,134,639
2035	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$25,654,512	$8,537,046
2036	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$24,907,294	$7,978,547
2037	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$24,181,839	$7,456,586
2038	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$23,477,513	$6,968,772
2039	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$22,793,702	$6,512,871
2040	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$22,129,808	$6,086,795
2041	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$21,485,250	$5,688,594
2042	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$20,859,466	$5,316,443
2043	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$20,251,909	$4,968,638
2044	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$19,662,048	$4,643,587
2045	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$19,089,367	$4,339,801

2046	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$18,533,366	$4,055,889
2047	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$17,993,559	$3,790,550
2048	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$17,469,475	$3,542,570
2049	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$16,960,655	$3,310,813
2050	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$16,466,655	$3,094,218
2051	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$15,987,044	$2,891,793
2052	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$15,521,402	$2,702,610
2053	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$15,069,322	$2,525,804
2054	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$14,630,410	$2,360,564
2055	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$14,204,282	$2,206,135
Year	**Nominal Costs @ 3%**		**Nominal Costs @ 7%**		**Discounted Costs**	
	Early Detection	**Late Detection**	**Early Detection**	**Late Detection**	**@ 3%**	**@ 7%**
2056	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$13,790,565	$2,061,808
2057	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$13,388,898	$1,926,924
2058	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$12,998,930	$1,800,863
2059	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$12,620,320	$1,683,050
2060	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$12,252,738	$1,572,944
2061	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$11,895,862	$1,470,041
2062	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$11,549,381	$1,373,870
2063	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$11,212,991	$1,283,991
2064	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$10,886,399	$1,199,991
2065	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$10,569,319	$1,121,487
2066	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$10,261,475	$1,048,119
2067	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$9,962,597	$979,550
2068	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$9,672,425	$915,468
2069	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$9,390,703	$855,577
2070	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$9,117,188	$799,605
2071	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$8,851,639	$747,294
2072	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$8,593,824	$698,406
2073	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$8,343,518	$652,716
2074	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$8,100,503	$610,015
2075	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$7,864,566	$570,107
2076	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$7,635,501	$532,810
2077	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$7,413,108	$497,954
2078	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$7,197,192	$465,377

2079	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$6,987,565	$434,932
2080	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$6,784,044	$406,479
2081	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$6,586,450	$379,886
2082	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$6,394,612	$355,034
2083	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$6,208,361	$331,808
2084	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$6,027,535	$310,101
2085	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$5,851,976	$289,814
2086	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$5,681,530	$270,854
2087	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$5,516,049	$253,134
2088	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$5,355,387	$236,574
2089	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$5,199,405	$221,097
2090	$5,283,026	$45,348,373.93	$4,798,470	$35,671,649.14	$5,047,966	$206,633
				Net Present Value	**$1,301,656,614**	**$420,256,135**

Table K.3 – Remediation Costs (Subtitle D Option)

Year	Nominal Costs @ 3%		Nominal Costs @ 7%		Discounted Costs	
	Early Detection	Late Detection	Early Detection	Late Detection	@ 3%	@ 7%
2015	$7,405,414		$6,726,195		$6,777,003	$5,490,578
2016	$7,405,414		$6,726,195		$6,579,615	$5,131,382
2017	$7,405,414		$6,726,195		$6,387,976	$4,795,684
2018	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$32,811,355	$21,135,920
2019	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$31,855,685	$19,753,196
2020	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$30,927,849	$18,460,931
2021	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$30,027,038	$17,253,207
2022	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$29,152,464	$16,124,492
2023	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$28,303,363	$15,069,619
2024	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$27,478,994	$14,083,756
2025	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$26,678,635	$13,162,389
2026	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$25,901,587	$12,301,298
2027	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$25,147,172	$11,496,540
2028	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$24,414,730	$10,744,430
2029	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$23,703,621	$10,041,523
2030	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$23,013,224	$9,384,601
2031	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$22,342,936	$8,770,655
2032	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$21,692,171	$8,196,874
2033	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$21,060,360	$7,660,630
2034	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$20,446,952	$7,159,467
2035	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$19,851,410	$6,691,091
2036	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$19,273,213	$6,253,356
2037	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$18,711,857	$5,844,258
2038	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$18,166,852	$5,461,923
2039	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$17,637,720	$5,104,601
2040	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$17,124,000	$4,770,655
2041	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$16,625,243	$4,458,556
2042	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$16,141,013	$4,166,875
2043	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$15,670,886	$3,894,276
2044	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$15,214,452	$3,639,510

2045	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$14,771,313	$3,401,411
2046	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$14,341,081	$3,178,889
2047	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$13,923,379	$2,970,924
2048	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$13,517,844	$2,776,565
2049	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$13,124,120	$2,594,920
2050	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$12,741,864	$2,425,159
2051	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$12,370,742	$2,266,504
2052	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$12,010,429	$2,118,228
2053	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$11,660,611	$1,979,652
2054	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$11,320,982	$1,850,142
2055	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$10,991,244	$1,729,105

Year	**Nominal Costs @ 3%**		**Nominal Costs @ 7%**		**Discounted Costs**	
	Early Detection	**Late Detection**	**Early Detection**	**Late Detection**	**@ 3%**	**@ 7%**
2056	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$10,671,111	$1,615,986
2057	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$10,360,302	$1,510,267
2058	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$10,058,545	$1,411,465
2059	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$9,765,578	$1,319,126
2060	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$9,481,144	$1,232,828
2061	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$9,204,994	$1,152,176
2062	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$8,936,887	$1,076,800
2063	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$8,676,590	$1,006,355
2064	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$8,423,873	$940,519
2065	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$8,178,518	$878,989
2066	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$7,940,309	$821,485
2067	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$7,709,038	$767,743
2068	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$7,484,502	$717,517
2069	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$7,266,507	$670,577
2070	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$7,054,861	$626,707
2071	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$6,849,380	$585,708
2072	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$6,649,883	$547,390
2073	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$6,456,198	$511,580
2074	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$6,268,153	$478,112
2075	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$6,085,585	$446,834
2076	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$5,908,335	$417,602
2077	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$5,736,248	$390,282

2078	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$5,569,173	$364,749
2079	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$5,406,964	$340,887
2080	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$5,249,479	$318,586
2081	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$5,096,582	$297,744
2082	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$4,948,138	$278,266
2083	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$4,804,017	$260,061
2084	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$4,664,094	$243,048
2085	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$4,528,247	$227,148
2086	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$4,396,356	$212,287
2087	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$4,268,307	$198,399
2088	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$4,143,988	$185,420
2089	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$4,023,289	$173,290
2090	$7,405,414	$31,773,059.76	$6,726,195	$24,993,121.94	$3,906,106	$161,953
				Net Present Value	**$1,016,064,270**	**$336,181,663**

Table K.4 – Remediation Costs (Subtitle C Option)

Year	Nominal Costs @ 3%		Nominal Costs @ 7%		Discounted Costs	
	Early Detection	Late Detection	Early Detection	Late Detection	@ 3%	@ 7%
2015	$3,427,510		$3,113,141		$3,136,657	$2,541,250
2016	$3,427,510		$3,113,141		$3,045,298	$2,375,000
2017	$3,427,510		$3,113,141		$2,956,600	$2,219,626
2018	$3,427,510	$0.00	$3,113,141	$0.00	$2,870,485	$2,074,417
2019	$3,427,510	$0.00	$3,113,141	$0.00	$2,786,879	$1,938,708
2020	$3,427,510	$0.00	$3,113,141	$0.00	$2,705,708	$1,811,876
2021	$3,427,510	$0.00	$3,113,141	$0.00	$2,626,901	$1,693,342
2022	$3,427,510	$0.00	$3,113,141	$0.00	$2,550,389	$1,582,563
2023	$3,427,510	$0.00	$3,113,141	$0.00	$2,476,106	$1,479,031
2024	$3,427,510	$0.00	$3,113,141	$0.00	$2,403,986	$1,382,272
2025	$3,427,510	$0.00	$3,113,141	$0.00	$2,333,967	$1,291,843
2026	$3,427,510	$0.00	$3,113,141	$0.00	$2,265,988	$1,207,330
2027	$3,427,510	$0.00	$3,113,141	$0.00	$2,199,988	$1,128,345
2028	$3,427,510	$0.00	$3,113,141	$0.00	$2,135,911	$1,054,528
2029	$3,427,510	$0.00	$3,113,141	$0.00	$2,073,700	$985,541
2030	$3,427,510	$0.00	$3,113,141	$0.00	$2,013,301	$921,066
2031	$3,427,510	$0.00	$3,113,141	$0.00	$1,954,661	$860,809
2032	$3,427,510	$0.00	$3,113,141	$0.00	$1,897,729	$804,495
2033	$3,427,510	$0.00	$3,113,141	$0.00	$1,842,455	$751,864
2034	$3,427,510	$0.00	$3,113,141	$0.00	$1,788,792	$702,677
2035	$3,427,510	$0.00	$3,113,141	$0.00	$1,736,691	$656,707
2036	$3,427,510	$0.00	$3,113,141	$0.00	$1,686,108	$613,745
2037	$3,427,510	$0.00	$3,113,141	$0.00	$1,636,998	$573,594
2038	$3,427,510	$0.00	$3,113,141	$0.00	$1,589,318	$536,069
2039	$3,427,510	$0.00	$3,113,141	$0.00	$1,543,027	$500,999
2040	$3,427,510	$0.00	$3,113,141	$0.00	$1,498,085	$468,223
2041	$3,427,510	$0.00	$3,113,141	$0.00	$1,454,451	$437,592
2042	$3,427,510	$0.00	$3,113,141	$0.00	$1,412,089	$408,964
2043	$3,427,510	$0.00	$3,113,141	$0.00	$1,370,960	$382,210
2044	$3,427,510	$0.00	$3,113,141	$0.00	$1,331,029	$357,205
2045	$3,427,510	$0.00	$3,113,141	$0.00	$1,292,261	$333,837

2046	$3,427,510	$0.00	$3,113,141	$0.00	$1,254,622	$311,997
2047	$3,427,510	$0.00	$3,113,141	$0.00	$1,218,080	$291,586
2048	$3,427,510	$0.00	$3,113,141	$0.00	$1,182,602	$272,510
2049	$3,427,510	$0.00	$3,113,141	$0.00	$1,148,157	$254,682
2050	$3,427,510	$0.00	$3,113,141	$0.00	$1,114,716	$238,021
2051	$3,427,510	$0.00	$3,113,141	$0.00	$1,082,248	$222,449
2052	$3,427,510	$0.00	$3,113,141	$0.00	$1,050,727	$207,897
2053	$3,427,510	$0.00	$3,113,141	$0.00	$1,020,123	$194,296
2054	$3,427,510	$0.00	$3,113,141	$0.00	$990,411	$181,585
2055	$3,427,510	$0.00	$3,113,141	$0.00	$961,564	$169,706
Year	**Nominal Costs @ 3%**		**Nominal Costs @ 7%**		**Discounted Costs**	
	Early Detection	**Late Detection**	**Early Detection**	**Late Detection**	**@ 3%**	**@ 7%**
2056	$3,427,510	$0.00	$3,113,141	$0.00	$933,557	$158,603
2057	$3,427,510	$0.00	$3,113,141	$0.00	$906,366	$148,227
2058	$3,427,510	$0.00	$3,113,141	$0.00	$879,967	$138,530
2059	$3,427,510	$0.00	$3,113,141	$0.00	$854,337	$129,468
2060	$3,427,510	$0.00	$3,113,141	$0.00	$829,453	$120,998
2061	$3,427,510	$0.00	$3,113,141	$0.00	$805,294	$113,082
2062	$3,427,510	$0.00	$3,113,141	$0.00	$781,839	$105,684
2063	$3,427,510	$0.00	$3,113,141	$0.00	$759,067	$98,770
2064	$3,427,510	$0.00	$3,113,141	$0.00	$736,958	$92,309
2065	$3,427,510	$0.00	$3,113,141	$0.00	$715,494	$86,270
2066	$3,427,510	$0.00	$3,113,141	$0.00	$694,654	$80,626
2067	$3,427,510	$0.00	$3,113,141	$0.00	$674,421	$75,351
2068	$3,427,510	$0.00	$3,113,141	$0.00	$654,778	$70,422
2069	$3,427,510	$0.00	$3,113,141	$0.00	$635,707	$65,815
2070	$3,427,510	$0.00	$3,113,141	$0.00	$617,191	$61,509
2071	$3,427,510	$0.00	$3,113,141	$0.00	$599,215	$57,485
2072	$3,427,510	$0.00	$3,113,141	$0.00	$581,762	$53,724
2073	$3,427,510	$0.00	$3,113,141	$0.00	$564,817	$50,210
2074	$3,427,510	$0.00	$3,113,141	$0.00	$548,366	$46,925
2075	$3,427,510	$0.00	$3,113,141	$0.00	$532,394	$43,855
2076	$3,427,510	$0.00	$3,113,141	$0.00	$516,888	$40,986
2077	$3,427,510	$0.00	$3,113,141	$0.00	$501,833	$38,305
2078	$3,427,510	$0.00	$3,113,141	$0.00	$487,216	$35,799

2079	$3,427,510	$0.00	$3,113,141	$0.00	$473,026	$33,457
2080	$3,427,510	$0.00	$3,113,141	$0.00	$459,248	$31,268
2081	$3,427,510	$0.00	$3,113,141	$0.00	$445,872	$29,223
2082	$3,427,510	$0.00	$3,113,141	$0.00	$432,885	$27,311
2083	$3,427,510	$0.00	$3,113,141	$0.00	$420,277	$25,524
2084	$3,427,510	$0.00	$3,113,141	$0.00	$408,036	$23,854
2085	$3,427,510	$0.00	$3,113,141	$0.00	$396,151	$22,294
2086	$3,427,510	$0.00	$3,113,141	$0.00	$384,613	$20,835
2087	$3,427,510	$0.00	$3,113,141	$0.00	$373,411	$19,472
2088	$3,427,510	$0.00	$3,113,141	$0.00	$362,535	$18,198
2089	$3,427,510	$0.00	$3,113,141	$0.00	$351,975	$17,008
2090	$3,427,510	$0.00	$3,113,141	$0.00	$341,724	$15,895
				Net Present Value	**$96,301,097**	**$38,617,752**

Appendix K11– Supporting Tables

Table L.1 – Information on 42 Units Reporting Releases

Company	Facility	Unit	Storage Capacity (acre ft)	Unit Height (ft)	Hazard Potential	Unit #
PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 Stage Evaporation Ponds (STEP)	4370	88	High	1
City of Springfield	Lakeside	Metal Cleaning Waste Basin		4	None	2
Duke Energy Corp	Walter C. Beckjord Power Station	Ash Pond C	1400	50	Significant	3
PPL Montana LLC	Colstrip Steam Electric Station	Units 3 & 4 Effluent Holding Pond (EHP)	17000	138	Low	4
PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 Stage Evaporation Ponds (STEP)	4370	88	High	5
Georgia Power Co	Harllee Branch Power Station	C	1240	83	None	6
Progress Energy Carolinas Inc	W. H. Weatherspoon Power Station	1979 Pond		28	Low	7
Georgia Power Co	Bowen Power Station	Ash Pond	3719	45	Low	8
MidAmerican Energy Co	Riverside Generating Station	South Surface Impoundment	109	10	None	9
PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 A Pond	245	25	Significant	10
PPL Montana LLC	Colstrip Steam Electric Station	Units 3 & 4 Effluent Holding Pond (EHP)	17000	138	Low	11
American Electric Power	Cardinal Operating Co - Cardinal Power Station	Fly Ash Reservoir 2	11350	237	High	12
PPL Generation, LLC	PPL Montour Power Station	Detention Basin	53	8	Less than Low	13
PPL Montana LLC	Colstrip Steam Electric Station	Units 3 & 4 Effluent Holding Pond (EHP)	17000	138	Low	14
Company	**Facility**	**Unit**	**Storage Capacity (acre ft)**	**Unit Height (ft)**	**Hazard Potential**	**Unit #**
Dominion	Chesterfield Power	Lower (Old) Ash Pond	740	19	None	15

	Station					
PPL Generation, LLC	PPL Martins Creek Power Station	Ash Basin 4	40	43	Significant	16
PPL Montana LLC	Colstrip Steam Electric Station	Units 1 & 2 Stage Evaporation Ponds (STEP)	4370	88	High	17
Ameren Energy Generating Co	Meredosia Power Station	Fly Ash Pond	650	24	None	18
PacifiCorp	Naughton Power Station	FGD Pond #2	382	25	Significant	19
Northern States Power Co	Sherburne County Power Station	Pond No. 2		57	Significant	20
PacifiCorp	Naughton Power Station	North Ash Pond	2100	61	Low	21
PPL Generation, LLC	PPL Montour Power Station	Ash Basin No. 1		40	Low	22
Xcel Energy	PSCo Comanche Station	Polishing Pond (#4)	12	0	None	23
Indianapolis Power & Light Co	Eagle Valley Generating Station	A/B/C Pond			None	24
Kansas City Power & Light Co	LaCygne Generating Station	Scrubber Sludge Ponds	6818	45	None	25
Kansas City Power & Light Co	LaCygne Generating Station	Scrubber Sludge Ponds	6818	45	None	26
Georgia Power Co	Bowen Power Station	Ash Pond	3719	45	Low	27
Indianapolis Power & Light Co	Eagle Valley Generating Station	A/B/C Pond			None	28
Allete Inc	Clay Boswell Power Station	Coal Pile Sump	1	20	None	29
East Kentucky Power Coop Inc	Dale Power Station	Dale Ash Pond #4	112	26	Low	30
Progress Energy Carolinas Inc	Roxboro Power Station	FGD Flush Pond		33	Significant	31
Company	**Facility**	**Unit**	**Storage Capacity (acre ft)**	**Unit Height (ft)**	**Hazard Potential**	**Unit #**
Santee Cooper (South Carolina Pub Serv Auth)	Winyah Power Station	Unit 3 & 4 Slurry Pond	1190	30	None	32
Tennessee Valley Authority	Kingston Power Station	Dredge Pond			High	33

Xcel Energy	PSCo Valmont Station	West Ash Settling Pond	16	0	None	34
PacifiCorp	Dave Johnston Power Station	Blowdown Canal	1	0	None	35
Tennessee Valley Authority	Widows Creek Power Station	Gypsum Stack (Wet Stacking Area)	11157	75	High	36
City of Springfield	Lakeside	Metal Cleaning Waste Basin		4	None	37
Kansas City Power & Light Co	LaCygne Generating Station	Scrubber Sludge Ponds	6818	45	None	38
First Energy Generation Corp	Bruce Mansfield Power Station	Lakeside Ash Pond		20	Low	39
Northern Indiana Pub Serv Co	R. M. Schahfer Power Station	Little Blue Run Dam	84300	388	High	40
PacifiCorp	Jim Bridger Power Station	FGD Pond #1	1340	32	Significant	41
PacifiCorp	Jim Bridger Power Station	FGD Pond #2	11534	42	Significant	42

Table L.2 – Discounted Annual Avoided Release Costs Using 1995-2009 Data

Year	7% Discount Rate				3% Discount Rate			
	99th %-ile	95th %-ile	90th %-ile	Average	99th %-ile	95th %-ile	90th %-ile	Average
2012	$0	$0	$0	$0	$0	$0	$0	$0
2013	$0	$0	$0	$0	$0	$0	$0	$0
2014	$0	$0	$0	$0	$0	$0	$0	$0
2015	$349,463,906	$305,903,857	$262,671,648	$147,384,283	$391,779,750	$342,945,108	$294,478,002	$165,230,734
2016	$321,691,353	$281,593,104	$241,796,639	$135,671,377	$374,649,882	$327,950,446	$281,602,478	$158,006,316
2017	$296,056,940	$259,153,974	$222,528,745	$124,860,219	$358,185,508	$313,538,328	$269,227,168	$151,062,566
2018	$272,399,771	$238,445,629	$204,747,030	$114,882,952	$342,362,396	$299,687,538	$257,333,857	$144,389,264
2019	$250,570,854	$219,337,647	$188,339,505	$105,676,738	$327,157,156	$286,377,604	$245,904,964	$137,976,546
2020	$230,432,226	$201,709,263	$173,202,473	$97,183,394	$312,547,220	$273,588,770	$234,923,527	$131,814,895
2021	$211,856,154	$185,448,665	$159,239,922	$89,349,048	$298,510,809	$261,301,972	$224,373,175	$125,895,123
2022	$194,724,380	$170,452,336	$146,362,966	$82,123,827	$285,026,907	$249,498,815	$214,238,112	$120,208,370
2023	$178,927,435	$156,624,451	$134,489,323	$75,461,561	$272,075,238	$238,161,548	$204,503,098	$114,746,082
2024	$164,363,988	$143,876,312	$123,542,829	$69,319,515	$259,636,237	$227,273,046	$195,153,425	$109,500,008
2025	$150,940,257	$132,125,825	$113,452,993	$63,658,138	$247,691,026	$216,816,784	$186,174,907	$104,462,188
2026	$138,569,448	$121,297,015	$104,154,577	$58,440,824	$236,221,394	$206,776,822	$177,553,853	$99,624,941
2027	$127,171,248	$111,319,580	$95,587,215	$53,633,703	$225,209,771	$197,137,777	$169,277,057	$94,980,855
2028	$116,671,345	$102,128,472	$87,695,050	$49,205,432	$214,639,206	$187,884,814	$161,331,780	$90,522,783
2029	$107,000,988	$93,663,507	$80,426,405	$45,127,018	$204,493,349	$179,003,620	$153,705,730	$86,243,830
2030	$98,096,574	$85,869,013	$73,733,477	$41,371,635	$194,756,426	$170,480,387	$146,387,053	$82,137,342
2031	$89,899,277	$78,693,493	$67,572,046	$37,914,475	$185,413,223	$162,301,798	$139,364,312	$78,196,903
2032	$82,354,684	$72,089,320	$61,901,215	$34,732,588	$176,449,066	$154,455,007	$132,626,478	$74,416,324
2033	$75,412,479	$66,012,449	$56,683,164	$31,804,756	$167,849,800	$146,927,624	$126,162,911	$70,789,635
2034	$69,026,134	$60,422,150	$51,882,921	$29,111,353	$159,601,774	$139,707,699	$119,963,350	$67,311,080
2035	$63,152,631	$55,280,769	$47,468,152	$26,634,239	$151,691,822	$132,783,709	$114,017,901	$63,975,106
2036	$57,752,203	$50,553,494	$43,408,965	$24,356,641	$144,107,248	$126,144,538	$108,317,019	$60,776,358
2037	$52,788,089	$46,208,148	$39,677,729	$22,263,056	$136,835,809	$119,779,471	$102,851,501	$57,709,672
2038	$48,226,314	$42,214,991	$36,248,909	$20,339,156	$129,865,697	$113,678,171	$97,612,474	$54,770,070
2039	$44,035,482	$38,546,539	$33,098,905	$18,571,698	$123,185,528	$107,830,673	$92,591,381	$51,952,749
2040	$40,186,582	$35,177,397	$30,205,911	$16,948,447	$116,784,325	$102,227,369	$87,779,970	$49,253,081
2041	$36,652,811	$32,084,104	$27,549,782	$15,458,101	$110,651,505	$96,858,994	$83,170,287	$46,666,601
2042	$33,409,410	$29,244,987	$25,111,906	$14,090,216	$104,776,865	$91,716,617	$78,754,662	$44,189,007
2043	$30,433,511	$26,640,028	$22,875,096	$12,835,149	$99,150,567	$86,791,626	$74,525,702	$41,816,150
2044	$27,703,994	$24,250,741	$20,823,478	$11,683,992	$93,763,128	$82,075,722	$70,476,278	$39,544,031
2045	$25,201,360	$22,060,056	$18,942,393	$10,628,521	$88,605,408	$77,560,903	$66,599,520	$37,368,793
2046	$22,907,604	$20,052,213	$17,218,311	$9,661,143	$83,668,594	$73,239,454	$62,888,805	$35,286,722
Year	7% Discount Rate				3% Discount Rate			
	99th %-ile	95th %-ile	90th %-ile	Average	99th %-ile	95th %-ile	90th %-ile	Average
2047	$20,806,108	$18,212,664	$15,638,739	$8,774,850	$78,944,195	$69,103,943	$59,337,750	$33,294,236
2048	$18,881,533	$16,527,984	$14,192,148	$7,963,172	$74,424,025	$65,147,204	$55,940,201	$31,387,881

2049	$17,119,724	$14,985,781	$12,867,899	$7,220,140	$70,100,194	$61,362,331	$52,690,230	$29,564,332
2050	$15,507,622	$13,574,625	$11,656,176	$6,540,246	$65,965,100	$57,742,669	$49,582,121	$27,820,381
2051	$14,033,180	$12,283,969	$10,547,923	$5,918,409	$62,011,417	$54,281,805	$46,610,368	$26,152,939
2052	$12,685,285	$11,104,087	$9,534,789	$5,349,942	$58,232,085	$50,973,560	$43,769,664	$24,559,029
2053	$11,453,690	$10,026,008	$8,609,071	$4,830,524	$54,620,302	$47,811,979	$41,054,897	$23,035,781
2054	$10,328,947	$9,041,463	$7,763,668	$4,356,171	$51,169,514	$44,791,326	$38,461,141	$21,580,432
2055	$9,302,347	$8,142,826	$6,992,032	$3,923,209	$47,873,405	$41,906,071	$35,983,648	$20,190,318
2056	$8,365,862	$7,323,072	$6,288,131	$3,528,252	$44,725,895	$39,150,892	$33,617,848	$18,862,875
2057	$7,512,095	$6,575,726	$5,646,404	$3,168,181	$41,721,121	$36,520,658	$31,359,335	$17,595,630
2058	$6,734,232	$5,894,822	$5,061,729	$2,840,121	$38,853,441	$34,010,429	$29,203,867	$16,386,203
2059	$6,025,994	$5,274,864	$4,529,388	$2,541,426	$36,117,416	$31,615,445	$27,147,356	$15,232,301
2060	$5,381,601	$4,710,794	$4,045,036	$2,269,658	$33,507,810	$29,331,122	$25,185,868	$14,131,716
2061	$4,795,731	$4,197,952	$3,604,672	$2,022,571	$31,019,581	$27,153,046	$23,315,611	$13,082,320
Total	**$4,177,013,385**	**$3,656,356,165**	**$3,139,617,488**	**$1,761,630,064**	**$7,406,628,134**	**$6,483,405,234**	**$5,567,130,644**	**$3,123,700,500**

Table L.3 – Discounted Annual Avoided Release Costs Using 2005-2009 Data

Year	7% Discount Rate				3% Discount Rate			
	99th %-ile	95th %-ile	90th %-ile	Average	99th %-ile	95th %-ile	90th %-ile	Average
2012	$0	$0	$0	$0	$0	$0	$0	$0
2013	$0	$0	$0	$0	$0	$0	$0	$0
2014	$0	$0	$0	$0	$0	$0	$0	$0
2015	$788,342,783	$658,973,995	$615,413,946	$442,157,270	$883,801,542	$738,767,761	$689,933,119	$495,697,159
2016	$725,691,703	$606,604,095	$566,505,845	$407,018,203	$845,158,901	$706,466,462	$659,767,027	$474,023,687
2017	$667,863,972	$558,266,022	$521,363,056	$374,584,403	$808,017,526	$675,420,069	$630,772,889	$453,192,230
2018	$614,496,634	$513,656,382	$479,702,240	$344,652,301	$772,322,748	$645,582,882	$602,908,024	$433,172,124
2019	$565,253,582	$472,494,223	$441,261,016	$317,033,385	$738,021,806	$616,910,801	$576,131,249	$413,933,779
2020	$519,823,592	$434,519,395	$405,796,432	$291,553,098	$705,063,788	$589,361,266	$550,402,816	$395,448,638
2021	$477,918,513	$399,491,032	$373,083,542	$268,049,825	$673,399,564	$562,893,211	$525,684,375	$377,689,147
2022	$439,271,574	$367,186,141	$342,914,096	$246,373,943	$642,981,726	$537,467,008	$501,938,916	$360,628,715
2023	$403,635,825	$337,398,297	$315,095,313	$226,386,945	$613,764,532	$513,044,420	$479,130,730	$344,241,688
2024	$370,782,681	$309,936,426	$289,448,750	$207,960,625	$585,703,846	$489,588,554	$457,225,363	$328,503,310
2025	$340,500,578	$284,623,683	$265,809,251	$190,976,323	$558,757,084	$467,063,815	$436,189,574	$313,389,699
2026	$312,593,726	$261,296,406	$244,023,973	$175,324,226	$532,883,163	$445,435,861	$415,991,289	$298,877,810
2027	$286,880,946	$239,803,150	$223,951,482	$160,902,717	$508,042,446	$424,671,561	$396,599,568	$284,945,415
2028	$263,194,601	$220,003,786	$205,460,913	$147,617,773	$484,196,698	$404,738,952	$377,984,561	$271,571,066
2029	$241,379,596	$201,768,672	$188,431,191	$135,382,407	$461,309,031	$385,607,202	$360,117,473	$258,734,076
2030	$221,292,458	$184,977,878	$172,750,316	$124,116,147	$439,343,864	$367,246,568	$342,970,529	$246,414,489
2031	$202,800,475	$169,520,470	$158,314,686	$113,744,562	$418,266,877	$349,628,361	$326,516,935	$234,593,053
2032	$185,780,905	$155,293,849	$145,028,486	$104,198,807	$398,044,964	$332,724,908	$310,730,849	$223,251,203
2033	$170,120,239	$142,203,133	$132,803,103	$95,415,221	$378,646,196	$316,509,520	$295,587,344	$212,371,029

2034	$155,713,518	$130,160,587	$121,556,603	$87,334,933	$360,039,777	$300,956,456	$281,062,381	$201,935,260
2035	$142,463,700	$119,085,093	$111,213,231	$79,903,517	$342,196,007	$286,040,888	$267,132,775	$191,927,237
2036	$130,281,072	$108,901,661	$101,702,953	$73,070,655	$325,086,246	$271,738,876	$253,776,167	$182,330,897
2037	$119,082,710	$99,540,975	$92,961,034	$66,789,837	$308,682,872	$258,027,333	$240,970,995	$173,130,749
2038	$108,791,970	$90,938,968	$84,927,645	$61,018,077	$292,959,253	$244,883,994	$228,696,468	$164,311,853
2039	$99,338,027	$83,036,437	$77,547,494	$55,715,650	$277,889,705	$232,287,392	$216,932,537	$155,859,806
2040	$90,655,434	$75,778,678	$70,769,492	$50,845,850	$263,449,468	$220,216,829	$205,659,873	$147,760,720
2041	$82,683,730	$69,115,148	$64,546,441	$46,374,766	$249,614,665	$208,652,348	$194,859,837	$140,001,204
2042	$75,367,061	$62,999,160	$58,834,737	$42,271,071	$236,362,279	$197,574,708	$184,514,460	$132,568,348
2043	$68,653,839	$57,387,593	$53,594,110	$38,505,831	$223,670,120	$186,965,360	$174,606,420	$125,449,705
2044	$62,496,423	$52,240,622	$48,787,369	$35,052,326	$211,516,795	$176,806,423	$165,119,017	$118,633,278
2045	$56,850,822	$47,521,477	$44,380,173	$31,885,881	$199,881,683	$167,080,659	$156,036,154	$112,107,501
2046	$51,676,423	$43,196,208	$40,340,816	$28,983,719	$188,744,908	$157,771,452	$147,342,312	$105,861,226
Year	**7% Discount Rate**				**3% Discount Rate**			
	99th %-ile	**95th %-ile**	**90th %-ile**	**Average**	**99th %-ile**	**95th %-ile**	**90th %-ile**	**Average**
2047	$46,935,734	$39,233,477	$36,640,033	$26,324,813	$178,087,309	$148,862,789	$139,022,537	$99,883,706
2048	$42,594,156	$35,604,361	$33,250,812	$23,889,755	$167,890,423	$140,339,235	$131,062,413	$94,164,585
2049	$38,619,756	$32,282,169	$30,148,226	$21,660,636	$158,136,452	$132,185,912	$123,448,048	$88,693,882
2050	$34,983,075	$29,242,276	$27,309,278	$19,620,933	$148,808,246	$124,388,485	$116,166,053	$83,461,978
2051	$31,656,935	$26,461,962	$24,712,751	$17,755,403	$139,889,278	$116,933,139	$109,203,527	$78,459,602
2052	$28,616,268	$23,920,275	$22,339,077	$16,049,986	$131,363,621	$109,806,562	$102,548,037	$73,677,823
2053	$25,837,958	$21,597,893	$20,170,211	$14,491,718	$123,215,932	$102,995,926	$96,187,604	$69,108,035
2054	$23,300,693	$19,476,998	$18,189,513	$13,068,643	$115,431,425	$96,488,874	$90,110,686	$64,741,943
2055	$20,984,823	$17,541,167	$16,381,647	$11,769,743	$107,995,856	$90,273,498	$84,306,164	$60,571,561
2056	$18,872,241	$15,775,265	$14,732,475	$10,584,861	$100,895,502	$84,338,328	$78,763,325	$56,589,190
2057	$16,946,260	$14,165,341	$13,228,972	$9,504,637	$94,117,144	$78,672,314	$73,471,851	$52,787,418
2058	$15,191,506	$12,698,546	$11,859,136	$8,520,449	$87,648,049	$73,264,811	$68,421,799	$49,159,100
2059	$13,593,818	$11,363,042	$10,611,913	$7,624,355	$81,475,951	$68,105,568	$63,603,597	$45,697,360
2060	$12,140,156	$10,147,930	$9,477,123	$6,809,041	$75,589,038	$63,184,710	$59,008,022	$42,395,571
2061	$10,818,514	$9,043,172	$8,445,392	$6,067,772	$69,975,933	$58,492,728	$54,626,193	$39,247,353
Total	**$9,422,771,005**	**$7,876,473,515**	**$7,355,816,295**	**$5,284,943,043**	**$16,708,340,241**	**$13,966,464,782**	**$13,043,241,881**	**$9,371,195,211**

Appendix K12– Selected State Programs

EPA compiled a list of selected current state government regulations that address industrial materials beneficial use programs, in order to evaluate the impact of EPA's proposal with respect to coal combustion products (CCPs) on current state government beneficial use programs. Ten states with the highest consumption of fly ash and/or cement were selected for this investigation. These ten states represent 39% of the net generation of electric power from coal.[12]

Nine of the ten states (FL, IL, MN, PA, TX, WI, MN, IA, and UT) currently impose some requirements limiting beneficial use programs to "non-hazardous" wastes. In addition, many of the state programs explicitly address the beneficial use coal combustion waste, codifying that certain uses have been authorized or approved as *per se* beneficial uses. Thus, continued reuse of CCPs under these programs should not be affected by EPA's proposed rule, because EPA is not proposing to change the regulatory status of CCPs that are beneficially used. That is, CCPs that are beneficially reused will remain Bevill-exempt solid wastes, or in some cases, would not be considered to be wastes at all.[13] EPA is only proposing to designate CCPs that are destined for disposal as "hazardous wastes." Since the prohibitions in state law only apply to hazardous waste and the Bevill exemption will continue to definitively exclude reused materials from this status, these authorizations will not be negated. Finally, the beneficial uses of CCPs that EPA is proposing to recognize are generally the same as those that these states have recognized; many states have additional restrictions on uses that involve some sort of "land placement," (e.g., FL, GA, MN) under their beneficial use programs and some states do not consider such uses to be "beneficial uses" (*e.g.*, PA, specifying that land application constitutes disposal; IA's proposed regulation would ban land placement).

Relevant excerpts of the applicable sections of the current state government solid waste and/or industrial waste beneficial use requirements are presented below.

On a related point, closer examination of the State beneficial use programs calls into question the validity of claims that the stigma from association with a hazardous waste will adversely affect beneficial use of CCPs. For example, Florida's beneficial use program continues to allow the use of municipal incineration ash, even though a subsequent court case changed the status of the ash. Prior to 1994, it was generally believed that the ash residue (ash) from municipal waste-to-energy (WTE) facilities was exempt from regulation under Subtitle C of RCRA. This changed on May 2, 1994, when the U.S. Supreme Court decided in *City of Chicago v. EDF*,114 S.Ct. 1588 (1994), that the ash generated by these facilities was not

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[12] Report No.: DOE/EIA-0226 (2009/06), Data for: March 2009, Report Released: June 12, 2009; http://www.eia.doe.gov/cneaf/electricity/epm/table1_6_a.html.

[13] For certain beneficial uses, CCPs are a raw material used as an ingredient in a manufacturing process that have never been "discarded" and thus, would not be solid wastes under the existing hazardous waste rules. For example, synthetic gypsum is a product of the FGD process at coal-fired power plants. In this case, the utility designs and operates its air pollution control devices to produce an optimal product, including oxidation of the FGD to produce synthetic gypsum. In this example, after its production, the utility treats FGD as a valuable input into a production process, *i.e.*, as a product, rather than as something that is intended to be discarded. (In order for EPA to regulate a material under RCRA, the material must be a solid waste, which the statute defines as materials that have been discarded. See Section 1004(27) of RCRA for definition of solid waste). Wallboard plants are sited in close proximity to power plants for access to raw material, with a considerable investment involved. Thus, FGD gypsum used for wallboard manufacture is a product rather than a waste or discarded material. This use and similar uses of CCPs that meet product specifications would not be affected by today's rule in any case, regardless of the option taken.

exempt from regulation. Consequently, owner/operators of WTE facilities had to determine if their ash was a hazardous waste. This decision placed a cloud of uncertainty on the prospects of using WTE ash as a product rather than disposing of it as a solid waste. Based in large measure on guidance from EPA following this decision, Florida continues to allow the ash to be beneficially reused, subject to testing requirements. Since the regulatory status of the ash may vary depending on individual test results for particular waste streams, the status is more uncertain than the regulatory status of CCP would be under EPA's proposed rule, because CCPs destined for beneficial reuse would be considered to be exempt. This suggests that the mere association with a hazardous waste would not necessarily be sufficient to adversely affect beneficial use.

State Beneficial Use Program Requirements

1. Florida

Under the Florida Resource Recovery and Management section 403.7045 http://www.dep.state.fl.us/waste/categories/solid_waste/pages/beneficialuse.htm, reuse of recovered materials and industrial products is generally permitted, provided that the materials do not constitute hazardous waste. Further, the statute generally prohibits regulation of coal ash, except to the extent that EPA has determined the material to be hazardous waste. Because this turns on EPA's designation, beneficial uses of CCPs should remain unaffected.

403.7045 Application of act and integration with other acts.--

(1) The following wastes or activities shall not be regulated pursuant to this act:

*****

(e) Recovered materials or recovered materials processing facilities, except as provided in s. 403.7046, if:

1. A majority of the recovered materials at the facility are demonstrated to be sold, used, or reused within 1 year.

2. The recovered materials handled by the facility or the products or byproducts of operations that process recovered materials are not discharged, deposited, injected, dumped, spilled, leaked, or placed into or upon any land or water by the owner or operator of such facility so that such recovered materials, products or byproducts, or any constituent thereof may enter other lands or be emitted into the air or discharged into any waters, including groundwaters, or otherwise enter the environment such that a threat of contamination in excess of applicable department standards and criteria is caused.

3. The recovered materials handled by the facility are not hazardous wastes as defined under s. 403.703, and rules promulgated pursuant thereto.

4. The facility is registered as required in s. 403.7046.

(f) Industrial byproducts, if:

1. A majority of the industrial byproducts are demonstrated to be sold, used, or reused within 1 year.

2. The industrial byproducts are not discharged, deposited, injected, dumped, spilled, leaked, or placed upon any land or water so that such industrial byproducts, or any constituent thereof, may enter other lands or be emitted into the air or discharged into any waters, including groundwaters, or otherwise enter the environment such that a threat of contamination in excess of applicable department standards and criteria or a significant threat to public health is caused.

3. The industrial byproducts are not hazardous wastes as defined under s. 403.703 and rules adopted under this section.

(2) Except as provided in s. 403.704(9), the following wastes shall not be regulated as a hazardous waste pursuant to this act, except when determined by the United States Environmental Protection Agency to be a hazardous waste:

(a) Ashes and scrubber sludges generated from the burning of boiler fuel for generation of electricity or steam.

http://www.leg.state.fl.us/statutes/index.cfm?App_mode=Display_Statute&Search_String=&URL=Ch0403/SEC7045.HTM&Title=->2008->Ch0403->Section%207045#0403.7045:

2. Georgia

Georgia law appears to provide no requirement that only solid (non-hazardous) wastes can be reused or recycled. Currently, CCPs are specifically designated as "Industrial waste," which is defined as a "solid waste that is not a hazardous waste." Given the specific designation, and the fact that EPA is proposing to maintain CCPs destined for beneficial use as Bevill-exempt hazardous waste, EPA's rule would not preclude beneficial reuse of CCPs under Georgia's program.

391-3-4 Solid Waste Management Rule

391-34-.04 General. Amended.

(7) Recovered Materials:

(a) **Recovered materials and recovered materials processing facilities are excluded from regulation as solid wastes and solid waste handling facilities.** To be considered exempt from regulation, the material must have a known use, reuse, or recycling potential; must be feasibly used, reused, or recycled; and must have been diverted or removed from the solid waste stream for sale, use, reuse, or recycling, whether or not requiring subsequent separation and processing.

(b) Materials accumulated speculatively are solid waste and must comply with all applicable provisions of these regulations.

(c) A recovered material is not accumulated speculatively if the person accumulating it can show that there is a known use, reuse, or recycling potential for the material, that the material can be feasibly sold, used, reused, or recycled and that during the preceding 90 days the amount of material that is recycled, sold, used, or reused equals at least 60 percent by weight or volume of the material received during that 90-day period and 60 percent by weight or volume of all material previously received and not recycled, sold, used, or reused and carried forward into that 90-day period.

(d) Proof of recycling, sale, use, or reuse shall be provided in the form of bills of sale, or other records showing adequate proof of movement of the material in question to a recognized recycling facility or for proper use or reuse from the accumulation point. In addition, proof must be provided that there is a known market or disposition for the recovered material. Persons claiming that they are owners or operators of recovered materials processing facilities must show that they have the necessary equipment to do so.

(e) A recovered material is "sold" if the generator of the recovered material or the person who recovered the material from the solid waste stream received consideration or compensation for the material because of its inherent value.

(f) A recovered material is "used, reused or recycled" if it is either:

1. Employed as an ingredient (including use as an intermediate) in a process to make a product (for example, utilizing old newspaper to make new paper products) or
2. Employed in the same or different fashion as its original intended purpose without physically changing its composition (for example, use of old automobiles for spare parts or donation of clothing or furniture to charitable organizations) or
3. Employed in a particular function or application as an effective substitute for a commercial product (for example, utilizing shredded tires in asphalt or utilizing refuse-derived fuel as a substitute for fuel oil, natural gas, coal, or wood in a boiler or industrial furnace) as long as such substitution does not pose a threat to human health or the environment and so long as the facility is not a solid waste thermal treatment facility.
4. A material is not "used, reused or recycled" when it is applied to or placed on or in the land in a manner that constitutes disposal which, in the opinion of the Director, may pose a threat to human health and the environment (for example, utilizing soil containing levels of hazardous constituents, as listed in Chapter 391-3-11, 40 CFR Part 261, Appendix VIII for fill material when those levels are greater than the background levels in the area to be filled, land applying sludge in excess of generally accepted agricultural

practices or use of inherently waste-like materials as fill material).

* * * * * * * *

(27) "Industrial Waste" means solid waste generated by manufacturing or industrial processes that is not a hazardous waste regulated under the Hazardous Waste Management Act and regulations promulgated by the Board of Natural Resources, Chapter 391-3-11**. Such waste includes, but is not limited to, wastes resulting from the following manufacturing processes: Electric power generation**; fertilizer/agricultural chemicals….

(55) "Recovered Materials" means those materials which have known use, reuse, or recycling potential; can be feasibly used, reused or recycled; and have been diverted or removed from the solid waste stream for sale, use, reuse, or recycling, whether or not requiring subsequent separation and processing.

(57) "Recycling" means any process by which materials which would otherwise become solid waste are collected, separated, or processed and reused or returned to use in the form of raw materials or products.

3. Illinois

Illinois has a beneficial use program that specifically addresses CCP. The program generally specifies that hazardous waste may not be mixed with CCP prior to use, but this should not operate as a general barrier under EPA's proposal to retain the Bevill exemption for beneficially used CCPs. Although the language is ambiguous, and potentially could be read to create a barrier if the CCP is disposed into a landfill (in which case it would be hazardous), and subsequently dug up and reused, this should be something that could be addressed, as under the proposal, such wastes, once destined for beneficial reuse, would no longer be considered hazardous waste. In any event, any CCP that was generated and beneficially reused, without first being disposed of would not be considered a hazardous waste. http://www.ipcb.state.il.us/SLR/TheEnvironmentalProtectionAct.asp
(415 ILCS 5/3.135)

Sec. 3.135. Coal combustion byproduct; CCB.
(a) "Coal combustion byproduct" (CCB) means coal combustion waste when used beneficially in any of the following ways:
(1) The extraction or recovery of material compounds contained within CCB.
(2) The use of CCB as a raw ingredient or mineral filler in the manufacture of the following commercial products: cement; concrete and concrete mortars; cementicous products including block, pipe and precast/prestressed components; asphalt or cementicious roofing products; plastic products including pipes and fittings; paints and metal alloys; kiln fired products including bricks, blocks, and tiles; abrasive media; gypsum wallboard; asphaltic concrete, or asphalt based paving material.
(3) CCB used (A) in accordance with the Illinois Department of Transportation ("IDOT") standard specifications and subsection (a-5) of this Section or (B) under the approval of the Department of Transportation for IDOT projects.

(4) Bottom ash used as antiskid material, athletic tracks, or foot paths.

(5) Use in the stabilization or modification of soils providing the CCB meets the IDOT specifications for soil modifiers.

(6) CCB used as a functionally equivalent substitute for agricultural lime as a soil conditioner.

(7) Bottom ash used in non IDOT pavement sub-base or base, pipe bedding, or foundation backfill.

(8) Structural fill, when used in an engineered application or combined with cement, sand, or water to produce a controlled strength fill material and covered with 12 inches of soil unless infiltration is prevented by the material itself or other cover material.

(9) Mine subsidence, mine fire control, mine sealing, and mine reclamation.

(a-5) Except to the extent that the uses are otherwise authorized by law without such restrictions, the uses specified in items (a)(3)(A) and (a)(7) through (9) shall be subject to the following conditions:

(A) CCB shall not have been mixed with hazardous waste prior to use.

(B) CCB shall not exceed Class I Groundwater Standards for metals when tested utilizing test method ASTM D3987   85. The sample or samples tested shall be representative of the CCB being considered for use.

(C) Unless otherwise exempted, users of CCB for the purposes described in items (a)(3)(A) and (a)(7) through (9) of this Section shall provide notification to the Agency for each project utilizing CCB documenting the quantity of CCB utilized and certification of compliance with conditions (A) and (B) of this subsection. Notification shall not be required for users of CCB for purposes described in items (a)(1), (a)(2), (a)(3)(B), (a)(4), (a)(5) and (a)(6) of this Section, or as required specifically under a beneficial use determination as provided under this Section, or pavement base, parking lot base, or building base projects utilizing less than 10,000 tons, flowable fill/grout projects utilizing less than 1,000 cubic yards or other applications utilizing less than 100 tons.

(D) Fly ash shall be managed in a manner that minimizes the generation of airborne particles and dust using techniques such as moisture conditioning, granulating, in ground application, or other demonstrated method.

(E) CCB is not to be accumulated speculatively. CCB is not accumulated speculatively if during the calendar year, the CCB used is equal to 75% of the CCB by weight or volume accumulated at the beginning of the period.

(F) CCB shall include any prescribed mixture of fly ash, bottom ash, boiler slag, flue gas desulfurization scrubber sludge, fluidized bed combustion ash, and stoker boiler ash and shall be tested as intended for use.

(b) To encourage and promote the utilization of CCB in productive and beneficial applications, upon request by the applicant, the Agency shall make a written beneficial use determination that coal combustion waste is CCB when used in a manner other than those uses specified in subsection (a) of this Section if the applicant demonstrates that use of the coal combustion waste satisfies all of the following criteria: the use will not cause, threaten, or allow the discharge of any contaminant into the environment; the use will otherwise protect human health and safety and the environment; and the use constitutes a legitimate use of the coal combustion waste as an ingredient or raw material that is an effective substitute for an analogous ingredient or raw material.

The Agency's beneficial use determinations may allow the uses set forth in items (a)(3)(A) and (a)(7) through (9) of this Section without the CCB being subject to the restrictions set forth in subdivisions (a5)(B) and (a)(5)(E) of this Section.

Within 90 days after the receipt of an application for a beneficial use determination under this subsection (b), the Agency shall, in writing, approve, disapprove, or approve with conditions the beneficial use. Any disapproval or approval with conditions shall include the Agency's reasons for the disapproval or conditions. Failure of the Agency to issue a decision within 90 days shall constitute disapproval of the beneficial use request. These beneficial use determinations are subject to review under Section 40 of this Act.

Any approval of a beneficial use under this subsection (b) shall become effective upon the date of the Agency's written decision and remain in effect for a period of 5 years. If an applicant desires to continue a beneficial use after the expiration of the 5-year period, the applicant must submit an application for renewal no later than 90 days prior to the expiration. The beneficial use approval shall be automatically extended unless denied by the Agency in writing with the Agency's reasons for disapproval, or unless the Agency has requested an extension for review, in which case the use will continue to be allowed until an Agency determination is made.

Coal-combustion waste for which a beneficial use is approved pursuant to this subsection (b) shall be considered CCB during the effective period of the approval, as long as it is used in accordance with the approval and any conditions.

Notwithstanding the other provisions of this subsection (b), written beneficial use determination applications for the use of CCB at sites governed by the federal Surface Mining Control and Reclamation Act of 1977 (P.L. 95-87) or the rules and regulations there under, or by any law or rule or regulation adopted by the State of Illinois pursuant thereto, shall be reviewed and approved by the Office of Mines and Minerals within the Department of Natural Resources pursuant to 62 Ill. Adm. Code §§ 1700-1850. Further, appeals of those determinations shall be made pursuant to the Illinois Administrative Review Law.

The Board shall adopt rules establishing standards and procedures for the Agency's issuance of beneficial use determinations under this subsection (b). The Board rules may also, but are not required to, include standards and procedures for the revocation of the beneficial use determinations. Prior to the effective date of Board rules adopted under this subsection (b), the Agency is authorized to make beneficial use determinations in accordance with this subsection (b).

The Agency is authorized to prepare and distribute guidance documents relating to its administration of this Section. Guidance documents prepared under this subsection are not rules for the purposes of the Illinois Administrative Procedure Act.
(Source: P.A. 94-66, eff. 1-1-06.)

(415 ILCS 5/3.140)

Sec. 3.140. Coal combustion waste. "Coal combustion waste" means any fly ash, bottom ash, slag, or flue gas or fluid bed boiler desulfurization byproducts generated as a result of the combustion of:

(1) coal, or

(2) coal in combination with: (i) fuel grade petroleum coke, (ii) other fossil fuel, or (iii) both fuel grade petroleum coke and other fossil fuel, or

(3) coal (with or without: (i) fuel grade petroleum coke, (ii) other fossil fuel, or (iii) both fuel grade petroleum coke and other fossil fuel) in combination with no more than 20% of tire derived fuel or wood or other materials by weight of the materials combusted; provided that the coal is burned with other materials, the Agency has made a written determination that the storage or disposal of the resultant wastes in accordance with the provisions of item (r) of Section 21 would result in no environmental impact greater than that of wastes generated as a result of the combustion of coal alone, and the storage disposal of the resultant wastes would not violate applicable federal law.

(Source: P.A. 92-574, eff. 6-26-02.)

4. Indiana

Beneficial use is managed by IDEM through a combination of rules and programs. Indiana Statute (IC 13-19-3) governs the use of coal combustion products (IC 13-19-3-3), foundry sand (IC 13-19-3-7) and iron and steel mill slag (IC 13-19-3-8). Other uses of byproducts are evaluated under Indiana's Solid Waste Rules (329 IAC 10-3-1) on a case-by-case basis. Finally, land application uses are addressed under the State's Water Rules (327 IAC 6.1).
http://www.epa.gov/epawaste/conserve/rrr/imr/pdfs/indian1.pdf

Given that the state requirements directly reference the RCRA determination, the beneficial use of CCPs would remain exempt, as its status under this program would be unaffected.

IC 13-19-3-1
Regulation of solid and hazardous waste and atomic radiation; review orders; development of operating policies
Sec. 1. The solid waste management board shall do the following:
(1) Except as provided in sections 3 through 4 of this chapter, adopt rules under IC 4-22-2 to regulate solid and hazardous waste and atomic radiation in Indiana, including rules necessary to the implementation of the federal Resource Conservation and Recovery Act (42 U.S.C. 6901 et seq.), as amended.
(2) Develop operating policy concerning the activities of the department.
(3) Carry out other duties imposed by law.
As added by P.L.1-1996, SEC.9. Amended by P.L.25-1997, SEC.14.

IC 13-19-3-3

Prohibited areas of regulation

Sec. 3. **The board may not adopt rules under section 1 of this chapter to regulate the following:**
(1) The disposal of waste indigenous to the coal mining process **and coal combustion products (**as defined by ASTM E-2201-02a), including fly ash, bottom ash, boiler slag, fluidized bed combustion ash, or flue gas desulfurization material produced from the combustion of coal or the cleaning of stack gases on coal combustion units **if the material**:
(A) is not included in the definition of hazardous waste or is exempt from regulation as a hazardous waste under 42 U.S.C. 6921; and
(B) is disposed of at a facility regulated under IC 14-34.
(2) **The use of coal combustion products (as defined by ASTM E-2201-02a), including fly ash, bottom ash, boiler slag, fluidized bed combustion ash, or flue gas desulfurization material produced from the combustion of coal or the cleaning of stack gases on coal combustion**

units, if the use includes one (1) of the following uses:

(A) The extraction or recovery of materials and compounds contained within coal combustion products.

(B) Bottom ash as an antiskid material.

(C) Raw material for manufacturing another product.

(D) Mine subsidence, mine fire control, and mine sealing.

(E) Structural fill when combined with cement, sand, or water to produce a controlled strength fill material.

(F) A base in road construction.

(G) Cover for coal processing waste disposal locations to inhibit infiltration at surface and underground mines subject to IC 14-34, so long as a demonstration is made in concurrence with the department of natural resources that the materials and methods to be employed are appropriate for the intended use.

(H) Providing buffering or enhancing structural integrity for refuse piles at surface and underground mines subject to IC 14-34, so long as a demonstration is made in concurrence with the department of natural resources that the materials and methods to be employed are appropriate for the intended use.

(I) Agricultural applications, when applied using appropriate agronomic amounts to improve crop or vegetative production.

As added by P.L.1-1996, SEC.9. Amended by P.L.215-2003, SEC.4.

5. Iowa

Pursuant to Iowa Administrative Code 567-108, bbeneficial reuse options apply to industrial, commercial, and institutional generators and users of solid by-products (*i.e.*, wastes), defined as "nonhazardous." The current regulations specifically address CCPs, identifying particular beneficial uses that are "universally approved."[14] Accordingly, EPA's proposed rule would not affect beneficial uses in this state, as beneficially used CCPs would remain as Bevill exempt solid wastes.

"Solid by-product" means a secondary material or residual, produced or created by an industrial, commercial or institutional process or activity, that has been source separated by the generating entity and that would otherwise be disposed of as solid waste. Solid by-products are composed of materials suitable for disposal as solid waste in a sanitary landfill.

"Suitable for disposal as solid waste in a sanitary landfill" means that the material is in compliance with all state and federal rules and regulations pertaining to what may be disposed of in an Iowa sanitary landfill. Such materials are at a minimum nonhazardous and nonradioactive, are solid or semisolid, and do not contain free liquids pursuant to the

[14] Iowa is in the process of revising their requirements. This analysis is based on the current requirements, but the proposed revisions, if adopted, do not change the basic requirement that the program is applicable only to solid wastes.

Paint Filter Liquids Test.

567—108.1(455B,455D) Purpose. The purpose of this chapter is to establish rules for determining when a solid by-product is a resource and not a solid waste. Solid byproducts determined by the department not to be a solid waste through a beneficial use determination may not be subject to all sanitary disposal project (SDP) permitting requirements. Furthermore, the purpose of this chapter is to encourage the utilization of solid by-products as resources when such utilization improves, or at a minimum does not adversely affect, human health and the environment

567—108.2(455B,455D) Applicability and compliance.

108.2(1) These rules apply to industrial, commercial, and institutional generators and users or proposed users of solid by-products and to sanitary landfills utilizing or desiring to utilize alternative cover material. These rules apply to solid by-products that before receiving a beneficial use determination by the department were being disposed of as solid waste. These rules do not apply to solid by-products that have already been disposed of as solid waste by the generator.

* * * * * * * *

108.2(6) The issuance of a beneficial use determination by the department relieves the generator and user(s) of all Iowa solid waste requirements specifically noted in the written determination. Requirements that may be relieved by a beneficial use determination may include rules, SDP permits, and permit conditions and variances. Solid by-products that have not received a beneficial use determination by the department are subject to all of Iowa’s regulations pertaining to solid waste. The issuance of a beneficial use determination by the department in no way relieves the generator or user of the responsibility of complying with all other local, state, and federal statutes, ordinances, and rules or other applicable requirements.

567—108.4(455B,455D) Universally approved beneficial use determinations. The following solid by-products may be utilized as resources in the specific manners listed provided that such utilization is in compliance with 567—108.6(455B,455D) and 567—108.7(455B,455D). Unless a user is otherwise notified by the department pursuant to 567—108.11(455B,455D), such utilization does not require further approval from the department.

108.4(4) *Coal combustion by-products.*
a. Coal combustion fly ash and flue gas desulfurization by-products may be used as follows:
(1) Raw material in manufactured gypsum, wallboard, plaster, or similar product.
(2) Raw material in manufactured calcium chloride.
(3) Raw material in the manufacture of absorbents.
(4) Fill material pursuant to 108.6(1).
(5) Alternative cover material at a sanitary landfill pursuant to 567—108.8(455B,455D).

b. Coal combustion fly ash or bottom ash or boiler slag may be used as follows:
(1) Raw material in the manufacture of cement or concrete products.
(2) Raw material to be used in mineral recovery.
(3) Raw material in the manufacture of asphalt products.
(4) Raw material in plastic products.
(5) Sub-base for hard-surface road construction.
(6) Soil stabilization for construction purposes.
(7) Fill material pursuant to 108.6(1).
(8) Alternative cover material at a sanitary landfill pursuant to 567—108.8(455B,455D).
Iowa Administrative Code 567—108.3(455B,455D)

6. Minnesota

Similar to other state programs, Minnesota's beneficial use program is specific to solid wastes, and excludes hazardous waste. Based on these requirements, EPA's current proposal, which would retain the Bevill exemption for CCPs destined for industrial uses, would not operate as a general bar to continued reuse of CCPs under the program.

7035.2860 BENEFICIAL USE OF SOLID WASTE.
Subpart 1.
Applicability.
This part establishes a procedure for determining when use of a material classified as a solid waste is a beneficial use. The uses listed in subpart 4 as standing beneficial use determinations have been reviewed and determined to be beneficial uses of solid waste by the agency. All other proposed uses of solid wastes must obtain case-specific beneficial use determinations in accordance with the procedures in subpart 5.

7035.0300 DEFINITIONS.
Subpart 1.
Scope.

As used in parts 7035.0300 to 7035.2915, the following terms have the meanings given them in this part.
Subp. 100.
Solid waste.
"Solid waste" means garbage, refuse, sludge from a water supply treatment plant or air contaminant treatment facility, and other discarded waste materials and sludges, in solid, semisolid, liquid, or contained gaseous form, resulting from industrial, commercial, mining and agricultural operations, and from community activities, **but does not include hazardous waste**; animal waste used as fertilizer; earthen fill, boulders, rock; sewage sludge; solid or dissolved material in domestic sewage or other common pollutants in water resources, such as silt, dissolved or suspended solids in industrial waste water effluents or discharges which are point sources subject to permits under section 402 of the Federal Water Pollution Control Act, as amended, dissolved materials in irrigation return flows; or source, special nuclear, or by-product material as defined by The Atomic Energy Act of 1954, as amended.

Subpart. 3. Regulatory exemption. Unless specified otherwise by the agency in a beneficial use determination or permit, a material remains a solid waste until it is incorporated into a manufactured product or utilized in accordance with a standing or a case-specific beneficial use determination. Until the time this regulatory exemption occurs, the material must be stored in compliance with part 7035.2855 and managed as a solid waste in accordance with this chapter.

Subpart. 4. Standing beneficial use determinations. A standing beneficial use determination means that the generator or end user of a material can do so in accordance with this subpart without contacting the agency. Only those specific solid wastes and the uses designated in items A to Q have been given standing beneficial use determinations. Any other uses of the solid waste are not authorized and must follow the procedure outlined in subpart 5.

* * * * * *

K. Coal combustion slag when used as a component in manufactured products such as roofing shingles, ceiling tiles, or asphalt products.

L. Coal combustion slag when used as a sand blast abrasive.

M. Coal combustion fly ash as defined by ASTM C 618 when used as a pozzolan or cement replacement in the formation of high-strength concrete.

N. Coal combustion fly ash or coal combustion gas scrubbing by-products when used as an ingredient for production of aggregate that will be used in concrete or concrete products. This does not include use in flowable fill.

7. Pennsylvania

Under Pennsylvania law, most materials are not regulated as waste when recycled. However, "beneficial use" is restricted to "residual wastes" which are defined as "not hazardous." The beneficial use of municipal and residual wastes is regulated under a General Permit (§271.821 or §287.621). Pennsylvania requires that materials must be managed so that there is no placement on the land. Materials are regulated as wastes, if the materials are beneficially used in a manner constituting disposal, or used to produce products that are applied to the land, even for non-hazardous waste. Based on these provisions, EPA's proposed rule would not operate as a general bar to continued reuse of CCPs in Pennsylvania.

Beneficial use -Use or reuse of residual waste or residual material derived from residual waste for commercial, industrial or governmental purposes, where the use does not harm or threaten public health, safety, welfare or the environment, or the use or reuse of processed municipal waste for any purpose, where the use does not harm or threaten public health, safety, welfare or the environment.

Residual waste -Garbage, refuse, other discarded material or other waste, including solid, liquid, semisolid or contained gaseous materials resulting from industrial, mining and agricultural operations; and sludge from an industrial, mining or agricultural water supply treatment facility, wastewater treatment facility or air pollution control facility, if it is not hazardous. The term does not include coal refuse as defined in the Coal Refuse Disposal Control Act (52 P. S. § § 30.51-30.66). The term does not include treatment sludges from coal mine drainage treatment plants, disposal of which is being carried on under and in compliance with a valid permit issued under The Clean Streams Law (35 P. S. § § 691.1-691.1001).

Waste -A material whose original purpose has been completed and which is directed to a disposal, processing or beneficial use facility or is otherwise disposed of, processed or beneficially used. The term does not include source separated recyclable materials, material approved by the Department for beneficial use under a beneficial use order issued by the Department prior to May 27, 1997, or material which is beneficially used in accordance with a general permit issued under Subchapter I or Subchapter J (relating to beneficial use; and beneficial use of sewage sludge by land application) if a term or condition of the general permit excludes the material from being regulated as a waste.

§ 287.7. Determination that a material is no longer a waste.

(a) Beneficial use. As a term or condition of a general permit for the beneficial use of residual waste, the Department will make a determination that the waste which is beneficially used under the permit ceases to be a waste if it is used in accordance with the terms and conditions of the permit and does not harm or present a threat of harm to public health, safety, welfare or the environment.

(b) Processing.

(1) As a term or condition of an individual or general permit for the processing of residual waste, or at the request of the owner or operator of a processing facility subject to a permit by rule, the Department may make a determination that, subsequent to the processing activity, the processed waste ceases to be a waste even if it does not meet the requirements for a co-product.

(2) The Department will only make this determination if the applicant demonstrates the following to the Department's satisfaction:

(i) The waste will be used as an ingredient in a manufacturing or production process or as a substitute for a commercial product.
(ii) At a minimum, use of the waste will not:

(A) Harm or present a threat of harm to the health, safety or welfare of the people or environment of this Commonwealth through exposure to constituents of the waste.
(B) Present a greater harm or threat of harm than the use of the product or ingredient which the waste is replacing.
(iii) The physical character and chemical composition of the residual waste contributes to the usefulness of the product, and nothing in the physical character or chemical composition of the waste interferes with the usefulness of the product.

§ 287.101. General requirements for permit.

(a) Except as provided in subsection (b), a person or municipality may not own or operate a residual waste disposal or processing facility unless the person or municipality has first applied for and obtained a permit for the activity from the Department under this article.

(b) A person or municipality is not required to obtain a permit under this article, comply with the bonding or insurance requirements of Subchapter E (relating to bonding and insurance requirements) or comply with Subchapter B (relating to duties of generators) **for** one or more of the following:

* * * * * * *

(3) The beneficial use of coal ash under Subchapter H (relating to beneficial use).[15]

http://www.pacode.com/secure/data/025/chapter271/chap271toc.html

8. Texas

Texas does not appear to have a specific "beneficial use" program, nor do the regulations specifically address CCPs. Texas allows both hazardous and non-hazardous wastes to be recycled (or reused). However, in general, the recycling of nonhazardous industrial waste is subject to significantly less regulation than is the recycling of hazardous waste. In most cases, the recycling of *non*hazardous industrial waste is subject only to the following requirements of 30 TAC Sections 335.4 (General Prohibitions) and 335.6 (Notification Requirements). The specific regulations for recycling nonhazardous industrial waste can be found in 30 TAC Section 335.24(h). Certain *non*hazardous industrial wastes can be directly applied to land. Under 30 TAC Section 335.1(131)(H), the material may not even be a waste. In most cases, facilities that recycle only *non*hazardous industrial wastes are not subject to permitting requirements. Because EPA is not proposing to change the status of CCPs that are beneficially reused, EPA's proposed rule would not impact the recycling or reuse of CCPs under Texas law.

[15] This appears to be an error; subchapter I relates to beneficial use.

http://www.tceq.state.tx.us/files/rg-240.pdf_4443350.pdf

9. Utah

Utah recently adopted a law entitled "Reuse of Industrial Byproduct." See http://le.utah.gov/~2009/htmdoc/sbillhtm/SB0224S01.htm. In part, the law directs the Utah DOT to encourage reuse of industrial by products and the Solid and Hazardous Waste Control Board to grant approvals of reuse of industrial byproducts. The law defines "industrial byproducts" to exclude "hazardous waste" and specifically identifies CCPs as an industrial product. Based on these requirements, EPA's current proposal to retain the Bevill exemption for CCPs destined for beneficial reuse would not create a barrier to continued application of this provision to CCPs.

19-6-1102. Definitions.

(3) (a) "Industrial byproduct" means an industrial residual, including:
  (i) inert construction debris;
  (ii) fly ash;
  (iii) bottom ash;
  (iv) slag;
  (v) flue gas emission control residuals generated primarily from the combustion of coal or other fossil fuel;

(b) "Industrial byproduct" does not include material that:
  (i) causes a public nuisance or public health hazard; or
  (ii) is a hazardous waste under Part 1, Solid and Hazardous Waste Act.

(5) "Reuse" means to use an industrial byproduct in place of a raw material.
19-6-1103.

19-6-1104. Applications for industrial byproduct reuse - Approval by the executive secretary.

(1) A person may submit to the executive secretary an application for reuse of an industrial byproduct from an inactive industrial site, as defined in Section 17C-1-102.
(2) The executive secretary shall respond to an application submitted under Subsection (1) within 60 days of the day on which the executive secretary determines the application is complete.
(3) The executive secretary shall approve an application submitted under Subsection (1) if the applicant shows:

(a) the industrial byproduct meets the applicable health risk standard;
(b) the industrial byproduct satisfies the applicable toxicity characteristic leaching procedure; and
(c) the proposed method of installation and type of reuse meet the applicable health risk standard.

10. Wisconsin

Similar to other states, Wisconsin restricts its beneficial use program to "industrial byproducts," and excludes hazardous wastes. CCPs are specifically identified as an "industrial byproduct." Based on these requirements, EPA's current proposal, which would retain the Bevill exemption for CCPs destined for industrial uses, would not operate as a general bar to continued reuse of CCPs under this program.

http://www.legis.state.wi.us/rsb/code/nr/nr538.pdf

NR 538.02 Applicability.
(1) Except as otherwise provided, this chapter governs the beneficial use of industrial byproducts, except hazardous waste and metallic mining waste.

(4) "Industrial byproduct" means papermill sludge, ash from energy recovery including coal ash and slag, material captured in flue gas desulfurization systems, ferrous and steel foundry excess
system sand and slag, lime kiln dust or non−hazardous solid waste with similar characteristics as determined by the department.

NR 538.05 Solid waste rules exemption.
(1) GENERAL.
Persons who generate, use, transport or store industrial byproducts that are characterized and beneficially used in compliance with this chapter are exempt from licensing under s.
289.31, Stats., and the regulatory requirements in chs. NR 500 to 536.

Appendix K13– Stigma Analysis

Item	CCR "beneficial utilitzation" categories as defined by ACAA* Total CCR generation	2005 ACAA tons (used in CCR RIA)** 123,126,093	% of Total 2005 Beneficial Uses (including all ACAA defined uses)	% of Total 2005 Beneficial Uses (excluding Mining) [1]
1	Concrete/concrete products/grout	16,353,331	33.0%	33.7%
2	Blended cement/raw feed for clinker	4,215,234	8.5%	8.7%
3	Flowable fill	259,907	0.5%	0.5%
4	Structural fill/embankments	8,349,999	16.8%	17.2%
5	Road base/sub-base	1,461,992	2.9%	3.0%
6	Soil modification/stabilization	1,139,640	2.3%	2.4%
7	Mineral filler in asphalt	140,838	0.3%	0.3%
8	Snow & ice control	547,541	1.1%	1.1%
9	Blasting grit/roofing granules	1,633,407	3.3%	3.4%
10	Mining applications [1]	1,132,945	2.3%	NA
11	Gypsum panel products (wallboard)	8,178,079	16.5%	16.9%
12	Waste stabilization/solidification	2,839,954	5.7%	5.9%
13	Agriculture	415,741	0.8%	0.9%
14	Aggregate	872,776	1.8%	1.8%
15	Miscellaneous / Other	2,071,157	4.2%	4.3%
	Total CCR Uses (w/out counting Miscellaneous/Other) =	47,541,384	95.8%	NA
	(As Percent of Total CCR generation) =	38.6%		
	CCR beneficial utilization totals =	49,612,541	100.0%	NA
	(As Percent of Total CCR generation) =	40.3%		
	CCR beneficial use (excluding Mining Applications) =	48,479,596	NA	100.0%
	(As Percent of Total CCR generation) =	39.4%		

Notes:
* ACAA provides annual CCR "beneficial utilization" data for years 2001 to 2008 at:
http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=3
** 2005 data used in ORCR's Oct 2009 draft CCR RIA because ORCR's Feb 2008 lifecycle analysis for CCR beneficial uses, used as a data reference in the RIA, was built upon 2005 data.
1) Modified projections of CCR Use assume that Mining and Structural Fill applications will cease and be reduced by 100%, and that 50% of these amounts will then be available in the market for use in other applications.

Assessment of CPG, Consolidated Uses for CCR

Item	CCR "beneficial utilitzation" categories as defined by ACAA*	2005 ACAA tons (used in CCR RIA)**	Amount Used in Public Construction (= to 25% of total based on Census)***	Amount Used in Private Construction (= to 75% of total based on Census)***	Estimate of Reductions (assuming a 50% loss in Private Construction related Uses)****
1	Concrete/concrete products/grout	16,353,331	4,088,333	12,264,998	6,132,499
3	Flowable fill	259,907	64,977	194,930	97,465
9	Blasting grit/roofing granules	1,633,407	408,352	1,225,055	612,528

	Conservative Estimate of Reductions in CCR Used for Private Construction (assuming 50% loss in Private Uses)
Estimate of Total Potential Reduction in CCR "Construction Related Uses":	6,842,492
(As Percent of Total CCR generation) =	5.6%
(As Percent of Total Beneficial CCR Use - w/ Mining excluded) =	14.1%

Notes:

* ACAA provides annual CCR "beneficial utilization" data for years 2001 to 2008 at:
http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=3

** 2005 data used in ORCR's Oct 2009 draft CCR RIA because ORCR's Feb 2008 lifecycle analysis for CCR beneficial uses, used as a data reference in the RIA, was built upon 2005 data.

*** Based on U.S. Census Bureau Data on Construction Statistics… Annual Census data on Total Spending for Public vs. Private Construction are available for year 1993 to 2007, as well as on a monthly basis up through November 2009. Based on an expedited review of these figures, the Public portion of total construction spending equaled 20.7% in 2005, 21.4% in 2006, and 24.6% in 2007, and has swelled to 35.4% in Nov. 2009 in direct relationship to current state of the economy and current federal stimulus spending.

**** Using this data, we assume that the public portion of these "Consolidated Uses in CPG Construction Products" will remain unaffected due to the CPGs, and conservatively attribute a 50% potential reduction in the remaining portion of Private uses, such that 50% of the total Private uses are potentially reduced.

Assessment of Non-CPG, Consolidated Uses for CCR

Item	CCR "beneficial utilitzation" categories as defined by ACAA*	2005 ACAA tons (used in CCR RIA)**	Assumed Percentage of Reductions [2]	Conservative Estimates of Potential Reductions in "Consolidated Uses"
2	Blended cement/raw feed for clinker	4,215,234	50.0%	2,107,617
7	Mineral filler in asphalt	140,838	50.0%	70,419
11	Gypsum panel products (wallboard)	8,178,079	50.0%	4,089,040
12	Waste stabilization/solidification [3]	2,839,954	0.0%	0
15	Miscellaneous/Other (assuming 50% "Consolidated") [4]	1,035,579	50.0%	517,789

	Conservative Estimate of Reductions in "Consolidated Uses" of CCR (as shown assumed above)
Estimate of Total Potential Reduction in "Consolidated Uses":	6,784,865
(As Percent of Total CCR generation) =	5.5%
(As Percent of Total Beneficial CCR Use - w/ Mining excluded) =	14.0%

Notes:

* ACAA provides annual CCR "beneficial utilization" data for years 2001 to 2008 at:
http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=3

** 2005 data used in ORCR's Oct 2009 draft CCR RIA because ORCR's Feb 2008 lifecycle analysis for CCR beneficial uses, used as a data reference in the RIA, was built upon 2005 data.

2) These percentages have been established on a case by case basis for each of the Consolidated Uses addressed here. In the case of CCR used in Blended Cement, Mineral Filler - Asphault, and Miscellaneous applications, we conservatively assume for the purposes of analyses that as much as 50% of these uses could be reduced, while as much as 50% of the market for "Consolidated Uses" would be maintained (especially since the continued market for "Cosolidated" should remain strongerthan that for "Unconsolidated Uses". In regards to the assumptions, EPA believe that these market are particularly strong, and then estimated reduction of 50% that's been chosen is a reasonable approximation in the absense of information to the contrary.

3) The use of CCR in Waste Stabilization/Solidification applications should in no way be negatively impacted by the proposed rule, and we therefore project no reduction in the amount of CCR used for these purposes.

4) Lastly, because ACAA reports no further available information on the types of reuse accounted for by this remaining category of Miscellaneous CCR Uses, the total quantity of Miscellaneous uses has been split evenly so that 50% of the total is considered both as "Consolidated" and "Unconsolidated".

Assessment of Unconsolidated Uses for CCR

Item	CCR "beneficial utilitzation" categories as defined by ACAA*	2005 ACAA tons (used in CCR RIA)**	Assumed Percentage of Reduction [5]	Conservative Estimates of Potential Reductions in "Unconsolidated Uses"
4	Structural fill/embankments	8,349,999	80.0%	6,679,999
5	Road base/sub-base	1,461,992	80.0%	1,169,594
6	Soil modification/stabilization	1,139,640	80.0%	911,712
8	Snow & ice control	547,541	80.0%	438,033
13	Agriculture	415,741	80.0%	332,593
14	Aggregate	872,776	80.0%	698,221
15	Misc./Other [4] (assuming 50% "Unconsolidated")	1,035,579	80.0%	828,463

	Conservative Estimate of Reductions in "Unconsolidated Uses" of CCR (as shown assumed above)
Estimate of Total Potential Reduction in "Unconsolidated Uses":	11,058,614
(As Percent of Total CCR generation) =	9.0%
(As Percent of Total Beneficial CCR Use - w/ Mining excluded) =	22.8%

Notes:

* ACAA provides annual CCR "beneficial utilization" data for years 2001 to 2008 at:
http://acaa.affiniscape.com/displaycommon.cfm?an=1&subarticlenbr=3

** 2005 data used in ORCR's Oct 2009 draft CCR RIA because ORCR's Feb 2008 lifecycle analysis for CCR beneficial uses, used as a data reference in the RIA, was built upon 2005 data.

4) As noted above, because ACAA reports no further information on the types of reuse accounted for by this remaining category of Miscellaneous CCR Uses, the total quantity of Miscellaneous uses has been split evenly so that 50% of the total is considered both as "Consolidated" and "Unconsolidated" (as shown here and on the previous table).

5) For all CCR Uses that represent "Unconsolidated Uses", we conservatively assume that as much as 80% of these uses may be potentially impacted as a basis for our projections of the potential losses of use in these areas. This was chosen as a highly conservative and reasonable approximation in the absense of information to the contrary.

Final Results for Worst Case Scenario Estimate of Potential Reductions in CCR Use

	Summary of Reduction Estimates
Estimate for "Construction Related / CPG Product Uses":	6,842,492
(As Percent of Total CCR generation) =	6%
(As Percent of Total Beneficial CCR Use - w/ Mining excluded) =	14%
Estimate for "Consolidated Uses" of CCR =	6,784,865
(As Percent of Total CCR generation) =	6%
(As Percent of Total Beneficial CCR Use - w/ Mining excluded) =	14%
Estimate for "Unconsolidated Uses" of CCR =	11,058,614
(As Percent of Total CCR generation) =	9%
(As Percent of Total Beneficial CCR Use - w/ Mining excluded) =	23%

Grand Total Estimate for Worst Case Reductions	**24,685,971**
(As Percent of Total CCR generation) =	**20%**
(As Percent of Total Beneficial CCR Use - w/ Mining excluded) =	**51%**

Appendix L:

Electricity Price Impact Analysis Spreadsheet

- **Exhibit L1: Plant-by-Plant Estimate of Annual Electricity Sales Revenues**
- **Exhibit L2: Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option**
- **Exhibit L3: Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option**

Exhibit L1 Plant-by-Plant Estimate of Annual Electricity Sales Revenue							
Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
1	79	Aurora Energy LLC Chena	Aurora Energy LLC	AK	0.24	$0.1518	$36.432
2	6288	Healy	Golden Valley Elec Assn Inc	AK	0.27	$0.1518	$40.986
3	56	Charles R Lowman	Alabama Electric Coop Inc	AL	4.71	$0.0856	$403.176
4	3	Barry	Alabama Power Co	AL	23.4	$0.0856	$2,003.040
5	26	E C Gaston	Alabama Power Co	AL	17.82	$0.0856	$1,525.392
6	7	Gadsden	Alabama Power Co	AL	1.21	$0.0856	$103.576
7	8	Gorgas	Alabama Power Co	AL	12.41	$0.0856	$1,062.296
8	10	Greene County	Alabama Power Co	AL	11.29	$0.0856	$966.424
9	6002	James H Miller Jr	Alabama Power Co	AL	24.72	$0.0856	$2,116.032
10	50407	Mobile Energy Services LLC	DTE Energy Services	AL	0.38	$0.0856	$32.528
11	47	Colbert	Tennessee Valley Authority	AL	16	$0.0856	$1,369.600
12	50	Widows Creek	Tennessee Valley Authority	AL	17.24	$0.0856	$1,475.744
13	6641	Independence	Entergy Arkansas Inc	AR	14.89	$0.0762	$1,134.618
14	6009	White Bluff	Entergy Arkansas Inc	AR	14.89	$0.0762	$1,134.618
15	6138	Flint Creek	Southwestern Electric Power Co	AR	4.89	$0.0762	$372.618
16	160	Apache Station	Arizona Electric Pwr Coop Inc	AZ	5.79	$0.1002	$580.158
17	113	Cholla	Arizona Public Service Co	AZ	9.89	$0.1002	$990.978
18	6177	Coronado	Salt River Project	AZ	7.2	$0.1002	$721.440
19	4941	Navajo	Salt River Project	AZ	21.11	$0.1002	$2,115.222
20	126	H Wilson Sundt Generating Station	Tucson Electric Power Co	AZ	4.89	$0.1002	$489.978
21	8223	Springerville	Tucson Electric Power Co	AZ	11.43	$0.1002	$1,145.286
22	10002	ACE Cogeneration Facility	ACE Cogeneration Co	CA	0.95	$0.1337	$127.015
23	10640	Stockton Cogen	Air Products Energy Enterprise	CA	0.53	$0.1337	$70.861
24	54238	Port of Stockton District Energy Fac	FPL Energy Operating Servs Inc	CA	0.47	$0.1337	$62.839
25	54626	Mt Poso Cogeneration	Mt Poso Cogeneration Co	CA	0.54	$0.1337	$72.198
26	10768	Rio Bravo Jasmin	Rio Bravo Jasmin	CA	0.33	$0.1337	$44.121
27	10769	Rio Bravo Poso	Rio Bravo Poso	CA	0.33	$0.1337	$44.121
28	462	W N Clark	Aquila, Inc.	CO	0.38	$0.0797	$30.286
29	10003	Colorado Energy Nations Company	Colorado Energy Nations Company LLLP	CO	0.31	$0.0797	$24.707
30	492	Martin Drake	Colorado Springs City of	CO	2.25	$0.0797	$179.325
31	8219	Ray D Nixon	Colorado Springs City of	CO	2.44	$0.0797	$194.468
32	6761	Rawhide	Platte River Power Authority	CO	5.7	$0.0797	$454.290
33	465	Arapahoe	Public Service Co of Colorado	CO	1.4	$0.0797	$111.580
34	468	Cameo	Public Service Co of Colorado	CO	0.58	$0.0797	$46.226
35	469	Cherokee	Public Service Co of Colorado	CO	7.07	$0.0797	$563.479
36	470	Comanche	Public Service Co of Colorado	CO	6.82	$0.0797	$543.554
37	525	Hayden	Public Service Co of Colorado	CO	4.08	$0.0797	$325.176
38	6248	Pawnee	Public Service Co of Colorado	CO	4.84	$0.0797	$385.748
39	477	Valmont	Public Service Co of Colorado	CO	2.08	$0.0797	$165.776
40	6021	Craig	Tri-State G & T Assn, Inc	CO	11.73	$0.0797	$934.881
41	527	Nucla	Tri-State G & T Assn, Inc	CO	1	$0.0797	$79.700
42	10675	AES Thames	AES Thames LLC	CT	1.87	$0.1712	$320.144
43	568	Bridgeport Station	PSEG Power Connecticut LLC	CT	5.09	$0.1712	$871.408

Exhibit L1 Plant-by-Plant Estimate of Annual Electricity Sales Revenue							
Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
44	593	Edge Moor	Conectiv Delmarva Gen Inc	DE	6.22	$0.1236	$768.792
45	594	Indian River Generating Station	Indian River Operations Inc	DE	7	$0.1236	$865.200
46	10030	NRG Energy Center Dover	NRG Energy Center Dover LLC	DE	1.03	$0.1236	$127.308
47	10333	Central Power & Lime	Central Power & Lime Inc	FL	1.1	$0.1136	$124.960
48	676	C D McIntosh Jr	City of Lakeland	FL	8.71	$0.1136	$989.456
49	663	Deerhaven Generating Station	Gainesville Regional Utilities	FL	4.13	$0.1136	$469.168
50	641	Crist	Gulf Power Co	FL	9.94	$0.1136	$1,129.184
51	643	Lansing Smith	Gulf Power Co	FL	8.77	$0.1136	$996.272
52	642	Scholz	Gulf Power Co	FL	0.86	$0.1136	$97.696
53	667	Northside Generating Station	JEA	FL	12.33	$0.1136	$1,400.688
54	207	St Johns River Power Park	JEA	FL	11.9	$0.1136	$1,351.840
55	564	Stanton Energy Center	Orlando Utilities Comm	FL	8.14	$0.1136	$924.704
56	628	Crystal River	Progress Energy Florida Inc	FL	29.2	$0.1136	$3,317.120
57	136	Seminole	Seminole Electric Coop, Inc	FL	12.52	$0.1136	$1,422.272
58	645	Big Bend	Tampa Electric Co	FL	17.5	$0.1136	$1,988.000
59	7242	Polk	Tampa Electric Co	FL	9.02	$0.1136	$1,024.672
60	10672	Cedar Bay Generating Company LP	US Operating Services Company	FL	2.55	$0.1136	$289.680
61	50976	Indiantown Cogeneration LP	US Operating Services Company	FL	3.46	$0.1136	$393.056
62	753	Crisp Plant	Crisp County Power Comm	GA	0.15	$0.0859	$12.885
63	703	Bowen	Georgia Power Co	GA	31.01	$0.0859	$2,663.759
64	708	Hammond	Georgia Power Co	GA	8.35	$0.0859	$717.265
65	709	Harllee Branch	Georgia Power Co	GA	15.3	$0.0859	$1,314.270
66	710	Jack McDonough	Georgia Power Co	GA	5.97	$0.0859	$512.823
67	733	Kraft	Georgia Power Co	GA	3.09	$0.0859	$265.431
68	6124	McIntosh	Georgia Power Co	GA	8.65	$0.0859	$743.035
69	727	Mitchell	Georgia Power Co	GA	2.53	$0.0859	$217.327
70	6257	Scherer	Georgia Power Co	GA	31.22	$0.0859	$2,681.798
71	6052	Wansley	Georgia Power Co	GA	17.14	$0.0859	$1,472.326
72	728	Yates	Georgia Power Co	GA	13.03	$0.0859	$1,119.277
73	10673	AES Hawaii	AES Hawaii Inc	HI	1.78	$0.1892	$336.776
74	10604	Hawaiian Comm & Sugar Puunene Mill	Hawaiian Com & Sugar Co Ltd	HI	0.4	$0.1892	$75.680
75	1122	Ames Electric Services Power Plant	Ames City of	IA	0.95	$0.0710	$67.450
76	1167	Muscatine Plant #1	Board of Water Electric & Communications	IA	2.57	$0.0710	$182.470
77	1131	Streeter Station	Cedar Falls Utilities	IA	0.45	$0.0710	$31.950
78	1218	Fair Station	Central Iowa Power Cooperative	IA	0.55	$0.0710	$39.050
79	1217	Earl F Wisdom	Corn Belt Power Coop	IA	1.25	$0.0710	$88.750
80	1104	Burlington	Interstate Power and Light Co	IA	2.65	$0.0710	$188.150
81	1046	Dubuque	Interstate Power and Light Co	IA	0.75	$0.0710	$53.250
82	1047	Lansing	Interstate Power and Light Co	IA	2.85	$0.0710	$202.350
83	1048	Milton L Kapp	Interstate Power and Light Co	IA	1.91	$0.0710	$135.610
84	6254	Ottumwa	Interstate Power and Light Co	IA	6.36	$0.0710	$451.560
85	1073	Prairie Creek	Interstate Power and Light Co	IA	2.14	$0.0710	$151.940
86	1058	Sixth Street	Interstate Power and Light Co	IA	0.57	$0.0710	$40.470

Exhibit L1
Plant-by-Plant Estimate of Annual Electricity Sales Revenue

Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
87	1077	Sutherland	Interstate Power and Light Co	IA	1.37	$0.0710	$97.270
88	1091	George Neal North	MidAmerican Energy Co	IA	9.16	$0.0710	$650.360
89	7343	George Neal South	MidAmerican Energy Co	IA	5.61	$0.0710	$398.310
90	6664	Louisa	MidAmerican Energy Co	IA	7.11	$0.0710	$504.810
91	1081	Riverside	MidAmerican Energy Co	IA	1.24	$0.0710	$88.040
92	1082	Walter Scott Jr Energy Center	MidAmerican Energy Co	IA	15.58	$0.0710	$1,106.180
93	1175	Pella	Pella City of	IA	0.33	$0.0710	$23.430
94	861	Coffeen	Ameren Energy Generating Co	IL	8.81	$0.0924	$814.044
95	863	Hutsonville	Ameren Energy Generating Co	IL	1.34	$0.0924	$123.816
96	864	Meredosia	Ameren Energy Generating Co	IL	3.93	$0.0924	$363.132
97	6017	Newton	Ameren Energy Generating Co	IL	10.82	$0.0924	$999.768
98	6016	Duck Creek	Ameren Energy Resources Generating Co.	IL	3.86	$0.0924	$356.664
99	856	E D Edwards	Ameren Energy Resources Generating Co.	IL	6.84	$0.0924	$632.016
100	963	Dallman	City of Springfield	IL	2.61	$0.0924	$241.164
101	964	Lakeside	City of Springfield	IL	0.7	$0.0924	$64.680
102	876	Kincaid Generation LLC	Dominion Energy Services Co	IL	11.55	$0.0924	$1,067.220
103	889	Baldwin Energy Complex	Dynegy Midwest Generation Inc	IL	16.59	$0.0924	$1,532.916
104	891	Havana	Dynegy Midwest Generation Inc	IL	6.29	$0.0924	$581.196
105	892	Hennepin Power Station	Dynegy Midwest Generation Inc	IL	2.68	$0.0924	$247.632
106	897	Vermilion	Dynegy Midwest Generation Inc	IL	1.73	$0.0924	$159.852
107	898	Wood River	Dynegy Midwest Generation Inc	IL	5.69	$0.0924	$525.756
108	887	Joppa Steam	Electric Energy Inc	IL	9.63	$0.0924	$889.812
109	867	Crawford	Midwest Generations EME LLC	IL	5.23	$0.0924	$483.252
110	886	Fisk Street	Midwest Generations EME LLC	IL	5.81	$0.0924	$536.844
111	384	Joliet 29	Midwest Generations EME LLC	IL	11.56	$0.0924	$1,068.144
112	874	Joliet 9	Midwest Generations EME LLC	IL	3.16	$0.0924	$291.984
113	879	Powerton	Midwest Generations EME LLC	IL	15.64	$0.0924	$1,445.136
114	883	Waukegan	Midwest Generations EME LLC	IL	6.95	$0.0924	$642.180
115	884	Will County	Midwest Generations EME LLC	IL	11.11	$0.0924	$1,026.564
116	976	Marion	Southern Illinois Power Coop	IL	3.7	$0.0924	$341.880
117	6238	Pearl Station	Soyland Power Coop Inc	IL	0.4	$0.0924	$36.960
118	55245	Tuscola Station	Trigen-Cinergy Sol-Tuscola LLC	IL	0.16	$0.0924	$14.784
119	6705	Warrick	AGC Division of APG Inc	IN	6.61	$0.0766	$506.326
120	992	CC Perry K	Citizens Thermal Energy	IN	0.18	$0.0766	$13.788
121	6225	Jasper 2	City of Jasper	IN	0.13	$0.0766	$9.958
122	1032	Logansport	City of Logansport	IN	0.53	$0.0766	$40.598
123	1040	Whitewater Valley	City of Richmond	IN	0.82	$0.0766	$62.812
124	1024	Crawfordsville	Crawfordsville Elec, Lgt & Pwr	IN	0.22	$0.0766	$16.852
125	1001	Cayuga	Duke Energy Indiana Inc	IN	10.45	$0.0766	$800.470
126	1004	Edwardsport	Duke Energy Indiana Inc	IN	1.26	$0.0766	$96.516
127	6113	Gibson	Duke Energy Indiana Inc	IN	29.25	$0.0766	$2,240.550
128	1008	R Gallagher	Duke Energy Indiana Inc	IN	5.26	$0.0766	$402.916
129	1010	Wabash River	Duke Energy Indiana Inc	IN	10.27	$0.0766	$786.682
130	1043	Frank E Ratts	Hoosier Energy R E C, Inc	IN	2.04	$0.0766	$156.264
131	6213	Merom	Hoosier Energy R E C, Inc	IN	9.46	$0.0766	$724.636
132	6166	Rockport	Indiana Michigan Power Co	IN	22.78	$0.0766	$1,744.948

Exhibit L1 Plant-by-Plant Estimate of Annual Electricity Sales Revenue							
Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
133	988	Tanners Creek	Indiana Michigan Power Co	IN	9.64	$0.0766	$738.424
134	983	Clifty Creek	Indiana-Kentucky Electric Corp	IN	11.42	$0.0766	$874.772
135	994	AES Petersburg	Indianapolis Power & Light Co	IN	16.48	$0.0766	$1,262.368
136	991	Eagle Valley	Indianapolis Power & Light Co	IN	3.47	$0.0766	$265.802
137	990	Harding Street	Indianapolis Power & Light Co	IN	10.38	$0.0766	$795.108
138	995	Bailly	Northern Indiana Pub Serv Co	IN	5.62	$0.0766	$430.492
139	997	Michigan City	Northern Indiana Pub Serv Co	IN	4.73	$0.0766	$362.318
140	6085	R M Schahfer	Northern Indiana Pub Serv Co	IN	19.28	$0.0766	$1,476.848
141	1037	Peru	Peru City of	IN	0.32	$0.0766	$24.512
142	6137	A B Brown	Southern Indiana Gas & Elec Co	IN	6.19	$0.0766	$474.154
143	1012	F B Culley	Southern Indiana Gas & Elec Co	IN	3.23	$0.0766	$247.418
144	981	State Line Energy	State Line Energy LLC	IN	5.38	$0.0766	$412.108
145	1239	Riverton	Empire District Electric Co	KS	2.47	$0.0822	$203.034
146	6064	Nearman Creek	Kansas City City of	KS	3.11	$0.0822	$255.642
147	1295	Quindaro	Kansas City City of	KS	3.4	$0.0822	$279.480
148	1241	La Cygne	Kansas City Power & Light Co	KS	13.82	$0.0822	$1,136.004
149	108	Holcomb	Sunflower Electric Power Corp	KS	3.05	$0.0822	$250.710
150	6068	Jeffrey Energy Center	Westar Energy Inc	KS	18.92	$0.0822	$1,555.224
151	1250	Lawrence Energy Center	Westar Energy Inc	KS	4.96	$0.0822	$407.712
152	1252	Tecumseh Energy Center	Westar Energy Inc	KS	2.54	$0.0822	$208.788
153	1374	Elmer Smith	City of Owensboro	KY	3.9	$0.0640	$249.600
154	6018	East Bend	Duke Energy Kentucky Inc	KY	5.86	$0.0640	$375.040
155	1384	Cooper	East Kentucky Power Coop, Inc	KY	3.01	$0.0640	$192.640
156	1385	Dale	East Kentucky Power Coop, Inc	KY	1.89	$0.0640	$120.960
157	6041	H L Spurlock	East Kentucky Power Coop, Inc	KY	11.2	$0.0640	$716.800
158	1372	Henderson I	Henderson City Utility Comm	KY	0.38	$0.0640	$24.320
159	1353	Big Sandy	Kentucky Power Co	KY	9.61	$0.0640	$615.040
160	1355	E W Brown	Kentucky Utilities Co	KY	15.07	$0.0640	$964.480
161	1356	Ghent	Kentucky Utilities Co	KY	19.5	$0.0640	$1,248.000
162	1357	Green River	Kentucky Utilities Co	KY	1.65	$0.0640	$105.600
163	1361	Tyrone	Kentucky Utilities Co	KY	0.66	$0.0640	$42.240
164	1363	Cane Run	Louisville Gas & Electric Co	KY	5.79	$0.0640	$370.560
165	1364	Mill Creek	Louisville Gas & Electric Co	KY	15.04	$0.0640	$962.560
166	6071	Trimble County	Louisville Gas & Electric Co	KY	15.42	$0.0640	$986.880
167	1378	Paradise	Tennessee Valley Authority	KY	22.41	$0.0640	$1,434.240
168	1379	Shawnee	Tennessee Valley Authority	KY	15.33	$0.0640	$981.120
169	6823	D B Wilson	Western Kentucky Energy Corp	KY	3.85	$0.0640	$246.400
170	1382	HMP&L Station Two Henderson	Western Kentucky Energy Corp	KY	3.2	$0.0640	$204.800
171	1381	Kenneth C Coleman	Western Kentucky Energy Corp	KY	4.57	$0.0640	$292.480
172	6639	R D Green	Western Kentucky Energy Corp	KY	4.63	$0.0640	$296.320
173	1383	Robert A Reid	Western Kentucky Energy Corp	KY	1.71	$0.0640	$109.440
174	51	Dolet Hills	Cleco Power LLC	LA	6.31	$0.0748	$471.988
175	6190	Rodemacher	Cleco Power LLC	LA	8.79	$0.0748	$657.492
176	1393	R S Nelson	Entergy Gulf States Louisiana LLC	LA	13.99	$0.0748	$1,046.452
177	6055	Big Cajun 2	Louisiana Generating LLC	LA	16.39	$0.0748	$1,225.972

Exhibit L1
Plant-by-Plant Estimate of Annual Electricity Sales Revenue

Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
178	1619	Brayton Point	Dominion Energy New England, LLC	MA	14.09	$0.1534	$2,161.406
179	1626	Salem Harbor	Dominion Energy New England, LLC	MA	7.05	$0.1534	$1,081.470
180	1606	Mount Tom	FirstLight Power Resources Services LLC	MA	1.19	$0.1534	$182.546
181	1613	Somerset Station	Somerset Power LLC	MA	1.1	$0.1534	$168.740
182	10678	AES Warrior Run Cogeneration Facility	AES WR Ltd Partnership	MD	2.01	$0.1316	$264.516
183	1570	R Paul Smith Power Station	Allegheny Energy Supply Co LLC	MD	0.96	$0.1316	$126.336
184	602	Brandon Shores	Constellation Power Source Gen	MD	12	$0.1316	$1,579.200
185	1552	C P Crane	Constellation Power Source Gen	MD	3.64	$0.1316	$479.024
186	1554	Herbert A Wagner	Constellation Power Source Gen	MD	9.27	$0.1316	$1,219.932
187	1571	Chalk Point LLC	Mirant Chalk Point LLC	MD	23.19	$0.1316	$3,051.804
188	1572	Dickerson	Mirant Mid-Atlantic LLC	MD	8.15	$0.1316	$1,072.540
189	1573	Morgantown Generating Plant	Mirant Mid-Atlantic LLC	MD	13.56	$0.1316	$1,784.496
190	10495	Rumford Cogeneration	NewPage Corporation	ME	0.9	$0.1222	$109.980
191	1825	J B Sims	City of Grand Haven	MI	0.7	$0.0986	$69.020
192	1830	James De Young	City of Holland	MI	0.55	$0.0986	$54.230
193	1843	Shiras	City of Marquette	MI	0.57	$0.0986	$56.202
194	1695	B C Cobb	Consumers Energy Co	MI	4.55	$0.0986	$448.630
195	1702	Dan E Karn	Consumers Energy Co	MI	17.05	$0.0986	$1,681.130
196	1720	J C Weadock	Consumers Energy Co	MI	2.9	$0.0986	$285.940
197	1710	J H Campbell	Consumers Energy Co	MI	13.89	$0.0986	$1,369.554
198	1723	J R Whiting	Consumers Energy Co	MI	3.19	$0.0986	$314.534
199	6034	Belle River	Detroit Edison Co	MI	14.58	$0.0986	$1,437.588
200	1731	Harbor Beach	Detroit Edison Co	MI	1.1	$0.0986	$108.460
201	1733	Monroe	Detroit Edison Co	MI	28.85	$0.0986	$2,844.610
202	1740	River Rouge	Detroit Edison Co	MI	5.79	$0.0986	$570.894
203	1743	St Clair	Detroit Edison Co	MI	13.76	$0.0986	$1,356.736
204	1745	Trenton Channel	Detroit Edison Co	MI	6.79	$0.0986	$669.494
205	1831	Eckert Station	Lansing Board of Water and Light	MI	3.29	$0.0986	$324.394
206	1832	Erickson Station	Lansing Board of Water and Light	MI	1.36	$0.0986	$134.096
207	4259	Endicott Station	Michigan South Central Pwr Agy	MI	0.51	$0.0986	$50.286
208	50835	TES Filer City Station	TES Filer City Station LP	MI	0.61	$0.0986	$60.146
209	1771	Escanaba	Upper Peninsula Power Co	MI	0.36	$0.0986	$35.496
210	10148	White Pine Electric Power	White Pine Electric Power LLC	MI	0.35	$0.0986	$34.510
211	1769	Presque Isle	Wisconsin Electric Power Co	MI	4.92	$0.0986	$485.112
212	1866	Wyandotte	Wyandotte Municipal Serv Comm	MI	0.69	$0.0986	$68.034
213	1961	Austin Northeast	Austin City of	MN	0.28	$0.0804	$22.512
214	2018	Virginia	City of Virginia	MN	0.26	$0.0804	$20.904
215	1979	Hibbing	Hibbing Public Utilities Comm	MN	0.31	$0.0804	$24.924
216	1893	Clay Boswell	Minnesota Power Inc	MN	9.4	$0.0804	$755.760
217	1897	M L Hibbard	Minnesota Power Inc	MN	0.64	$0.0804	$51.456
218	10686	Rapids Energy Center	Minnesota Power Inc	MN	0.25	$0.0804	$20.100
219	1891	Syl Laskin	Minnesota Power Inc	MN	1.02	$0.0804	$82.008
220	10075	Taconite Harbor Energy Center	Minnesota Power Inc	MN	2.21	$0.0804	$177.684
221	2001	New Ulm	New Ulm Public Utilities Comm	MN	0.64	$0.0804	$51.456
222	1915	Allen S King	Northern States Power Co	MN	5.24	$0.0804	$421.296

Exhibit L1
Plant-by-Plant Estimate of Annual Electricity Sales Revenue

Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
223	1904	Black Dog	Northern States Power Co	MN	5.42	$0.0804	$435.768
224	1927	Riverside	Northern States Power Co	MN	3.54	$0.0804	$284.616
225	6090	Sherburne County	Northern States Power Co	MN	18.65	$0.0804	$1,499.460
226	1943	Hoot Lake	Otter Tail Power Co	MN	1.14	$0.0804	$91.656
227	2008	Silver Lake	Rochester Public Utilities	MN	0.87	$0.0804	$69.948
228	2022	Willmar	Willmar Municipal Utils Comm	MN	0.23	$0.0804	$18.492
229	2098	Lake Road	Aquila, Inc.	MO	2.39	$0.0757	$180.923
230	2094	Sibley	Aquila, Inc.	MO	4.59	$0.0757	$347.463
231	2167	New Madrid	Associated Electric Coop, Inc	MO	10.51	$0.0757	$795.607
232	2168	Thomas Hill	Associated Electric Coop, Inc	MO	9.94	$0.0757	$752.458
233	2169	Chamois	Central Electric Power Coop	MO	0.52	$0.0757	$39.364
234	2123	Columbia	City of Columbia	MO	0.83	$0.0757	$62.831
235	2144	Marshall	City of Marshall	MO	0.5	$0.0757	$37.850
236	6768	Sikeston Power Station	City of Sikeston	MO	2.29	$0.0757	$173.353
237	2161	James River Power Station	City Utilities of Springfield	MO	3.95	$0.0757	$299.015
238	6195	Southwest Power Station	City Utilities of Springfield	MO	2.65	$0.0757	$200.605
239	2076	Asbury	Empire District Electric Co	MO	2.03	$0.0757	$153.671
240	2132	Blue Valley	Independence City of	MO	1.54	$0.0757	$116.578
241	2171	Missouri City	Independence City of	MO	0.4	$0.0757	$30.280
242	2079	Hawthorn	Kansas City Power & Light Co	MO	9.38	$0.0757	$710.066
243	6065	Iatan	Kansas City Power & Light Co	MO	6.36	$0.0757	$481.452
244	2080	Montrose	Kansas City Power & Light Co	MO	4.94	$0.0757	$373.958
245	2103	Labadie	Union Electric Co	MO	20.93	$0.0757	$1,584.401
246	2104	Meramec	Union Electric Co	MO	9.12	$0.0757	$690.384
247	6155	Rush Island	Union Electric Co	MO	10.88	$0.0757	$823.616
248	2107	Sioux	Union Electric Co	MO	9.63	$0.0757	$728.991
249	55076	Red Hills Generating Facility	Choctaw Generating LP	MS	4.5	$0.0893	$401.850
250	2062	Henderson	Greenwood Utilities Comm	MS	0.4	$0.0893	$35.720
251	2049	Jack Watson	Mississippi Power Co	MS	10.65	$0.0893	$951.045
252	6073	Victor J Daniel Jr	Mississippi Power Co	MS	19.53	$0.0893	$1,744.029
253	6061	R D Morrow	South Mississippi El Pwr Assn	MS	3.5	$0.0893	$312.550
254	10784	Colstrip Energy LP	Colstrip Energy LP	MT	0.36	$0.0720	$25.920
255	6089	Lewis & Clark	MDU Resources Group Inc	MT	0.44	$0.0720	$31.680
256	6076	Colstrip	PPL Montana LLC	MT	19.9	$0.0720	$1,432.800
257	2187	J E Corette Plant	PPL Montana LLC	MT	1.51	$0.0720	$108.720
258	55749	Hardin Generator Project	Rocky Mountain Power Inc	MT	1.01	$0.0720	$72.720
259	10381	Coastal Carolina Clean Power	Carlyle/Riverstone Renewable Energy	NC	0.39	$0.0839	$32.721
260	8042	Belews Creek	Duke Energy Carolinas, LLC	NC	18.92	$0.0839	$1,587.388
261	2720	Buck	Duke Energy Carolinas, LLC	NC	4.16	$0.0839	$349.024
262	2721	Cliffside	Duke Energy Carolinas, LLC	NC	6.84	$0.0839	$573.876
263	2723	Dan River	Duke Energy Carolinas, LLC	NC	3.4	$0.0839	$285.260
264	2718	G G Allen	Duke Energy Carolinas, LLC	NC	10.12	$0.0839	$849.068
265	2727	Marshall	Duke Energy Carolinas, LLC	NC	17.48	$0.0839	$1,466.572
266	2732	Riverbend	Duke Energy Carolinas, LLC	NC	5.27	$0.0839	$442.153
267	10384	Edgecombe Genco LLC	Edgecombe Operating Services LLC	NC	1.01	$0.0839	$84.739
268	10380	Elizabethtown Power LLC	North Carolina Power Holdings, LLC	NC	0.3	$0.0839	$25.170

Exhibit L1
Plant-by-Plant Estimate of Annual Electricity Sales Revenue

Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
269	10382	Lumberton	North Carolina Power Holdings, LLC	NC	0.3	$0.0839	$25.170
270	10379	Primary Energy Roxboro	Primary Energy of North Carolina LLC	NC	0.59	$0.0839	$49.501
271	10378	Primary Energy Southport	Primary Energy of North Carolina LLC	NC	1.18	$0.0839	$99.002
272	2706	Asheville	Progress Energy Carolinas Inc	NC	7.33	$0.0839	$614.987
273	2708	Cape Fear	Progress Energy Carolinas Inc	NC	3.77	$0.0839	$316.303
274	2713	L V Sutton	Progress Energy Carolinas Inc	NC	6.68	$0.0839	$560.452
275	2709	Lee	Progress Energy Carolinas Inc	NC	4.45	$0.0839	$373.355
276	6250	Mayo	Progress Energy Carolinas Inc	NC	6.45	$0.0839	$541.155
277	2712	Roxboro	Progress Energy Carolinas Inc	NC	22.41	$0.0839	$1,880.199
278	2716	W H Weatherspoon	Progress Energy Carolinas Inc	NC	3	$0.0839	$251.700
279	54035	Roanoke Valley Energy Facililty I	Westmoreland Partners	NC	1.6	$0.0839	$134.240
280	54755	Roanoke Valley Energy Facility II	Westmoreland Partners	NC	0.51	$0.0839	$42.789
281	6469	Antelope Valley	Basin Electric Power Coop	ND	7.62	$0.0698	$531.876
282	2817	Leland Olds	Basin Electric Power Coop	ND	5.75	$0.0698	$401.350
283	6030	Coal Creek	Great River Energy	ND	10.62	$0.0698	$741.276
284	2824	Stanton	Great River Energy	ND	1.67	$0.0698	$116.566
285	2790	R M Heskett	MDU Resources Group Inc	ND	1.01	$0.0698	$70.498
286	2823	Milton R Young	Minnkota Power Coop, Inc	ND	6.43	$0.0698	$448.814
287	8222	Coyote	Otter Tail Power Co	ND	3.94	$0.0698	$275.012
288	2240	Lon Wright	Fremont City of	NE	1.49	$0.0705	$105.045
289	59	Platte	Grand Island City of	NE	0.96	$0.0705	$67.680
290	60	Whelan Energy Center	Hastings City of	NE	0.67	$0.0705	$47.235
291	6077	Gerald Gentleman	Nebraska Public Power District	NE	11.94	$0.0705	$841.770
292	2277	Sheldon	Nebraska Public Power District	NE	2	$0.0705	$141.000
293	6096	Nebraska City	Omaha Public Power District	NE	5.71	$0.0705	$402.555
294	2291	North Omaha	Omaha Public Power District	NE	5.65	$0.0705	$398.325
295	2364	Merrimack	Public Service Co of NH	NH	4.35	$0.1544	$671.640
296	2367	Schiller	Public Service Co of NH	NH	1.5	$0.1544	$231.600
297	2384	Deepwater	Conectiv Atlantic Generatn Inc	NJ	1.36	$0.1421	$193.256
298	2403	PSEG Hudson Generating Station	PSEG Fossil LLC	NJ	9.76	$0.1421	$1,386.896
299	2408	PSEG Mercer Generating Station	PSEG Fossil LLC	NJ	6.73	$0.1421	$956.333
300	2378	B L England	RC Cape May Holdings LLC	NJ	4.24	$0.1421	$602.504
301	10566	Chambers Cogeneration LP	US Operating Services Company	NJ	2.5	$0.1421	$355.250
302	10043	Logan Generating Company LP	US Operating Services Company	NJ	2.12	$0.1421	$301.252
303	2434	Howard Down	Vineland City of	NJ	0.47	$0.1421	$66.787
304	2442	Four Corners	Arizona Public Service Co	NM	19.88	$0.0769	$1,528.772
305	2451	San Juan	Public Service Co of NM	NM	16.19	$0.0769	$1,245.011
306	87	Escalante	Tri-State G & T Assn, Inc	NM	2.25	$0.0769	$173.025
307	2324	Reid Gardner	Nevada Power Co	NV	5.58	$0.0960	$535.680
308	8224	North Valmy	Sierra Pacific Power Co	NV	4.97	$0.0960	$477.120
309	2535	AES Cayuga	AES Cayuga LLC	NY	2.83	$0.1543	$436.669
310	2527	AES Greenidge LLC	AES Greenidge	NY	1.42	$0.1543	$219.106

Exhibit L1
Plant-by-Plant Estimate of Annual Electricity Sales Revenue

Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
311	6082	AES Somerset LLC	AES Somerset LLC	NY	5.74	$0.1543	$885.682
312	2526	AES Westover	AES Westover LLC	NY	1.04	$0.1543	$160.472
313	10464	Black River Generation	Black River Generation LLC	NY	0.49	$0.1543	$75.607
314	2554	Dunkirk Generating Plant	Dunkirk Power LLC	NY	5.49	$0.1543	$847.107
315	2480	Danskammer Generating Station	Dynegy Northeast Gen Inc	NY	4.71	$0.1543	$726.753
316	2682	S A Carlson	Jamestown Board of Public Util	NY	0.88	$0.1543	$135.784
317	2629	Lovett	Mirant New York Inc	NY	1.76	$0.1543	$271.568
318	50202	WPS Power Niagara	Niagara Generation LLC	NY	0.49	$0.1543	$75.607
319	2549	C R Huntley Generating Station	NRG Huntley Operations Inc	NY	3.82	$0.1543	$589.426
320	2642	Rochester 7	Rochester Gas & Electric Corp	NY	2.21	$0.1543	$341.003
321	50651	Trigen Syracuse Energy	Syracuse Energy Corp	NY	0.89	$0.1543	$137.327
322	7286	Richard Gorsuch	American Mun Power-Ohio, Inc	OH	1.75	$0.0930	$162.750
323	2828	Cardinal	Cardinal Operating Co	OH	16.47	$0.0930	$1,531.710
324	2914	Dover	City of Dover	OH	0.43	$0.0930	$39.990
325	2917	Hamilton	City of Hamilton	OH	1.21	$0.0930	$112.530
326	2935	Orrville	City of Orrville	OH	0.63	$0.0930	$58.590
327	2936	Painesville	City of Painesville	OH	0.47	$0.0930	$43.710
328	2943	Shelby Municipal Light Plant	City of Shelby	OH	0.31	$0.0930	$28.830
329	2840	Conesville	Columbus Southern Power Co	OH	16.56	$0.0930	$1,540.080
330	2843	Picway	Columbus Southern Power Co	OH	0.93	$0.0930	$86.490
331	2850	J M Stuart	Dayton Power & Light Co	OH	21.48	$0.0930	$1,997.640
332	6031	Killen Station	Dayton Power & Light Co	OH	6.04	$0.0930	$561.720
333	2848	O H Hutchings	Dayton Power & Light Co	OH	3.91	$0.0930	$363.630
334	2832	Miami Fort	Duke Energy Ohio Inc	OH	12.65	$0.0930	$1,176.450
335	6019	W H Zimmer	Duke Energy Ohio Inc	OH	12.49	$0.0930	$1,161.570
336	2830	Walter C Beckjord	Duke Energy Ohio Inc	OH	12.55	$0.0930	$1,167.150
337	2835	Ashtabula	FirstEnergy Generation Corp	OH	2.24	$0.0930	$208.320
338	2878	Bay Shore	FirstEnergy Generation Corp	OH	5.74	$0.0930	$533.820
339	2837	Eastlake	FirstEnergy Generation Corp	OH	11.29	$0.0930	$1,049.970
340	2838	Lake Shore	FirstEnergy Generation Corp	OH	2.28	$0.0930	$212.040
341	2864	R E Burger	FirstEnergy Generation Corp	OH	3.71	$0.0930	$345.030
342	2866	W H Sammis	FirstEnergy Generation Corp	OH	21.62	$0.0930	$2,010.660
343	8102	General James M Gavin	Ohio Power Co	OH	22.78	$0.0930	$2,118.540
344	2872	Muskingum River	Ohio Power Co	OH	13.4	$0.0930	$1,246.200
345	2876	Kyger Creek	Ohio Valley Electric Corp	OH	9.52	$0.0930	$885.360
346	2836	Avon Lake	Orion Power Midwest LP	OH	6.96	$0.0930	$647.280
347	2861	Niles	Orion Power Midwest LP	OH	2.56	$0.0930	$238.080
348	10671	AES Shady Point LLC	AES Shady Point LLC	OK	3.07	$0.0698	$214.286
349	165	GRDA	Grand River Dam Authority	OK	8.85	$0.0698	$617.730
350	2952	Muskogee	Oklahoma Gas & Electric Co	OK	16.55	$0.0698	$1,155.190
351	6095	Sooner	Oklahoma Gas & Electric Co	OK	9.97	$0.0698	$695.906
352	2963	Northeastern	Public Service Co of Oklahoma	OK	17.09	$0.0698	$1,192.882
353	6772	Hugo	Western Farmers Elec Coop, Inc	OK	3.91	$0.0698	$272.918
354	6106	Boardman	Portland General Electric Co	OR	5.26	$0.0751	$395.026
355	10676	AES Beaver Valley Partners Beaver Valley	AES Beaver Valley	PA	1.31	$0.0960	$125.760

Exhibit L1
Plant-by-Plant Estimate of Annual Electricity Sales Revenue

Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
356	3178	Armstrong Power Station	Allegheny Energy Supply Co LLC	PA	2.86	$0.0960	$274.560
357	3179	Hatfields Ferry Power Station	Allegheny Energy Supply Co LLC	PA	15.14	$0.0960	$1,453.440
358	3181	Mitchell Power Station	Allegheny Energy Supply Co LLC	PA	3.28	$0.0960	$314.880
359	10641	Cambria Cogen	Cambria CoGen Co	PA	0.86	$0.0960	$82.560
360	54144	Piney Creek Project	Colmac Clarion Inc	PA	0.32	$0.0960	$30.720
361	10603	Ebensburg Power	Ebensburg Power Co	PA	0.5	$0.0960	$48.000
362	3159	Cromby Generating Station	Exelon Power	PA	3.68	$0.0960	$353.280
363	3161	Eddystone Generating Station	Exelon Power	PA	13.74	$0.0960	$1,319.040
364	6094	Bruce Mansfield	FirstEnergy Generation Corp	PA	24.01	$0.0960	$2,304.960
365	10113	John B Rich Memorial Power Station	Gilberton Power Co	PA	0.77	$0.0960	$73.920
366	10143	Colver Power Project	Inter-Power/AhlCon Partners, L.P.	PA	1.03	$0.0960	$98.880
367	3122	Homer City Station	Midwest Generations EME LLC	PA	17.63	$0.0960	$1,692.480
368	10343	Foster Wheeler Mt Carmel Cogen	Mount Carmel Cogen Inc	PA	0.41	$0.0960	$39.360
369	50039	Kline Township Cogen Facility	Northeastern Power Co	PA	0.5	$0.0960	$48.000
370	8226	Cheswick Power Plant	Orion Power Midwest LP	PA	5.58	$0.0960	$535.680
371	3098	Elrama Power Plant	Orion Power Midwest LP	PA	4.47	$0.0960	$429.120
372	3138	New Castle Plant	Orion Power Midwest LP	PA	3.1	$0.0960	$297.600
373	50776	Panther Creek Energy Facility	Panther Creek Partners	PA	0.82	$0.0960	$78.720
374	3140	PPL Brunner Island	PPL Brunner Island LLC	PA	13.73	$0.0960	$1,318.080
375	3149	PPL Montour	PPL Montour LLC	PA	14.38	$0.0960	$1,380.480
376	3113	Portland	Reliant Energy Mid-Atlantic PH LLC	PA	5.44	$0.0960	$522.240
377	3131	Shawville	Reliant Energy Mid-Atlantic PH LLC	PA	5.54	$0.0960	$531.840
378	3115	Titus	Reliant Energy Mid-Atlantic PH LLC	PA	2.29	$0.0960	$219.840
379	3130	Seward	Reliant Energy Seward LLC	PA	5.12	$0.0960	$491.520
380	3118	Conemaugh	Reliant Engy NE Management Co	PA	16.5	$0.0960	$1,584.000
381	3136	Keystone	Reliant Engy NE Management Co	PA	16.5	$0.0960	$1,584.000
382	54634	St Nicholas Cogen Project	Schuylkill Energy Resource Inc	PA	0.87	$0.0960	$83.520
383	3152	Sunbury Generation LP	Sunbury Generation LP	PA	4.3	$0.0960	$412.800
384	3176	Hunlock Power Station	UGI Development Co	PA	0.44	$0.0960	$42.240
385	50888	Northampton Generating Company LP	US Operating Services Company	PA	1	$0.0960	$96.000
386	50974	Scrubgrass Generating Company LP	US Operating Services Company	PA	0.83	$0.0960	$79.680
387	50879	Wheelabrator Frackville Energy	Wheelabrator Environmental Systems	PA	0.42	$0.0960	$40.320
388	50611	WPS Westwood Generation LLC	WPS Power Developement	PA	0.32	$0.0960	$30.720
389	3264	W S Lee	Duke Energy Carolinas, LLC	SC	3.83	$0.0826	$316.358
390	3251	H B Robinson	Progress Energy Carolinas Inc	SC	8.69	$0.0826	$717.794
391	7652	US DOE Savannah River Site (D Area)	Savannah River Nuclear Solutions LLC	SC	0.69	$0.0826	$56.994
392	3280	Canadys Steam	South Carolina Electric&Gas Co	SC	4.29	$0.0826	$354.354
393	7737	Cogen South	South Carolina Electric&Gas Co	SC	0.87	$0.0826	$71.862
394	7210	Cope	South Carolina Electric&Gas Co	SC	3.66	$0.0826	$302.316
395	3287	McMeekin	South Carolina Electric&Gas Co	SC	2.57	$0.0826	$212.282

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Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
396	3295	Urquhart	South Carolina Electric&Gas Co	SC	6.65	$0.0826	$549.290
397	3297	Wateree	South Carolina Electric&Gas Co	SC	6.76	$0.0826	$558.376
398	3298	Williams	South Carolina Genertg Co, Inc	SC	6.01	$0.0826	$496.426
399	130	Cross	South Carolina Pub Serv Auth	SC	15.23	$0.0826	$1,257.998
400	3317	Dolphus M Grainger	South Carolina Pub Serv Auth	SC	1.43	$0.0826	$118.118
401	3319	Jefferies	South Carolina Pub Serv Auth	SC	5.07	$0.0826	$418.782
402	6249	Winyah	South Carolina Pub Serv Auth	SC	11.04	$0.0826	$911.904
403	3325	Ben French	Black Hills Power Inc	SD	1.18	$0.0742	$87.556
404	6098	Big Stone	Otter Tail Power Co	SD	4	$0.0742	$296.800
405	3393	Allen Steam Plant	Tennessee Valley Authority	TN	14.11	$0.0860	$1,213.460
406	3396	Bull Run	Tennessee Valley Authority	TN	8.32	$0.0860	$715.520
407	3399	Cumberland	Tennessee Valley Authority	TN	22.78	$0.0860	$1,959.080
408	3403	Gallatin	Tennessee Valley Authority	TN	16.81	$0.0860	$1,445.660
409	3405	John Sevier	Tennessee Valley Authority	TN	7.01	$0.0860	$602.860
410	3406	Johnsonville	Tennessee Valley Authority	TN	25.5	$0.0860	$2,193.000
411	3407	Kingston	Tennessee Valley Authority	TN	14.89	$0.0860	$1,280.540
412	7030	Twin Oaks Power One	Altura Power	TX	3.06	$0.1019	$311.814
413	6178	Coleto Creek	ANP-Coleto Creek	TX	5.26	$0.1019	$535.994
414	6179	Fayette Power Project	Lower Colorado River Authority	TX	14.8	$0.1019	$1,508.120
415	54972	Norit Americas Marshall Plant	Norit Americas Inc	TX	0.02	$0.1019	$2.038
416	298	Limestone	NRG Texas LLC	TX	16.2	$0.1019	$1,650.780
417	3470	W A Parish	NRG Texas LLC	TX	34.77	$0.1019	$3,543.063
418	127	Oklaunion	Public Service Co of Oklahoma	TX	6.31	$0.1019	$642.989
419	7097	J K Spruce	San Antonio City of	TX	4.96	$0.1019	$505.424
420	6181	J T Deely	San Antonio City of	TX	8.16	$0.1019	$831.504
421	6183	San Miguel	San Miguel Electric Coop, Inc	TX	3.59	$0.1019	$365.821
422	7902	Pirkey	Southwestern Electric Power Co	TX	6.32	$0.1019	$644.008
423	6139	Welsh	Southwestern Electric Power Co	TX	14.66	$0.1019	$1,493.854
424	6193	Harrington	Southwestern Public Service Co	TX	9.46	$0.1019	$963.974
425	6194	Tolk	Southwestern Public Service Co	TX	9.95	$0.1019	$1,013.905
426	6136	Gibbons Creek	Texas Municipal Power Agency	TX	3.97	$0.1019	$404.543
427	3497	Big Brown	TXU Generation Co LP	TX	10.4	$0.1019	$1,059.760
428	6146	Martin Lake	TXU Generation Co LP	TX	20.85	$0.1019	$2,124.615
429	6147	Monticello	TXU Generation Co LP	TX	17.34	$0.1019	$1,766.946
430	6648	Sandow No 4	TXU Generation Co LP	TX	5.17	$0.1019	$526.823
431	7790	Bonanza	Deseret Generation & Tran Coop	UT	4.38	$0.0690	$302.220
432	6481	Intermountain Power Project	Los Angeles City of	UT	14.37	$0.0690	$991.530
433	3644	Carbon	PacifiCorp	UT	1.65	$0.0690	$113.850
434	6165	Hunter	PacifiCorp	UT	12.9	$0.0690	$890.100
435	8069	Huntington	PacifiCorp	UT	8.72	$0.0690	$601.680
436	50951	Sunnyside Cogen Associates	Sunnyside Cogeneration Assoc	UT	0.51	$0.0690	$35.190
437	3775	Clinch River	Appalachian Power Co	VA	6.24	$0.0916	$571.584
438	3776	Glen Lyn	Appalachian Power Co	VA	2.96	$0.0916	$271.136
439	54304	Birchwood Power	Birchwood Power Partners LP	VA	2.26	$0.0916	$207.016
440	10071	Cogentrix Virginia Leasing Corporation	Cogentrix-Virginia Leas'g Corp	VA	1.01	$0.0916	$92.516

Exhibit L1 Plant-by-Plant Estimate of Annual Electricity Sales Revenue							
Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
441	10377	James River Cogeneration	James River Cogeneration Co	VA	1.01	$0.0916	$92.516
442	3788	Potomac River	Mirant Potomac River LLC	VA	4.5	$0.0916	$412.200
443	54081	Spruance Genco LLC	Spruance Operating Services LLC	VA	2.01	$0.0916	$184.116
444	10773	Altavista Power Station	Virginia Electric & Power Co	VA	0.62	$0.0916	$56.792
445	3796	Bremo Bluff	Virginia Electric & Power Co	VA	2.23	$0.0916	$204.268
446	3803	Chesapeake	Virginia Electric & Power Co	VA	7.11	$0.0916	$651.276
447	3797	Chesterfield	Virginia Electric & Power Co	VA	15.76	$0.0916	$1,443.616
448	7213	Clover	Virginia Electric & Power Co	VA	7.43	$0.0916	$680.588
449	10771	Hopewell Power Station	Virginia Electric & Power Co	VA	0.62	$0.0916	$56.792
450	52007	Mecklenburg Power Station	Virginia Electric & Power Co	VA	1.22	$0.0916	$111.752
451	10774	Southampton Power Station	Virginia Electric & Power Co	VA	0.62	$0.0916	$56.792
452	3809	Yorktown	Virginia Electric & Power Co	VA	11.01	$0.0916	$1,008.516
453	3845	Transalta Centralia Generation	TransAlta Centralia Gen LLC	WA	15.61	$0.0684	$1,067.724
454	4127	Menasha	City of Menasha	WI	0.25	$0.0918	$22.950
455	4140	Alma	Dairyland Power Coop	WI	1.59	$0.0918	$145.962
456	4143	Genoa	Dairyland Power Coop	WI	3.03	$0.0918	$278.154
457	4271	John P Madgett	Dairyland Power Coop	WI	3.39	$0.0918	$311.202
458	3992	Blount Street	Madison Gas & Electric Co	WI	1.55	$0.0918	$142.290
459	4125	Manitowoc	Manitowoc Public Utilities	WI	1.21	$0.0918	$111.078
460	4146	E J Stoneman Station	Mid-America Power LLC	WI	0.46	$0.0918	$42.228
461	3982	Bay Front	Northern States Power Co	WI	0.6	$0.0918	$55.080
462	7549	Milwaukee County	Wisconsin Electric Power Co	WI	0.1	$0.0918	$9.180
463	6170	Pleasant Prairie	Wisconsin Electric Power Co	WI	10.82	$0.0918	$993.276
464	4041	South Oak Creek	Wisconsin Electric Power Co	WI	10.61	$0.0918	$973.998
465	4042	Valley	Wisconsin Electric Power Co	WI	2.41	$0.0918	$221.238
466	8023	Columbia	Wisconsin Power & Light Co	WI	8.96	$0.0918	$822.528
467	4050	Edgewater	Wisconsin Power & Light Co	WI	6.75	$0.0918	$619.650
468	4054	Nelson Dewey	Wisconsin Power & Light Co	WI	1.75	$0.0918	$160.650
469	4072	Pulliam	Wisconsin Public Service Corp	WI	3.86	$0.0918	$354.348
470	4078	Weston	Wisconsin Public Service Corp	WI	4.98	$0.0918	$457.164
471	3944	Harrison Power Station	Allegheny Energy Supply Co LLC	WV	17.98	$0.0668	$1,201.064
472	6004	Pleasants Power Station	Allegheny Energy Supply Co LLC	WV	11.98	$0.0668	$800.264
473	10151	Grant Town Power Plant	American Bituminous Power LP	WV	0.84	$0.0668	$56.112
474	3935	John E Amos	Appalachian Power Co	WV	25.69	$0.0668	$1,716.092
475	3936	Kanawha River	Appalachian Power Co	WV	3.85	$0.0668	$257.180
476	6264	Mountaineer	Appalachian Power Co	WV	11.39	$0.0668	$760.852
477	3938	Philip Sporn	Appalachian Power Co	WV	9.68	$0.0668	$646.624
478	3942	Albright	Monongahela Power Co	WV	2.44	$0.0668	$162.992
479	3943	Fort Martin Power Station	Monongahela Power Co	WV	10.09	$0.0668	$674.012
480	3945	Rivesville	Monongahela Power Co	WV	0.96	$0.0668	$64.128
481	3946	Willow Island	Monongahela Power Co	WV	1.87	$0.0668	$124.916
482	10743	Morgantown Energy Facility	Morgantown Energy Associates	WV	0.6	$0.0668	$40.080
483	3947	Kammer	Ohio Power Co	WV	6.24	$0.0668	$416.832
484	3948	Mitchell	Ohio Power Co	WV	14.3	$0.0668	$955.240
485	3954	Mt Storm	Virginia Electric & Power Co	WV	14.72	$0.0668	$983.296
486	7537	North Branch	Virginia Electric & Power Co	WV	0.7	$0.0668	$46.760

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Item	Plant code	Plant name	Onwer entity name	State	Annual million mega watt hours (2007)	May 2009 state "All Sector" electricity price ($ per kwh)	Annual electricity sales revenues ($millions per year)
487	6204	Laramie River Station	Basin Electric Power Coop	WY	14.98	$0.0602	$901.796
488	4150	Neil Simpson	Black Hills Power Inc	WY	0.19	$0.0602	$11.438
489	7504	Neil Simpson II	Black Hills Power Inc	WY	1.05	$0.0602	$63.210
490	4151	Osage	Black Hills Power Inc	WY	0.3	$0.0602	$18.060
491	55479	Wygen 1	Black Hills Power Inc	WY	0.77	$0.0602	$46.354
492	4158	Dave Johnston	PacifiCorp	WY	7.15	$0.0602	$430.430
493	8066	Jim Bridger	PacifiCorp	WY	20.3	$0.0602	$1,222.060
494	4162	Naughton	PacifiCorp	WY	6.2	$0.0602	$373.240
495	6101	Wyodak	PacifiCorp	WY	3.17	$0.0602	$190.834
			Nationwide across 495 plants:		3234.04	**$0.0884**	$285,862

Exhibit L2
Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option

Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
1	79	Aurora Energy LLC Chena	AK	$37.023	$0.1543	1.6225%	$36.990	$0.1541	1.5322%	$36.999	$0.1542	1.5571%
2	6288	Healy	AK	$41.400	$0.1533	1.0099%	$41.377	$0.1532	0.9537%	$41.383	$0.1533	0.9692%
3	56	Charles R Lowman	AL	$403.984	$0.0858	0.2004%	$403.421	$0.0857	0.0609%	$403.425	$0.0857	0.0619%
4	3	Barry	AL	$2,007.419	$0.0858	0.2186%	$2,007.175	$0.0858	0.2064%	$2,007.242	$0.0858	0.2098%
5	26	E C Gaston	AL	$1,525.805	$0.0856	0.0271%	$1,525.782	$0.0856	0.0256%	$1,525.789	$0.0856	0.0260%
6	7	Gadsden	AL	$103.862	$0.0858	0.2762%	$103.846	$0.0858	0.2608%	$103.851	$0.0858	0.2650%
7	8	Gorgas	AL	$1,067.825	$0.0860	0.5204%	$1,067.517	$0.0860	0.4915%	$1,067.602	$0.0860	0.4995%
8	10	Greene County	AL	$972.116	$0.0861	0.5890%	$971.799	$0.0861	0.5562%	$971.887	$0.0861	0.5653%
9	6002	James H Miller Jr	AL	$2,118.379	$0.0857	0.1109%	$2,118.249	$0.0857	0.1048%	$2,118.285	$0.0857	0.1065%
10	50407	Mobile Energy Services LLC	AL	$32.589	$0.0858	0.1890%	$32.539	$0.0856	0.0351%	$32.540	$0.0856	0.0357%
11	47	Colbert	AL	$1,370.381	$0.0856	0.0571%	$1,370.336	$0.0856	0.0537%	$1,370.348	$0.0856	0.0546%
12	50	Widows Creek	AL	$1,478.159	$0.0857	0.1637%	$1,478.024	$0.0857	0.1545%	$1,478.061	$0.0857	0.1570%
13	6641	Independence	AR	$1,137.217	$0.0764	0.2291%	$1,137.072	$0.0764	0.2163%	$1,137.112	$0.0764	0.2198%
14	6009	White Bluff	AR	$1,137.857	$0.0764	0.2855%	$1,137.677	$0.0764	0.2696%	$1,137.727	$0.0764	0.2740%
15	6138	Flint Creek	AR	$373.065	$0.0763	0.1199%	$373.040	$0.0763	0.1132%	$373.047	$0.0763	0.1151%
16	160	Apache Station	AZ	$585.548	$0.1011	0.9291%	$585.248	$0.1011	0.8774%	$585.331	$0.1011	0.8916%
17	113	Cholla	AZ	$992.594	$0.1004	0.1630%	$992.504	$0.1004	0.1540%	$992.528	$0.1004	0.1565%
18	6177	Coronado	AZ	$724.971	$0.1007	0.4894%	$724.774	$0.1007	0.4622%	$724.829	$0.1007	0.4697%
19	4941	Navajo	AZ	$2,131.843	$0.1010	0.7858%	$2,130.918	$0.1009	0.7421%	$2,131.173	$0.1010	0.7541%
20	126	H Wilson Sundt Generating Station	AZ	$490.142	$0.1002	0.0335%	$490.101	$0.1002	0.0252%	$490.103	$0.1002	0.0256%
21	8223	Springerville	AZ	$1,157.817	$0.1013	1.0941%	$1,157.120	$0.1012	1.0332%	$1,157.312	$0.1013	1.0500%
22	10002	ACE Cogeneration Facility	CA	$127.017	$0.1337	0.0016%	$127.015	$0.1337	0.0000%	$127.015	$0.1337	0.0000%
23	10640	Stockton Cogen	CA	$72.127	$0.1361	1.7868%	$72.057	$0.1360	1.6874%	$72.076	$0.1360	1.7148%
24	54238	Port of Stockton District Energy Fac	CA	$63.377	$0.1348	0.8556%	$63.347	$0.1348	0.8079%	$63.355	$0.1348	0.8211%
25	54626	Mt Poso Cogeneration	CA	$72.765	$0.1347	0.7847%	$72.733	$0.1347	0.7410%	$72.742	$0.1347	0.7530%
26	10768	Rio Bravo Jasmin	CA	$44.447	$0.1347	0.7399%	$44.429	$0.1346	0.6987%	$44.434	$0.1346	0.7101%
27	10769	Rio Bravo Poso	CA	$44.441	$0.1347	0.7249%	$44.423	$0.1346	0.6846%	$44.428	$0.1346	0.6957%
28	462	W N Clark	CO	$30.393	$0.0800	0.3531%	$30.286	$0.0797	0.0000%	$30.286	$0.0797	0.0000%
29	10003	Colorado Energy Nations Company	CO	$24.841	$0.0801	0.5409%	$24.707	$0.0797	0.0000%	$24.707	$0.0797	0.0000%
30	492	Martin Drake	CO	$179.325	$0.0797	0.0000%	$179.325	$0.0797	0.0000%	$179.325	$0.0797	0.0000%
31	8219	Ray D Nixon	CO	$194.468	$0.0797	0.0000%	$194.468	$0.0797	0.0000%	$194.468	$0.0797	0.0000%
32	6761	Rawhide	CO	$454.559	$0.0797	0.0592%	$454.544	$0.0797	0.0559%	$454.548	$0.0797	0.0568%
33	465	Arapahoe	CO	$111.774	$0.0798	0.1735%	$111.580	$0.0797	0.0000%	$111.580	$0.0797	0.0000%
34	468	Cameo	CO	$46.398	$0.0800	0.3710%	$46.226	$0.0797	0.0000%	$46.226	$0.0797	0.0000%
35	469	Cherokee	CO	$564.928	$0.0799	0.2572%	$563.479	$0.0797	0.0000%	$563.479	$0.0797	0.0000%
36	470	Comanche	CO	$543.554	$0.0797	0.0000%	$543.554	$0.0797	0.0000%	$543.554	$0.0797	0.0000%
37	525	Hayden	CO	$325.176	$0.0797	0.0000%	$325.176	$0.0797	0.0000%	$325.176	$0.0797	0.0000%
38	6248	Pawnee	CO	$385.748	$0.0797	0.0000%	$385.748	$0.0797	0.0000%	$385.748	$0.0797	0.0000%
39	477	Valmont	CO	$165.796	$0.0797	0.0120%	$165.776	$0.0797	0.0000%	$165.776	$0.0797	0.0000%

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Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
40	6021	Craig	CO	$936.997	$0.0799	0.2264%	$934.881	$0.0797	0.0000%	$934.881	$0.0797	0.0000%
41	527	Nucla	CO	$79.700	$0.0797	0.0000%	$79.700	$0.0797	0.0000%	$79.700	$0.0797	0.0000%
42	10675	AES Thames	CT	$320.908	$0.1716	0.2387%	$320.144	$0.1712	0.0000%	$320.144	$0.1712	0.0000%
43	568	Bridgeport Station	CT	$871.526	$0.1712	0.0136%	$871.408	$0.1712	0.0000%	$871.408	$0.1712	0.0000%
44	593	Edge Moor	DE	$769.174	$0.1237	0.0497%	$768.792	$0.1236	0.0000%	$768.792	$0.1236	0.0000%
45	594	Indian River Generating Station	DE	$867.269	$0.1239	0.2391%	$867.154	$0.1239	0.2258%	$867.186	$0.1239	0.2295%
46	10030	NRG Energy Center Dover	DE	$127.611	$0.1239	0.2381%	$127.594	$0.1239	0.2249%	$127.599	$0.1239	0.2285%
47	10333	Central Power & Lime	FL	$124.960	$0.1136	0.0000%	$124.960	$0.1136	0.0000%	$124.960	$0.1136	0.0000%
48	676	C D McIntosh Jr	FL	$990.422	$0.1137	0.0977%	$990.369	$0.1137	0.0922%	$990.384	$0.1137	0.0937%
49	663	Deerhaven Generating Station	FL	$469.236	$0.1136	0.0145%	$469.232	$0.1136	0.0137%	$469.233	$0.1136	0.0139%
50	641	Crist	FL	$1,129.184	$0.1136	0.0000%	$1,129.184	$0.1136	0.0000%	$1,129.184	$0.1136	0.0000%
51	643	Lansing Smith	FL	$996.590	$0.1136	0.0320%	$996.573	$0.1136	0.0302%	$996.578	$0.1136	0.0307%
52	642	Scholz	FL	$97.696	$0.1136	0.0000%	$97.696	$0.1136	0.0000%	$97.696	$0.1136	0.0000%
53	667	Northside Generating Station	FL	$1,403.608	$0.1138	0.2084%	$1,403.445	$0.1138	0.1968%	$1,403.490	$0.1138	0.2000%
54	207	St Johns River Power Park	FL	$1,353.835	$0.1138	0.1475%	$1,353.724	$0.1138	0.1393%	$1,353.754	$0.1138	0.1416%
55	564	Stanton Energy Center	FL	$926.966	$0.1139	0.2446%	$926.840	$0.1139	0.2310%	$926.875	$0.1139	0.2347%
56	628	Crystal River	FL	$3,317.431	$0.1136	0.0094%	$3,317.414	$0.1136	0.0089%	$3,317.419	$0.1136	0.0090%
57	136	Seminole	FL	$1,425.443	$0.1139	0.2229%	$1,425.262	$0.1138	0.2102%	$1,425.310	$0.1138	0.2136%
58	645	Big Bend	FL	$1,988.043	$0.1136	0.0022%	$1,988.041	$0.1136	0.0021%	$1,988.042	$0.1136	0.0021%
59	7242	Polk	FL	$1,025.638	$0.1137	0.0943%	$1,025.584	$0.1137	0.0890%	$1,025.599	$0.1137	0.0905%
60	10672	Cedar Bay Generating Company LP	FL	$290.909	$0.1141	0.4243%	$289.680	$0.1136	0.0000%	$289.680	$0.1136	0.0000%
61	50976	Indiantown Cogeneration LP	FL	$394.106	$0.1139	0.2671%	$393.056	$0.1136	0.0000%	$393.056	$0.1136	0.0000%
62	753	Crisp Plant	GA	$12.895	$0.0860	0.0794%	$12.894	$0.0860	0.0708%	$12.894	$0.0860	0.0720%
63	703	Bowen	GA	$2,674.005	$0.0862	0.3846%	$2,673.434	$0.0862	0.3632%	$2,673.592	$0.0862	0.3691%
64	708	Hammond	GA	$717.749	$0.0860	0.0675%	$717.722	$0.0860	0.0638%	$717.730	$0.0860	0.0648%
65	709	Harllee Branch	GA	$1,315.581	$0.0860	0.0998%	$1,315.508	$0.0860	0.0942%	$1,315.528	$0.0860	0.0957%
66	710	Jack McDonough	GA	$512.965	$0.0859	0.0277%	$512.957	$0.0859	0.0262%	$512.959	$0.0859	0.0266%
67	733	Kraft	GA	$265.849	$0.0860	0.1576%	$265.633	$0.0860	0.0760%	$265.636	$0.0860	0.0772%
68	6124	McIntosh	GA	$743.489	$0.0860	0.0611%	$743.463	$0.0859	0.0577%	$743.470	$0.0860	0.0586%
69	727	Mitchell	GA	$217.327	$0.0859	0.0000%	$217.327	$0.0859	0.0000%	$217.327	$0.0859	0.0000%
70	6257	Scherer	GA	$2,685.836	$0.0860	0.1506%	$2,685.611	$0.0860	0.1422%	$2,685.673	$0.0860	0.1445%
71	6052	Wansley	GA	$1,475.066	$0.0861	0.1861%	$1,474.914	$0.0861	0.1758%	$1,474.956	$0.0861	0.1786%
72	728	Yates	GA	$1,119.890	$0.0859	0.0547%	$1,119.856	$0.0859	0.0517%	$1,119.865	$0.0859	0.0525%
73	10673	AES Hawaii	HI	$337.040	$0.1893	0.0783%	$336.776	$0.1892	0.0000%	$336.776	$0.1892	0.0000%
74	10604	Hawaiian Comm & Sugar Puunene Mill	HI	$76.428	$0.1911	0.9879%	$76.386	$0.1910	0.9329%	$76.398	$0.1910	0.9481%
75	1122	Ames Electric Services Power Plant	IA	$67.471	$0.0710	0.0304%	$67.469	$0.0710	0.0287%	$67.470	$0.0710	0.0292%
76	1167	Muscatine Plant #1	IA	$182.476	$0.0710	0.0035%	$182.476	$0.0710	0.0033%	$182.476	$0.0710	0.0033%
77	1131	Streeter Station	IA	$31.954	$0.0710	0.0110%	$31.953	$0.0710	0.0104%	$31.953	$0.0710	0.0106%
78	1218	Fair Station	IA	$39.117	$0.0711	0.1718%	$39.113	$0.0711	0.1622%	$39.114	$0.0711	0.1649%
79	1217	Earl F Wisdom	IA	$88.750	$0.0710	0.0000%	$88.750	$0.0710	0.0000%	$88.750	$0.0710	0.0000%
80	1104	Burlington	IA	$188.150	$0.0710	0.0000%	$188.150	$0.0710	0.0000%	$188.150	$0.0710	0.0000%

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Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
81	1046	Dubuque	IA	$53.275	$0.0710	0.0474%	$53.274	$0.0710	0.0448%	$53.274	$0.0710	0.0455%
82	1047	Lansing	IA	$202.718	$0.0711	0.1819%	$202.676	$0.0711	0.1610%	$202.681	$0.0711	0.1637%
83	1048	Milton L Kapp	IA	$135.610	$0.0710	0.0000%	$135.610	$0.0710	0.0000%	$135.610	$0.0710	0.0000%
84	6254	Ottumwa	IA	$451.560	$0.0710	0.0000%	$451.560	$0.0710	0.0000%	$451.560	$0.0710	0.0000%
85	1073	Prairie Creek	IA	$151.940	$0.0710	0.0000%	$151.940	$0.0710	0.0000%	$151.940	$0.0710	0.0000%
86	1058	Sixth Street	IA	$40.509	$0.0711	0.0952%	$40.506	$0.0711	0.0899%	$40.507	$0.0711	0.0913%
87	1077	Sutherland	IA	$97.270	$0.0710	0.0000%	$97.270	$0.0710	0.0000%	$97.270	$0.0710	0.0000%
88	1091	George Neal North	IA	$653.387	$0.0713	0.4654%	$653.218	$0.0713	0.4395%	$653.265	$0.0713	0.4466%
89	7343	George Neal South	IA	$398.502	$0.0710	0.0481%	$398.491	$0.0710	0.0455%	$398.494	$0.0710	0.0462%
90	6664	Louisa	IA	$506.895	$0.0713	0.4131%	$506.779	$0.0713	0.3901%	$506.811	$0.0713	0.3964%
91	1081	Riverside	IA	$88.134	$0.0711	0.1070%	$88.040	$0.0710	0.0000%	$88.040	$0.0710	0.0000%
92	1082	Walter Scott Jr Energy Center	IA	$1,109.825	$0.0712	0.3295%	$1,109.622	$0.0712	0.3112%	$1,109.678	$0.0712	0.3163%
93	1175	Pella	IA	$23.430	$0.0710	0.0000%	$23.430	$0.0710	0.0000%	$23.430	$0.0710	0.0000%
94	861	Coffeen	IL	$814.536	$0.0925	0.0604%	$814.044	$0.0924	0.0000%	$814.044	$0.0924	0.0000%
95	863	Hutsonville	IL	$124.240	$0.0927	0.3422%	$124.216	$0.0927	0.3232%	$124.223	$0.0927	0.3284%
96	864	Meredosia	IL	$364.071	$0.0926	0.2586%	$364.019	$0.0926	0.2442%	$364.033	$0.0926	0.2481%
97	6017	Newton	IL	$1,000.998	$0.0925	0.1230%	$1,000.930	$0.0925	0.1162%	$1,000.948	$0.0925	0.1181%
98	6016	Duck Creek	IL	$362.361	$0.0939	1.5973%	$362.044	$0.0938	1.5084%	$362.131	$0.0938	1.5329%
99	856	E D Edwards	IL	$632.939	$0.0925	0.1461%	$632.380	$0.0925	0.0576%	$632.386	$0.0925	0.0586%
100	963	Dallman	IL	$242.081	$0.0928	0.3804%	$242.030	$0.0927	0.3592%	$242.044	$0.0927	0.3651%
101	964	Lakeside	IL	$64.739	$0.0925	0.0912%	$64.680	$0.0924	0.0000%	$64.680	$0.0924	0.0000%
102	876	Kincaid Generation LLC	IL	$1,067.627	$0.0924	0.0382%	$1,067.220	$0.0924	0.0000%	$1,067.220	$0.0924	0.0000%
103	889	Baldwin Energy Complex	IL	$1,536.011	$0.0926	0.2019%	$1,535.839	$0.0926	0.1907%	$1,535.886	$0.0926	0.1938%
104	891	Havana	IL	$582.608	$0.0926	0.2429%	$582.529	$0.0926	0.2294%	$582.551	$0.0926	0.2331%
105	892	Hennepin Power Station	IL	$247.862	$0.0925	0.0927%	$247.849	$0.0925	0.0875%	$247.852	$0.0925	0.0890%
106	897	Vermilion	IL	$160.000	$0.0925	0.0926%	$159.992	$0.0925	0.0875%	$159.994	$0.0925	0.0889%
107	898	Wood River	IL	$526.048	$0.0925	0.0555%	$526.032	$0.0924	0.0524%	$526.036	$0.0924	0.0533%
108	887	Joppa Steam	IL	$889.812	$0.0924	0.0000%	$889.812	$0.0924	0.0000%	$889.812	$0.0924	0.0000%
109	867	Crawford	IL	$483.349	$0.0924	0.0201%	$483.252	$0.0924	0.0000%	$483.252	$0.0924	0.0000%
110	886	Fisk Street	IL	$536.891	$0.0924	0.0087%	$536.844	$0.0924	0.0000%	$536.844	$0.0924	0.0000%
111	384	Joliet 29	IL	$1,068.144	$0.0924	0.0000%	$1,068.144	$0.0924	0.0000%	$1,068.144	$0.0924	0.0000%
112	874	Joliet 9	IL	$291.984	$0.0924	0.0000%	$291.984	$0.0924	0.0000%	$291.984	$0.0924	0.0000%
113	879	Powerton	IL	$1,445.785	$0.0924	0.0449%	$1,445.136	$0.0924	0.0000%	$1,445.136	$0.0924	0.0000%
114	883	Waukegan	IL	$642.509	$0.0924	0.0513%	$642.180	$0.0924	0.0000%	$642.180	$0.0924	0.0000%
115	884	Will County	IL	$1,027.056	$0.0924	0.0479%	$1,026.564	$0.0924	0.0000%	$1,026.564	$0.0924	0.0000%
116	976	Marion	IL	$344.453	$0.0931	0.7527%	$341.880	$0.0924	0.0000%	$341.880	$0.0924	0.0000%
117	6238	Pearl Station	IL	$37.142	$0.0929	0.4920%	$37.132	$0.0928	0.4646%	$37.135	$0.0928	0.4722%
118	55245	Tuscola Station	IL	$15.056	$0.0941	1.8421%	$15.041	$0.0940	1.7395%	$15.045	$0.0940	1.7678%
119	6705	Warrick	IN	$511.049	$0.0773	0.9328%	$510.786	$0.0773	0.8809%	$510.859	$0.0773	0.8952%
120	992	CC Perry K	IN	$13.857	$0.0770	0.4995%	$13.796	$0.0766	0.0574%	$13.796	$0.0766	0.0583%
121	6225	Jasper 2	IN	$9.971	$0.0767	0.1330%	$9.964	$0.0766	0.0651%	$9.965	$0.0767	0.0662%
122	1032	Logansport	IN	$40.644	$0.0767	0.1135%	$40.610	$0.0766	0.0286%	$40.610	$0.0766	0.0290%
123	1040	Whitewater Valley	IN	$62.873	$0.0767	0.0975%	$62.870	$0.0767	0.0920%	$62.871	$0.0767	0.0935%
124	1024	Crawfordsville	IN	$16.877	$0.0767	0.1459%	$16.865	$0.0767	0.0796%	$16.866	$0.0767	0.0809%

Exhibit L2
Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option

Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
125	1001	Cayuga	IN	$804.950	$0.0770	0.5596%	$804.700	$0.0770	0.5285%	$804.769	$0.0770	0.5371%
126	1004	Edwardsport	IN	$96.842	$0.0769	0.3375%	$96.824	$0.0768	0.3187%	$96.829	$0.0768	0.3239%
127	6113	Gibson	IN	$2,246.297	$0.0768	0.2565%	$2,245.977	$0.0768	0.2422%	$2,246.065	$0.0768	0.2462%
128	1008	R Gallagher	IN	$403.918	$0.0768	0.2486%	$403.862	$0.0768	0.2347%	$403.877	$0.0768	0.2386%
129	1010	Wabash River	IN	$793.852	$0.0773	0.9114%	$793.453	$0.0773	0.8607%	$793.563	$0.0773	0.8747%
130	1043	Frank E Ratts	IN	$156.574	$0.0768	0.1982%	$156.557	$0.0767	0.1872%	$156.561	$0.0767	0.1902%
131	6213	Merom	IN	$724.676	$0.0766	0.0055%	$724.674	$0.0766	0.0052%	$724.675	$0.0766	0.0053%
132	6166	Rockport	IN	$1,746.698	$0.0767	0.1003%	$1,746.601	$0.0767	0.0947%	$1,746.627	$0.0767	0.0962%
133	988	Tanners Creek	IN	$740.547	$0.0768	0.2875%	$740.429	$0.0768	0.2715%	$740.462	$0.0768	0.2759%
134	983	Clifty Creek	IN	$875.378	$0.0767	0.0693%	$875.338	$0.0766	0.0647%	$875.348	$0.0767	0.0658%
135	994	AES Petersburg	IN	$1,265.942	$0.0768	0.2832%	$1,262.374	$0.0766	0.0005%	$1,262.374	$0.0766	0.0005%
136	991	Eagle Valley	IN	$265.971	$0.0766	0.0636%	$265.962	$0.0766	0.0601%	$265.964	$0.0766	0.0611%
137	990	Harding Street	IN	$796.149	$0.0767	0.1309%	$796.091	$0.0767	0.1236%	$796.107	$0.0767	0.1257%
138	995	Bailly	IN	$431.202	$0.0767	0.1650%	$431.075	$0.0767	0.1354%	$431.084	$0.0767	0.1376%
139	997	Michigan City	IN	$362.513	$0.0766	0.0539%	$362.503	$0.0766	0.0509%	$362.506	$0.0766	0.0518%
140	6085	R M Schahfer	IN	$1,477.107	$0.0766	0.0175%	$1,477.092	$0.0766	0.0166%	$1,477.096	$0.0766	0.0168%
141	1037	Peru	IN	$24.540	$0.0767	0.1147%	$24.529	$0.0767	0.0711%	$24.530	$0.0767	0.0722%
142	6137	A B Brown	IN	$475.826	$0.0769	0.3526%	$475.733	$0.0769	0.3329%	$475.758	$0.0769	0.3384%
143	1012	F B Culley	IN	$248.441	$0.0769	0.4133%	$247.834	$0.0767	0.1682%	$247.841	$0.0767	0.1710%
144	981	State Line Energy	IN	$412.210	$0.0766	0.0249%	$412.108	$0.0766	0.0000%	$412.108	$0.0766	0.0000%
145	1239	Riverton	KS	$203.121	$0.0822	0.0431%	$203.117	$0.0822	0.0407%	$203.118	$0.0822	0.0413%
146	6064	Nearman Creek	KS	$256.022	$0.0823	0.1486%	$255.969	$0.0823	0.1278%	$255.974	$0.0823	0.1299%
147	1295	Quindaro	KS	$279.686	$0.0823	0.0737%	$279.480	$0.0822	0.0000%	$279.480	$0.0822	0.0000%
148	1241	La Cygne	KS	$1,138.097	$0.0824	0.1842%	$1,137.980	$0.0823	0.1740%	$1,138.012	$0.0823	0.1768%
149	108	Holcomb	KS	$251.649	$0.0825	0.3746%	$251.597	$0.0825	0.3537%	$251.611	$0.0825	0.3595%
150	6068	Jeffrey Energy Center	KS	$1,560.364	$0.0825	0.3305%	$1,560.078	$0.0825	0.3121%	$1,560.157	$0.0825	0.3172%
151	1250	Lawrence Energy Center	KS	$407.725	$0.0822	0.0031%	$407.724	$0.0822	0.0030%	$407.724	$0.0822	0.0030%
152	1252	Tecumseh Energy Center	KS	$208.808	$0.0822	0.0094%	$208.806	$0.0822	0.0089%	$208.807	$0.0822	0.0090%
153	1374	Elmer Smith	KY	$250.590	$0.0643	0.3964%	$249.600	$0.0640	0.0000%	$249.600	$0.0640	0.0000%
154	6018	East Bend	KY	$377.197	$0.0644	0.5751%	$377.077	$0.0643	0.5431%	$377.110	$0.0644	0.5519%
155	1384	Cooper	KY	$192.861	$0.0641	0.1150%	$192.849	$0.0641	0.1086%	$192.853	$0.0641	0.1103%
156	1385	Dale	KY	$121.907	$0.0645	0.7830%	$121.854	$0.0645	0.7390%	$121.868	$0.0645	0.7510%
157	6041	H L Spurlock	KY	$725.271	$0.0648	1.1817%	$724.799	$0.0647	1.1159%	$724.929	$0.0647	1.1341%
158	1372	Henderson I	KY	$24.331	$0.0640	0.0466%	$24.331	$0.0640	0.0440%	$24.331	$0.0640	0.0447%
159	1353	Big Sandy	KY	$620.966	$0.0646	0.9635%	$620.636	$0.0646	0.9098%	$620.727	$0.0646	0.9246%
160	1355	E W Brown	KY	$964.813	$0.0640	0.0345%	$964.794	$0.0640	0.0326%	$964.799	$0.0640	0.0331%
161	1356	Ghent	KY	$1,259.851	$0.0646	0.9496%	$1,259.191	$0.0646	0.8967%	$1,259.373	$0.0646	0.9113%
162	1357	Green River	KY	$105.964	$0.0642	0.3446%	$105.944	$0.0642	0.3255%	$105.949	$0.0642	0.3307%
163	1361	Tyrone	KY	$42.433	$0.0643	0.4571%	$42.422	$0.0643	0.4317%	$42.425	$0.0643	0.4387%
164	1363	Cane Run	KY	$372.358	$0.0643	0.4853%	$372.258	$0.0643	0.4583%	$372.286	$0.0643	0.4658%
165	1364	Mill Creek	KY	$971.768	$0.0646	0.9566%	$967.728	$0.0643	0.5369%	$967.812	$0.0643	0.5456%
166	6071	Trimble County	KY	$987.097	$0.0640	0.0220%	$987.085	$0.0640	0.0207%	$987.088	$0.0640	0.0211%
167	1378	Paradise	KY	$1,441.870	$0.0643	0.5320%	$1,441.430	$0.0643	0.5013%	$1,441.547	$0.0643	0.5094%
168	1379	Shawnee	KY	$981.775	$0.0640	0.0668%	$981.734	$0.0640	0.0626%	$981.744	$0.0640	0.0636%

Exhibit L2
Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option

Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
169	6823	D B Wilson	KY	$252.795	$0.0657	2.5955%	$252.439	$0.0656	2.4510%	$252.538	$0.0656	2.4909%
170	1382	HMP&L Station Two Henderson	KY	$211.053	$0.0660	3.0534%	$210.705	$0.0658	2.8834%	$210.801	$0.0659	2.9303%
171	1381	Kenneth C Coleman	KY	$292.802	$0.0641	0.1100%	$292.784	$0.0641	0.1038%	$292.789	$0.0641	0.1055%
172	6639	R D Green	KY	$303.311	$0.0655	2.3591%	$302.921	$0.0654	2.2278%	$303.029	$0.0654	2.2641%
173	1383	Robert A Reid	KY	$109.478	$0.0640	0.0343%	$109.475	$0.0640	0.0324%	$109.476	$0.0640	0.0329%
174	51	Dolet Hills	LA	$473.294	$0.0750	0.2768%	$473.222	$0.0750	0.2614%	$473.242	$0.0750	0.2656%
175	6190	Rodemacher	LA	$657.492	$0.0748	0.0000%	$657.492	$0.0748	0.0000%	$657.492	$0.0748	0.0000%
176	1393	R S Nelson	LA	$1,046.452	$0.0748	0.0000%	$1,046.452	$0.0748	0.0000%	$1,046.452	$0.0748	0.0000%
177	6055	Big Cajun 2	LA	$1,226.118	$0.0748	0.0119%	$1,226.110	$0.0748	0.0112%	$1,226.112	$0.0748	0.0114%
178	1619	Brayton Point	MA	$2,161.698	$0.1534	0.0135%	$2,161.406	$0.1534	0.0000%	$2,161.406	$0.1534	0.0000%
179	1626	Salem Harbor	MA	$1,081.831	$0.1535	0.0333%	$1,081.470	$0.1534	0.0000%	$1,081.470	$0.1534	0.0000%
180	1606	Mount Tom	MA	$182.710	$0.1535	0.0901%	$182.546	$0.1534	0.0000%	$182.546	$0.1534	0.0000%
181	1613	Somerset Station	MA	$168.894	$0.1535	0.0912%	$168.740	$0.1534	0.0000%	$168.740	$0.1534	0.0000%
182	10678	AES Warrior Run Cogeneration Facility	MD	$266.450	$0.1326	0.7311%	$264.516	$0.1316	0.0000%	$264.516	$0.1316	0.0000%
183	1570	R Paul Smith Power Station	MD	$127.070	$0.1324	0.5806%	$127.029	$0.1323	0.5483%	$127.040	$0.1323	0.5572%
184	602	Brandon Shores	MD	$1,579.825	$0.1317	0.0396%	$1,579.200	$0.1316	0.0000%	$1,579.200	$0.1316	0.0000%
185	1552	C P Crane	MD	$479.495	$0.1317	0.0984%	$479.024	$0.1316	0.0000%	$479.024	$0.1316	0.0000%
186	1554	Herbert A Wagner	MD	$1,220.941	$0.1317	0.0827%	$1,219.932	$0.1316	0.0000%	$1,219.932	$0.1316	0.0000%
187	1571	Chalk Point LLC	MD	$3,052.526	$0.1316	0.0236%	$3,052.485	$0.1316	0.0223%	$3,052.496	$0.1316	0.0227%
188	1572	Dickerson	MD	$1,072.702	$0.1316	0.0151%	$1,072.693	$0.1316	0.0142%	$1,072.695	$0.1316	0.0145%
189	1573	Morgantown Generating Plant	MD	$1,784.599	$0.1316	0.0058%	$1,784.593	$0.1316	0.0055%	$1,784.595	$0.1316	0.0056%
190	10495	Rumford Cogeneration	ME	$110.552	$0.1228	0.5205%	$110.361	$0.1226	0.3464%	$110.367	$0.1226	0.3520%
191	1825	J B Sims	MI	$69.043	$0.0986	0.0328%	$69.041	$0.0986	0.0309%	$69.042	$0.0986	0.0314%
192	1830	James De Young	MI	$54.244	$0.0986	0.0250%	$54.243	$0.0986	0.0236%	$54.243	$0.0986	0.0240%
193	1843	Shiras	MI	$56.213	$0.0986	0.0202%	$56.213	$0.0986	0.0190%	$56.213	$0.0986	0.0194%
194	1695	B C Cobb	MI	$448.630	$0.0986	0.0000%	$448.630	$0.0986	0.0000%	$448.630	$0.0986	0.0000%
195	1702	Dan E Karn	MI	$1,681.147	$0.0986	0.0010%	$1,681.146	$0.0986	0.0010%	$1,681.146	$0.0986	0.0010%
196	1720	J C Weadock	MI	$286.657	$0.0988	0.2506%	$286.617	$0.0988	0.2366%	$286.628	$0.0988	0.2405%
197	1710	J H Campbell	MI	$1,369.580	$0.0986	0.0019%	$1,369.579	$0.0986	0.0018%	$1,369.579	$0.0986	0.0018%
198	1723	J R Whiting	MI	$314.561	$0.0986	0.0087%	$314.560	$0.0986	0.0082%	$314.560	$0.0986	0.0083%
199	6034	Belle River	MI	$1,437.618	$0.0986	0.0021%	$1,437.616	$0.0986	0.0020%	$1,437.617	$0.0986	0.0020%
200	1731	Harbor Beach	MI	$108.470	$0.0986	0.0088%	$108.469	$0.0986	0.0084%	$108.469	$0.0986	0.0085%
201	1733	Monroe	MI	$2,850.116	$0.0988	0.1936%	$2,849.809	$0.0988	0.1828%	$2,849.894	$0.0988	0.1858%
202	1740	River Rouge	MI	$570.915	$0.0986	0.0036%	$570.914	$0.0986	0.0034%	$570.914	$0.0986	0.0035%
203	1743	St Clair	MI	$1,356.763	$0.0986	0.0020%	$1,356.761	$0.0986	0.0019%	$1,356.762	$0.0986	0.0019%
204	1745	Trenton Channel	MI	$669.523	$0.0986	0.0043%	$669.521	$0.0986	0.0041%	$669.522	$0.0986	0.0041%
205	1831	Eckert Station	MI	$324.436	$0.0986	0.0129%	$324.394	$0.0986	0.0000%	$324.394	$0.0986	0.0000%
206	1832	Erickson Station	MI	$134.443	$0.0989	0.2586%	$134.393	$0.0988	0.2215%	$134.398	$0.0988	0.2251%
207	4259	Endicott Station	MI	$50.307	$0.0986	0.0420%	$50.306	$0.0986	0.0396%	$50.306	$0.0986	0.0403%
208	50835	TES Filer City Station	MI	$60.163	$0.0986	0.0280%	$60.162	$0.0986	0.0264%	$60.162	$0.0986	0.0268%
209	1771	Escanaba	MI	$35.557	$0.0988	0.1717%	$35.505	$0.0986	0.0244%	$35.505	$0.0986	0.0248%
210	10148	White Pine Electric Power	MI	$34.553	$0.0987	0.1246%	$34.518	$0.0986	0.0241%	$34.518	$0.0986	0.0245%

Exhibit L2
Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option

Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
211	1769	Presque Isle	MI	$485.131	$0.0986	0.0038%	$485.130	$0.0986	0.0036%	$485.130	$0.0986	0.0037%
212	1866	Wyandotte	MI	$68.049	$0.0986	0.0216%	$68.048	$0.0986	0.0204%	$68.048	$0.0986	0.0207%
213	1961	Austin Northeast	MN	$22.514	$0.0804	0.0067%	$22.513	$0.0804	0.0063%	$22.513	$0.0804	0.0064%
214	2018	Virginia	MN	$20.911	$0.0804	0.0329%	$20.910	$0.0804	0.0311%	$20.911	$0.0804	0.0316%
215	1979	Hibbing	MN	$24.927	$0.0804	0.0135%	$24.927	$0.0804	0.0127%	$24.927	$0.0804	0.0129%
216	1893	Clay Boswell	MN	$758.386	$0.0807	0.3475%	$758.240	$0.0807	0.3281%	$758.280	$0.0807	0.3335%
217	1897	M L Hibbard	MN	$51.469	$0.0804	0.0254%	$51.456	$0.0804	0.0000%	$51.456	$0.0804	0.0000%
218	10686	Rapids Energy Center	MN	$20.111	$0.0804	0.0567%	$20.100	$0.0804	0.0000%	$20.100	$0.0804	0.0000%
219	1891	Syl Laskin	MN	$82.193	$0.0806	0.2254%	$82.183	$0.0806	0.2128%	$82.185	$0.0806	0.2163%
220	10075	Taconite Harbor Energy Center	MN	$177.725	$0.0804	0.0229%	$177.722	$0.0804	0.0216%	$177.723	$0.0804	0.0220%
221	2001	New Ulm	MN	$51.465	$0.0804	0.0168%	$51.464	$0.0804	0.0158%	$51.464	$0.0804	0.0161%
222	1915	Allen S King	MN	$421.310	$0.0804	0.0033%	$421.309	$0.0804	0.0031%	$421.309	$0.0804	0.0032%
223	1904	Black Dog	MN	$435.959	$0.0804	0.0438%	$435.948	$0.0804	0.0414%	$435.951	$0.0804	0.0421%
224	1927	Riverside	MN	$284.911	$0.0805	0.1035%	$284.894	$0.0805	0.0978%	$284.899	$0.0805	0.0994%
225	6090	Sherburne County	MN	$1,516.121	$0.0813	1.1111%	$1,515.193	$0.0812	1.0493%	$1,515.449	$0.0813	1.0663%
226	1943	Hoot Lake	MN	$91.665	$0.0804	0.0096%	$91.664	$0.0804	0.0090%	$91.664	$0.0804	0.0092%
227	2008	Silver Lake	MN	$69.976	$0.0804	0.0405%	$69.975	$0.0804	0.0383%	$69.975	$0.0804	0.0389%
228	2022	Willmar	MN	$18.501	$0.0804	0.0482%	$18.500	$0.0804	0.0455%	$18.501	$0.0804	0.0463%
229	2098	Lake Road	MO	$181.006	$0.0757	0.0459%	$180.923	$0.0757	0.0000%	$180.923	$0.0757	0.0000%
230	2094	Sibley	MO	$347.621	$0.0757	0.0456%	$347.613	$0.0757	0.0431%	$347.615	$0.0757	0.0438%
231	2167	New Madrid	MO	$798.300	$0.0760	0.3385%	$798.150	$0.0759	0.3196%	$798.191	$0.0759	0.3248%
232	2168	Thomas Hill	MO	$752.563	$0.0757	0.0140%	$752.557	$0.0757	0.0132%	$752.559	$0.0757	0.0134%
233	2169	Chamois	MO	$39.563	$0.0761	0.5058%	$39.552	$0.0761	0.4776%	$39.555	$0.0761	0.4854%
234	2123	Columbia	MO	$62.870	$0.0757	0.0617%	$62.852	$0.0757	0.0335%	$62.852	$0.0757	0.0340%
235	2144	Marshall	MO	$37.884	$0.0758	0.0887%	$37.870	$0.0757	0.0519%	$37.870	$0.0757	0.0528%
236	6768	Sikeston Power Station	MO	$174.345	$0.0761	0.5723%	$174.290	$0.0761	0.5405%	$174.305	$0.0761	0.5493%
237	2161	James River Power Station	MO	$299.106	$0.0757	0.0304%	$299.101	$0.0757	0.0287%	$299.102	$0.0757	0.0291%
238	6195	Southwest Power Station	MO	$201.844	$0.0762	0.6175%	$201.775	$0.0761	0.5831%	$201.794	$0.0761	0.5926%
239	2076	Asbury	MO	$153.819	$0.0758	0.0966%	$153.811	$0.0758	0.0912%	$153.814	$0.0758	0.0927%
240	2132	Blue Valley	MO	$116.891	$0.0759	0.2685%	$116.874	$0.0759	0.2535%	$116.878	$0.0759	0.2577%
241	2171	Missouri City	MO	$30.360	$0.0759	0.2647%	$30.321	$0.0758	0.1342%	$30.321	$0.0758	0.1363%
242	2079	Hawthorn	MO	$710.865	$0.0758	0.1126%	$710.279	$0.0757	0.0300%	$710.282	$0.0757	0.0304%
243	6065	Iatan	MO	$481.782	$0.0758	0.0686%	$481.764	$0.0757	0.0647%	$481.769	$0.0757	0.0658%
244	2080	Montrose	MO	$374.147	$0.0757	0.0506%	$374.137	$0.0757	0.0478%	$374.140	$0.0757	0.0486%
245	2103	Labadie	MO	$1,585.221	$0.0757	0.0518%	$1,584.963	$0.0757	0.0354%	$1,584.972	$0.0757	0.0360%
246	2104	Meramec	MO	$691.260	$0.0758	0.1269%	$691.211	$0.0758	0.1199%	$691.225	$0.0758	0.1218%
247	6155	Rush Island	MO	$825.841	$0.0759	0.2701%	$825.475	$0.0759	0.2257%	$825.505	$0.0759	0.2294%
248	2107	Sioux	MO	$729.319	$0.0757	0.0450%	$729.301	$0.0757	0.0425%	$729.306	$0.0757	0.0432%
249	55076	Red Hills Generating Facility	MS	$402.591	$0.0895	0.1844%	$402.550	$0.0895	0.1741%	$402.561	$0.0895	0.1770%
250	2062	Henderson	MS	$35.743	$0.0894	0.0639%	$35.733	$0.0893	0.0373%	$35.734	$0.0893	0.0379%
251	2049	Jack Watson	MS	$951.396	$0.0893	0.0369%	$951.377	$0.0893	0.0349%	$951.382	$0.0893	0.0354%
252	6073	Victor J Daniel Jr	MS	$1,744.904	$0.0893	0.0502%	$1,744.855	$0.0893	0.0474%	$1,744.869	$0.0893	0.0482%
253	6061	R D Morrow	MS	$314.431	$0.0898	0.6020%	$314.327	$0.0898	0.5684%	$314.356	$0.0898	0.5777%
254	10784	Colstrip Energy LP	MT	$25.933	$0.0720	0.0489%	$25.932	$0.0720	0.0462%	$25.932	$0.0720	0.0470%

Exhibit L2
Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option

Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
255	6089	Lewis & Clark	MT	$31.690	$0.0720	0.0329%	$31.690	$0.0720	0.0310%	$31.690	$0.0720	0.0315%
256	6076	Colstrip	MT	$1,453.855	$0.0731	1.4695%	$1,452.683	$0.0730	1.3877%	$1,453.006	$0.0730	1.4102%
257	2187	J E Corette Plant	MT	$108.720	$0.0720	0.0000%	$108.720	$0.0720	0.0000%	$108.720	$0.0720	0.0000%
258	55749	Hardin Generator Project	MT	$72.758	$0.0720	0.0525%	$72.756	$0.0720	0.0496%	$72.757	$0.0720	0.0504%
259	10381	Coastal Carolina Clean Power	NC	$32.874	$0.0843	0.4665%	$32.809	$0.0841	0.2683%	$32.810	$0.0841	0.2727%
260	8042	Belews Creek	NC	$1,592.102	$0.0841	0.2969%	$1,591.839	$0.0841	0.2804%	$1,591.912	$0.0841	0.2850%
261	2720	Buck	NC	$349.237	$0.0840	0.0611%	$349.225	$0.0839	0.0577%	$349.228	$0.0839	0.0586%
262	2721	Cliffside	NC	$574.401	$0.0840	0.0915%	$574.372	$0.0840	0.0864%	$574.380	$0.0840	0.0878%
263	2723	Dan River	NC	$286.026	$0.0841	0.2685%	$285.983	$0.0841	0.2535%	$285.995	$0.0841	0.2577%
264	2718	G G Allen	NC	$849.789	$0.0840	0.0849%	$849.749	$0.0840	0.0802%	$849.760	$0.0840	0.0815%
265	2727	Marshall	NC	$1,470.754	$0.0841	0.2852%	$1,470.521	$0.0841	0.2693%	$1,470.585	$0.0841	0.2737%
266	2732	Riverbend	NC	$444.131	$0.0843	0.4472%	$444.020	$0.0843	0.4224%	$444.051	$0.0843	0.4292%
267	10384	Edgecombe Genco LLC	NC	$85.103	$0.0843	0.4291%	$84.739	$0.0839	0.0000%	$84.739	$0.0839	0.0000%
268	10380	Elizabethtown Power LLC	NC	$25.211	$0.0840	0.1629%	$25.205	$0.0840	0.1378%	$25.205	$0.0840	0.1400%
269	10382	Lumberton	NC	$25.205	$0.0840	0.1407%	$25.202	$0.0840	0.1269%	$25.202	$0.0840	0.1289%
270	10379	Primary Energy Roxboro	NC	$49.609	$0.0841	0.2182%	$49.566	$0.0840	0.1314%	$49.567	$0.0840	0.1335%
271	10378	Primary Energy Southport	NC	$99.120	$0.0840	0.1190%	$99.002	$0.0839	0.0000%	$99.002	$0.0839	0.0000%
272	2706	Asheville	NC	$615.353	$0.0839	0.0595%	$615.299	$0.0839	0.0507%	$615.304	$0.0839	0.0515%
273	2708	Cape Fear	NC	$316.620	$0.0840	0.1001%	$316.602	$0.0840	0.0946%	$316.607	$0.0840	0.0961%
274	2713	L V Sutton	NC	$560.850	$0.0840	0.0709%	$560.827	$0.0840	0.0670%	$560.834	$0.0840	0.0681%
275	2709	Lee	NC	$373.792	$0.0840	0.1170%	$373.767	$0.0840	0.1105%	$373.774	$0.0840	0.1123%
276	6250	Mayo	NC	$541.639	$0.0840	0.0895%	$541.612	$0.0840	0.0845%	$541.620	$0.0840	0.0859%
277	2712	Roxboro	NC	$1,881.170	$0.0839	0.0516%	$1,881.116	$0.0839	0.0488%	$1,881.131	$0.0839	0.0495%
278	2716	W H Weatherspoon	NC	$251.922	$0.0840	0.0883%	$251.910	$0.0840	0.0834%	$251.913	$0.0840	0.0847%
279	54035	Roanoke Valley Energy Facililty I	NC	$134.935	$0.0843	0.5178%	$134.267	$0.0839	0.0203%	$134.268	$0.0839	0.0206%
280	54755	Roanoke Valley Energy Facility II	NC	$42.963	$0.0842	0.4062%	$42.867	$0.0841	0.1814%	$42.868	$0.0841	0.1843%
281	6469	Antelope Valley	ND	$531.975	$0.0698	0.0185%	$531.969	$0.0698	0.0175%	$531.971	$0.0698	0.0178%
282	2817	Leland Olds	ND	$401.406	$0.0698	0.0140%	$401.403	$0.0698	0.0132%	$401.404	$0.0698	0.0134%
283	6030	Coal Creek	ND	$741.317	$0.0698	0.0055%	$741.315	$0.0698	0.0052%	$741.315	$0.0698	0.0053%
284	2824	Stanton	ND	$116.584	$0.0698	0.0152%	$116.583	$0.0698	0.0143%	$116.583	$0.0698	0.0145%
285	2790	R M Heskett	ND	$70.538	$0.0698	0.0560%	$70.521	$0.0698	0.0330%	$70.522	$0.0698	0.0336%
286	2823	Milton R Young	ND	$449.121	$0.0698	0.0684%	$448.855	$0.0698	0.0090%	$448.855	$0.0698	0.0092%
287	8222	Coyote	ND	$275.051	$0.0698	0.0141%	$275.049	$0.0698	0.0133%	$275.049	$0.0698	0.0135%
288	2240	Lon Wright	NE	$105.140	$0.0706	0.0906%	$105.079	$0.0705	0.0326%	$105.080	$0.0705	0.0331%
289	59	Platte	NE	$67.710	$0.0705	0.0439%	$67.680	$0.0705	0.0000%	$67.680	$0.0705	0.0000%
290	60	Whelan Energy Center	NE	$47.944	$0.0716	1.5005%	$47.904	$0.0715	1.4170%	$47.915	$0.0715	1.4400%
291	6077	Gerald Gentleman	NE	$844.650	$0.0707	0.3421%	$844.490	$0.0707	0.3231%	$844.534	$0.0707	0.3283%
292	2277	Sheldon	NE	$141.259	$0.0706	0.1838%	$141.245	$0.0706	0.1736%	$141.249	$0.0706	0.1764%
293	6096	Nebraska City	NE	$402.904	$0.0706	0.0867%	$402.885	$0.0706	0.0819%	$402.890	$0.0706	0.0832%
294	2291	North Omaha	NE	$398.471	$0.0705	0.0367%	$398.463	$0.0705	0.0347%	$398.465	$0.0705	0.0352%
295	2364	Merrimack	NH	$671.680	$0.1544	0.0059%	$671.678	$0.1544	0.0056%	$671.678	$0.1544	0.0057%
296	2367	Schiller	NH	$232.057	$0.1547	0.1975%	$231.600	$0.1544	0.0000%	$231.600	$0.1544	0.0000%

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Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
297	2384	Deepwater	NJ	$193.291	$0.1421	0.0180%	$193.256	$0.1421	0.0000%	$193.256	$0.1421	0.0000%
298	2403	PSEG Hudson Generating Station	NJ	$1,387.703	$0.1422	0.0582%	$1,386.896	$0.1421	0.0000%	$1,386.896	$0.1421	0.0000%
299	2408	PSEG Mercer Generating Station	NJ	$956.739	$0.1422	0.0425%	$956.333	$0.1421	0.0000%	$956.333	$0.1421	0.0000%
300	2378	B L England	NJ	$602.530	$0.1421	0.0043%	$602.504	$0.1421	0.0000%	$602.504	$0.1421	0.0000%
301	10566	Chambers Cogeneration LP	NJ	$356.080	$0.1424	0.2336%	$355.250	$0.1421	0.0000%	$355.250	$0.1421	0.0000%
302	10043	Logan Generating Company LP	NJ	$303.526	$0.1432	0.7548%	$302.809	$0.1428	0.5169%	$302.835	$0.1428	0.5253%
303	2434	Howard Down	NJ	$66.959	$0.1425	0.2570%	$66.949	$0.1424	0.2427%	$66.952	$0.1425	0.2467%
304	2442	Four Corners	NM	$1,535.122	$0.0772	0.4154%	$1,530.077	$0.0770	0.0854%	$1,530.098	$0.0770	0.0868%
305	2451	San Juan	NM	$1,259.427	$0.0778	1.1579%	$1,253.372	$0.0774	0.6715%	$1,253.508	$0.0774	0.6825%
306	87	Escalante	NM	$175.488	$0.0780	1.4236%	$175.351	$0.0779	1.3443%	$175.389	$0.0780	1.3662%
307	2324	Reid Gardner	NV	$536.959	$0.0962	0.2388%	$536.888	$0.0962	0.2255%	$536.907	$0.0962	0.2291%
308	8224	North Valmy	NV	$481.393	$0.0969	0.8956%	$481.155	$0.0968	0.8457%	$481.221	$0.0968	0.8595%
309	2535	AES Cayuga	NY	$436.669	$0.1543	0.0000%	$436.669	$0.1543	0.0000%	$436.669	$0.1543	0.0000%
310	2527	AES Greenidge LLC	NY	$219.106	$0.1543	0.0000%	$219.106	$0.1543	0.0000%	$219.106	$0.1543	0.0000%
311	6082	AES Somerset LLC	NY	$885.682	$0.1543	0.0000%	$885.682	$0.1543	0.0000%	$885.682	$0.1543	0.0000%
312	2526	AES Westover	NY	$160.685	$0.1545	0.1327%	$160.472	$0.1543	0.0000%	$160.472	$0.1543	0.0000%
313	10464	Black River Generation	NY	$75.607	$0.1543	0.0000%	$75.607	$0.1543	0.0000%	$75.607	$0.1543	0.0000%
314	2554	Dunkirk Generating Plant	NY	$847.374	$0.1543	0.0316%	$847.107	$0.1543	0.0000%	$847.107	$0.1543	0.0000%
315	2480	Danskammer Generating Station	NY	$726.753	$0.1543	0.0000%	$726.753	$0.1543	0.0000%	$726.753	$0.1543	0.0000%
316	2682	S A Carlson	NY	$135.784	$0.1543	0.0000%	$135.784	$0.1543	0.0000%	$135.784	$0.1543	0.0000%
317	2629	Lovett	NY	$272.115	$0.1546	0.2014%	$271.568	$0.1543	0.0000%	$271.568	$0.1543	0.0000%
318	50202	WPS Power Niagara	NY	$75.607	$0.1543	0.0000%	$75.607	$0.1543	0.0000%	$75.607	$0.1543	0.0000%
319	2549	C R Huntley Generating Station	NY	$589.426	$0.1543	0.0000%	$589.426	$0.1543	0.0000%	$589.426	$0.1543	0.0000%
320	2642	Rochester 7	NY	$341.129	$0.1544	0.0369%	$341.003	$0.1543	0.0000%	$341.003	$0.1543	0.0000%
321	50651	Trigen Syracuse Energy	NY	$137.327	$0.1543	0.0000%	$137.327	$0.1543	0.0000%	$137.327	$0.1543	0.0000%
322	7286	Richard Gorsuch	OH	$162.750	$0.0930	0.0000%	$162.750	$0.0930	0.0000%	$162.750	$0.0930	0.0000%
323	2828	Cardinal	OH	$1,533.699	$0.0931	0.1298%	$1,533.588	$0.0931	0.1226%	$1,533.619	$0.0931	0.1246%
324	2914	Dover	OH	$40.005	$0.0930	0.0367%	$39.990	$0.0930	0.0000%	$39.990	$0.0930	0.0000%
325	2917	Hamilton	OH	$112.688	$0.0931	0.1402%	$112.530	$0.0930	0.0000%	$112.530	$0.0930	0.0000%
326	2935	Orrville	OH	$58.590	$0.0930	0.0000%	$58.590	$0.0930	0.0000%	$58.590	$0.0930	0.0000%
327	2936	Painesville	OH	$43.759	$0.0931	0.1113%	$43.710	$0.0930	0.0000%	$43.710	$0.0930	0.0000%
328	2943	Shelby Municipal Light Plant	OH	$28.852	$0.0931	0.0773%	$28.830	$0.0930	0.0000%	$28.830	$0.0930	0.0000%
329	2840	Conesville	OH	$1,544.348	$0.0933	0.2771%	$1,544.111	$0.0932	0.2617%	$1,544.176	$0.0932	0.2660%
330	2843	Picway	OH	$86.765	$0.0933	0.3177%	$86.749	$0.0933	0.3000%	$86.754	$0.0933	0.3049%
331	2850	J M Stuart	OH	$2,002.332	$0.0932	0.2349%	$2,002.071	$0.0932	0.2218%	$2,002.143	$0.0932	0.2254%
332	6031	Killen Station	OH	$567.023	$0.0939	0.9441%	$566.728	$0.0938	0.8916%	$566.810	$0.0938	0.9061%
333	2848	O H Hutchings	OH	$364.040	$0.0931	0.1127%	$363.630	$0.0930	0.0000%	$363.630	$0.0930	0.0000%
334	2832	Miami Fort	OH	$1,181.852	$0.0934	0.4592%	$1,181.551	$0.0934	0.4336%	$1,181.634	$0.0934	0.4406%
335	6019	W H Zimmer	OH	$1,161.570	$0.0930	0.0000%	$1,161.570	$0.0930	0.0000%	$1,161.570	$0.0930	0.0000%
336	2830	Walter C Beckjord	OH	$1,167.778	$0.0931	0.0538%	$1,167.743	$0.0930	0.0508%	$1,167.753	$0.0930	0.0516%
337	2835	Ashtabula	OH	$208.382	$0.0930	0.0297%	$208.320	$0.0930	0.0000%	$208.320	$0.0930	0.0000%

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338	2878	Bay Shore	OH	$534.084	$0.0930	0.0494%	$533.820	$0.0930	0.0000%	$533.820	$0.0930	0.0000%
339	2837	Eastlake	OH	$1,050.619	$0.0931	0.0619%	$1,049.970	$0.0930	0.0000%	$1,049.970	$0.0930	0.0000%
340	2838	Lake Shore	OH	$212.167	$0.0931	0.0597%	$212.040	$0.0930	0.0000%	$212.040	$0.0930	0.0000%
341	2864	R E Burger	OH	$345.348	$0.0931	0.0922%	$345.030	$0.0930	0.0000%	$345.030	$0.0930	0.0000%
342	2866	W H Sammis	OH	$2,013.325	$0.0931	0.1325%	$2,010.660	$0.0930	0.0000%	$2,010.660	$0.0930	0.0000%
343	8102	General James M Gavin	OH	$2,119.124	$0.0930	0.0276%	$2,119.092	$0.0930	0.0260%	$2,119.101	$0.0930	0.0265%
344	2872	Muskingum River	OH	$1,247.908	$0.0931	0.1371%	$1,247.813	$0.0931	0.1294%	$1,247.839	$0.0931	0.1315%
345	2876	Kyger Creek	OH	$887.716	$0.0932	0.2661%	$887.585	$0.0932	0.2513%	$887.621	$0.0932	0.2553%
346	2836	Avon Lake	OH	$648.079	$0.0931	0.1234%	$647.280	$0.0930	0.0000%	$647.280	$0.0930	0.0000%
347	2861	Niles	OH	$238.369	$0.0931	0.1215%	$238.080	$0.0930	0.0000%	$238.080	$0.0930	0.0000%
348	10671	AES Shady Point LLC	OK	$216.449	$0.0705	1.0096%	$214.286	$0.0698	0.0000%	$214.286	$0.0698	0.0000%
349	165	GRDA	OK	$619.933	$0.0700	0.3565%	$619.810	$0.0700	0.3367%	$619.844	$0.0700	0.3422%
350	2952	Muskogee	OK	$1,155.454	$0.0698	0.0228%	$1,155.190	$0.0698	0.0000%	$1,155.190	$0.0698	0.0000%
351	6095	Sooner	OK	$696.282	$0.0698	0.0541%	$695.906	$0.0698	0.0000%	$695.906	$0.0698	0.0000%
352	2963	Northeastern	OK	$1,192.882	$0.0698	0.0000%	$1,192.882	$0.0698	0.0000%	$1,192.882	$0.0698	0.0000%
353	6772	Hugo	OK	$272.923	$0.0698	0.0020%	$272.923	$0.0698	0.0019%	$272.923	$0.0698	0.0019%
354	6106	Boardman	OR	$395.864	$0.0753	0.2121%	$395.817	$0.0753	0.2003%	$395.830	$0.0753	0.2036%
355	10676	AES Beaver Valley Partners Beaver Valley	PA	$126.653	$0.0967	0.7099%	$125.760	$0.0960	0.0000%	$125.760	$0.0960	0.0000%
356	3178	Armstrong Power Station	PA	$274.610	$0.0960	0.0182%	$274.607	$0.0960	0.0172%	$274.608	$0.0960	0.0175%
357	3179	Hatfields Ferry Power Station	PA	$1,453.971	$0.0960	0.0366%	$1,453.520	$0.0960	0.0055%	$1,453.521	$0.0960	0.0056%
358	3181	Mitchell Power Station	PA	$315.882	$0.0963	0.3181%	$314.892	$0.0960	0.0038%	$314.892	$0.0960	0.0039%
359	10641	Cambria Cogen	PA	$83.160	$0.0967	0.7266%	$83.126	$0.0967	0.6861%	$83.136	$0.0967	0.6973%
360	54144	Piney Creek Project	PA	$30.858	$0.0964	0.4476%	$30.850	$0.0964	0.4227%	$30.852	$0.0964	0.4296%
361	10603	Ebensburg Power	PA	$48.426	$0.0969	0.8878%	$48.402	$0.0968	0.8384%	$48.409	$0.0968	0.8520%
362	3159	Cromby Generating Station	PA	$353.433	$0.0960	0.0433%	$353.280	$0.0960	0.0000%	$353.280	$0.0960	0.0000%
363	3161	Eddystone Generating Station	PA	$1,319.589	$0.0960	0.0416%	$1,319.040	$0.0960	0.0000%	$1,319.040	$0.0960	0.0000%
364	6094	Bruce Mansfield	PA	$2,337.862	$0.0974	1.4275%	$2,336.031	$0.0973	1.3480%	$2,336.536	$0.0973	1.3699%
365	10113	John B Rich Memorial Power Station	PA	$74.473	$0.0967	0.7485%	$74.443	$0.0967	0.7069%	$74.451	$0.0967	0.7184%
366	10143	Colver Power Project	PA	$99.020	$0.0961	0.1414%	$98.880	$0.0960	0.0000%	$98.880	$0.0960	0.0000%
367	3122	Homer City Station	PA	$1,692.907	$0.0960	0.0252%	$1,692.883	$0.0960	0.0238%	$1,692.889	$0.0960	0.0242%
368	10343	Foster Wheeler Mt Carmel Cogen	PA	$39.962	$0.0975	1.5299%	$39.929	$0.0974	1.4448%	$39.938	$0.0974	1.4682%
369	50039	Kline Township Cogen Facility	PA	$48.446	$0.0969	0.9291%	$48.421	$0.0968	0.8774%	$48.428	$0.0969	0.8917%
370	8226	Cheswick Power Plant	PA	$535.707	$0.0960	0.0051%	$535.706	$0.0960	0.0048%	$535.706	$0.0960	0.0049%
371	3098	Elrama Power Plant	PA	$429.120	$0.0960	0.0000%	$429.120	$0.0960	0.0000%	$429.120	$0.0960	0.0000%
372	3138	New Castle Plant	PA	$297.623	$0.0960	0.0076%	$297.621	$0.0960	0.0072%	$297.622	$0.0960	0.0073%
373	50776	Panther Creek Energy Facility	PA	$79.087	$0.0964	0.4660%	$79.066	$0.0964	0.4401%	$79.072	$0.0964	0.4472%
374	3140	PPL Brunner Island	PA	$1,318.080	$0.0960	0.0000%	$1,318.080	$0.0960	0.0000%	$1,318.080	$0.0960	0.0000%
375	3149	PPL Montour	PA	$1,380.480	$0.0960	0.0000%	$1,380.480	$0.0960	0.0000%	$1,380.480	$0.0960	0.0000%
376	3113	Portland	PA	$522.260	$0.0960	0.0038%	$522.258	$0.0960	0.0035%	$522.259	$0.0960	0.0036%
377	3131	Shawville	PA	$532.111	$0.0960	0.0510%	$532.096	$0.0960	0.0481%	$532.100	$0.0960	0.0489%
378	3115	Titus	PA	$219.840	$0.0960	0.0000%	$219.840	$0.0960	0.0000%	$219.840	$0.0960	0.0000%

Exhibit L2
Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option

Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
379	3130	Seward	PA	$493.634	$0.0964	0.4301%	$493.516	$0.0964	0.4061%	$493.549	$0.0964	0.4127%
380	3118	Conemaugh	PA	$1,585.196	$0.0961	0.0755%	$1,585.129	$0.0961	0.0713%	$1,585.147	$0.0961	0.0724%
381	3136	Keystone	PA	$1,584.145	$0.0960	0.0091%	$1,584.137	$0.0960	0.0086%	$1,584.139	$0.0960	0.0088%
382	54634	St Nicholas Cogen Project	PA	$84.838	$0.0975	1.5787%	$84.765	$0.0974	1.4908%	$84.785	$0.0975	1.5150%
383	3152	Sunbury Generation LP	PA	$413.244	$0.0961	0.1077%	$413.010	$0.0960	0.0509%	$413.014	$0.0960	0.0518%
384	3176	Hunlock Power Station	PA	$42.296	$0.0961	0.1328%	$42.293	$0.0961	0.1254%	$42.294	$0.0961	0.1275%
385	50888	Northampton Generating Company LP	PA	$97.755	$0.0978	1.8286%	$96.183	$0.0962	0.1902%	$96.186	$0.0962	0.1933%
386	50974	Scrubgrass Generating Company LP	PA	$80.038	$0.0964	0.4488%	$80.018	$0.0964	0.4238%	$80.023	$0.0964	0.4307%
387	50879	Wheelabrator Frackville Energy	PA	$40.862	$0.0973	1.3437%	$40.832	$0.0972	1.2689%	$40.840	$0.0972	1.2895%
388	50611	WPS Westwood Generation LLC	PA	$31.242	$0.0976	1.7008%	$31.213	$0.0975	1.6061%	$31.221	$0.0976	1.6322%
389	3264	W S Lee	SC	$316.400	$0.0826	0.0132%	$316.398	$0.0826	0.0125%	$316.398	$0.0826	0.0127%
390	3251	H B Robinson	SC	$718.117	$0.0826	0.0450%	$718.099	$0.0826	0.0425%	$718.104	$0.0826	0.0432%
391	7652	US DOE Savannah River Site (D Area)	SC	$56.994	$0.0826	0.0000%	$56.994	$0.0826	0.0000%	$56.994	$0.0826	0.0000%
392	3280	Canadys Steam	SC	$354.828	$0.0827	0.1338%	$354.802	$0.0827	0.1263%	$354.809	$0.0827	0.1284%
393	7737	Cogen South	SC	$71.862	$0.0826	0.0000%	$71.862	$0.0826	0.0000%	$71.862	$0.0826	0.0000%
394	7210	Cope	SC	$302.316	$0.0826	0.0000%	$302.316	$0.0826	0.0000%	$302.316	$0.0826	0.0000%
395	3287	McMeekin	SC	$212.282	$0.0826	0.0000%	$212.282	$0.0826	0.0000%	$212.282	$0.0826	0.0000%
396	3295	Urquhart	SC	$549.436	$0.0826	0.0266%	$549.428	$0.0826	0.0251%	$549.430	$0.0826	0.0255%
397	3297	Wateree	SC	$558.376	$0.0826	0.0000%	$558.376	$0.0826	0.0000%	$558.376	$0.0826	0.0000%
398	3298	Williams	SC	$496.426	$0.0826	0.0000%	$496.426	$0.0826	0.0000%	$496.426	$0.0826	0.0000%
399	130	Cross	SC	$1,258.387	$0.0826	0.0309%	$1,258.275	$0.0826	0.0220%	$1,258.279	$0.0826	0.0223%
400	3317	Dolphus M Grainger	SC	$118.455	$0.0828	0.2852%	$118.176	$0.0826	0.0490%	$118.177	$0.0826	0.0498%
401	3319	Jefferies	SC	$418.891	$0.0826	0.0259%	$418.884	$0.0826	0.0245%	$418.886	$0.0826	0.0249%
402	6249	Winyah	SC	$912.523	$0.0827	0.0679%	$912.303	$0.0826	0.0437%	$912.309	$0.0826	0.0444%
403	3325	Ben French	SD	$87.717	$0.0743	0.1835%	$87.676	$0.0743	0.1376%	$87.678	$0.0743	0.1399%
404	6098	Big Stone	SD	$297.015	$0.0743	0.0724%	$297.003	$0.0743	0.0684%	$297.006	$0.0743	0.0695%
405	3393	Allen Steam Plant	TN	$1,213.472	$0.0860	0.0010%	$1,213.471	$0.0860	0.0009%	$1,213.471	$0.0860	0.0009%
406	3396	Bull Run	TN	$715.557	$0.0860	0.0052%	$715.532	$0.0860	0.0017%	$715.532	$0.0860	0.0017%
407	3399	Cumberland	TN	$1,959.080	$0.0860	0.0000%	$1,959.080	$0.0860	0.0000%	$1,959.080	$0.0860	0.0000%
408	3403	Gallatin	TN	$1,445.674	$0.0860	0.0010%	$1,445.672	$0.0860	0.0008%	$1,445.672	$0.0860	0.0009%
409	3405	John Sevier	TN	$602.905	$0.0860	0.0075%	$602.869	$0.0860	0.0014%	$602.869	$0.0860	0.0015%
410	3406	Johnsonville	TN	$2,194.155	$0.0860	0.0527%	$2,193.010	$0.0860	0.0004%	$2,193.010	$0.0860	0.0005%
411	3407	Kingston	TN	$1,280.543	$0.0860	0.0002%	$1,280.543	$0.0860	0.0002%	$1,280.543	$0.0860	0.0002%
412	7030	Twin Oaks Power One	TX	$311.994	$0.1020	0.0578%	$311.984	$0.1020	0.0546%	$311.987	$0.1020	0.0555%
413	6178	Coleto Creek	TX	$536.951	$0.1021	0.1786%	$536.898	$0.1021	0.1687%	$536.913	$0.1021	0.1714%
414	6179	Fayette Power Project	TX	$1,508.331	$0.1019	0.0140%	$1,508.319	$0.1019	0.0132%	$1,508.322	$0.1019	0.0134%
415	54972	Norit Americas Marshall Plant	TX	$2.043	$0.1022	0.2644%	$2.041	$0.1020	0.1244%	$2.041	$0.1020	0.1264%
416	298	Limestone	TX	$1,651.378	$0.1019	0.0363%	$1,651.345	$0.1019	0.0342%	$1,651.354	$0.1019	0.0348%
417	3470	W A Parish	TX	$3,543.129	$0.1019	0.0019%	$3,543.126	$0.1019	0.0018%	$3,543.127	$0.1019	0.0018%
418	127	Oklaunion	TX	$643.649	$0.1020	0.1027%	$643.612	$0.1020	0.0970%	$643.623	$0.1020	0.0985%

Exhibit L2
Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option

Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
419	7097	J K Spruce	TX	$505.694	$0.1020	0.0533%	$505.503	$0.1019	0.0156%	$505.504	$0.1019	0.0159%
420	6181	J T Deely	TX	$831.549	$0.1019	0.0054%	$831.547	$0.1019	0.0051%	$831.547	$0.1019	0.0052%
421	6183	San Miguel	TX	$372.364	$0.1037	1.7886%	$365.821	$0.1019	0.0000%	$365.821	$0.1019	0.0000%
422	7902	Pirkey	TX	$646.415	$0.1023	0.3738%	$646.281	$0.1023	0.3530%	$646.318	$0.1023	0.3588%
423	6139	Welsh	TX	$1,493.907	$0.1019	0.0035%	$1,493.904	$0.1019	0.0033%	$1,493.905	$0.1019	0.0034%
424	6193	Harrington	TX	$963.974	$0.1019	0.0000%	$963.974	$0.1019	0.0000%	$963.974	$0.1019	0.0000%
425	6194	Tolk	TX	$1,013.905	$0.1019	0.0000%	$1,013.905	$0.1019	0.0000%	$1,013.905	$0.1019	0.0000%
426	6136	Gibbons Creek	TX	$404.607	$0.1019	0.0158%	$404.603	$0.1019	0.0149%	$404.604	$0.1019	0.0152%
427	3497	Big Brown	TX	$1,059.869	$0.1019	0.0103%	$1,059.863	$0.1019	0.0097%	$1,059.865	$0.1019	0.0099%
428	6146	Martin Lake	TX	$2,125.027	$0.1019	0.0194%	$2,125.004	$0.1019	0.0183%	$2,125.010	$0.1019	0.0186%
429	6147	Monticello	TX	$1,767.148	$0.1019	0.0114%	$1,767.137	$0.1019	0.0108%	$1,767.140	$0.1019	0.0110%
430	6648	Sandow No 4	TX	$528.816	$0.1023	0.3783%	$528.705	$0.1023	0.3572%	$528.736	$0.1023	0.3631%
431	7790	Bonanza	UT	$303.651	$0.0693	0.4735%	$303.571	$0.0693	0.4471%	$303.593	$0.0693	0.4544%
432	6481	Intermountain Power Project	UT	$993.677	$0.0691	0.2165%	$993.557	$0.0691	0.2044%	$993.590	$0.0691	0.2078%
433	3644	Carbon	UT	$114.021	$0.0691	0.1504%	$114.012	$0.0691	0.1420%	$114.014	$0.0691	0.1444%
434	6165	Hunter	UT	$892.410	$0.0692	0.2595%	$892.281	$0.0692	0.2450%	$892.316	$0.0692	0.2490%
435	8069	Huntington	UT	$604.980	$0.0694	0.5484%	$604.796	$0.0694	0.5179%	$604.847	$0.0694	0.5263%
436	50951	Sunnyside Cogen Associates	UT	$36.264	$0.0711	3.0508%	$36.204	$0.0710	2.8810%	$36.220	$0.0710	2.9279%
437	3775	Clinch River	VA	$571.584	$0.0916	0.0000%	$571.584	$0.0916	0.0000%	$571.584	$0.0916	0.0000%
438	3776	Glen Lyn	VA	$271.428	$0.0917	0.1077%	$271.412	$0.0917	0.1017%	$271.416	$0.0917	0.1034%
439	54304	Birchwood Power	VA	$207.620	$0.0919	0.2919%	$207.016	$0.0916	0.0000%	$207.016	$0.0916	0.0000%
440	10071	Cogentrix Virginia Leasing Corporation	VA	$92.731	$0.0918	0.2325%	$92.516	$0.0916	0.0000%	$92.516	$0.0916	0.0000%
441	10377	James River Cogeneration	VA	$92.752	$0.0918	0.2547%	$92.516	$0.0916	0.0000%	$92.516	$0.0916	0.0000%
442	3788	Potomac River	VA	$412.200	$0.0916	0.0000%	$412.200	$0.0916	0.0000%	$412.200	$0.0916	0.0000%
443	54081	Spruance Genco LLC	VA	$184.925	$0.0920	0.4395%	$184.116	$0.0916	0.0000%	$184.116	$0.0916	0.0000%
444	10773	Altavista Power Station	VA	$56.894	$0.0918	0.1790%	$56.792	$0.0916	0.0000%	$56.792	$0.0916	0.0000%
445	3796	Bremo Bluff	VA	$205.329	$0.0921	0.5195%	$205.270	$0.0920	0.4906%	$205.286	$0.0921	0.4986%
446	3803	Chesapeake	VA	$653.041	$0.0918	0.2710%	$651.708	$0.0917	0.0663%	$651.715	$0.0917	0.0674%
447	3797	Chesterfield	VA	$1,446.824	$0.0918	0.2222%	$1,446.645	$0.0918	0.2098%	$1,446.695	$0.0918	0.2133%
448	7213	Clover	VA	$680.588	$0.0916	0.0000%	$680.588	$0.0916	0.0000%	$680.588	$0.0916	0.0000%
449	10771	Hopewell Power Station	VA	$56.864	$0.0917	0.1270%	$56.792	$0.0916	0.0000%	$56.792	$0.0916	0.0000%
450	52007	Mecklenburg Power Station	VA	$111.752	$0.0916	0.0000%	$111.752	$0.0916	0.0000%	$111.752	$0.0916	0.0000%
451	10774	Southampton Power Station	VA	$56.792	$0.0916	0.0000%	$56.792	$0.0916	0.0000%	$56.792	$0.0916	0.0000%
452	3809	Yorktown	VA	$1,008.516	$0.0916	0.0000%	$1,008.516	$0.0916	0.0000%	$1,008.516	$0.0916	0.0000%
453	3845	Transalta Centralia Generation	WA	$1,067.724	$0.0684	0.0000%	$1,067.724	$0.0684	0.0000%	$1,067.724	$0.0684	0.0000%
454	4127	Menasha	WI	$23.169	$0.0927	0.9542%	$23.157	$0.0926	0.9011%	$23.160	$0.0926	0.9158%
455	4140	Alma	WI	$145.998	$0.0918	0.0245%	$145.996	$0.0918	0.0232%	$145.996	$0.0918	0.0235%
456	4143	Genoa	WI	$278.154	$0.0918	0.0000%	$278.154	$0.0918	0.0000%	$278.154	$0.0918	0.0000%
457	4271	John P Madgett	WI	$311.989	$0.0920	0.2528%	$311.945	$0.0920	0.2387%	$311.957	$0.0920	0.2426%
458	3992	Blount Street	WI	$142.293	$0.0918	0.0018%	$142.290	$0.0918	0.0000%	$142.290	$0.0918	0.0000%
459	4125	Manitowoc	WI	$111.473	$0.0921	0.3555%	$111.451	$0.0921	0.3357%	$111.457	$0.0921	0.3412%
460	4146	E J Stoneman Station	WI	$42.389	$0.0922	0.3818%	$42.380	$0.0921	0.3606%	$42.383	$0.0921	0.3664%
461	3982	Bay Front	WI	$55.124	$0.0919	0.0807%	$55.080	$0.0918	0.0000%	$55.080	$0.0918	0.0000%

Exhibit L2
Plant-by-Plant Estimate of Potential Electricity Price Impact Without Land Treatment Dewatering Sub-Option

Plant Identity				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
462	7549	Milwaukee County	WI	$9.402	$0.0940	2.4226%	$9.390	$0.0939	2.2878%	$9.393	$0.0939	2.3250%
463	6170	Pleasant Prairie	WI	$993.276	$0.0918	0.0000%	$993.276	$0.0918	0.0000%	$993.276	$0.0918	0.0000%
464	4041	South Oak Creek	WI	$973.998	$0.0918	0.0000%	$973.998	$0.0918	0.0000%	$973.998	$0.0918	0.0000%
465	4042	Valley	WI	$221.238	$0.0918	0.0000%	$221.238	$0.0918	0.0000%	$221.238	$0.0918	0.0000%
466	8023	Columbia	WI	$824.510	$0.0920	0.2410%	$824.400	$0.0920	0.2276%	$824.430	$0.0920	0.2313%
467	4050	Edgewater	WI	$619.661	$0.0918	0.0018%	$619.661	$0.0918	0.0017%	$619.661	$0.0918	0.0017%
468	4054	Nelson Dewey	WI	$160.650	$0.0918	0.0000%	$160.650	$0.0918	0.0000%	$160.650	$0.0918	0.0000%
469	4072	Pulliam	WI	$354.348	$0.0918	0.0000%	$354.348	$0.0918	0.0000%	$354.348	$0.0918	0.0000%
470	4078	Weston	WI	$457.164	$0.0918	0.0000%	$457.164	$0.0918	0.0000%	$457.164	$0.0918	0.0000%
471	3944	Harrison Power Station	WV	$1,202.475	$0.0669	0.1174%	$1,202.396	$0.0669	0.1109%	$1,202.418	$0.0669	0.1127%
472	6004	Pleasants Power Station	WV	$805.673	$0.0673	0.6759%	$805.372	$0.0672	0.6383%	$805.455	$0.0672	0.6487%
473	10151	Grant Town Power Plant	WV	$56.854	$0.0677	1.3231%	$56.813	$0.0676	1.2495%	$56.824	$0.0676	1.2698%
474	3935	John E Amos	WV	$1,725.139	$0.0672	0.5272%	$1,724.635	$0.0671	0.4978%	$1,724.774	$0.0671	0.5059%
475	3936	Kanawha River	WV	$257.258	$0.0668	0.0303%	$257.254	$0.0668	0.0287%	$257.255	$0.0668	0.0291%
476	6264	Mountaineer	WV	$763.150	$0.0670	0.3020%	$763.022	$0.0670	0.2852%	$763.057	$0.0670	0.2899%
477	3938	Philip Sporn	WV	$649.730	$0.0671	0.4804%	$649.557	$0.0671	0.4536%	$649.605	$0.0671	0.4610%
478	3942	Albright	WV	$163.747	$0.0671	0.4633%	$163.705	$0.0671	0.4375%	$163.717	$0.0671	0.4446%
479	3943	Fort Martin Power Station	WV	$675.082	$0.0669	0.1587%	$674.034	$0.0668	0.0033%	$674.034	$0.0668	0.0033%
480	3945	Rivesville	WV	$64.543	$0.0672	0.6469%	$64.520	$0.0672	0.6109%	$64.526	$0.0672	0.6208%
481	3946	Willow Island	WV	$125.201	$0.0670	0.2279%	$125.185	$0.0669	0.2152%	$125.189	$0.0669	0.2187%
482	10743	Morgantown Energy Facility	WV	$40.628	$0.0677	1.3666%	$40.597	$0.0677	1.2905%	$40.606	$0.0677	1.3115%
483	3947	Kammer	WV	$417.233	$0.0669	0.0962%	$417.211	$0.0669	0.0908%	$417.217	$0.0669	0.0923%
484	3948	Mitchell	WV	$981.177	$0.0686	2.7153%	$979.734	$0.0685	2.5641%	$980.132	$0.0685	2.6058%
485	3954	Mt Storm	WV	$990.909	$0.0673	0.7742%	$988.486	$0.0672	0.5278%	$988.570	$0.0672	0.5364%
486	7537	North Branch	WV	$48.842	$0.0698	4.4515%	$48.726	$0.0696	4.2037%	$48.758	$0.0697	4.2721%
487	6204	Laramie River Station	WY	$904.063	$0.0604	0.2514%	$903.937	$0.0603	0.2374%	$903.971	$0.0603	0.2412%
488	4150	Neil Simpson	WY	$11.473	$0.0604	0.3030%	$11.438	$0.0602	0.0000%	$11.438	$0.0602	0.0000%
489	7504	Neil Simpson II	WY	$63.934	$0.0609	1.1452%	$63.894	$0.0609	1.0814%	$63.905	$0.0609	1.0990%
490	4151	Osage	WY	$18.224	$0.0607	0.9076%	$18.215	$0.0607	0.8570%	$18.217	$0.0607	0.8710%
491	55479	Wygen 1	WY	$46.354	$0.0602	0.0000%	$46.354	$0.0602	0.0000%	$46.354	$0.0602	0.0000%
492	4158	Dave Johnston	WY	$430.624	$0.0602	0.0450%	$430.613	$0.0602	0.0425%	$430.616	$0.0602	0.0432%
493	8066	Jim Bridger	WY	$1,228.307	$0.0605	0.5112%	$1,227.959	$0.0605	0.4827%	$1,228.055	$0.0605	0.4905%
494	4162	Naughton	WY	$374.145	$0.0603	0.2425%	$374.095	$0.0603	0.2290%	$374.109	$0.0603	0.2327%
495	6101	Wyodak	WY	$192.178	$0.0606	0.7040%	$191.169	$0.0603	0.1757%	$191.175	$0.0603	0.1785%
				$286,460	$0.0886	**0.2092%**	$286,354	$0.0885	**0.1721%**	$286,362	$0.0885	**0.1749%**

Exhibit L3
Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option

				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
1	79	Aurora Energy LLC Chena	AK	$37.023	$0.1543	1.6225%	$36.990	$0.1541	1.5322%	$36.999	$0.1542	1.5571%
2	6288	Healy	AK	$41.400	$0.1533	1.0099%	$41.377	$0.1532	0.9537%	$41.383	$0.1533	0.9692%
3	56	Charles R Lowman	AL	$406.464	$0.0863	0.8156%	$405.902	$0.0862	0.6761%	$405.906	$0.0862	0.6771%
4	3	Barry	AL	$2,028.618	$0.0867	1.2770%	$2,028.375	$0.0867	1.2648%	$2,028.442	$0.0867	1.2682%
5	26	E C Gaston	AL	$1,525.805	$0.0856	0.0271%	$1,525.782	$0.0856	0.0256%	$1,525.789	$0.0856	0.0260%
6	7	Gadsden	AL	$106.417	$0.0879	2.7433%	$106.401	$0.0879	2.7279%	$106.406	$0.0879	2.7322%
7	8	Gorgas	AL	$1,090.673	$0.0879	2.6713%	$1,090.365	$0.0879	2.6423%	$1,090.450	$0.0879	2.6503%
8	10	Greene County	AL	$987.995	$0.0875	2.2321%	$987.679	$0.0875	2.1993%	$987.766	$0.0875	2.2083%
9	6002	James H Miller Jr	AL	$2,122.988	$0.0859	0.3287%	$2,122.857	$0.0859	0.3226%	$2,122.893	$0.0859	0.3243%
10	50407	Mobile Energy Services LLC	AL	$32.589	$0.0858	0.1890%	$32.539	$0.0856	0.0351%	$32.540	$0.0856	0.0357%
11	47	Colbert	AL	$1,372.570	$0.0858	0.2168%	$1,372.524	$0.0858	0.2135%	$1,372.536	$0.0858	0.2144%
12	50	Widows Creek	AL	$1,542.066	$0.0894	4.4941%	$1,541.931	$0.0894	4.4850%	$1,541.968	$0.0894	4.4875%
13	6641	Independence	AR	$1,137.217	$0.0764	0.2291%	$1,137.072	$0.0764	0.2163%	$1,137.112	$0.0764	0.2198%
14	6009	White Bluff	AR	$1,137.857	$0.0764	0.2855%	$1,137.677	$0.0764	0.2696%	$1,137.727	$0.0764	0.2740%
15	6138	Flint Creek	AR	$374.519	$0.0766	0.5101%	$374.494	$0.0766	0.5034%	$374.501	$0.0766	0.5052%
16	160	Apache Station	AZ	$588.021	$0.1016	1.3553%	$587.721	$0.1015	1.3036%	$587.804	$0.1015	1.3179%
17	113	Cholla	AZ	$1,014.925	$0.1026	2.4165%	$1,014.835	$0.1026	2.4074%	$1,014.860	$0.1026	2.4099%
18	6177	Coronado	AZ	$729.235	$0.1013	1.0805%	$729.038	$0.1013	1.0532%	$729.092	$0.1013	1.0607%
19	4941	Navajo	AZ	$2,131.843	$0.1010	0.7858%	$2,130.918	$0.1009	0.7421%	$2,131.173	$0.1010	0.7541%
20	126	H Wilson Sundt Generating Station	AZ	$490.142	$0.1002	0.0335%	$490.101	$0.1002	0.0252%	$490.103	$0.1002	0.0256%
21	8223	Springerville	AZ	$1,157.817	$0.1013	1.0941%	$1,157.120	$0.1012	1.0332%	$1,157.312	$0.1013	1.0500%
22	10002	ACE Cogeneration Facility	CA	$127.017	$0.1337	0.0016%	$127.015	$0.1337	0.0000%	$127.015	$0.1337	0.0000%
23	10640	Stockton Cogen	CA	$72.127	$0.1361	1.7868%	$72.057	$0.1360	1.6874%	$72.076	$0.1360	1.7148%
24	54238	Port of Stockton District Energy Fac	CA	$63.377	$0.1348	0.8556%	$63.347	$0.1348	0.8079%	$63.355	$0.1348	0.8211%
25	54626	Mt Poso Cogeneration	CA	$72.765	$0.1347	0.7847%	$72.733	$0.1347	0.7410%	$72.742	$0.1347	0.7530%
26	10768	Rio Bravo Jasmin	CA	$44.447	$0.1347	0.7399%	$44.429	$0.1346	0.6987%	$44.434	$0.1346	0.7101%
27	10769	Rio Bravo Poso	CA	$44.441	$0.1347	0.7249%	$44.423	$0.1346	0.6846%	$44.428	$0.1346	0.6957%
28	462	W N Clark	CO	$30.393	$0.0800	0.3531%	$30.286	$0.0797	0.0000%	$30.286	$0.0797	0.0000%
29	10003	Colorado Energy Nations Company	CO	$24.841	$0.0801	0.5409%	$24.707	$0.0797	0.0000%	$24.707	$0.0797	0.0000%
30	492	Martin Drake	CO	$179.325	$0.0797	0.0000%	$179.325	$0.0797	0.0000%	$179.325	$0.0797	0.0000%
31	8219	Ray D Nixon	CO	$194.468	$0.0797	0.0000%	$194.468	$0.0797	0.0000%	$194.468	$0.0797	0.0000%
32	6761	Rawhide	CO	$454.986	$0.0798	0.1532%	$454.971	$0.0798	0.1499%	$454.975	$0.0798	0.1508%
33	465	Arapahoe	CO	$111.774	$0.0798	0.1735%	$111.580	$0.0797	0.0000%	$111.580	$0.0797	0.0000%
34	468	Cameo	CO	$46.398	$0.0800	0.3710%	$46.226	$0.0797	0.0000%	$46.226	$0.0797	0.0000%
35	469	Cherokee	CO	$564.928	$0.0799	0.2572%	$563.479	$0.0797	0.0000%	$563.479	$0.0797	0.0000%
36	470	Comanche	CO	$543.554	$0.0797	0.0000%	$543.554	$0.0797	0.0000%	$543.554	$0.0797	0.0000%
37	525	Hayden	CO	$325.176	$0.0797	0.0000%	$325.176	$0.0797	0.0000%	$325.176	$0.0797	0.0000%
38	6248	Pawnee	CO	$385.748	$0.0797	0.0000%	$385.748	$0.0797	0.0000%	$385.748	$0.0797	0.0000%

Exhibit L3 Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option												
				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
39	477	Valmont	CO	$165.796	$0.0797	0.0120%	$165.776	$0.0797	0.0000%	$165.776	$0.0797	0.0000%
40	6021	Craig	CO	$936.997	$0.0799	0.2264%	$934.881	$0.0797	0.0000%	$934.881	$0.0797	0.0000%
41	527	Nucla	CO	$79.700	$0.0797	0.0000%	$79.700	$0.0797	0.0000%	$79.700	$0.0797	0.0000%
42	10675	AES Thames	CT	$320.908	$0.1716	0.2387%	$320.144	$0.1712	0.0000%	$320.144	$0.1712	0.0000%
43	568	Bridgeport Station	CT	$871.526	$0.1712	0.0136%	$871.408	$0.1712	0.0000%	$871.408	$0.1712	0.0000%
44	593	Edge Moor	DE	$769.174	$0.1237	0.0497%	$768.792	$0.1236	0.0000%	$768.792	$0.1236	0.0000%
45	594	Indian River Generating Station	DE	$867.269	$0.1239	0.2391%	$867.154	$0.1239	0.2258%	$867.186	$0.1239	0.2295%
46	10030	NRG Energy Center Dover	DE	$127.611	$0.1239	0.2381%	$127.594	$0.1239	0.2249%	$127.599	$0.1239	0.2285%
47	10333	Central Power & Lime	FL	$124.960	$0.1136	0.0000%	$124.960	$0.1136	0.0000%	$124.960	$0.1136	0.0000%
48	676	C D McIntosh Jr	FL	$990.422	$0.1137	0.0977%	$990.369	$0.1137	0.0922%	$990.384	$0.1137	0.0937%
49	663	Deerhaven Generating Station	FL	$469.236	$0.1136	0.0145%	$469.232	$0.1136	0.0137%	$469.233	$0.1136	0.0139%
50	641	Crist	FL	$1,129.184	$0.1136	0.0000%	$1,129.184	$0.1136	0.0000%	$1,129.184	$0.1136	0.0000%
51	643	Lansing Smith	FL	$1,001.859	$0.1142	0.5607%	$1,001.841	$0.1142	0.5590%	$1,001.846	$0.1142	0.5595%
52	642	Scholz	FL	$97.696	$0.1136	0.0000%	$97.696	$0.1136	0.0000%	$97.696	$0.1136	0.0000%
53	667	Northside Generating Station	FL	$1,403.608	$0.1138	0.2084%	$1,403.445	$0.1138	0.1968%	$1,403.490	$0.1138	0.2000%
54	207	St Johns River Power Park	FL	$1,353.835	$0.1138	0.1475%	$1,353.724	$0.1138	0.1393%	$1,353.754	$0.1138	0.1416%
55	564	Stanton Energy Center	FL	$926.966	$0.1139	0.2446%	$926.840	$0.1139	0.2310%	$926.875	$0.1139	0.2347%
56	628	Crystal River	FL	$3,317.431	$0.1136	0.0094%	$3,317.414	$0.1136	0.0089%	$3,317.419	$0.1136	0.0090%
57	136	Seminole	FL	$1,425.443	$0.1139	0.2229%	$1,425.262	$0.1138	0.2102%	$1,425.310	$0.1138	0.2136%
58	645	Big Bend	FL	$1,988.321	$0.1136	0.0161%	$1,988.318	$0.1136	0.0160%	$1,988.319	$0.1136	0.0160%
59	7242	Polk	FL	$1,025.638	$0.1137	0.0943%	$1,025.584	$0.1137	0.0890%	$1,025.599	$0.1137	0.0905%
60	10672	Cedar Bay Generating Company LP	FL	$290.909	$0.1141	0.4243%	$289.680	$0.1136	0.0000%	$289.680	$0.1136	0.0000%
61	50976	Indiantown Cogeneration LP	FL	$394.106	$0.1139	0.2671%	$393.056	$0.1136	0.0000%	$393.056	$0.1136	0.0000%
62	753	Crisp Plant	GA	$12.895	$0.0860	0.0794%	$12.894	$0.0860	0.0708%	$12.894	$0.0860	0.0720%
63	703	Bowen	GA	$2,680.996	$0.0865	0.6471%	$2,680.426	$0.0864	0.6257%	$2,680.583	$0.0864	0.6316%
64	708	Hammond	GA	$717.749	$0.0860	0.0675%	$717.722	$0.0860	0.0638%	$717.730	$0.0860	0.0648%
65	709	Harllee Branch	GA	$1,346.777	$0.0880	2.4734%	$1,346.704	$0.0880	2.4679%	$1,346.725	$0.0880	2.4694%
66	710	Jack McDonough	GA	$512.965	$0.0859	0.0277%	$512.957	$0.0859	0.0262%	$512.959	$0.0859	0.0266%
67	733	Kraft	GA	$266.599	$0.0863	0.4399%	$266.382	$0.0862	0.3583%	$266.385	$0.0862	0.3595%
68	6124	McIntosh	GA	$744.613	$0.0861	0.2123%	$744.587	$0.0861	0.2089%	$744.594	$0.0861	0.2099%
69	727	Mitchell	GA	$217.327	$0.0859	0.0000%	$217.327	$0.0859	0.0000%	$217.327	$0.0859	0.0000%
70	6257	Scherer	GA	$2,721.101	$0.0872	1.4656%	$2,720.877	$0.0872	1.4572%	$2,720.939	$0.0872	1.4595%
71	6052	Wansley	GA	$1,515.285	$0.0884	2.9178%	$1,515.133	$0.0884	2.9074%	$1,515.175	$0.0884	2.9103%
72	728	Yates	GA	$1,119.890	$0.0859	0.0547%	$1,119.856	$0.0859	0.0517%	$1,119.865	$0.0859	0.0525%
73	10673	AES Hawaii	HI	$337.040	$0.1893	0.0783%	$336.776	$0.1892	0.0000%	$336.776	$0.1892	0.0000%
74	10604	Hawaiian Comm & Sugar Puunene Mill	HI	$76.428	$0.1911	0.9879%	$76.386	$0.1910	0.9329%	$76.398	$0.1910	0.9481%
75	1122	Ames Electric Services Power Plant	IA	$67.471	$0.0710	0.0304%	$67.469	$0.0710	0.0287%	$67.470	$0.0710	0.0292%
76	1167	Muscatine Plant #1	IA	$182.476	$0.0710	0.0035%	$182.476	$0.0710	0.0033%	$182.476	$0.0710	0.0033%

Exhibit L3
Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option

				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
77	1131	Streeter Station	IA	$31.954	$0.0710	0.0110%	$31.953	$0.0710	0.0104%	$31.953	$0.0710	0.0106%
78	1218	Fair Station	IA	$39.117	$0.0711	0.1718%	$39.113	$0.0711	0.1622%	$39.114	$0.0711	0.1649%
79	1217	Earl F Wisdom	IA	$88.750	$0.0710	0.0000%	$88.750	$0.0710	0.0000%	$88.750	$0.0710	0.0000%
80	1104	Burlington	IA	$188.150	$0.0710	0.0000%	$188.150	$0.0710	0.0000%	$188.150	$0.0710	0.0000%
81	1046	Dubuque	IA	$53.275	$0.0710	0.0474%	$53.274	$0.0710	0.0448%	$53.274	$0.0710	0.0455%
82	1047	Lansing	IA	$204.517	$0.0718	1.0707%	$204.474	$0.0717	1.0498%	$204.480	$0.0717	1.0525%
83	1048	Milton L Kapp	IA	$135.610	$0.0710	0.0000%	$135.610	$0.0710	0.0000%	$135.610	$0.0710	0.0000%
84	6254	Ottumwa	IA	$451.560	$0.0710	0.0000%	$451.560	$0.0710	0.0000%	$451.560	$0.0710	0.0000%
85	1073	Prairie Creek	IA	$151.940	$0.0710	0.0000%	$151.940	$0.0710	0.0000%	$151.940	$0.0710	0.0000%
86	1058	Sixth Street	IA	$40.509	$0.0711	0.0952%	$40.506	$0.0711	0.0899%	$40.507	$0.0711	0.0913%
87	1077	Sutherland	IA	$97.270	$0.0710	0.0000%	$97.270	$0.0710	0.0000%	$97.270	$0.0710	0.0000%
88	1091	George Neal North	IA	$657.148	$0.0717	1.0438%	$656.980	$0.0717	1.0179%	$657.026	$0.0717	1.0250%
89	7343	George Neal South	IA	$398.502	$0.0710	0.0481%	$398.491	$0.0710	0.0455%	$398.494	$0.0710	0.0462%
90	6664	Louisa	IA	$508.619	$0.0715	0.7545%	$508.503	$0.0715	0.7315%	$508.535	$0.0715	0.7378%
91	1081	Riverside	IA	$88.134	$0.0711	0.1070%	$88.040	$0.0710	0.0000%	$88.040	$0.0710	0.0000%
92	1082	Walter Scott Jr Energy Center	IA	$1,117.656	$0.0717	1.0375%	$1,117.453	$0.0717	1.0191%	$1,117.509	$0.0717	1.0242%
93	1175	Pella	IA	$23.430	$0.0710	0.0000%	$23.430	$0.0710	0.0000%	$23.430	$0.0710	0.0000%
94	861	Coffeen	IL	$814.536	$0.0925	0.0604%	$814.044	$0.0924	0.0000%	$814.044	$0.0924	0.0000%
95	863	Hutsonville	IL	$126.563	$0.0944	2.2184%	$126.539	$0.0944	2.1994%	$126.546	$0.0944	2.2046%
96	864	Meredosia	IL	$367.668	$0.0936	1.2491%	$367.616	$0.0935	1.2347%	$367.630	$0.0935	1.2387%
97	6017	Newton	IL	$1,009.166	$0.0933	0.9400%	$1,009.098	$0.0933	0.9332%	$1,009.117	$0.0933	0.9351%
98	6016	Duck Creek	IL	$376.224	$0.0975	5.4843%	$375.907	$0.0974	5.3953%	$375.995	$0.0974	5.4199%
99	856	E D Edwards	IL	$636.836	$0.0931	0.7627%	$636.277	$0.0930	0.6742%	$636.283	$0.0930	0.6751%
100	963	Dallman	IL	$247.484	$0.0948	2.6208%	$247.433	$0.0948	2.5996%	$247.447	$0.0948	2.6055%
101	964	Lakeside	IL	$64.739	$0.0925	0.0912%	$64.680	$0.0924	0.0000%	$64.680	$0.0924	0.0000%
102	876	Kincaid Generation LLC	IL	$1,067.627	$0.0924	0.0382%	$1,067.220	$0.0924	0.0000%	$1,067.220	$0.0924	0.0000%
103	889	Baldwin Energy Complex	IL	$1,544.704	$0.0931	0.7690%	$1,544.531	$0.0931	0.7577%	$1,544.579	$0.0931	0.7608%
104	891	Havana	IL	$589.052	$0.0936	1.3517%	$588.974	$0.0936	1.3382%	$588.995	$0.0936	1.3419%
105	892	Hennepin Power Station	IL	$249.420	$0.0931	0.7221%	$249.407	$0.0931	0.7170%	$249.411	$0.0931	0.7184%
106	897	Vermilion	IL	$161.027	$0.0931	0.7349%	$161.018	$0.0931	0.7297%	$161.021	$0.0931	0.7312%
107	898	Wood River	IL	$527.112	$0.0926	0.2579%	$527.096	$0.0926	0.2548%	$527.100	$0.0926	0.2557%
108	887	Joppa Steam	IL	$889.812	$0.0924	0.0000%	$889.812	$0.0924	0.0000%	$889.812	$0.0924	0.0000%
109	867	Crawford	IL	$483.349	$0.0924	0.0201%	$483.252	$0.0924	0.0000%	$483.252	$0.0924	0.0000%
110	886	Fisk Street	IL	$536.891	$0.0924	0.0087%	$536.844	$0.0924	0.0000%	$536.844	$0.0924	0.0000%
111	384	Joliet 29	IL	$1,068.144	$0.0924	0.0000%	$1,068.144	$0.0924	0.0000%	$1,068.144	$0.0924	0.0000%
112	874	Joliet 9	IL	$291.984	$0.0924	0.0000%	$291.984	$0.0924	0.0000%	$291.984	$0.0924	0.0000%
113	879	Powerton	IL	$1,445.785	$0.0924	0.0449%	$1,445.136	$0.0924	0.0000%	$1,445.136	$0.0924	0.0000%
114	883	Waukegan	IL	$642.509	$0.0924	0.0513%	$642.180	$0.0924	0.0000%	$642.180	$0.0924	0.0000%
115	884	Will County	IL	$1,027.056	$0.0924	0.0479%	$1,026.564	$0.0924	0.0000%	$1,026.564	$0.0924	0.0000%
116	976	Marion	IL	$344.453	$0.0931	0.7527%	$341.880	$0.0924	0.0000%	$341.880	$0.0924	0.0000%
117	6238	Pearl Station	IL	$37.142	$0.0929	0.4920%	$37.132	$0.0928	0.4646%	$37.135	$0.0928	0.4722%

Exhibit L3
Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option

				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
118	55245	Tuscola Station	IL	$15.056	$0.0941	1.8421%	$15.041	$0.0940	1.7395%	$15.045	$0.0940	1.7678%
119	6705	Warrick	IN	$529.176	$0.0801	4.5130%	$528.914	$0.0800	4.4611%	$528.986	$0.0800	4.4754%
120	992	CC Perry K	IN	$13.857	$0.0770	0.4995%	$13.796	$0.0766	0.0574%	$13.796	$0.0766	0.0583%
121	6225	Jasper 2	IN	$9.971	$0.0767	0.1330%	$9.964	$0.0766	0.0651%	$9.965	$0.0767	0.0662%
122	1032	Logansport	IN	$40.644	$0.0767	0.1135%	$40.610	$0.0766	0.0286%	$40.610	$0.0766	0.0290%
123	1040	Whitewater Valley	IN	$62.873	$0.0767	0.0975%	$62.870	$0.0767	0.0920%	$62.871	$0.0767	0.0935%
124	1024	Crawfordsville	IN	$16.877	$0.0767	0.1459%	$16.865	$0.0767	0.0796%	$16.866	$0.0767	0.0809%
125	1001	Cayuga	IN	$820.754	$0.0785	2.5340%	$820.505	$0.0785	2.5028%	$820.573	$0.0785	2.5114%
126	1004	Edwardsport	IN	$97.704	$0.0775	1.2304%	$97.685	$0.0775	1.2116%	$97.690	$0.0775	1.2168%
127	6113	Gibson	IN	$2,313.576	$0.0791	3.2593%	$2,313.256	$0.0791	3.2450%	$2,313.344	$0.0791	3.2489%
128	1008	R Gallagher	IN	$413.330	$0.0786	2.5846%	$413.274	$0.0786	2.5707%	$413.289	$0.0786	2.5746%
129	1010	Wabash River	IN	$808.247	$0.0787	2.7413%	$807.848	$0.0787	2.6906%	$807.958	$0.0787	2.7046%
130	1043	Frank E Ratts	IN	$159.556	$0.0782	2.1069%	$159.539	$0.0782	2.0958%	$159.544	$0.0782	2.0989%
131	6213	Merom	IN	$724.676	$0.0766	0.0055%	$724.674	$0.0766	0.0052%	$724.675	$0.0766	0.0053%
132	6166	Rockport	IN	$1,747.582	$0.0767	0.1510%	$1,747.485	$0.0767	0.1454%	$1,747.512	$0.0767	0.1469%
133	988	Tanners Creek	IN	$751.083	$0.0779	1.7144%	$750.965	$0.0779	1.6984%	$750.998	$0.0779	1.7028%
134	983	Clifty Creek	IN	$877.005	$0.0768	0.2552%	$876.965	$0.0768	0.2506%	$876.974	$0.0768	0.2517%
135	994	AES Petersburg	IN	$1,265.942	$0.0768	0.2832%	$1,262.374	$0.0766	0.0005%	$1,262.374	$0.0766	0.0005%
136	991	Eagle Valley	IN	$265.971	$0.0766	0.0636%	$265.962	$0.0766	0.0601%	$265.964	$0.0766	0.0611%
137	990	Harding Street	IN	$809.330	$0.0780	1.7887%	$809.273	$0.0780	1.7815%	$809.289	$0.0780	1.7835%
138	995	Bailly	IN	$431.202	$0.0767	0.1650%	$431.075	$0.0767	0.1354%	$431.084	$0.0767	0.1376%
139	997	Michigan City	IN	$362.513	$0.0766	0.0539%	$362.503	$0.0766	0.0509%	$362.506	$0.0766	0.0518%
140	6085	R M Schahfer	IN	$1,477.294	$0.0766	0.0302%	$1,477.280	$0.0766	0.0292%	$1,477.284	$0.0766	0.0295%
141	1037	Peru	IN	$24.540	$0.0767	0.1147%	$24.529	$0.0767	0.0711%	$24.530	$0.0767	0.0722%
142	6137	A B Brown	IN	$488.247	$0.0789	2.9721%	$488.153	$0.0789	2.9525%	$488.179	$0.0789	2.9579%
143	1012	F B Culley	IN	$251.108	$0.0777	1.4915%	$250.502	$0.0776	1.2465%	$250.509	$0.0776	1.2492%
144	981	State Line Energy	IN	$412.210	$0.0766	0.0249%	$412.108	$0.0766	0.0000%	$412.108	$0.0766	0.0000%
145	1239	Riverton	KS	$203.121	$0.0822	0.0431%	$203.117	$0.0822	0.0407%	$203.118	$0.0822	0.0413%
146	6064	Nearman Creek	KS	$256.786	$0.0826	0.4476%	$256.733	$0.0826	0.4268%	$256.738	$0.0826	0.4289%
147	1295	Quindaro	KS	$279.686	$0.0823	0.0737%	$279.480	$0.0822	0.0000%	$279.480	$0.0822	0.0000%
148	1241	La Cygne	KS	$1,138.097	$0.0824	0.1842%	$1,137.980	$0.0823	0.1740%	$1,138.012	$0.0823	0.1768%
149	108	Holcomb	KS	$251.649	$0.0825	0.3746%	$251.597	$0.0825	0.3537%	$251.611	$0.0825	0.3595%
150	6068	Jeffrey Energy Center	KS	$1,574.160	$0.0832	1.2175%	$1,573.874	$0.0832	1.1992%	$1,573.952	$0.0832	1.2042%
151	1250	Lawrence Energy Center	KS	$407.725	$0.0822	0.0031%	$407.724	$0.0822	0.0030%	$407.724	$0.0822	0.0030%
152	1252	Tecumseh Energy Center	KS	$208.808	$0.0822	0.0094%	$208.806	$0.0822	0.0089%	$208.807	$0.0822	0.0090%
153	1374	Elmer Smith	KY	$250.590	$0.0643	0.3964%	$249.600	$0.0640	0.0000%	$249.600	$0.0640	0.0000%
154	6018	East Bend	KY	$390.153	$0.0666	4.0298%	$390.033	$0.0666	3.9978%	$390.067	$0.0666	4.0066%
155	1384	Cooper	KY	$192.861	$0.0641	0.1150%	$192.849	$0.0641	0.1086%	$192.853	$0.0641	0.1103%
156	1385	Dale	KY	$126.403	$0.0669	4.5001%	$126.350	$0.0669	4.4561%	$126.365	$0.0669	4.4681%
157	6041	H L Spurlock	KY	$725.593	$0.0648	1.2267%	$725.121	$0.0647	1.1609%	$725.251	$0.0648	1.1790%
158	1372	Henderson I	KY	$24.331	$0.0640	0.0466%	$24.331	$0.0640	0.0440%	$24.331	$0.0640	0.0447%

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				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
159	1353	Big Sandy	KY	$643.319	$0.0669	4.5980%	$642.990	$0.0669	4.5444%	$643.081	$0.0669	4.5592%
160	1355	E W Brown	KY	$975.342	$0.0647	1.1262%	$975.323	$0.0647	1.1242%	$975.328	$0.0647	1.1248%
161	1356	Ghent	KY	$1,307.413	$0.0670	4.7607%	$1,306.754	$0.0670	4.7078%	$1,306.936	$0.0670	4.7224%
162	1357	Green River	KY	$108.257	$0.0656	2.5161%	$108.237	$0.0656	2.4969%	$108.242	$0.0656	2.5022%
163	1361	Tyrone	KY	$43.849	$0.0664	3.8102%	$43.839	$0.0664	3.7847%	$43.842	$0.0664	3.7917%
164	1363	Cane Run	KY	$375.139	$0.0648	1.2356%	$375.038	$0.0648	1.2086%	$375.066	$0.0648	1.2160%
165	1364	Mill Creek	KY	$976.617	$0.0649	1.4603%	$972.576	$0.0647	1.0406%	$972.660	$0.0647	1.0493%
166	6071	Trimble County	KY	$1,000.818	$0.0649	1.4123%	$1,000.806	$0.0649	1.4111%	$1,000.809	$0.0649	1.4114%
167	1378	Paradise	KY	$1,483.662	$0.0662	3.4459%	$1,483.222	$0.0662	3.4152%	$1,483.339	$0.0662	3.4233%
168	1379	Shawnee	KY	$986.354	$0.0643	0.5335%	$986.313	$0.0643	0.5293%	$986.323	$0.0643	0.5303%
169	6823	D B Wilson	KY	$252.795	$0.0657	2.5955%	$252.439	$0.0656	2.4510%	$252.538	$0.0656	2.4909%
170	1382	HMP&L Station Two Henderson	KY	$211.975	$0.0662	3.5034%	$211.627	$0.0661	3.3335%	$211.723	$0.0662	3.3804%
171	1381	Kenneth C Coleman	KY	$292.802	$0.0641	0.1100%	$292.784	$0.0641	0.1038%	$292.789	$0.0641	0.1055%
172	6639	R D Green	KY	$304.944	$0.0659	2.9104%	$304.555	$0.0658	2.7791%	$304.662	$0.0658	2.8154%
173	1383	Robert A Reid	KY	$109.478	$0.0640	0.0343%	$109.475	$0.0640	0.0324%	$109.476	$0.0640	0.0329%
174	51	Dolet Hills	LA	$477.184	$0.0756	1.1008%	$477.111	$0.0756	1.0854%	$477.131	$0.0756	1.0896%
175	6190	Rodemacher	LA	$657.492	$0.0748	0.0000%	$657.492	$0.0748	0.0000%	$657.492	$0.0748	0.0000%
176	1393	R S Nelson	LA	$1,046.452	$0.0748	0.0000%	$1,046.452	$0.0748	0.0000%	$1,046.452	$0.0748	0.0000%
177	6055	Big Cajun 2	LA	$1,236.564	$0.0754	0.8640%	$1,236.556	$0.0754	0.8633%	$1,236.558	$0.0754	0.8635%
178	1619	Brayton Point	MA	$2,161.698	$0.1534	0.0135%	$2,161.406	$0.1534	0.0000%	$2,161.406	$0.1534	0.0000%
179	1626	Salem Harbor	MA	$1,081.831	$0.1535	0.0333%	$1,081.470	$0.1534	0.0000%	$1,081.470	$0.1534	0.0000%
180	1606	Mount Tom	MA	$182.710	$0.1535	0.0901%	$182.546	$0.1534	0.0000%	$182.546	$0.1534	0.0000%
181	1613	Somerset Station	MA	$168.894	$0.1535	0.0912%	$168.740	$0.1534	0.0000%	$168.740	$0.1534	0.0000%
182	10678	AES Warrior Run Cogeneration Facility	MD	$266.450	$0.1326	0.7311%	$264.516	$0.1316	0.0000%	$264.516	$0.1316	0.0000%
183	1570	R Paul Smith Power Station	MD	$128.950	$0.1343	2.0694%	$128.910	$0.1343	2.0371%	$128.921	$0.1343	2.0460%
184	602	Brandon Shores	MD	$1,579.825	$0.1317	0.0396%	$1,579.200	$0.1316	0.0000%	$1,579.200	$0.1316	0.0000%
185	1552	C P Crane	MD	$479.495	$0.1317	0.0984%	$479.024	$0.1316	0.0000%	$479.024	$0.1316	0.0000%
186	1554	Herbert A Wagner	MD	$1,220.941	$0.1317	0.0827%	$1,219.932	$0.1316	0.0000%	$1,219.932	$0.1316	0.0000%
187	1571	Chalk Point LLC	MD	$3,052.526	$0.1316	0.0236%	$3,052.485	$0.1316	0.0223%	$3,052.496	$0.1316	0.0227%
188	1572	Dickerson	MD	$1,072.702	$0.1316	0.0151%	$1,072.693	$0.1316	0.0142%	$1,072.695	$0.1316	0.0145%
189	1573	Morgantown Generating Plant	MD	$1,784.599	$0.1316	0.0058%	$1,784.593	$0.1316	0.0055%	$1,784.595	$0.1316	0.0056%
190	10495	Rumford Cogeneration	ME	$110.552	$0.1228	0.5205%	$110.361	$0.1226	0.3464%	$110.367	$0.1226	0.3520%
191	1825	J B Sims	MI	$69.043	$0.0986	0.0328%	$69.041	$0.0986	0.0309%	$69.042	$0.0986	0.0314%
192	1830	James De Young	MI	$54.244	$0.0986	0.0250%	$54.243	$0.0986	0.0236%	$54.243	$0.0986	0.0240%
193	1843	Shiras	MI	$56.213	$0.0986	0.0202%	$56.213	$0.0986	0.0190%	$56.213	$0.0986	0.0194%
194	1695	B C Cobb	MI	$448.630	$0.0986	0.0000%	$448.630	$0.0986	0.0000%	$448.630	$0.0986	0.0000%
195	1702	Dan E Karn	MI	$1,689.300	$0.0991	0.4860%	$1,689.299	$0.0991	0.4859%	$1,689.300	$0.0991	0.4860%
196	1720	J C Weadock	MI	$291.895	$0.1007	2.0825%	$291.855	$0.1006	2.0685%	$291.866	$0.1006	2.0724%
197	1710	J H Campbell	MI	$1,369.580	$0.0986	0.0019%	$1,369.579	$0.0986	0.0018%	$1,369.579	$0.0986	0.0018%

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				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
198	1723	J R Whiting	MI	$314.816	$0.0987	0.0897%	$314.815	$0.0987	0.0892%	$314.815	$0.0987	0.0893%
199	6034	Belle River	MI	$1,437.618	$0.0986	0.0021%	$1,437.616	$0.0986	0.0020%	$1,437.617	$0.0986	0.0020%
200	1731	Harbor Beach	MI	$108.470	$0.0986	0.0088%	$108.469	$0.0986	0.0084%	$108.469	$0.0986	0.0085%
201	1733	Monroe	MI	$2,886.235	$0.1000	1.4633%	$2,885.929	$0.1000	1.4525%	$2,886.014	$0.1000	1.4555%
202	1740	River Rouge	MI	$570.915	$0.0986	0.0036%	$570.914	$0.0986	0.0034%	$570.914	$0.0986	0.0035%
203	1743	St Clair	MI	$1,356.763	$0.0986	0.0020%	$1,356.761	$0.0986	0.0019%	$1,356.762	$0.0986	0.0019%
204	1745	Trenton Channel	MI	$669.523	$0.0986	0.0043%	$669.521	$0.0986	0.0041%	$669.522	$0.0986	0.0041%
205	1831	Eckert Station	MI	$324.436	$0.0986	0.0129%	$324.394	$0.0986	0.0000%	$324.394	$0.0986	0.0000%
206	1832	Erickson Station	MI	$134.825	$0.0991	0.5436%	$134.775	$0.0991	0.5065%	$134.780	$0.0991	0.5101%
207	4259	Endicott Station	MI	$50.307	$0.0986	0.0420%	$50.306	$0.0986	0.0396%	$50.306	$0.0986	0.0403%
208	50835	TES Filer City Station	MI	$60.163	$0.0986	0.0280%	$60.162	$0.0986	0.0264%	$60.162	$0.0986	0.0268%
209	1771	Escanaba	MI	$35.557	$0.0988	0.1717%	$35.505	$0.0986	0.0244%	$35.505	$0.0986	0.0248%
210	10148	White Pine Electric Power	MI	$34.553	$0.0987	0.1246%	$34.518	$0.0986	0.0241%	$34.518	$0.0986	0.0245%
211	1769	Presque Isle	MI	$485.131	$0.0986	0.0038%	$485.130	$0.0986	0.0036%	$485.130	$0.0986	0.0037%
212	1866	Wyandotte	MI	$68.049	$0.0986	0.0216%	$68.048	$0.0986	0.0204%	$68.048	$0.0986	0.0207%
213	1961	Austin Northeast	MN	$22.514	$0.0804	0.0067%	$22.513	$0.0804	0.0063%	$22.513	$0.0804	0.0064%
214	2018	Virginia	MN	$20.911	$0.0804	0.0329%	$20.910	$0.0804	0.0311%	$20.911	$0.0804	0.0316%
215	1979	Hibbing	MN	$24.927	$0.0804	0.0135%	$24.927	$0.0804	0.0127%	$24.927	$0.0804	0.0129%
216	1893	Clay Boswell	MN	$779.458	$0.0829	3.1357%	$779.312	$0.0829	3.1164%	$779.353	$0.0829	3.1217%
217	1897	M L Hibbard	MN	$51.469	$0.0804	0.0254%	$51.456	$0.0804	0.0000%	$51.456	$0.0804	0.0000%
218	10686	Rapids Energy Center	MN	$20.111	$0.0804	0.0567%	$20.100	$0.0804	0.0000%	$20.100	$0.0804	0.0000%
219	1891	Syl Laskin	MN	$83.707	$0.0821	2.0712%	$83.696	$0.0821	2.0587%	$83.699	$0.0821	2.0621%
220	10075	Taconite Harbor Energy Center	MN	$177.725	$0.0804	0.0229%	$177.722	$0.0804	0.0216%	$177.723	$0.0804	0.0220%
221	2001	New Ulm	MN	$51.465	$0.0804	0.0168%	$51.464	$0.0804	0.0158%	$51.464	$0.0804	0.0161%
222	1915	Allen S King	MN	$421.310	$0.0804	0.0033%	$421.309	$0.0804	0.0031%	$421.309	$0.0804	0.0032%
223	1904	Black Dog	MN	$436.319	$0.0805	0.1264%	$436.308	$0.0805	0.1239%	$436.311	$0.0805	0.1246%
224	1927	Riverside	MN	$285.413	$0.0806	0.2799%	$285.396	$0.0806	0.2742%	$285.401	$0.0806	0.2758%
225	6090	Sherburne County	MN	$1,553.664	$0.0833	3.6149%	$1,552.737	$0.0833	3.5531%	$1,552.993	$0.0833	3.5701%
226	1943	Hoot Lake	MN	$91.665	$0.0804	0.0096%	$91.664	$0.0804	0.0090%	$91.664	$0.0804	0.0092%
227	2008	Silver Lake	MN	$69.976	$0.0804	0.0405%	$69.975	$0.0804	0.0383%	$69.975	$0.0804	0.0389%
228	2022	Willmar	MN	$18.501	$0.0804	0.0482%	$18.500	$0.0804	0.0455%	$18.501	$0.0804	0.0463%
229	2098	Lake Road	MO	$181.006	$0.0757	0.0459%	$180.923	$0.0757	0.0000%	$180.923	$0.0757	0.0000%
230	2094	Sibley	MO	$347.621	$0.0757	0.0456%	$347.613	$0.0757	0.0431%	$347.615	$0.0757	0.0438%
231	2167	New Madrid	MO	$806.483	$0.0767	1.3670%	$806.333	$0.0767	1.3482%	$806.374	$0.0767	1.3534%
232	2168	Thomas Hill	MO	$752.563	$0.0757	0.0140%	$752.557	$0.0757	0.0132%	$752.559	$0.0757	0.0134%
233	2169	Chamois	MO	$39.563	$0.0761	0.5058%	$39.552	$0.0761	0.4776%	$39.555	$0.0761	0.4854%
234	2123	Columbia	MO	$62.870	$0.0757	0.0617%	$62.852	$0.0757	0.0335%	$62.852	$0.0757	0.0340%
235	2144	Marshall	MO	$37.884	$0.0758	0.0887%	$37.870	$0.0757	0.0519%	$37.870	$0.0757	0.0528%
236	6768	Sikeston Power Station	MO	$175.192	$0.0765	1.0608%	$175.137	$0.0765	1.0290%	$175.152	$0.0765	1.0377%
237	2161	James River Power Station	MO	$299.106	$0.0757	0.0304%	$299.101	$0.0757	0.0287%	$299.102	$0.0757	0.0291%
238	6195	Southwest Power Station	MO	$201.844	$0.0762	0.6175%	$201.775	$0.0761	0.5831%	$201.794	$0.0761	0.5926%

Exhibit L3

Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option

				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
239	2076	Asbury	MO	$157.829	$0.0777	2.7055%	$157.820	$0.0777	2.7002%	$157.823	$0.0777	2.7016%
240	2132	Blue Valley	MO	$119.120	$0.0774	2.1808%	$119.103	$0.0773	2.1659%	$119.108	$0.0773	2.1700%
241	2171	Missouri City	MO	$30.360	$0.0759	0.2647%	$30.321	$0.0758	0.1342%	$30.321	$0.0758	0.1363%
242	2079	Hawthorn	MO	$710.865	$0.0758	0.1126%	$710.279	$0.0757	0.0300%	$710.282	$0.0757	0.0304%
243	6065	Iatan	MO	$483.011	$0.0759	0.3238%	$482.993	$0.0759	0.3200%	$482.998	$0.0759	0.3211%
244	2080	Montrose	MO	$374.147	$0.0757	0.0506%	$374.137	$0.0757	0.0478%	$374.140	$0.0757	0.0486%
245	2103	Labadie	MO	$1,603.955	$0.0766	1.2342%	$1,603.697	$0.0766	1.2179%	$1,603.706	$0.0766	1.2184%
246	2104	Meramec	MO	$699.578	$0.0767	1.3318%	$699.529	$0.0767	1.3247%	$699.543	$0.0767	1.3266%
247	6155	Rush Island	MO	$833.035	$0.0766	1.1436%	$832.669	$0.0765	1.0992%	$832.699	$0.0765	1.1028%
248	2107	Sioux	MO	$736.963	$0.0765	1.0935%	$736.945	$0.0765	1.0910%	$736.950	$0.0765	1.0917%
249	55076	Red Hills Generating Facility	MS	$402.591	$0.0895	0.1844%	$402.550	$0.0895	0.1741%	$402.561	$0.0895	0.1770%
250	2062	Henderson	MS	$35.743	$0.0894	0.0639%	$35.733	$0.0893	0.0373%	$35.734	$0.0893	0.0379%
251	2049	Jack Watson	MS	$954.326	$0.0896	0.3450%	$954.307	$0.0896	0.3430%	$954.312	$0.0896	0.3435%
252	6073	Victor J Daniel Jr	MS	$1,744.904	$0.0893	0.0502%	$1,744.855	$0.0893	0.0474%	$1,744.869	$0.0893	0.0482%
253	6061	R D Morrow	MS	$314.431	$0.0898	0.6020%	$314.327	$0.0898	0.5684%	$314.356	$0.0898	0.5777%
254	10784	Colstrip Energy LP	MT	$25.933	$0.0720	0.0489%	$25.932	$0.0720	0.0462%	$25.932	$0.0720	0.0470%
255	6089	Lewis & Clark	MT	$31.690	$0.0720	0.0329%	$31.690	$0.0720	0.0310%	$31.690	$0.0720	0.0315%
256	6076	Colstrip	MT	$1,526.064	$0.0767	6.5092%	$1,524.892	$0.0766	6.4274%	$1,525.215	$0.0766	6.4500%
257	2187	J E Corette Plant	MT	$108.720	$0.0720	0.0000%	$108.720	$0.0720	0.0000%	$108.720	$0.0720	0.0000%
258	55749	Hardin Generator Project	MT	$72.758	$0.0720	0.0525%	$72.756	$0.0720	0.0496%	$72.757	$0.0720	0.0504%
259	10381	Coastal Carolina Clean Power	NC	$32.874	$0.0843	0.4665%	$32.809	$0.0841	0.2683%	$32.810	$0.0841	0.2727%
260	8042	Belews Creek	NC	$1,595.204	$0.0843	0.4924%	$1,594.942	$0.0843	0.4759%	$1,595.014	$0.0843	0.4804%
261	2720	Buck	NC	$358.372	$0.0861	2.6783%	$358.360	$0.0861	2.6749%	$358.363	$0.0861	2.6758%
262	2721	Cliffside	NC	$581.663	$0.0850	1.3568%	$581.633	$0.0850	1.3517%	$581.641	$0.0850	1.3531%
263	2723	Dan River	NC	$288.162	$0.0848	1.0172%	$288.119	$0.0847	1.0022%	$288.131	$0.0847	1.0064%
264	2718	G G Allen	NC	$860.535	$0.0850	1.3505%	$860.495	$0.0850	1.3458%	$860.506	$0.0850	1.3471%
265	2727	Marshall	NC	$1,473.264	$0.0843	0.4563%	$1,473.032	$0.0843	0.4405%	$1,473.096	$0.0843	0.4448%
266	2732	Riverbend	NC	$451.107	$0.0856	2.0251%	$450.997	$0.0856	2.0002%	$451.027	$0.0856	2.0071%
267	10384	Edgecombe Genco LLC	NC	$85.103	$0.0843	0.4291%	$84.739	$0.0839	0.0000%	$84.739	$0.0839	0.0000%
268	10380	Elizabethtown Power LLC	NC	$25.211	$0.0840	0.1629%	$25.205	$0.0840	0.1378%	$25.205	$0.0840	0.1400%
269	10382	Lumberton	NC	$25.205	$0.0840	0.1407%	$25.202	$0.0840	0.1269%	$25.202	$0.0840	0.1289%
270	10379	Primary Energy Roxboro	NC	$49.609	$0.0841	0.2182%	$49.566	$0.0840	0.1314%	$49.567	$0.0840	0.1335%
271	10378	Primary Energy Southport	NC	$99.120	$0.0840	0.1190%	$99.002	$0.0839	0.0000%	$99.002	$0.0839	0.0000%
272	2706	Asheville	NC	$623.297	$0.0850	1.3512%	$623.242	$0.0850	1.3424%	$623.247	$0.0850	1.3432%
273	2708	Cape Fear	NC	$324.211	$0.0860	2.5001%	$324.193	$0.0860	2.4945%	$324.198	$0.0860	2.4961%
274	2713	L V Sutton	NC	$573.289	$0.0858	2.2905%	$573.267	$0.0858	2.2866%	$573.273	$0.0858	2.2876%
275	2709	Lee	NC	$381.743	$0.0858	2.2465%	$381.718	$0.0858	2.2400%	$381.725	$0.0858	2.2418%
276	6250	Mayo	NC	$557.586	$0.0864	3.0362%	$557.559	$0.0864	3.0313%	$557.566	$0.0864	3.0326%
277	2712	Roxboro	NC	$1,884.639	$0.0841	0.2362%	$1,884.585	$0.0841	0.2333%	$1,884.600	$0.0841	0.2341%
278	2716	W H Weatherspoon	NC	$255.444	$0.0851	1.4876%	$255.432	$0.0851	1.4827%	$255.435	$0.0851	1.4840%
279	54035	Roanoke Valley Energy	NC	$134.935	$0.0843	0.5178%	$134.267	$0.0839	0.0203%	$134.268	$0.0839	0.0206%

Exhibit L3
Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option

				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
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280	54755	Roanoke Valley Energy Facility II	NC	$42.963	$0.0842	0.4062%	$42.867	$0.0841	0.1814%	$42.868	$0.0841	0.1843%
281	6469	Antelope Valley	ND	$531.975	$0.0698	0.0185%	$531.969	$0.0698	0.0175%	$531.971	$0.0698	0.0178%
282	2817	Leland Olds	ND	$416.004	$0.0723	3.6512%	$416.001	$0.0723	3.6504%	$416.002	$0.0723	3.6506%
283	6030	Coal Creek	ND	$741.317	$0.0698	0.0055%	$741.315	$0.0698	0.0052%	$741.315	$0.0698	0.0053%
284	2824	Stanton	ND	$116.584	$0.0698	0.0152%	$116.583	$0.0698	0.0143%	$116.583	$0.0698	0.0145%
285	2790	R M Heskett	ND	$70.538	$0.0698	0.0560%	$70.521	$0.0698	0.0330%	$70.522	$0.0698	0.0336%
286	2823	Milton R Young	ND	$459.612	$0.0715	2.4059%	$459.346	$0.0714	2.3466%	$459.346	$0.0714	2.3467%
287	8222	Coyote	ND	$275.051	$0.0698	0.0141%	$275.049	$0.0698	0.0133%	$275.049	$0.0698	0.0135%
288	2240	Lon Wright	NE	$105.140	$0.0706	0.0906%	$105.079	$0.0705	0.0326%	$105.080	$0.0705	0.0331%
289	59	Platte	NE	$67.710	$0.0705	0.0439%	$67.680	$0.0705	0.0000%	$67.680	$0.0705	0.0000%
290	60	Whelan Energy Center	NE	$47.944	$0.0716	1.5005%	$47.904	$0.0715	1.4170%	$47.915	$0.0715	1.4400%
291	6077	Gerald Gentleman	NE	$844.650	$0.0707	0.3421%	$844.490	$0.0707	0.3231%	$844.534	$0.0707	0.3283%
292	2277	Sheldon	NE	$141.259	$0.0706	0.1838%	$141.245	$0.0706	0.1736%	$141.249	$0.0706	0.1764%
293	6096	Nebraska City	NE	$402.904	$0.0706	0.0867%	$402.885	$0.0706	0.0819%	$402.890	$0.0706	0.0832%
294	2291	North Omaha	NE	$398.471	$0.0705	0.0367%	$398.463	$0.0705	0.0347%	$398.465	$0.0705	0.0352%
295	2364	Merrimack	NH	$671.680	$0.1544	0.0059%	$671.678	$0.1544	0.0056%	$671.678	$0.1544	0.0057%
296	2367	Schiller	NH	$232.057	$0.1547	0.1975%	$231.600	$0.1544	0.0000%	$231.600	$0.1544	0.0000%
297	2384	Deepwater	NJ	$193.291	$0.1421	0.0180%	$193.256	$0.1421	0.0000%	$193.256	$0.1421	0.0000%
298	2403	PSEG Hudson Generating Station	NJ	$1,387.703	$0.1422	0.0582%	$1,386.896	$0.1421	0.0000%	$1,386.896	$0.1421	0.0000%
299	2408	PSEG Mercer Generating Station	NJ	$956.739	$0.1422	0.0425%	$956.333	$0.1421	0.0000%	$956.333	$0.1421	0.0000%
300	2378	B L England	NJ	$602.530	$0.1421	0.0043%	$602.504	$0.1421	0.0000%	$602.504	$0.1421	0.0000%
301	10566	Chambers Cogeneration LP	NJ	$356.080	$0.1424	0.2336%	$355.250	$0.1421	0.0000%	$355.250	$0.1421	0.0000%
302	10043	Logan Generating Company LP	NJ	$303.526	$0.1432	0.7548%	$302.809	$0.1428	0.5169%	$302.835	$0.1428	0.5253%
303	2434	Howard Down	NJ	$66.959	$0.1425	0.2570%	$66.949	$0.1424	0.2427%	$66.952	$0.1425	0.2467%
304	2442	Four Corners	NM	$1,572.696	$0.0791	2.8731%	$1,567.651	$0.0789	2.5431%	$1,567.672	$0.0789	2.5445%
305	2451	San Juan	NM	$1,259.427	$0.0778	1.1579%	$1,253.372	$0.0774	0.6715%	$1,253.508	$0.0774	0.6825%
306	87	Escalante	NM	$176.665	$0.0785	2.1035%	$176.528	$0.0785	2.0243%	$176.565	$0.0785	2.0461%
307	2324	Reid Gardner	NV	$536.959	$0.0962	0.2388%	$536.888	$0.0962	0.2255%	$536.907	$0.0962	0.2291%
308	8224	North Valmy	NV	$481.393	$0.0969	0.8956%	$481.155	$0.0968	0.8457%	$481.221	$0.0968	0.8595%
309	2535	AES Cayuga	NY	$436.669	$0.1543	0.0000%	$436.669	$0.1543	0.0000%	$436.669	$0.1543	0.0000%
310	2527	AES Greenidge LLC	NY	$219.106	$0.1543	0.0000%	$219.106	$0.1543	0.0000%	$219.106	$0.1543	0.0000%
311	6082	AES Somerset LLC	NY	$885.682	$0.1543	0.0000%	$885.682	$0.1543	0.0000%	$885.682	$0.1543	0.0000%
312	2526	AES Westover	NY	$160.685	$0.1545	0.1327%	$160.472	$0.1543	0.0000%	$160.472	$0.1543	0.0000%
313	10464	Black River Generation	NY	$75.607	$0.1543	0.0000%	$75.607	$0.1543	0.0000%	$75.607	$0.1543	0.0000%
314	2554	Dunkirk Generating Plant	NY	$847.374	$0.1543	0.0316%	$847.107	$0.1543	0.0000%	$847.107	$0.1543	0.0000%
315	2480	Danskammer Generating Station	NY	$726.753	$0.1543	0.0000%	$726.753	$0.1543	0.0000%	$726.753	$0.1543	0.0000%
316	2682	S A Carlson	NY	$135.784	$0.1543	0.0000%	$135.784	$0.1543	0.0000%	$135.784	$0.1543	0.0000%

Exhibit L3
Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option

				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
317	2629	Lovett	NY	$272.115	$0.1546	0.2014%	$271.568	$0.1543	0.0000%	$271.568	$0.1543	0.0000%
318	50202	WPS Power Niagara	NY	$75.607	$0.1543	0.0000%	$75.607	$0.1543	0.0000%	$75.607	$0.1543	0.0000%
319	2549	C R Huntley Generating Station	NY	$589.426	$0.1543	0.0000%	$589.426	$0.1543	0.0000%	$589.426	$0.1543	0.0000%
320	2642	Rochester 7	NY	$341.129	$0.1544	0.0369%	$341.003	$0.1543	0.0000%	$341.003	$0.1543	0.0000%
321	50651	Trigen Syracuse Energy	NY	$137.327	$0.1543	0.0000%	$137.327	$0.1543	0.0000%	$137.327	$0.1543	0.0000%
322	7286	Richard Gorsuch	OH	$162.750	$0.0930	0.0000%	$162.750	$0.0930	0.0000%	$162.750	$0.0930	0.0000%
323	2828	Cardinal	OH	$1,570.448	$0.0954	2.5291%	$1,570.337	$0.0953	2.5218%	$1,570.368	$0.0953	2.5238%
324	2914	Dover	OH	$40.005	$0.0930	0.0367%	$39.990	$0.0930	0.0000%	$39.990	$0.0930	0.0000%
325	2917	Hamilton	OH	$112.688	$0.0931	0.1402%	$112.530	$0.0930	0.0000%	$112.530	$0.0930	0.0000%
326	2935	Orrville	OH	$58.590	$0.0930	0.0000%	$58.590	$0.0930	0.0000%	$58.590	$0.0930	0.0000%
327	2936	Painesville	OH	$43.759	$0.0931	0.1113%	$43.710	$0.0930	0.0000%	$43.710	$0.0930	0.0000%
328	2943	Shelby Municipal Light Plant	OH	$28.852	$0.0931	0.0773%	$28.830	$0.0930	0.0000%	$28.830	$0.0930	0.0000%
329	2840	Conesville	OH	$1,581.352	$0.0955	2.6799%	$1,581.115	$0.0955	2.6645%	$1,581.180	$0.0955	2.6687%
330	2843	Picway	OH	$87.559	$0.0941	1.2361%	$87.544	$0.0941	1.2184%	$87.548	$0.0941	1.2233%
331	2850	J M Stuart	OH	$2,051.288	$0.0955	2.6856%	$2,051.027	$0.0955	2.6725%	$2,051.099	$0.0955	2.6761%
332	6031	Killen Station	OH	$585.953	$0.0970	4.3140%	$585.657	$0.0970	4.2614%	$585.739	$0.0970	4.2759%
333	2848	O H Hutchings	OH	$364.040	$0.0931	0.1127%	$363.630	$0.0930	0.0000%	$363.630	$0.0930	0.0000%
334	2832	Miami Fort	OH	$1,198.660	$0.0948	1.8879%	$1,198.359	$0.0947	1.8623%	$1,198.442	$0.0947	1.8694%
335	6019	W H Zimmer	OH	$1,161.570	$0.0930	0.0000%	$1,161.570	$0.0930	0.0000%	$1,161.570	$0.0930	0.0000%
336	2830	Walter C Beckjord	OH	$1,173.526	$0.0935	0.5462%	$1,173.491	$0.0935	0.5433%	$1,173.500	$0.0935	0.5441%
337	2835	Ashtabula	OH	$208.382	$0.0930	0.0297%	$208.320	$0.0930	0.0000%	$208.320	$0.0930	0.0000%
338	2878	Bay Shore	OH	$534.084	$0.0930	0.0494%	$533.820	$0.0930	0.0000%	$533.820	$0.0930	0.0000%
339	2837	Eastlake	OH	$1,050.619	$0.0931	0.0619%	$1,049.970	$0.0930	0.0000%	$1,049.970	$0.0930	0.0000%
340	2838	Lake Shore	OH	$212.167	$0.0931	0.0597%	$212.040	$0.0930	0.0000%	$212.040	$0.0930	0.0000%
341	2864	R E Burger	OH	$345.348	$0.0931	0.0922%	$345.030	$0.0930	0.0000%	$345.030	$0.0930	0.0000%
342	2866	W H Sammis	OH	$2,013.325	$0.0931	0.1325%	$2,010.660	$0.0930	0.0000%	$2,010.660	$0.0930	0.0000%
343	8102	General James M Gavin	OH	$2,125.921	$0.0933	0.3484%	$2,125.889	$0.0933	0.3469%	$2,125.898	$0.0933	0.3473%
344	2872	Muskingum River	OH	$1,258.654	$0.0939	0.9994%	$1,258.559	$0.0939	0.9917%	$1,258.585	$0.0939	0.9938%
345	2876	Kyger Creek	OH	$905.064	$0.0951	2.2255%	$904.932	$0.0951	2.2107%	$904.969	$0.0951	2.2148%
346	2836	Avon Lake	OH	$648.079	$0.0931	0.1234%	$647.280	$0.0930	0.0000%	$647.280	$0.0930	0.0000%
347	2861	Niles	OH	$238.369	$0.0931	0.1215%	$238.080	$0.0930	0.0000%	$238.080	$0.0930	0.0000%
348	10671	AES Shady Point LLC	OK	$216.449	$0.0705	1.0096%	$214.286	$0.0698	0.0000%	$214.286	$0.0698	0.0000%
349	165	GRDA	OK	$619.933	$0.0700	0.3565%	$619.810	$0.0700	0.3367%	$619.844	$0.0700	0.3422%
350	2952	Muskogee	OK	$1,155.454	$0.0698	0.0228%	$1,155.190	$0.0698	0.0000%	$1,155.190	$0.0698	0.0000%
351	6095	Sooner	OK	$696.282	$0.0698	0.0541%	$695.906	$0.0698	0.0000%	$695.906	$0.0698	0.0000%
352	2963	Northeastern	OK	$1,192.882	$0.0698	0.0000%	$1,192.882	$0.0698	0.0000%	$1,192.882	$0.0698	0.0000%
353	6772	Hugo	OK	$274.164	$0.0701	0.4567%	$274.164	$0.0701	0.4566%	$274.164	$0.0701	0.4566%
354	6106	Boardman	OR	$395.864	$0.0753	0.2121%	$395.817	$0.0753	0.2003%	$395.830	$0.0753	0.2036%
355	10676	AES Beaver Valley Partners Beaver Valley	PA	$126.653	$0.0967	0.7099%	$125.760	$0.0960	0.0000%	$125.760	$0.0960	0.0000%
356	3178	Armstrong Power Station	PA	$274.610	$0.0960	0.0182%	$274.607	$0.0960	0.0172%	$274.608	$0.0960	0.0175%

Exhibit L3
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				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
357	3179	Hatfields Ferry Power Station	PA	$1,453.971	$0.0960	0.0366%	$1,453.520	$0.0960	0.0055%	$1,453.521	$0.0960	0.0056%
358	3181	Mitchell Power Station	PA	$315.882	$0.0963	0.3181%	$314.892	$0.0960	0.0038%	$314.892	$0.0960	0.0039%
359	10641	Cambria Cogen	PA	$83.160	$0.0967	0.7266%	$83.126	$0.0967	0.6861%	$83.136	$0.0967	0.6973%
360	54144	Piney Creek Project	PA	$30.858	$0.0964	0.4476%	$30.850	$0.0964	0.4227%	$30.852	$0.0964	0.4296%
361	10603	Ebensburg Power	PA	$48.426	$0.0969	0.8878%	$48.402	$0.0968	0.8384%	$48.409	$0.0968	0.8520%
362	3159	Cromby Generating Station	PA	$353.433	$0.0960	0.0433%	$353.280	$0.0960	0.0000%	$353.280	$0.0960	0.0000%
363	3161	Eddystone Generating Station	PA	$1,319.589	$0.0960	0.0416%	$1,319.040	$0.0960	0.0000%	$1,319.040	$0.0960	0.0000%
364	6094	Bruce Mansfield	PA	$2,415.715	$0.1006	4.8051%	$2,413.883	$0.1005	4.7256%	$2,414.388	$0.1006	4.7475%
365	10113	John B Rich Memorial Power Station	PA	$74.473	$0.0967	0.7485%	$74.443	$0.0967	0.7069%	$74.451	$0.0967	0.7184%
366	10143	Colver Power Project	PA	$99.020	$0.0961	0.1414%	$98.880	$0.0960	0.0000%	$98.880	$0.0960	0.0000%
367	3122	Homer City Station	PA	$1,692.907	$0.0960	0.0252%	$1,692.883	$0.0960	0.0238%	$1,692.889	$0.0960	0.0242%
368	10343	Foster Wheeler Mt Carmel Cogen	PA	$39.962	$0.0975	1.5299%	$39.929	$0.0974	1.4448%	$39.938	$0.0974	1.4682%
369	50039	Kline Township Cogen Facility	PA	$48.446	$0.0969	0.9291%	$48.421	$0.0968	0.8774%	$48.428	$0.0969	0.8917%
370	8226	Cheswick Power Plant	PA	$535.707	$0.0960	0.0051%	$535.706	$0.0960	0.0048%	$535.706	$0.0960	0.0049%
371	3098	Elrama Power Plant	PA	$429.120	$0.0960	0.0000%	$429.120	$0.0960	0.0000%	$429.120	$0.0960	0.0000%
372	3138	New Castle Plant	PA	$297.623	$0.0960	0.0076%	$297.621	$0.0960	0.0072%	$297.622	$0.0960	0.0073%
373	50776	Panther Creek Energy Facility	PA	$79.087	$0.0964	0.4660%	$79.066	$0.0964	0.4401%	$79.072	$0.0964	0.4472%
374	3140	PPL Brunner Island	PA	$1,318.080	$0.0960	0.0000%	$1,318.080	$0.0960	0.0000%	$1,318.080	$0.0960	0.0000%
375	3149	PPL Montour	PA	$1,380.480	$0.0960	0.0000%	$1,380.480	$0.0960	0.0000%	$1,380.480	$0.0960	0.0000%
376	3113	Portland	PA	$522.260	$0.0960	0.0038%	$522.258	$0.0960	0.0035%	$522.259	$0.0960	0.0036%
377	3131	Shawville	PA	$532.111	$0.0960	0.0510%	$532.096	$0.0960	0.0481%	$532.100	$0.0960	0.0489%
378	3115	Titus	PA	$219.840	$0.0960	0.0000%	$219.840	$0.0960	0.0000%	$219.840	$0.0960	0.0000%
379	3130	Seward	PA	$493.634	$0.0964	0.4301%	$493.516	$0.0964	0.4061%	$493.549	$0.0964	0.4127%
380	3118	Conemaugh	PA	$1,585.196	$0.0961	0.0755%	$1,585.129	$0.0961	0.0713%	$1,585.147	$0.0961	0.0724%
381	3136	Keystone	PA	$1,584.145	$0.0960	0.0091%	$1,584.137	$0.0960	0.0086%	$1,584.139	$0.0960	0.0088%
382	54634	St Nicholas Cogen Project	PA	$84.838	$0.0975	1.5787%	$84.765	$0.0974	1.4908%	$84.785	$0.0975	1.5150%
383	3152	Sunbury Generation LP	PA	$413.282	$0.0961	0.1168%	$413.048	$0.0961	0.0600%	$413.051	$0.0961	0.0609%
384	3176	Hunlock Power Station	PA	$42.296	$0.0961	0.1328%	$42.293	$0.0961	0.1254%	$42.294	$0.0961	0.1275%
385	50888	Northampton Generating Company LP	PA	$97.755	$0.0978	1.8286%	$96.183	$0.0962	0.1902%	$96.186	$0.0962	0.1933%
386	50974	Scrubgrass Generating Company LP	PA	$80.038	$0.0964	0.4488%	$80.018	$0.0964	0.4238%	$80.023	$0.0964	0.4307%
387	50879	Wheelabrator Frackville Energy	PA	$40.862	$0.0973	1.3437%	$40.832	$0.0972	1.2689%	$40.840	$0.0972	1.2895%
388	50611	WPS Westwood Generation LLC	PA	$31.242	$0.0976	1.7008%	$31.213	$0.0975	1.6061%	$31.221	$0.0976	1.6322%
389	3264	W S Lee	SC	$321.158	$0.0839	1.5174%	$321.156	$0.0839	1.5166%	$321.157	$0.0839	1.5168%
390	3251	H B Robinson	SC	$722.778	$0.0832	0.6944%	$722.760	$0.0832	0.6919%	$722.765	$0.0832	0.6926%
391	7652	US DOE Savannah River Site (D Area)	SC	$56.994	$0.0826	0.0000%	$56.994	$0.0826	0.0000%	$56.994	$0.0826	0.0000%

Exhibit L3 Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option												
				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
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392	3280	Canadys Steam	SC	$362.404	$0.0845	2.2718%	$362.378	$0.0845	2.2644%	$362.385	$0.0845	2.2664%
393	7737	Cogen South	SC	$71.862	$0.0826	0.0000%	$71.862	$0.0826	0.0000%	$71.862	$0.0826	0.0000%
394	7210	Cope	SC	$302.316	$0.0826	0.0000%	$302.316	$0.0826	0.0000%	$302.316	$0.0826	0.0000%
395	3287	McMeekin	SC	$212.282	$0.0826	0.0000%	$212.282	$0.0826	0.0000%	$212.282	$0.0826	0.0000%
396	3295	Urquhart	SC	$550.373	$0.0828	0.1971%	$550.365	$0.0828	0.1956%	$550.367	$0.0828	0.1961%
397	3297	Wateree	SC	$558.376	$0.0826	0.0000%	$558.376	$0.0826	0.0000%	$558.376	$0.0826	0.0000%
398	3298	Williams	SC	$496.426	$0.0826	0.0000%	$496.426	$0.0826	0.0000%	$496.426	$0.0826	0.0000%
399	130	Cross	SC	$1,259.203	$0.0827	0.0958%	$1,259.091	$0.0827	0.0869%	$1,259.096	$0.0827	0.0873%
400	3317	Dolphus M Grainger	SC	$118.979	$0.0832	0.7293%	$118.700	$0.0830	0.4931%	$118.701	$0.0830	0.4939%
401	3319	Jefferies	SC	$421.506	$0.0831	0.6504%	$421.500	$0.0831	0.6490%	$421.501	$0.0831	0.6494%
402	6249	Winyah	SC	$913.193	$0.0827	0.1414%	$912.973	$0.0827	0.1173%	$912.980	$0.0827	0.1180%
403	3325	Ben French	SD	$87.717	$0.0743	0.1835%	$87.676	$0.0743	0.1376%	$87.678	$0.0743	0.1399%
404	6098	Big Stone	SD	$297.015	$0.0743	0.0724%	$297.003	$0.0743	0.0684%	$297.006	$0.0743	0.0695%
405	3393	Allen Steam Plant	TN	$1,216.439	$0.0862	0.2455%	$1,216.439	$0.0862	0.2455%	$1,216.439	$0.0862	0.2455%
406	3396	Bull Run	TN	$717.236	$0.0862	0.2398%	$717.210	$0.0862	0.2363%	$717.211	$0.0862	0.2363%
407	3399	Cumberland	TN	$1,959.080	$0.0860	0.0000%	$1,959.080	$0.0860	0.0000%	$1,959.080	$0.0860	0.0000%
408	3403	Gallatin	TN	$1,459.200	$0.0868	0.9366%	$1,459.198	$0.0868	0.9365%	$1,459.198	$0.0868	0.9365%
409	3405	John Sevier	TN	$603.655	$0.0861	0.1318%	$603.618	$0.0861	0.1257%	$603.618	$0.0861	0.1258%
410	3406	Johnsonville	TN	$2,198.179	$0.0862	0.2361%	$2,197.034	$0.0862	0.1839%	$2,197.034	$0.0862	0.1840%
411	3407	Kingston	TN	$1,304.965	$0.0876	1.9074%	$1,304.965	$0.0876	1.9074%	$1,304.965	$0.0876	1.9074%
412	7030	Twin Oaks Power One	TX	$311.994	$0.1020	0.0578%	$311.984	$0.1020	0.0546%	$311.987	$0.1020	0.0555%
413	6178	Coleto Creek	TX	$541.710	$0.1030	1.0664%	$541.657	$0.1030	1.0565%	$541.671	$0.1030	1.0592%
414	6179	Fayette Power Project	TX	$1,511.321	$0.1021	0.2123%	$1,511.310	$0.1021	0.2115%	$1,511.313	$0.1021	0.2117%
415	54972	Norit Americas Marshall Plant	TX	$2.043	$0.1022	0.2644%	$2.041	$0.1020	0.1244%	$2.041	$0.1020	0.1264%
416	298	Limestone	TX	$1,651.378	$0.1019	0.0363%	$1,651.345	$0.1019	0.0342%	$1,651.354	$0.1019	0.0348%
417	3470	W A Parish	TX	$3,543.129	$0.1019	0.0019%	$3,543.126	$0.1019	0.0018%	$3,543.127	$0.1019	0.0018%
418	127	Oklaunion	TX	$646.572	$0.1025	0.5572%	$646.535	$0.1025	0.5515%	$646.545	$0.1025	0.5531%
419	7097	J K Spruce	TX	$505.694	$0.1020	0.0533%	$505.503	$0.1019	0.0156%	$505.504	$0.1019	0.0159%
420	6181	J T Deely	TX	$831.549	$0.1019	0.0054%	$831.547	$0.1019	0.0051%	$831.547	$0.1019	0.0052%
421	6183	San Miguel	TX	$372.364	$0.1037	1.7886%	$365.821	$0.1019	0.0000%	$365.821	$0.1019	0.0000%
422	7902	Pirkey	TX	$655.408	$0.1037	1.7702%	$655.274	$0.1037	1.7493%	$655.311	$0.1037	1.7551%
423	6139	Welsh	TX	$1,493.907	$0.1019	0.0035%	$1,493.904	$0.1019	0.0033%	$1,493.905	$0.1019	0.0034%
424	6193	Harrington	TX	$963.974	$0.1019	0.0000%	$963.974	$0.1019	0.0000%	$963.974	$0.1019	0.0000%
425	6194	Tolk	TX	$1,013.905	$0.1019	0.0000%	$1,013.905	$0.1019	0.0000%	$1,013.905	$0.1019	0.0000%
426	6136	Gibbons Creek	TX	$404.607	$0.1019	0.0158%	$404.603	$0.1019	0.0149%	$404.604	$0.1019	0.0152%
427	3497	Big Brown	TX	$1,059.869	$0.1019	0.0103%	$1,059.863	$0.1019	0.0097%	$1,059.865	$0.1019	0.0099%
428	6146	Martin Lake	TX	$2,125.027	$0.1019	0.0194%	$2,125.004	$0.1019	0.0183%	$2,125.010	$0.1019	0.0186%
429	6147	Monticello	TX	$1,767.148	$0.1019	0.0114%	$1,767.137	$0.1019	0.0108%	$1,767.140	$0.1019	0.0110%
430	6648	Sandow No 4	TX	$552.376	$0.1068	4.8504%	$552.265	$0.1068	4.8294%	$552.296	$0.1068	4.8352%
431	7790	Bonanza	UT	$303.651	$0.0693	0.4735%	$303.571	$0.0693	0.4471%	$303.593	$0.0693	0.4544%
432	6481	Intermountain Power Project	UT	$1,000.923	$0.0697	0.9473%	$1,000.804	$0.0696	0.9353%	$1,000.836	$0.0696	0.9386%

Exhibit L3
Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option

				SUBTITLE C HAZ WASTE			SUBTITLE D VERSION 1			HYBRID C & D		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
433	3644	Carbon	UT	$114.021	$0.0691	0.1504%	$114.012	$0.0691	0.1420%	$114.014	$0.0691	0.1444%
434	6165	Hunter	UT	$892.410	$0.0692	0.2595%	$892.281	$0.0692	0.2450%	$892.316	$0.0692	0.2490%
435	8069	Huntington	UT	$604.980	$0.0694	0.5484%	$604.796	$0.0694	0.5179%	$604.847	$0.0694	0.5263%
436	50951	Sunnyside Cogen Associates	UT	$36.264	$0.0711	3.0508%	$36.204	$0.0710	2.8810%	$36.220	$0.0710	2.9279%
437	3775	Clinch River	VA	$571.584	$0.0916	0.0000%	$571.584	$0.0916	0.0000%	$571.584	$0.0916	0.0000%
438	3776	Glen Lyn	VA	$271.863	$0.0918	0.2680%	$271.846	$0.0918	0.2620%	$271.851	$0.0918	0.2637%
439	54304	Birchwood Power	VA	$207.620	$0.0919	0.2919%	$207.016	$0.0916	0.0000%	$207.016	$0.0916	0.0000%
440	10071	Cogentrix Virginia Leasing Corp	VA	$92.731	$0.0918	0.2325%	$92.516	$0.0916	0.0000%	$92.516	$0.0916	0.0000%
441	10377	James River Cogeneration	VA	$92.752	$0.0918	0.2547%	$92.516	$0.0916	0.0000%	$92.516	$0.0916	0.0000%
442	3788	Potomac River	VA	$412.200	$0.0916	0.0000%	$412.200	$0.0916	0.0000%	$412.200	$0.0916	0.0000%
443	54081	Spruance Genco LLC	VA	$184.925	$0.0920	0.4395%	$184.116	$0.0916	0.0000%	$184.116	$0.0916	0.0000%
444	10773	Altavista Power Station	VA	$56.894	$0.0918	0.1790%	$56.792	$0.0916	0.0000%	$56.792	$0.0916	0.0000%
445	3796	Bremo Bluff	VA	$211.699	$0.0949	3.6378%	$211.640	$0.0949	3.6089%	$211.656	$0.0949	3.6169%
446	3803	Chesapeake	VA	$655.648	$0.0922	0.6714%	$654.316	$0.0920	0.4668%	$654.323	$0.0920	0.4678%
447	3797	Chesterfield	VA	$1,470.999	$0.0933	1.8968%	$1,470.820	$0.0933	1.8844%	$1,470.869	$0.0933	1.8879%
448	7213	Clover	VA	$680.588	$0.0916	0.0000%	$680.588	$0.0916	0.0000%	$680.588	$0.0916	0.0000%
449	10771	Hopewell Power Station	VA	$56.864	$0.0917	0.1270%	$56.792	$0.0916	0.0000%	$56.792	$0.0916	0.0000%
450	52007	Mecklenburg Power Station	VA	$111.752	$0.0916	0.0000%	$111.752	$0.0916	0.0000%	$111.752	$0.0916	0.0000%
451	10774	Southampton Power Station	VA	$56.792	$0.0916	0.0000%	$56.792	$0.0916	0.0000%	$56.792	$0.0916	0.0000%
452	3809	Yorktown	VA	$1,008.516	$0.0916	0.0000%	$1,008.516	$0.0916	0.0000%	$1,008.516	$0.0916	0.0000%
453	3845	Transalta Centralia Generation	WA	$1,067.724	$0.0684	0.0000%	$1,067.724	$0.0684	0.0000%	$1,067.724	$0.0684	0.0000%
454	4127	Menasha	WI	$23.169	$0.0927	0.9542%	$23.157	$0.0926	0.9011%	$23.160	$0.0926	0.9158%
455	4140	Alma	WI	$145.998	$0.0918	0.0245%	$145.996	$0.0918	0.0232%	$145.996	$0.0918	0.0235%
456	4143	Genoa	WI	$278.154	$0.0918	0.0000%	$278.154	$0.0918	0.0000%	$278.154	$0.0918	0.0000%
457	4271	John P Madgett	WI	$311.989	$0.0920	0.2528%	$311.945	$0.0920	0.2387%	$311.957	$0.0920	0.2426%
458	3992	Blount Street	WI	$142.293	$0.0918	0.0018%	$142.290	$0.0918	0.0000%	$142.290	$0.0918	0.0000%
459	4125	Manitowoc	WI	$111.473	$0.0921	0.3555%	$111.451	$0.0921	0.3357%	$111.457	$0.0921	0.3412%
460	4146	E J Stoneman Station	WI	$42.389	$0.0922	0.3818%	$42.380	$0.0921	0.3606%	$42.383	$0.0921	0.3664%
461	3982	Bay Front	WI	$55.124	$0.0919	0.0807%	$55.080	$0.0918	0.0000%	$55.080	$0.0918	0.0000%
462	7549	Milwaukee County	WI	$9.402	$0.0940	2.4226%	$9.390	$0.0939	2.2878%	$9.393	$0.0939	2.3250%
463	6170	Pleasant Prairie	WI	$993.276	$0.0918	0.0000%	$993.276	$0.0918	0.0000%	$993.276	$0.0918	0.0000%
464	4041	South Oak Creek	WI	$973.998	$0.0918	0.0000%	$973.998	$0.0918	0.0000%	$973.998	$0.0918	0.0000%
465	4042	Valley	WI	$221.238	$0.0918	0.0000%	$221.238	$0.0918	0.0000%	$221.238	$0.0918	0.0000%
466	8023	Columbia	WI	$825.335	$0.0921	0.3412%	$825.224	$0.0921	0.3278%	$825.255	$0.0921	0.3315%
467	4050	Edgewater	WI	$619.661	$0.0918	0.0018%	$619.661	$0.0918	0.0017%	$619.661	$0.0918	0.0017%
468	4054	Nelson Dewey	WI	$160.650	$0.0918	0.0000%	$160.650	$0.0918	0.0000%	$160.650	$0.0918	0.0000%
469	4072	Pulliam	WI	$354.348	$0.0918	0.0000%	$354.348	$0.0918	0.0000%	$354.348	$0.0918	0.0000%
470	4078	Weston	WI	$457.164	$0.0918	0.0000%	$457.164	$0.0918	0.0000%	$457.164	$0.0918	0.0000%
471	3944	Harrison Power Station	WV	$1,202.475	$0.0669	0.1174%	$1,202.396	$0.0669	0.1109%	$1,202.418	$0.0669	0.1127%
472	6004	Pleasants Power Station	WV	$805.673	$0.0673	0.6759%	$805.372	$0.0672	0.6383%	$805.455	$0.0672	0.6487%

Exhibit L3 Plant-by-Plant Estimate of Potential Electricity Price Impact With Land Treatment Dewatering Sub-Option												
				SUBTITLE C HAZ WASTE			**SUBTITLE D VERSION 1**			**HYBRID C & D**		
Item	Plant code	Plant name	State	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase	Implied future annual revenue target with 100% regulatory cost pass-thru ($millions per year)	Implied future price to meet future new revenue target ($ per kwh)	Implied future percentage price increase
473	10151	Grant Town Power Plant	WV	$56.854	$0.0677	1.3231%	$56.813	$0.0676	1.2495%	$56.824	$0.0676	1.2698%
474	3935	John E Amos	WV	$1,754.507	$0.0683	2.2385%	$1,754.003	$0.0683	2.2092%	$1,754.142	$0.0683	2.2173%
475	3936	Kanawha River	WV	$257.378	$0.0669	0.0770%	$257.374	$0.0669	0.0753%	$257.375	$0.0669	0.0757%
476	6264	Mountaineer	WV	$763.862	$0.0671	0.3956%	$763.734	$0.0671	0.3788%	$763.769	$0.0671	0.3834%
477	3938	Philip Sporn	WV	$660.004	$0.0682	2.0692%	$659.831	$0.0682	2.0425%	$659.879	$0.0682	2.0498%
478	3942	Albright	WV	$163.747	$0.0671	0.4633%	$163.705	$0.0671	0.4375%	$163.717	$0.0671	0.4446%
479	3943	Fort Martin Power Station	WV	$675.082	$0.0669	0.1587%	$674.034	$0.0668	0.0033%	$674.034	$0.0668	0.0033%
480	3945	Rivesville	WV	$64.543	$0.0672	0.6469%	$64.520	$0.0672	0.6109%	$64.526	$0.0672	0.6208%
481	3946	Willow Island	WV	$125.201	$0.0670	0.2279%	$125.185	$0.0669	0.2152%	$125.189	$0.0669	0.2187%
482	10743	Morgantown Energy Facility	WV	$40.628	$0.0677	1.3666%	$40.597	$0.0677	1.2905%	$40.606	$0.0677	1.3115%
483	3947	Kammer	WV	$420.882	$0.0674	0.9717%	$420.860	$0.0674	0.9664%	$420.866	$0.0674	0.9678%
484	3948	Mitchell	WV	$1,004.213	$0.0702	5.1268%	$1,002.769	$0.0701	4.9756%	$1,003.168	$0.0702	5.0173%
485	3954	Mt Storm	WV	$990.909	$0.0673	0.7742%	$988.486	$0.0672	0.5278%	$988.570	$0.0672	0.5364%
486	7537	North Branch	WV	$48.842	$0.0698	4.4515%	$48.726	$0.0696	4.2037%	$48.758	$0.0697	4.2721%
487	6204	Laramie River Station	WY	$909.990	$0.0607	0.9087%	$909.864	$0.0607	0.8947%	$909.899	$0.0607	0.8985%
488	4150	Neil Simpson	WY	$11.473	$0.0604	0.3030%	$11.438	$0.0602	0.0000%	$11.438	$0.0602	0.0000%
489	7504	Neil Simpson II	WY	$63.934	$0.0609	1.1452%	$63.894	$0.0609	1.0814%	$63.905	$0.0609	1.0990%
490	4151	Osage	WY	$18.224	$0.0607	0.9076%	$18.215	$0.0607	0.8570%	$18.217	$0.0607	0.8710%
491	55479	Wygen 1	WY	$46.354	$0.0602	0.0000%	$46.354	$0.0602	0.0000%	$46.354	$0.0602	0.0000%
492	4158	Dave Johnston	WY	$431.898	$0.0604	0.3410%	$431.887	$0.0604	0.3385%	$431.890	$0.0604	0.3392%
493	8066	Jim Bridger	WY	$1,239.847	$0.0611	1.4555%	$1,239.499	$0.0611	1.4270%	$1,239.595	$0.0611	1.4349%
494	4162	Naughton	WY	$386.884	$0.0624	3.6557%	$386.834	$0.0624	3.6422%	$386.848	$0.0624	3.6459%
495	6101	Wyodak	WY	$194.276	$0.0613	1.8035%	$193.268	$0.0610	1.2752%	$193.273	$0.0610	1.2781%
				$288,136	$0.0891	**0.7955%**	$288,030	$0.0891	**0.7584%**	$288,038	$0.0891	**0.7612%**

Appendix M:

Small Entity Impact Data & Analysis Spreadsheet (RFA/SBREFA)

- **Exhibit M1: Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option**
- **Exhibit M2: Small Entity Impact Analysis For Regulatory Options With Land Treatment Dewatering Sub-Option**

Exhibit M1 Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option													
											Subtitle C haz waste	**Subtitle D Version 1**	**Hybrid C & D**
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
1	52	Constellation Energy (ACE Cogeneration Co)	CA	Non-Small Company	1	0.95	12.45	$0.1245		$102.66	1.2288%	1.1583%	1.1772%
2	142	AES Corp - AES Beaver Valley	PA	Non-Small Company	1	1.31	9.64	$0.0964		$109.61	0.8985%	0.0000%	0.0000%
3	22125	AES Corp - AES Cayuga LLC	NY	Non-Small Company	1	2.83	15.27	$0.1527		$375.10	0.0000%	0.0000%	0.0000%
4	25	AES Corp - AES Greenidge	NY	Non-Small Company	1	1.42	15.27	$0.1527		$188.21	0.0000%	0.0000%	0.0000%
5	177	AES Corp - AES Hawaii Inc	HI	Non-Small Company	1	1.78	20.54	$0.2054		$317.35	0.0917%	0.0000%	0.0000%
6	21	AES Corp - AES Shady Point LLC	OK	Non-Small Company	1	3.07	7.67	$0.0767		$204.39	1.1678%	0.0000%	0.0000%
7	22129	AES Corp - AES Somerset LLC	NY	Non-Small Company	1	5.74	15.27	$0.1527		$760.80	0.0000%	0.0000%	0.0000%
8	42	AES Corp - AES Thames LLC	CT	Non-Small Company	1	1.87	17.55	$0.1755		$284.86	0.2959%	0.0000%	0.0000%
9	22146	AES Corp - AES Westover LLC	NY	Non-Small Company	1	1.04	15.27	$0.1527		$137.85	0.1704%	0.0000%	0.0000%
10	35	AES Corp - AES WR Ltd Partnership	MD	Non-Small Company	1	2.01	13.45	$0.1345		$234.66	0.9092%	0.0000%	0.0000%
11	261	AGC Division of APG Inc	IN	Non-Small Company	1	6.61	7.62	$0.0762		$437.20	0.6333%	0.5980%	0.6077%
12	353	Air Products Energy Enterprise	CA	Non-Small Company	1	0.53	12.45	$0.1245		$57.27	1.6241%	1.5337%	1.5587%
13	189	Alabama Electric Coop Inc	AL	Non-Small Coop	1	13.46	8.87	$0.0887		$1,036.31	0.0784%	0.0189%	0.0192%
14	195	Alabama Power Co	AL	Non-Small Company	6	125.92	8.87	$0.0887		$9,694.78	0.1253%	0.1184%	0.1203%
15	23279	Allegheny Energy Supply Co LLC	MD	Non-Small Company	6	63.58	13.45	$0.1345	$0.0927	$5,114.96	0.2504%	0.2072%	0.2106%
16		Allegheny Energy Supply Co LLC	PA				9.64	$0.0964					
17		Allegheny Energy Supply Co LLC	WV				6.62	$0.0662					
18	54891	Altura Power	TX	Non-Small Company	1	3.06	10.73	$0.1073		$285.00	0.0577%	0.0544%	0.0553%
19	520	Ameren Energy Generating Co	IL	Non-Small Company	4	40.1	9.34	$0.0934		$3,250.96	0.1154%	0.0760%	0.0773%
20	49756	Ameren Energy Resources Generating Co.	IL	Non-Small Company	2	11.01	9.34	$0.0934		$892.59	0.7356%	0.6946%	0.7059%
21	563	American Bituminous Power LP	WV	Non-Small Company	1	0.84	6.62	$0.0662		$48.27	0.0000%	0.0000%	0.0000%
22	40577	American Mun Power-Ohio, Inc	OH	Non-Small City	1	5.09	8.55	$0.0855		$377.75	0.0000%	0.0000%	0.0000%

Exhibit M1
Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
23	554	Ames City of	IA	Non-Small City	1	1.64	6.99	$0.0699		$99.50	0.0344%	0.0325%	0.0331%
24	54865	ANP-Coleto Creek	TX	Non-Small Company	1	5.26	10.73	$0.1073		$489.90	0.1102%	0.1040%	0.1057%
25	733	American Electric Power Co - Appalachian Power Co	VA	Non-Small Company	6	71.11	9.01	$0.0901	$0.0742	$4,577.82	0.1465%	0.1384%	0.1406%
26		American Electric Power Co - Appalachian Power Co	WV				6.62	$0.0662					
27	770	Aquila, Inc.	CO	Non-Small Company	3	14.2	7.8	$0.0780	$0.0691	$851.29	0.0243%	0.0127%	0.0130%
28		Aquila, Inc.	MO				6.46	$0.0646					
29	796	Arizona Electric Pwr Coop Inc	AZ	Non-Small Coop	1	5.79	8.65	$0.0865		$434.72	1.3490%	1.2740%	1.2947%
30	803	Arizona Public Service Co	AZ	Non-Small Company	2	101.48	8.65	$0.0865	$0.0853	$7,513.62	0.1267%	0.0508%	0.0516%
31		Arizona Public Service Co	NM				8.41	$0.0841					
32	924	Associated Electric Coop, Inc	MO	Non-Small Coop	2	42.13	6.46	$0.0646		$2,362.35	0.0727%	0.0686%	0.0698%
33	986	Aurora Energy LLC	AK	Small Company	1	0.25	14.64	$0.1464		$31.77	1.6895%	1.5955%	1.6214%
34	1009	Austin City of	MN	Small City	1	0.57	8	$0.0800		$39.58	0.0043%	0.0041%	0.0041%
35	1307	Basin Electric Power Coop	ND	Non-Small Coop	3	30.98	6.44	$0.0644	$0.0625	$1,681.56	0.1825%	0.1723%	0.1751%
36		Basin Electric Power Coop	WY				5.88	$0.0588					
37	1735	Birchwood Power Partners LP	VA	Non-Small Company	1	2.26	9.01	$0.0901		$176.75	0.3772%	0.0000%	0.0000%
38	19545	Black Hills Power Inc	WY	Non-Small Company	5	4.2	5.88	$0.0588		$214.36	0.3664%	0.3460%	0.3516%
39	1746	Black River Generation LLC	NY	Non-Small Company	1	0.49	15.27	$0.1527		$64.95	0.0000%	0.0000%	0.0000%
40	13143	Board of Water Electric & Communications	IA	Small City	1	2.57	6.99	$0.0699		$155.93	0.0041%	0.0038%	0.0039%
41	2884	Cambria CoGen Co	PA	Non-Small Company	1	0.86	9.64	$0.0964		$71.96	0.4789%	0.4522%	0.4596%
42	3006	Cardinal Operating Co	OH	Non-Small Company	1	16.47	8.55	$0.0855		$1,222.30	0.1317%	0.1244%	0.1264%
43	54889	Carlyle/Riverstone Renewable Energy	NC	Non-Small Company	1	0.39	8.53	$0.0853		$28.88	0.2001%	0.1889%	0.1920%
44	3203	Cedar Falls Utilities	IA	Small City	1	0.92	6.99	$0.0699		$55.82	0.0336%	0.0317%	0.0322%
45	3242	Central Electric Power Coop	MO	Small Coop	1	0.52	6.46	$0.0646		$29.16	0.2509%	0.2369%	0.2408%
46	3258	Central Iowa Power Cooperative	IA	Small Coop	1	1.31	6.99	$0.0699		$79.48	0.1274%	0.1203%	0.1223%
47	3303	Central Power & Lime Inc	FL	Non-Small	1	1.1	11.89	$0.1189		$113.53	0.0000%	0.0000%	0.0000%

Exhibit M1
Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
				Company									
48	3593	Choctaw Generating LP	MS	Non-Small Company	1	4.5	8.98	$0.0898		$350.76	0.1961%	0.1852%	0.1882%
49	3599	Citizens Thermal Energy	IN	Non-Small Company	1	0.18	7.62	$0.0762		$11.91	0.0719%	0.0679%	0.0690%
50	4045	City of Columbia	MO	Non-Small City	1	0.83	6.46	$0.0646		$46.54	0.0260%	0.0246%	0.0250%
51	5336	City of Dover	OH	Small City	1	0.47	8.55	$0.0855		$34.88	0.0000%	0.0000%	0.0000%
52	7483	City of Grand Haven	MI	Small City	1	0.88	9.23	$0.0923		$70.50	0.0183%	0.0173%	0.0176%
53	7977	City of Hamilton	OH	Non-Small City	1	1.84	8.55	$0.0855		$136.55	0.1274%	0.0000%	0.0000%
54	8723	City of Holland	MI	Small City	1	2.18	9.23	$0.0923		$174.65	0.0044%	0.0042%	0.0043%
55	9667	City of Jasper	IN	Small City	1	0.13	7.62	$0.0762		$8.60	0.0527%	0.0498%	0.0506%
56	10623	City of Lakeland	FL	Non-Small City	1	10.67	11.89	$0.1189		$1,101.20	0.0822%	0.0776%	0.0788%
57	11142	City of Logansport	IN	Small City	1	0.53	7.62	$0.0762		$35.06	0.0272%	0.0257%	0.0261%
58	11701	City of Marquette	MI	Small City	1	0.92	9.23	$0.0923		$73.71	0.0088%	0.0083%	0.0084%
59	11732	City of Marshall	MO	Small City	1	0.5	6.46	$0.0646		$28.04	0.0396%	0.0374%	0.0380%
60	12298	City of Menasha	WI	Small City	1	0.25	9.49	$0.0949		$20.59	0.6795%	0.6417%	0.6522%
61	14194	City of Orrville	OH	Small City	1	0.74	8.55	$0.0855		$54.92	0.0000%	0.0000%	0.0000%
62	14268	City of Owensboro	KY	Non-Small City	1	3.9	6.63	$0.0663		$224.44	0.4864%	0.0000%	0.0000%
63	14381	City of Painesville	OH	Small City	1	0.47	8.55	$0.0855		$34.88	0.0000%	0.0000%	0.0000%
64	15989	City of Richmond	IN	Small City	1	0.82	7.62	$0.0762		$54.24	0.0923%	0.0872%	0.0886%
65	17043	City of Shelby	OH	Small City	1	0.37	8.55	$0.0855		$27.46	0.0000%	0.0000%	0.0000%
66	17177	City of Sikeston	MO	Small City	1	2.32	6.46	$0.0646		$130.09	0.2073%	0.1958%	0.1989%
67	17828	City of Springfield	IL	Non-Small City	2	5.7	9.34	$0.0934		$462.11	0.2108%	0.1990%	0.2023%
68	19883	City of Virginia	MN	Small City	1	0.26	8	$0.0800		$18.05	0.0438%	0.0414%	0.0420%
69	17833	City Utilities of Springfield	MO	Non-Small City	2	7.79	6.46	$0.0646		$436.81	0.0604%	0.0570%	0.0579%
70	3265	Cleco Power LLC	LA	Non-Small Company	2	18.94	8.2	$0.0820		$1,348.07	0.0243%	0.0230%	0.0234%
71	3901	Cogentrix Energy - Cogentrix-Virginia Leas'g Corp	VA	Non-Small Company	1	1.01	9.01	$0.0901		$78.99	0.3005%	0.0000%	0.0000%
72	4129	Colmac Clarion Inc	PA	Non-Small Company	1	0.32	9.64	$0.0964		$26.78	0.2950%	0.2786%	0.2831%
73	19173	Suez Energy - Colorado Energy Nations Company LLP	CO	Non-Small Company	1	0.31	7.8	$0.0780		$20.99	0.0550%	0.0520%	0.0528%
74	3989	Colorado Springs City of	CO	Non-Small City	2	10.27	7.8	$0.0780		$695.32	0.0073%	0.0069%	0.0070%
75	4217	Colstrip Energy LP	MT	Small Company	1	0.36	7.26	$0.0726		$22.69	0.0316%	0.0298%	0.0303%
76	4062	American Electric Power Co - Columbus Southern Power Co	OH	Non-Small Company	2	33	8.55	$0.0855		$2,449.06	0.1760%	0.1662%	0.1689%
77	4158	Conectiv Atlantic Generatn Inc	NJ	Non-Small	1	6.98	14.45	$0.1445		$875.47	0.0044%	0.0000%	0.0000%

Exhibit M1
Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	**Subtitle D Version 1**	**Hybrid C & D**
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
				Company									
78	4252	Conectiv Delmarva Gen Inc	DE	Non-Small Company	1	18.05	12.06	$0.1206		$1,889.49	0.0223%	0.0000%	0.0000%
79	4161	Constellation Power Source Gen	MD	Non-Small Company	3	34.67	13.45	$0.1345		$4,047.58	0.0574%	0.0000%	0.0000%
80	4254	Consumers Energy Co	MI	Non-Small Company	5	71.86	9.23	$0.0923		$5,757.16	0.0080%	0.0075%	0.0076%
81	4363	Corn Belt Power Coop	IA	Small Coop	1	1.25	6.99	$0.0699		$75.84	0.0175%	0.0166%	0.0168%
82	4508	Crawfordsville Elec, Lgt & Pwr	IN	Small City	1	0.22	7.62	$0.0762		$14.55	0.0642%	0.0606%	0.0616%
83	4538	Crisp County Power Comm	GA	Small County	1	0.3	8.79	$0.0879		$22.89	0.0192%	0.0181%	0.0184%
84	4716	Dairyland Power Coop	WI	Non-Small Coop	3	8.84	9.49	$0.0949		$728.18	0.0781%	0.0738%	0.0749%
85	4922	DPL Inc - Dayton Power & Light Co	OH	Non-Small Company	3	35.43	8.55	$0.0855		$2,629.40	0.2945%	0.2618%	0.2661%
86	40230	Deseret Generation & Tran Coop	UT	Non-Small Coop	1	4.38	6.26	$0.0626		$238.00	0.6373%	0.6018%	0.6116%
87	5109	Detroit Edison Co	MI	Non-Small Company	6	106.39	9.23	$0.0923		$8,523.58	0.0374%	0.0353%	0.0359%
88	50018	Dominion Energy New England, LLC	MA	Non-Small Company	2	25.68	16.05	$0.1605		$3,577.58	0.0201%	0.0000%	0.0000%
89	5269	Dominion Energy Services Co	IL	Non-Small Company	1	11.55	9.34	$0.0934		$936.37	0.0480%	0.0000%	0.0000%
90	34672	DTE Energy Services	AL	Non-Small Company	1	0.8	8.87	$0.0887		$61.59	0.0112%	0.0106%	0.0107%
91	5416	Duke Energy Carolinas, LLC	NC	Non-Small Company	8	192.46	8.53	$0.0853		$14,249.82	0.1090%	0.1029%	0.1046%
92	15470	Duke Energy Indiana Inc	IN	Non-Small Company	5	73.49	7.62	$0.0762		$4,860.75	0.2601%	0.2456%	0.2496%
93	55729	Duke Energy Kentucky Inc	KY	Non-Small Company	1	10.15	6.63	$0.0663		$584.12	1.4151%	1.3363%	1.3580%
94	3542	Duke Energy Ohio Inc	OH	Non-Small Company	3	74.97	8.55	$0.0855		$5,563.82	0.1095%	0.1034%	0.1051%
95	13579	NRG Energy - Dunkirk Power LLC	NY	Non-Small Company	1	5.49	15.27	$0.1527		$727.66	0.0405%	0.0000%	0.0000%
96	5517	Dynegy Midwest Generation Inc	IL	Non-Small Company	5	47.09	9.34	$0.0934		$3,817.64	0.1332%	0.1258%	0.1278%
97	5511	Dynegy Northeast Gen Inc	NY	Non-Small Company	1	15.59	15.27	$0.1527		$2,066.35	0.0000%	0.0000%	0.0000%
98	5580	East Kentucky Power Coop, Inc	KY	Non-Small Coop	3	23.77	6.63	$0.0663		$1,367.93	1.1066%	1.0449%	1.0619%
99	5670	Babcox & Wicox & ESI Inc - Ebensburg Power Co	PA	Non-Small Company	1	0.5	9.64	$0.0964		$41.84	0.5850%	0.5524%	0.5614%
100	55739	Edgecombe Operating Services LLC	NC	Small Company	1	1.01	8.53	$0.0853		$74.78	0.5365%	0.0000%	0.0000%
101	5748	Electric Energy Inc	IL	Non-Small Company	1	9.63	9.34	$0.0934		$780.72	0.0000%	0.0000%	0.0000%
102	5860	Empire District Electric Co	KS	Non-Small	2	13.91	8.03	$0.0803	$0.0725	$874.75	0.0167%	0.0157%	0.0160%

Exhibit M1
Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option

Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Subtitle C haz waste Total Annual Cost as % Electricity Plant Annual Revenues	Subtitle D Version 1 Total Annual Cost as % Electricity Plant Annual Revenues	Hybrid C & D Total Annual Cost as % Electricity Plant Annual Revenues
				Company									
103		Empire District Electric Co	MO				6.46	$0.0646					
104	814	Entergy Arkansas Inc	AR	Non-Small Company	2	66.71	7.96	$0.0796		$4,609.18	0.1382%	0.1306%	0.1327%
105	55936	Entergy Gulf States Louisiana LLC	LA	Non-Small Company	1	47.23	8.2	$0.0820		$3,361.64	0.0000%	0.0000%	0.0000%
106	6035	Exelon Power	PA	Non-Small Company	2	77.96	9.64	$0.0964		$6,523.32	0.0119%	0.0000%	0.0000%
107	6526	FirstEnergy Generation Corp	OH	Non-Small Company	7	93.78	8.55	$0.0855	$0.0871	$7,086.54	0.3258%	0.2476%	0.2516%
108		FirstEnergy Generation Corp	PA				9.64	$0.0964					
109	54895	FirstLight Power Resources Services LLC	MA	Non-Small Company	1	11.23	16.05	$0.1605		$1,564.50	0.0116%	0.0000%	0.0000%
110	6811	FPL Energy Operating Servs Inc	CA	Non-Small Company	1	0.47	12.45	$0.1245		$50.79	0.9843%	0.9295%	0.9446%
111	6779	Fremont City of	NE	Small City	1	1.49	6.67	$0.0667		$86.26	0.1183%	0.0406%	0.0413%
112	6909	Gainesville Regional Utilities	FL	Non-Small City	1	6.24	11.89	$0.1189		$644.00	0.0063%	0.0059%	0.0060%
113	7140	Georgia Power Co	GA	Non-Small Company	10	207.69	8.79	$0.0879		$15,846.17	0.1319%	0.1232%	0.1253%
114	7199	Gilberton Power Co	PA	Non-Small Company	1	0.77	9.64	$0.0964		$64.43	0.4932%	0.4658%	0.4733%
115	7353	Golden Valley Elec Assn Inc	AK	Small Company	1	2.42	14.64	$0.1464		$307.52	0.1096%	0.1035%	0.1052%
116	40606	Grand Island City of	NE	Small City	1	3.07	6.67	$0.0667		$177.74	0.0184%	0.0000%	0.0000%
117	7490	Grand River Dam Authority	OK	Non-Small State	1	13.56	7.67	$0.0767		$902.77	0.1821%	0.1720%	0.1748%
118	7570	Great River Energy	ND	Non-Small Coop	2	24.23	6.44	$0.0644		$1,354.44	0.0227%	0.0215%	0.0218%
119	7651	Greenwood Utilities Comm	MS	Small City	1	0.67	8.98	$0.0898		$52.22	0.0139%	0.0132%	0.0134%
120	7801	Gulf Power Co	FL	Non-Small Company	3	20.52	11.89	$0.1189		$2,117.77	0.0084%	0.0080%	0.0081%
121	8245	Hastings City of	NE	Small City	1	1.2	6.67	$0.0667		$69.47	1.0284%	0.9712%	0.9870%
122	8286	Hawaiian Com & Sugar Co Ltd	HI	Non-Small Company	1	0.58	20.54	$0.2054		$103.41	0.7528%	0.7109%	0.7225%
123	8449	Henderson City Utility Comm	KY	Small City	1	0.4	6.63	$0.0663		$23.02	0.0497%	0.0469%	0.0477%
124	8543	Hibbing Public Utilities Comm	MN	Small City	1	0.31	8	$0.0800		$21.53	0.0173%	0.0164%	0.0166%
125	9267	Hoosier Energy R E C, Inc	IN	Non-Small Company	2	17.16	7.62	$0.0762		$1,134.99	0.0752%	0.0710%	0.0721%
126	9231	Independence City of	MO	Non-Small City	2	2.97	6.46	$0.0646		$166.54	0.1267%	0.1196%	0.1216%
127	9332	NRG Energy - Indian River Operations Inc	DE	Non-Small Company	1	7	12.06	$0.1206		$732.77	0.3217%	0.3038%	0.3087%
128	9324	American Electric Power Co - Indiana Michigan Power Co	IN	Non-Small Company	2	52.63	7.62	$0.0762		$3,481.03	0.1095%	0.1034%	0.1051%

Exhibit M1 Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option													
											Subtitle C haz waste	**Subtitle D Version 1**	**Hybrid C & D**
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
129	9269	Indiana-Kentucky Electric Corp	IN	Non-Small Company	1	11.42	7.62	$0.0762		$755.34	0.0732%	0.0682%	0.0693%
130	9273	Indianapolis Power & Light Co	IN	Non-Small Company	3	33.01	7.62	$0.0762		$2,183.33	0.2358%	0.0524%	0.0532%
131	9379	Constellation Energy - Inter-Power/AhlCon Partners, L.P.	PA	Non-Small Company	1	1.03	9.64	$0.0964		$86.19	0.5383%	0.3393%	0.3448%
132	9417	Interstate Power and Light Co	IA	Non-Small Company	8	29.86	6.99	$0.0699		$1,811.70	0.0231%	0.0205%	0.0209%
133	9628	Cogentrix Energy - James River Cogeneration Co	VA	Non-Small Company	1	1.01	9.01	$0.0901		$78.99	0.0000%	0.0000%	0.0000%
134	9645	Jamestown Board of Public Util	NY	Small City	1	0.88	15.27	$0.1527		$116.64	0.0000%	0.0000%	0.0000%
135	9617	JEA	FL	Non-Small City	2	36.23	11.89	$0.1189		$3,739.12	0.1004%	0.0948%	0.0963%
136	9996	Kansas City City of	KS	Non-Small City	2	7.96	8.03	$0.0803		$554.82	0.0828%	0.0331%	0.0337%
137	10000	Kansas City Power & Light Co	KS	Non-Small Company	4	44.36	8.03	$0.0803	$0.0685	$2,638.52	0.1427%	0.1120%	0.1139%
138		Kansas City Power & Light Co	MO				6.46	$0.0646					
139	22053	American Electric Power Co - Kentucky Power Co	KY	Non-Small Company	1	9.61	6.63	$0.0663		$553.04	1.5960%	1.5072%	1.5317%
140	10171	EON USA LLC - Kentucky Utilities Co	KY	Non-Small Company	4	39.2	6.63	$0.0663		$2,255.90	1.1562%	1.0919%	1.1096%
141	56155	Lansing Board of Water and Light	MI	Non-Small City	2	4.64	9.23	$0.0923		$371.74	0.0697%	0.0450%	0.0458%
142	11208	Los Angeles City of	UT	Non-Small City	1	70.99	6.26	$0.0626		$3,857.37	0.0861%	0.0813%	0.0826%
143	11252	NRG Energy - Louisiana Generating LLC	LA	Non-Small Company	1	20.71	8.2	$0.0820		$1,474.05	0.0002%	0.0002%	0.0002%
144	11249	Louisville Gas & Electric Co	KY	Non-Small Company	3	39.49	6.63	$0.0663		$2,272.59	0.6757%	0.4668%	0.4744%
145	11269	Lower Colorado River Authority	TX	Non-Small State	1	31.9	10.73	$0.1073		$2,971.05	0.0040%	0.0038%	0.0038%
146	11479	Madison Gas & Electric Co	WI	Non-Small Company	1	5.43	9.49	$0.0949		$447.29	0.0006%	0.0000%	0.0000%
147	11571	Manitowoc Public Utilities	WI	Small City	1	1.56	9.49	$0.0949		$128.50	0.2202%	0.2079%	0.2113%
148	12199	MDU Resources Group Inc	ND	Non-Small Company	2	2.66	6.44	$0.0644	$0.0685	$158.16	0.0686%	0.0550%	0.0559%
149		MDU Resources Group Inc	MT				7.26	$0.0726					
150	12807	Michigan South Central Pwr Agy	MI	Small City	1	0.78	9.23	$0.0923		$62.49	0.0193%	0.0182%	0.0185%
151	12435	Integrys Energy Group - Mid-America Power LLC	WI	Non-Small Company	1	0.46	9.49	$0.0949		$37.89	0.2543%	0.2402%	0.2441%
152	12341	MidAmerican Energy Co	IA	Non-Small Company	5	58.13	6.99	$0.0699		$3,526.93	0.2671%	0.2495%	0.2535%
153	12384	Midwest Generations EME LLC	IL	Non-Small Company	8	113.38	9.34	$0.0934	$0.0938	$9,228.76	0.0220%	0.0025%	0.0025%
154		Midwest Generations EME LLC	PA				9.64	$0.0964					
155	12647	Minnesota Power Inc	M	Non-Small	5	15	8	$0.0800		$1,041.60	0.1062%	0.1003%	0.1019%

Exhibit M1
Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
			N	Company									
156	12658	Minnkota Power Coop, Inc	ND	Non-Small Coop	1	6.56	6.44	$0.0644		$366.70	0.1151%	0.0337%	0.0343%
157	12628	Mirant - Chalk Point LLC	MD	Non-Small Company	1	23.19	13.45	$0.1345		$2,707.34	0.0356%	0.0336%	0.0342%
158	12653	Mirant - Mid-Atlantic LLC	MD	Non-Small Company	2	21.71	13.45	$0.1345		$2,534.56	0.0113%	0.0106%	0.0108%
159	12792	Mirant - New York Inc	NY	Non-Small Company	1	14.81	15.27	$0.1527		$1,962.97	0.0307%	0.0000%	0.0000%
160	12588	Mirant - Potomac River LLC	VA	Non-Small Company	1	4.5	9.01	$0.0901		$351.93	0.0000%	0.0000%	0.0000%
161	12686	Mississippi Power Co	MS	Non-Small Company	2	33.55	8.98	$0.0898		$2,615.10	0.0348%	0.0328%	0.0334%
162	12796	Monongahela Power Co	WV	Non-Small Company	4	15.36	6.62	$0.0662		$882.61	0.2474%	0.1101%	0.1119%
163	12949	Cogentrix Energy - Morgantown Energy Associates	WV	Non-Small Company	1	0.6	6.62	$0.0662		$34.48	0.0000%	0.0000%	0.0000%
164	49889	Mount Carmel Cogen Inc	PA	Small Company	1	0.41	9.64	$0.0964		$34.31	1.0083%	0.9521%	0.9676%
165	13060	Mt Poso Cogeneration Co	CA	Non-Small Company	1	0.54	12.45	$0.1245		$58.36	0.9029%	0.8526%	0.8665%
166	13337	Nebraska Public Power District	NE	Non-Small State	2	26.88	6.67	$0.0667		$1,556.23	0.2066%	0.1951%	0.1983%
167	13407	Nevada Power Co	NV	Non-Small Company	1	34.7	9.56	$0.0956		$2,879.43	0.0440%	0.0415%	0.0422%
168	13488	New Ulm Public Utilities Comm	MN	Small City	1	0.69	8	$0.0800		$47.91	0.0193%	0.0182%	0.0185%
169	54784	NewPage Corporation	ME	Non-Small Company	1	1.01	14.47	$0.1447		$126.86	0.4372%	0.2741%	0.2785%
170	55807	Niagara Generation LLC	NY	Non-Small City	1	0.49	15.27	$0.1527		$64.95	0.0000%	0.0000%	0.0000%
171	35120	Norit Americas Inc	TX	Non-Small Company	1	0.02	10.73	$0.1073		$1.86	0.0813%	0.0768%	0.0781%
172	13695	North Carolina Power Holdings, LLC	NC	Non-Small Company	2	0.61	8.53	$0.0853		$45.16	0.0853%	0.0806%	0.0819%
173	13833	Suez Energy - Northeastern Power Co	PA	Non-Small Company	1	0.5	9.64	$0.0964		$41.84	0.6122%	0.5781%	0.5875%
174	13756	Northern Indiana Pub Serv Co	IN	Non-Small Company	3	35.73	7.62	$0.0762		$2,363.24	0.0472%	0.0405%	0.0411%
175	13781	Northern States Power Co	MN	Non-Small Company	5	73.7	8	$0.0800	$0.0830	$5,308.36	0.2448%	0.2312%	0.2349%
176		Northern States Power Co	WI				9.49	$0.0949					
177	7860	NRG Energy - Energy Center Dover LLC	DE	Non-Small Company	1	1.03	12.06	$0.1206		$107.82	0.2417%	0.2283%	0.2320%
178	13168	NRG Energy - Huntley Operations Inc	NY	Non-Small Company	1	7.15	15.27	$0.1527		$947.69	0.0000%	0.0000%	0.0000%
179	54888	NRG Energy - Texas LLC	TX	Non-Small	2	125.29	10.73	$0.1073		$11,669.06	0.0071%	0.0067%	0.0068%

Exhibit M1
Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
				Company									
180	14006	American Electric Power Co - Ohio Power Co	OH	Non-Small Company	4	57.13	8.55	$0.0855	$0.0759	$3,761.31	0.6108%	0.5768%	0.5862%
181		American Electric Power Co - Ohio Power Co	WV				6.62	$0.0662					
182	14015	Ohio Valley Electric Corp	OH	Non-Small Company	1	9.52	8.55	$0.0855		$706.52	0.3144%	0.2969%	0.3017%
183	14063	Oklahoma Gas & Electric Co	OK	Non-Small Company	2	62.7	7.67	$0.0767		$4,174.29	0.0169%	0.0000%	0.0000%
184	14127	Omaha Public Power District	NE	Non-Small State	2	22.92	6.67	$0.0667		$1,326.97	0.0362%	0.0342%	0.0347%
185	14165	Orion Power Midwest LP	OH	Non-Small Company	5	31.19	8.55	$0.0855	$0.0920	$2,491.79	0.0493%	0.0011%	0.0011%
186		Orion Power Midwest LP	PA				9.64	$0.0964					
187	14610	Orlando Utilities Comm	FL	Non-Small City	1	11.4	11.89	$0.1189		$1,176.54	0.1774%	0.1676%	0.1703%
188	14232	Otter Tail Power Co	MN	Non-Small Company	3	10.48	8	$0.0800	$0.0716	$651.62	0.0742%	0.0701%	0.0712%
189		Otter Tail Power Co	SD				7.05	$0.0705					
190		Otter Tail Power Co	ND				6.44	$0.0644					
191	14354	PacifiCorp	UT	Non-Small Company	7	88.08	6.26	$0.0626	$0.0604	$4,619.97	0.3219%	0.2817%	0.2863%
192		PacifiCorp	WY				5.88	$0.0588					
193	14432	Constellation Energy - Panther Creek Partners	PA	Non-Small Company	1	0.82	9.64	$0.0964		$68.61	0.3071%	0.2900%	0.2947%
194	14645	Pella City of	IA	Small City	1	0.61	6.99	$0.0699		$37.01	0.0358%	0.0338%	0.0344%
195	14839	Peru City of	IN	Small City	1	0.32	7.62	$0.0762		$21.17	0.0567%	0.0535%	0.0544%
196	15143	Platte River Power Authority	CO	Non-Small State	1	5.78	7.8	$0.0780		$391.33	0.0457%	0.0432%	0.0439%
197	15248	Portland General Electric Co	OR	Non-Small Company	1	23.32	7.7	$0.0770		$1,558.62	0.0539%	0.0509%	0.0517%
198	15537	PPL - Brunner Island LLC	PA	Non-Small Company	1	13.73	9.64	$0.0964		$1,148.86	0.0000%	0.0000%	0.0000%
199	15298	PPL - Montana LLC	MT	Non-Small Company	2	26.46	7.26	$0.0726		$1,667.42	1.2403%	1.1713%	1.1903%
200	15534	PPL - Montour LLC	PA	Non-Small Company	1	14.38	9.64	$0.0964		$1,203.25	0.0000%	0.0000%	0.0000%
201	54708	Primary Energy of North Carolina LLC	NC	Non-Small Company	2	1.77	8.53	$0.0853		$131.05	0.1309%	0.0299%	0.0304%
202	3046	Progress Energy Carolinas Inc	NC	Non-Small Company	8	120.48	8.53	$0.0853	$0.0850	$8,892.94	0.0294%	0.0273%	0.0277%
203		Progress Energy Carolinas Inc	SC				8.32	$0.0832					
204	6455	Progress Energy Florida Inc	FL	Non-Small Company	1	95.44	11.89	$0.1189		$9,849.90	0.0022%	0.0021%	0.0021%
205	15147	PSEG Fossil LLC	NJ	Non-Small	2	77.94	14.45	$0.1445		$9,775.70	0.0137%	0.0000%	0.0000%

Exhibit M1
Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
				Company									
206	15452	PSEG Power Connecticut LLC	CT	Non-Small Company	1	9.12	17.55	$0.1755		$1,389.29	0.0094%	0.0000%	0.0000%
207	15466	Public Service Co of Colorado	CO	Non-Small Company	7	39.41	7.8	$0.0780		$2,668.21	0.0724%	0.0038%	0.0039%
208	15472	Public Service Co of NH	NH	Non-Small Company	2	10.38	15.5	$0.1550		$1,396.53	0.0379%	0.0017%	0.0017%
209	15473	Public Service Co of NM	NM	Non-Small Company	1	27.09	8.41	$0.0841		$1,977.54	0.4838%	0.4569%	0.4643%
210	15474	American Electric Power Co - Public Service Co of Oklahoma	OK	Non-Small Company	2	43.84	7.67	$0.0767	$0.0920	$3,500.89	0.0162%	0.0153%	0.0155%
211		American Electric Power Co - Public Service Co of Oklahoma	TX				10.73	$0.1073					
212	55768	RC Cape May Holdings LLC	NJ	Non-Small Company	1	4.24	14.45	$0.1445		$531.81	0.0054%	0.0000%	0.0000%
213	17235	NRG Energy - Reliant Energy Mid-Atlantic PH LLC	PA	Non-Small Company	3	17.19	9.64	$0.0964		$1,438.38	0.0116%	0.0110%	0.0111%
214	15998	NRG Energy - Reliant Energy Seward LLC	PA	Non-Small Company	1	7.04	9.64	$0.0964		$589.07	0.4252%	0.4015%	0.4080%
215	15873	NRG Energy - Reliant Engy NE Management Co	PA	Non-Small Company	2	33	9.64	$0.0964		$2,761.28	0.0579%	0.0547%	0.0556%
216	16061	Constellation Energy - Rio Bravo Jasmin	CA	Non-Small Company	1	0.33	12.45	$0.1245		$35.66	0.7842%	0.7406%	0.7526%
217	16002	Constellation Energy - Rio Bravo Poso	CA	Non-Small Company	1	0.33	12.45	$0.1245		$35.66	0.7683%	0.7256%	0.7374%
218	16183	Energy East Corporation - Rochester Gas & Electric Corp	NY	Non-Small Company	1	3.61	15.27	$0.1527		$478.48	0.0290%	0.0000%	0.0000%
219	16181	Rochester Public Utilities	MN	Non-Small City	1	1.67	8	$0.0800		$115.96	0.0249%	0.0236%	0.0239%
220	16233	Rocky Mountain Power Inc	MT	Non-Small Company	1	1.01	7.26	$0.0726		$63.65	0.0339%	0.0320%	0.0325%
221	16572	Salt River Project	AZ	Non-Small State	2	58.44	8.65	$0.0865		$4,387.79	0.5005%	0.4726%	0.4803%
222	16604	San Antonio City of	TX	Non-Small City	2	42.57	10.73	$0.1073		$3,964.82	0.0077%	0.0024%	0.0024%
223	16624	San Miguel Electric Coop, Inc	TX	Small Coop	1	3.59	10.73	$0.1073		$334.36	2.1589%	0.0000%	0.0000%
224	56190	Savannah River Nuclear Solutions LLC	SC	Non-Small Company	1	0.69	8.32	$0.0832		$49.83	0.0000%	0.0000%	0.0000%
225	16793	Schuylkill Energy Resource Inc	PA	Small Company	1	0.87	9.64	$0.0964		$72.80	1.0407%	0.9828%	0.9987%
226	21554	Seminole Electric Coop, Inc	FL	Non-Small Coop	1	20.38	11.89	$0.1189		$2,103.32	0.3157%	0.2979%	0.3027%
227	17166	Sierra Pacific Power Co	NV	Non-Small Company	1	12.53	9.56	$0.0956		$1,039.75	0.3230%	0.3050%	0.3099%
228	29878	Somerset Power LLC	MA	Small City	1	1.96	16.05	$0.1605		$273.06	0.0622%	0.0000%	0.0000%
229	17539	South Carolina Electric&Gas Co	SC	Non-Small	6	51.25	8.32	$0.0832		$3,701.15	0.0174%	0.0165%	0.0167%

Exhibit M1
Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	**Subtitle D Version 1**	**Hybrid C & D**
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
				Company									
230	17554	South Carolina Genertg Co, Inc	SC	Non-Small Company	1	6.01	8.32	$0.0832		$434.03	0.0000%	0.0000%	0.0000%
231	17543	South Carolina Pub Serv Auth	SC	Non-Small State	4	44.79	8.32	$0.0832		$3,234.63	0.0523%	0.0311%	0.0316%
232	17568	South Mississippi El Pwr Assn	MS	Non-Small Coop	1	10.26	8.98	$0.0898		$799.73	0.1820%	0.1719%	0.1747%
233	17632	Southern Illinois Power Coop	IL	Small Coop	1	3.7	9.34	$0.0934		$299.96	0.9464%	0.0000%	0.0000%
234	17633	Southern Indiana Gas & Elec Co	IN	Non-Small Company	2	11.26	7.62	$0.0762		$744.75	0.3450%	0.2444%	0.2484%
235	17698	American Electric Power Co - Southwestern Electric Power Co	AR	Non-Small Company	3	44.92	7.96	$0.0796	$0.0981	$3,823.67	0.0675%	0.0637%	0.0648%
236		American Electric Power Co - Southwestern Electric Power Co	TX				10.73	$0.1073					
237	17718	Southwestern Public Service Co	TX	Non-Small Company	2	39.52	10.73	$0.1073		$3,680.75	0.0000%	0.0000%	0.0000%
238	40307	Soyland Power Coop Inc	IL	Small Coop	1	1.58	9.34	$0.0934		$128.09	0.0866%	0.0818%	0.0831%
239	55740	Spruance Operating Services LLC	VA	Small Company	1	2.01	9.01	$0.0901		$157.20	0.5679%	0.0000%	0.0000%
240	18041	State Line Energy LLC	IN	Non-Small Company	1	5.38	7.62	$0.0762		$355.84	0.0318%	0.0000%	0.0000%
241	22001	Sunbury Generation LP	PA	Non-Small Company	1	4.3	9.64	$0.0964		$359.80	0.1644%	0.0910%	0.0925%
242	18315	Sunflower Electric Power Corp	KS	Non-Small Company	1	8.76	8.03	$0.0803		$610.58	0.1186%	0.1120%	0.1138%
243	21734	Sunnyside Cogeneration Assoc	UT	Non-Small City	1	0.51	6.26	$0.0626		$27.71	2.7001%	2.5498%	2.5913%
244	19194	Syracuse Energy Corp	NY	Non-Small City	1	0.89	15.27	$0.1527		$117.96	0.0000%	0.0000%	0.0000%
245	18454	Tampa Electric Co	FL	Non-Small City	2	52.3	11.89	$0.1189		$5,397.63	0.0489%	0.0462%	0.0469%
246	18642	Tennessee Valley Authority	AL	Non-Small Federal	11	321.26	8.87	$0.0887	$0.0849	$23,687.35	0.0988%	0.0879%	0.0893%
247		Tennessee Valley Authority	KY				6.63	$0.0663					
248		Tennessee Valley Authority	TN				8.92	$0.0892					
249	18414	TES Filer City Station LP	MI	Small Company	1	0.61	9.23	$0.0923		$48.87	0.0197%	0.0186%	0.0189%
250	18715	Texas Municipal Power Agency	TX	Small City	1	3.97	10.73	$0.1073		$369.75	0.0102%	0.0096%	0.0098%
251	19099	TransAlta Centralia Gen LLC	WA	Non-Small Company	1	15.62	6.98	$0.0698		$946.36	0.0624%	0.0589%	0.0598%
252	19145	Trigen-Cinergy Sol-Tuscola LLC	IL	Non-Small Company	1	0.16	9.34	$0.0934		$12.97	1.3790%	1.3022%	1.3234%
253	30151	Tri-State G & T Assn, Inc	NM	Non-Small Company	3	21.39	8.41	$0.0841	$0.0800	$1,485.94	0.3394%	0.1722%	0.1750%
254		Tri-State G & T Assn, Inc	CO				7.8	$0.0780					
255	24211	Tucson Electric Power Co	AZ	Non-Small City	2	18.01	8.65	$0.0865		$1,352.23	0.9718%	0.9151%	0.9300%
256	19323	TXU Generation Co LP	TX	Non-Small Company	4	128.13	10.73	$0.1073		$11,933.57	0.0222%	0.0210%	0.0213%
257	19391	UGI Development Co	PA	Non-Small Company	1	0.44	9.64	$0.0964		$36.82	0.0875%	0.0826%	0.0840%
258	19436	Union Electric Co	M	Non-Small	4	105.42	6.46	$0.0646		$5,911.19	0.0472%	0.0361%	0.0367%

Exhibit M1
Small Entity Impact Analysis For Regulatory Options Without Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	**Subtitle D Version 1**	**Hybrid C & D**
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
			O	Company									
259	19578	Integrys Energy Group - Upper Peninsula Power Co	MI	Non-Small Company	1	1	9.23	$0.0923		$80.12	0.0066%	0.0062%	0.0063%
260	14932	US Operating Services Company	NJ	Non-Small Company	6	12.47	14.45	$0.1445	$0.1199	$1,298.15	0.6009%	0.1424%	0.1447%
261		US Operating Services Company	FL				11.89	$0.1189					
262		US Operating Services Company	PA				9.64	$0.0964					
263	19856	Vineland City of	NJ	Non-Small City	1	0.85	14.45	$0.1445		$106.61	0.0999%	0.0943%	0.0959%
264	19876	Virginia Electric & Power Co	VA	Non-Small Company	11	169.16	9.01	$0.0901	$0.0858	$12,591.42	0.1211%	0.0861%	0.0875%
265		Virginia Electric & Power Co	WV				6.62	$0.0662					
266	22500	Westar Energy Inc	KS	Non-Small Company	3	35.26	8.03	$0.0803		$2,457.64	0.1310%	0.1237%	0.1257%
267	20447	Western Farmers Elec Coop, Inc	OK	Non-Small Coop	1	10.87	7.67	$0.0767		$723.68	0.0004%	0.0003%	0.0004%
268	20546	Western Kentucky Energy Corp	KY	Non-Small Company	5	17.95	6.63	$0.0663		$1,032.99	2.8822%	2.7218%	2.7660%
269	55808	Westmoreland Partners	NC	Small Company	2	2.1	8.53	$0.0853		$155.48	0.5146%	0.0395%	0.0401%
270	20541	Wheelabrator Environmental Systems	PA	Non-Small Company	1	7.82	9.64	$0.0964		$654.34	0.0475%	0.0449%	0.0456%
271	1951	White Pine Electric Power LLC	MI	Small Company	1	0.53	9.23	$0.0923		$42.46	0.0119%	0.0112%	0.0114%
272	20737	Willmar Municipal Utils Comm	MN	Small City	1	0.26	8	$0.0800		$18.05	0.0579%	0.0546%	0.0555%
273	20847	Wisconsin Electric Power Co	MI	Non-Small Company	5	48.11	9.23	$0.0923	$0.0944	$3,941.26	0.0040%	0.0038%	0.0038%
274		Wisconsin Electric Power Co	WI				9.49	$0.0949					
275	20856	Wisconsin Power & Light Co	WI	Non-Small Company	3	27.51	9.49	$0.0949		$2,266.09	0.0583%	0.0550%	0.0559%
276	20860	Wisconsin Public Service Corp	WI	Non-Small Company	2	13.19	9.49	$0.0949		$1,086.50	0.1040%	0.0982%	0.0998%
277	21025	Integrys Energy Group - WPS Power Developement	PA	Non-Small Company	1	2.62	9.64	$0.0964		$219.23	0.1369%	0.1292%	0.1313%
278	21048	Wyandotte Municipal Serv Comm	MI	Small City	1	0.69	9.23	$0.0923		$55.28	0.0152%	0.0143%	0.0146%
				TOTALS =	495	5,437.3				$423,565.22	**0.1412%**	**0.1162%**	**0.1180%**

Exhibit M2 Small Entity Impact Analysis For Regulatory Options With Land Treatment Dewatering Sub-Option													
											Subtitle C haz waste	**Subtitle D Version 1**	**Hybrid C & D**
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
1	52	Constellation Energy (ACE Cogeneration Co)	CA	Non-Small Company	1	0.95	12.45	$0.1245		$102.66	1.2288%	1.1583%	1.1772%
2	142	AES Corp - AES Beaver Valley	PA	Non-Small Company	1	1.31	9.64	$0.0964		$109.61	0.8985%	0.0000%	0.0000%
3	22125	AES Corp - AES Cayuga LLC	NY	Non-Small Company	1	2.83	15.27	$0.1527		$375.10	0.0000%	0.0000%	0.0000%
4	25	AES Corp - AES Greenidge	NY	Non-Small Company	1	1.42	15.27	$0.1527		$188.21	0.0000%	0.0000%	0.0000%
5	177	AES Corp - AES Hawaii Inc	HI	Non-Small Company	1	1.78	20.54	$0.2054		$317.35	0.0917%	0.0000%	0.0000%
6	21	AES Corp - AES Shady Point LLC	OK	Non-Small Company	1	3.07	7.67	$0.0767		$204.39	1.1678%	0.0000%	0.0000%
7	22129	AES Corp - AES Somerset LLC	NY	Non-Small Company	1	5.74	15.27	$0.1527		$760.80	0.0000%	0.0000%	0.0000%
8	42	AES Corp - AES Thames LLC	CT	Non-Small Company	1	1.87	17.55	$0.1755		$284.86	0.2959%	0.0000%	0.0000%
9	22146	AES Corp - AES Westover LLC	NY	Non-Small Company	1	1.04	15.27	$0.1527		$137.85	0.1704%	0.0000%	0.0000%
10	35	AES Corp - AES WR Ltd Partnership	MD	Non-Small Company	1	2.01	13.45	$0.1345		$234.66	0.9092%	0.0000%	0.0000%
11	261	AGC Division of APG Inc	IN	Non-Small Company	1	6.61	7.62	$0.0762		$437.20	4.7795%	4.7443%	4.7540%
12	353	Air Products Energy Enterprise	CA	Non-Small Company	1	0.53	12.45	$0.1245		$57.27	1.6241%	1.5337%	1.5587%
13	189	Alabama Electric Coop Inc	AL	Non-Small Coop	1	13.46	8.87	$0.0887		$1,036.31	0.3177%	0.2583%	0.2586%
14	195	Alabama Power Co	AL	Non-Small Company	6	125.92	8.87	$0.0887		$9,694.78	0.8174%	0.8104%	0.8123%
15	23279	Allegheny Energy Supply Co LLC	MD	Non-Small Company	6	63.58	13.45	$0.1345	$0.0927	$5,114.96	0.2872%	0.2440%	0.2474%
16		Allegheny Energy Supply Co LLC	PA				9.64	$0.0964					
17		Allegheny Energy Supply Co LLC	WV				6.62	$0.0662					
18	54891	Altura Power	TX	Non-Small Company	1	3.06	10.73	$0.1073		$285.00	0.0577%	0.0544%	0.0553%
19	520	Ameren Energy Generating Co	IL	Non-Small Company	4	40.1	9.34	$0.0934		$3,250.96	0.5488%	0.5094%	0.5106%
20	49756	Ameren Energy Resources Generating Co.	IL	Non-Small Company	2	11.01	9.34	$0.0934		$892.59	2.7253%	2.6843%	2.6956%
21	563	American Bituminous Power LP	WV	Non-Small Company	1	0.84	6.62	$0.0662		$48.27	0.0000%	0.0000%	0.0000%
22	40577	American Mun Power-Ohio, Inc	OH	Non-Small City	1	5.09	8.55	$0.0855		$377.75	0.0000%	0.0000%	0.0000%
23	554	Ames City of	IA	Non-Small City	1	1.64	6.99	$0.0699		$99.50	0.0344%	0.0325%	0.0331%
24	54865	ANP-Coleto Creek	TX	Non-Small	1	5.26	10.73	$0.1073		$489.90	1.0815%	1.0754%	1.0771%

Exhibit M2
Small Entity Impact Analysis For Regulatory Options With Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	**Subtitle D Version 1**	**Hybrid C & D**
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
				Company									
25	733	American Electric Power Co - Appalachian Power Co	VA	Non-Small Company	6	71.11	9.01	$0.0901	$0.0742	$4,577.82	1.0401%	1.0320%	1.0342%
26		American Electric Power Co - Appalachian Power Co	WV				6.62	$0.0662					
27	770	Aquila, Inc.	CO	Non-Small Company	3	14.2	7.8	$0.0780	$0.0691	$851.29	0.0243%	0.0127%	0.0130%
28		Aquila, Inc.	MO				6.46	$0.0646					
29	796	Arizona Electric Pwr Coop Inc	AZ	Non-Small Coop	1	5.79	8.65	$0.0865		$434.72	1.9179%	1.8428%	1.8635%
30	803	Arizona Public Service Co	AZ	Non-Small Company	2	101.48	8.65	$0.0865	$0.0853	$7,513.62	0.9240%	0.8481%	0.8489%
31		Arizona Public Service Co	NM				8.41	$0.0841					
32	924	Associated Electric Coop, Inc	MO	Non-Small Coop	2	42.13	6.46	$0.0646		$2,362.35	0.4191%	0.4150%	0.4162%
33	986	Aurora Energy LLC	AK	Small Company	1	0.25	14.64	$0.1464		$31.77	1.6895%	1.5955%	1.6214%
34	1009	Austin City of	MN	Small City	1	0.57	8	$0.0800		$39.58	0.0043%	0.0041%	0.0041%
35	1307	Basin Electric Power Coop	ND	Non-Small Coop	3	30.98	6.44	$0.0644	$0.0625	$1,681.56	1.4031%	1.3929%	1.3957%
36		Basin Electric Power Coop	WY				5.88	$0.0588					
37	1735	Birchwood Power Partners LP	VA	Non-Small Company	1	2.26	9.01	$0.0901		$176.75	0.3772%	0.0000%	0.0000%
38	19545	Black Hills Power Inc	WY	Non-Small Company	5	4.2	5.88	$0.0588		$214.36	0.3664%	0.3460%	0.3516%
39	1746	Black River Generation LLC	NY	Non-Small Company	1	0.49	15.27	$0.1527		$64.95	0.0000%	0.0000%	0.0000%
40	13143	Board of Water Electric & Communications	IA	Small City	1	2.57	6.99	$0.0699		$155.93	0.0041%	0.0038%	0.0039%
41	2884	Cambria CoGen Co	PA	Non-Small Company	1	0.86	9.64	$0.0964		$71.96	0.4789%	0.4522%	0.4596%
42	3006	Cardinal Operating Co	OH	Non-Small Company	1	16.47	8.55	$0.0855		$1,222.30	3.1383%	3.1309%	3.1330%
43	54889	Carlyle/Riverstone Renewable Energy	NC	Non-Small Company	1	0.39	8.53	$0.0853		$28.88	0.2001%	0.1889%	0.1920%
44	3203	Cedar Falls Utilities	IA	Small City	1	0.92	6.99	$0.0699		$55.82	0.0336%	0.0317%	0.0322%
45	3242	Central Electric Power Coop	MO	Small Coop	1	0.52	6.46	$0.0646		$29.16	0.2509%	0.2369%	0.2408%
46	3258	Central Iowa Power Cooperative	IA	Small Coop	1	1.31	6.99	$0.0699		$79.48	0.1274%	0.1203%	0.1223%
47	3303	Central Power & Lime Inc	FL	Non-Small Company	1	1.1	11.89	$0.1189		$113.53	0.0000%	0.0000%	0.0000%
48	3593	Choctaw Generating LP	MS	Non-Small	1	4.5	8.98	$0.0898		$350.76	0.1961%	0.1852%	0.1882%

Exhibit M2
Small Entity Impact Analysis For Regulatory Options With Land Treatment Dewatering Sub-Option

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				Company									
49	3599	Citizens Thermal Energy	IN	Non-Small Company	1	0.18	7.62	$0.0762		$11.91	0.0719%	0.0679%	0.0690%
50	4045	City of Columbia	MO	Non-Small City	1	0.83	6.46	$0.0646		$46.54	0.0260%	0.0246%	0.0250%
51	5336	City of Dover	OH	Small City	1	0.47	8.55	$0.0855		$34.88	0.0000%	0.0000%	0.0000%
52	7483	City of Grand Haven	MI	Small City	1	0.88	9.23	$0.0923		$70.50	0.0183%	0.0173%	0.0176%
53	7977	City of Hamilton	OH	Non-Small City	1	1.84	8.55	$0.0855		$136.55	0.1274%	0.0000%	0.0000%
54	8723	City of Holland	MI	Small City	1	2.18	9.23	$0.0923		$174.65	0.0044%	0.0042%	0.0043%
55	9667	City of Jasper	IN	Small City	1	0.13	7.62	$0.0762		$8.60	0.0527%	0.0498%	0.0506%
56	10623	City of Lakeland	FL	Non-Small City	1	10.67	11.89	$0.1189		$1,101.20	0.0822%	0.0776%	0.0788%
57	11142	City of Logansport	IN	Small City	1	0.53	7.62	$0.0762		$35.06	0.0272%	0.0257%	0.0261%
58	11701	City of Marquette	MI	Small City	1	0.92	9.23	$0.0923		$73.71	0.0088%	0.0083%	0.0084%
59	11732	City of Marshall	MO	Small City	1	0.5	6.46	$0.0646		$28.04	0.0396%	0.0374%	0.0380%
60	12298	City of Menasha	WI	Small City	1	0.25	9.49	$0.0949		$20.59	0.6795%	0.6417%	0.6522%
61	14194	City of Orrville	OH	Small City	1	0.74	8.55	$0.0855		$54.92	0.0000%	0.0000%	0.0000%
62	14268	City of Owensboro	KY	Non-Small City	1	3.9	6.63	$0.0663		$224.44	0.4864%	0.0000%	0.0000%
63	14381	City of Painesville	OH	Small City	1	0.47	8.55	$0.0855		$34.88	0.0000%	0.0000%	0.0000%
64	15989	City of Richmond	IN	Small City	1	0.82	7.62	$0.0762		$54.24	0.0923%	0.0872%	0.0886%
65	17043	City of Shelby	OH	Small City	1	0.37	8.55	$0.0855		$27.46	0.0000%	0.0000%	0.0000%
66	17177	City of Sikeston	MO	Small City	1	2.32	6.46	$0.0646		$130.09	0.8582%	0.8467%	0.8499%
67	17828	City of Springfield	IL	Non-Small City	2	5.7	9.34	$0.0934		$462.11	1.3800%	1.3682%	1.3715%
68	19883	City of Virginia	MN	Small City	1	0.26	8	$0.0800		$18.05	0.0438%	0.0414%	0.0420%
69	17833	City Utilities of Springfield	MO	Non-Small City	2	7.79	6.46	$0.0646		$436.81	0.0604%	0.0570%	0.0579%
70	3265	Cleco Power LLC	LA	Non-Small Company	2	18.94	8.2	$0.0820		$1,348.07	0.3128%	0.3115%	0.3119%
71	3901	Cogentrix Energy - Cogentrix-Virginia Leas'g Corp	VA	Non-Small Company	1	1.01	9.01	$0.0901		$78.99	0.3005%	0.0000%	0.0000%
72	4129	Colmac Clarion Inc	PA	Non-Small Company	1	0.32	9.64	$0.0964		$26.78	0.2950%	0.2786%	0.2831%
73	19173	Suez Energy - Colorado Energy Nations Company LLP	CO	Non-Small Company	1	0.31	7.8	$0.0780		$20.99	0.0550%	0.0520%	0.0528%
74	3989	Colorado Springs City of	CO	Non-Small City	2	10.27	7.8	$0.0780		$695.32	0.0073%	0.0069%	0.0070%
75	4217	Colstrip Energy LP	MT	Small Company	1	0.36	7.26	$0.0726		$22.69	0.0316%	0.0298%	0.0303%
76	4062	American Electric Power Co - Columbus Southern Power Co	OH	Non-Small Company	2	33	8.55	$0.0855		$2,449.06	1.7194%	1.7096%	1.7123%
77	4158	Conectiv Atlantic Generatn Inc	NJ	Non-Small Company	1	6.98	14.45	$0.1445		$875.47	0.0044%	0.0000%	0.0000%
78	4252	Conectiv Delmarva Gen Inc	DE	Non-Small	1	18.05	12.06	$0.1206		$1,889.49	0.0223%	0.0000%	0.0000%

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				Company									
79	4161	Constellation Power Source Gen	MD	Non-Small Company	3	34.67	13.45	$0.1345		$4,047.58	0.0574%	0.0000%	0.0000%
80	4254	Consumers Energy Co	MI	Non-Small Company	5	71.86	9.23	$0.0923		$5,757.16	0.2450%	0.2445%	0.2447%
81	4363	Corn Belt Power Coop	IA	Small Coop	1	1.25	6.99	$0.0699		$75.84	0.0175%	0.0166%	0.0168%
82	4508	Crawfordsville Elec, Lgt & Pwr	IN	Small City	1	0.22	7.62	$0.0762		$14.55	0.0642%	0.0606%	0.0616%
83	4538	Crisp County Power Comm	GA	Small County	1	0.3	8.79	$0.0879		$22.89	0.0192%	0.0181%	0.0184%
84	4716	Dairyland Power Coop	WI	Non-Small Coop	3	8.84	9.49	$0.0949		$728.18	0.0781%	0.0738%	0.0749%
85	4922	DPL Inc - Dayton Power & Light Co	OH	Non-Small Company	3	35.43	8.55	$0.0855		$2,629.40	2.8763%	2.8436%	2.8479%
86	40230	Deseret Generation & Tran Coop	UT	Non-Small Coop	1	4.38	6.26	$0.0626		$238.00	0.6373%	0.6018%	0.6116%
87	5109	Detroit Edison Co	MI	Non-Small Company	6	106.39	9.23	$0.0923		$8,523.58	0.4612%	0.4591%	0.4596%
88	50018	Dominion Energy New England, LLC	MA	Non-Small Company	2	25.68	16.05	$0.1605		$3,577.58	0.0201%	0.0000%	0.0000%
89	5269	Dominion Energy Services Co	IL	Non-Small Company	1	11.55	9.34	$0.0934		$936.37	0.0480%	0.0000%	0.0000%
90	34672	DTE Energy Services	AL	Non-Small Company	1	0.8	8.87	$0.0887		$61.59	0.0112%	0.0106%	0.0107%
91	5416	Duke Energy Carolinas, LLC	NC	Non-Small Company	8	192.46	8.53	$0.0853		$14,249.82	0.4362%	0.4301%	0.4318%
92	15470	Duke Energy Indiana Inc	IN	Non-Small Company	5	73.49	7.62	$0.0762		$4,860.75	2.4769%	2.4624%	2.4664%
93	55729	Duke Energy Kentucky Inc	KY	Non-Small Company	1	10.15	6.63	$0.0663		$584.12	3.6332%	3.5545%	3.5762%
94	3542	Duke Energy Ohio Inc	OH	Non-Small Company	3	74.97	8.55	$0.0855		$5,563.82	0.5149%	0.5088%	0.5105%
95	13579	NRG Energy - Dunkirk Power LLC	NY	Non-Small Company	1	5.49	15.27	$0.1527		$727.66	0.0405%	0.0000%	0.0000%
96	5517	Dynegy Midwest Generation Inc	IL	Non-Small Company	5	47.09	9.34	$0.0934		$3,817.64	0.6253%	0.6179%	0.6199%
97	5511	Dynegy Northeast Gen Inc	NY	Non-Small Company	1	15.59	15.27	$0.1527		$2,066.35	0.0000%	0.0000%	0.0000%
98	5580	East Kentucky Power Coop, Inc	KY	Non-Small Coop	3	23.77	6.63	$0.0663		$1,367.93	1.4588%	1.3972%	1.4142%
99	5670	Babcox & Wicox & ESI Inc - Ebensburg Power Co	PA	Non-Small Company	1	0.5	9.64	$0.0964		$41.84	0.5850%	0.5524%	0.5614%
100	55739	Edgecombe Operating Services LLC	NC	Small Company	1	1.01	8.53	$0.0853		$74.78	0.5365%	0.0000%	0.0000%
101	5748	Electric Energy Inc	IL	Non-Small Company	1	9.63	9.34	$0.0934		$780.72	0.0000%	0.0000%	0.0000%
102	5860	Empire District Electric Co	KS	Non-Small Company	2	13.91	8.03	$0.0803	$0.0725	$874.75	0.4750%	0.4740%	0.4743%
103		Empire District Electric Co	M				6.46	$0.0646					

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			O										
104	814	Entergy Arkansas Inc	AR	Non-Small Company	2	66.71	7.96	$0.0796		$4,609.18	0.1382%	0.1306%	0.1327%
105	55936	Entergy Gulf States Louisiana LLC	LA	Non-Small Company	1	47.23	8.2	$0.0820		$3,361.64	0.0000%	0.0000%	0.0000%
106	6035	Exelon Power	PA	Non-Small Company	2	77.96	9.64	$0.0964		$6,523.32	0.0119%	0.0000%	0.0000%
107	6526	FirstEnergy Generation Corp	OH	Non-Small Company	7	93.78	8.55	$0.0855	$0.0871	$7,086.54	1.4244%	1.3462%	1.3502%
108		FirstEnergy Generation Corp	PA				9.64	$0.0964					
109	54895	FirstLight Power Resources Services LLC	MA	Non-Small Company	1	11.23	16.05	$0.1605		$1,564.50	0.0116%	0.0000%	0.0000%
110	6811	FPL Energy Operating Servs Inc	CA	Non-Small Company	1	0.47	12.45	$0.1245		$50.79	0.9843%	0.9295%	0.9446%
111	6779	Fremont City of	NE	Small City	1	1.49	6.67	$0.0667		$86.26	0.1183%	0.0406%	0.0413%
112	6909	Gainesville Regional Utilities	FL	Non-Small City	1	6.24	11.89	$0.1189		$644.00	0.0063%	0.0059%	0.0060%
113	7140	Georgia Power Co	GA	Non-Small Company	10	207.69	8.79	$0.0879		$15,846.17	0.8611%	0.8524%	0.8544%
114	7199	Gilberton Power Co	PA	Non-Small Company	1	0.77	9.64	$0.0964		$64.43	0.4932%	0.4658%	0.4733%
115	7353	Golden Valley Elec Assn Inc	AK	Small Company	1	2.42	14.64	$0.1464		$307.52	0.1096%	0.1035%	0.1052%
116	40606	Grand Island City of	NE	Small City	1	3.07	6.67	$0.0667		$177.74	0.0184%	0.0000%	0.0000%
117	7490	Grand River Dam Authority	OK	Non-Small State	1	13.56	7.67	$0.0767		$902.77	0.1821%	0.1720%	0.1748%
118	7570	Great River Energy	ND	Non-Small Coop	2	24.23	6.44	$0.0644		$1,354.44	0.0227%	0.0215%	0.0218%
119	7651	Greenwood Utilities Comm	MS	Small City	1	0.67	8.98	$0.0898		$52.22	0.0139%	0.0132%	0.0134%
120	7801	Gulf Power Co	FL	Non-Small Company	3	20.52	11.89	$0.1189		$2,117.77	0.2572%	0.2567%	0.2569%
121	8245	Hastings City of	NE	Small City	1	1.2	6.67	$0.0667		$69.47	1.0284%	0.9712%	0.9870%
122	8286	Hawaiian Com & Sugar Co Ltd	HI	Non-Small Company	1	0.58	20.54	$0.2054		$103.41	0.7528%	0.7109%	0.7225%
123	8449	Henderson City Utility Comm	KY	Small City	1	0.4	6.63	$0.0663		$23.02	0.0497%	0.0469%	0.0477%
124	8543	Hibbing Public Utilities Comm	MN	Small City	1	0.31	8	$0.0800		$21.53	0.0173%	0.0164%	0.0166%
125	9267	Hoosier Energy R E C, Inc	IN	Non-Small Company	2	17.16	7.62	$0.0762		$1,134.99	0.3380%	0.3338%	0.3349%
126	9231	Independence City of	MO	Non-Small City	2	2.97	6.46	$0.0646		$166.54	1.4654%	1.4583%	1.4603%
127	9332	NRG Energy - Indian River Operations Inc	DE	Non-Small Company	1	7	12.06	$0.1206		$732.77	0.3217%	0.3038%	0.3087%
128	9324	American Electric Power Co - Indiana Michigan Power Co	IN	Non-Small Company	2	52.63	7.62	$0.0762		$3,481.03	0.4376%	0.4315%	0.4332%
129	9269	Indiana-Kentucky Electric Corp	IN	Non-Small Company	1	11.42	7.62	$0.0762		$755.34	0.2885%	0.2835%	0.2846%

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130	9273	Indianapolis Power & Light Co	IN	Non-Small Company	3	33.01	7.62	$0.0762		$2,183.33	0.8395%	0.6561%	0.6570%
131	9379	Constellation Energy - Inter-Power/AhlCon Partners, L.P.	PA	Non-Small Company	1	1.03	9.64	$0.0964		$86.19	0.5383%	0.3393%	0.3448%
132	9417	Interstate Power and Light Co	IA	Non-Small Company	8	29.86	6.99	$0.0699		$1,811.70	0.1224%	0.1198%	0.1201%
133	9628	Cogentrix Energy - James River Cogeneration Co	VA	Non-Small Company	1	1.01	9.01	$0.0901		$78.99	0.0000%	0.0000%	0.0000%
134	9645	Jamestown Board of Public Util	NY	Small City	1	0.88	15.27	$0.1527		$116.64	0.0000%	0.0000%	0.0000%
135	9617	JEA	FL	Non-Small City	2	36.23	11.89	$0.1189		$3,739.12	0.1004%	0.0948%	0.0963%
136	9996	Kansas City City of	KS	Non-Small City	2	7.96	8.03	$0.0803		$554.82	0.2205%	0.1709%	0.1715%
137	10000	Kansas City Power & Light Co	KS	Non-Small Company	4	44.36	8.03	$0.0803	$0.0685	$2,638.52	0.1892%	0.1586%	0.1604%
138		Kansas City Power & Light Co	MO				6.46	$0.0646					
139	22053	American Electric Power Co - Kentucky Power Co	KY	Non-Small Company	1	9.61	6.63	$0.0663		$553.04	5.6380%	5.5491%	5.5736%
140	10171	EON USA LLC - Kentucky Utilities Co	KY	Non-Small Company	4	39.2	6.63	$0.0663		$2,255.90	3.8957%	3.8314%	3.8491%
141	56155	Lansing Board of Water and Light	MI	Non-Small City	2	4.64	9.23	$0.0923		$371.74	0.1726%	0.1479%	0.1486%
142	11208	Los Angeles City of	UT	Non-Small City	1	70.99	6.26	$0.0626		$3,857.37	0.2739%	0.2691%	0.2704%
143	11252	NRG Energy - Louisiana Generating LLC	LA	Non-Small Company	1	20.71	8.2	$0.0820		$1,474.05	0.7089%	0.7089%	0.7089%
144	11249	Louisville Gas & Electric Co	KY	Non-Small Company	3	39.49	6.63	$0.0663		$2,272.59	1.6151%	1.4063%	1.4139%
145	11269	Lower Colorado River Authority	TX	Non-Small State	1	31.9	10.73	$0.1073		$2,971.05	0.1046%	0.1044%	0.1045%
146	11479	Madison Gas & Electric Co	WI	Non-Small Company	1	5.43	9.49	$0.0949		$447.29	0.0006%	0.0000%	0.0000%
147	11571	Manitowoc Public Utilities	WI	Small City	1	1.56	9.49	$0.0949		$128.50	0.2202%	0.2079%	0.2113%
148	12199	MDU Resources Group Inc	ND	Non-Small Company	2	2.66	6.44	$0.0644	$0.0685	$158.16	0.0686%	0.0550%	0.0559%
149		MDU Resources Group Inc	MT				7.26	$0.0726					
150	12807	Michigan South Central Pwr Agy	MI	Small City	1	0.78	9.23	$0.0923		$62.49	0.0193%	0.0182%	0.0185%
151	12435	Integrys Energy Group - Mid-America Power LLC	WI	Non-Small Company	1	0.46	9.49	$0.0949		$37.89	0.2543%	0.2402%	0.2441%
152	12341	MidAmerican Energy Co	IA	Non-Small Company	5	58.13	6.99	$0.0699		$3,526.93	0.6447%	0.6270%	0.6311%
153	12384	Midwest Generations EME LLC	IL	Non-Small Company	8	113.38	9.34	$0.0934	$0.0938	$9,228.76	0.0220%	0.0025%	0.0025%
154		Midwest Generations EME LLC	PA				9.64	$0.0964					
155	12647	Minnesota Power Inc	MN	Non-Small Company	5	15	8	$0.0800		$1,041.60	2.2746%	2.2687%	2.2703%
156	12658	Minnkota Power Coop, Inc	ND	Non-Small Coop	1	6.56	6.44	$0.0644		$366.70	2.9761%	2.8947%	2.8953%

Exhibit M2
Small Entity Impact Analysis For Regulatory Options With Land Treatment Dewatering Sub-Option

											Subtitle C haz waste	Subtitle D Version 1	Hybrid C & D
Item	Utility Code	Owner Entity Name	State	Owner Entity Size/Type	Number of Affected Plants	Estimated annual million megawatt hours for Col. D size assignment	State Electricty rate (cents per kilamwatt hour) 2009	2009 price in dollar units	Weighted average price ($per kwhour)	Annual Revenue (Million $)	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues	Total Annual Cost as % Electricity Plant Annual Revenues
157	12628	Mirant - Chalk Point LLC	MD	Non-Small Company	1	23.19	13.45	$0.1345		$2,707.34	0.0356%	0.0336%	0.0342%
158	12653	Mirant - Mid-Atlantic LLC	MD	Non-Small Company	2	21.71	13.45	$0.1345		$2,534.56	0.0113%	0.0106%	0.0108%
159	12792	Mirant - New York Inc	NY	Non-Small Company	1	14.81	15.27	$0.1527		$1,962.97	0.0307%	0.0000%	0.0000%
160	12588	Mirant - Potomac River LLC	VA	Non-Small Company	1	4.5	9.01	$0.0901		$351.93	0.0000%	0.0000%	0.0000%
161	12686	Mississippi Power Co	MS	Non-Small Company	2	33.55	8.98	$0.0898		$2,615.10	0.1468%	0.1449%	0.1454%
162	12796	Monongahela Power Co	WV	Non-Small Company	4	15.36	6.62	$0.0662		$882.61	0.2474%	0.1101%	0.1119%
163	12949	Cogentrix Energy - Morgantown Energy Associates	WV	Non-Small Company	1	0.6	6.62	$0.0662		$34.48	0.0000%	0.0000%	0.0000%
164	49889	Mount Carmel Cogen Inc	PA	Small Company	1	0.41	9.64	$0.0964		$34.31	1.0083%	0.9521%	0.9676%
165	13060	Mt Poso Cogeneration Co	CA	Non-Small Company	1	0.54	12.45	$0.1245		$58.36	0.9029%	0.8526%	0.8665%
166	13337	Nebraska Public Power District	NE	Non-Small State	2	26.88	6.67	$0.0667		$1,556.23	0.2066%	0.1951%	0.1983%
167	13407	Nevada Power Co	NV	Non-Small Company	1	34.7	9.56	$0.0956		$2,879.43	0.0440%	0.0415%	0.0422%
168	13488	New Ulm Public Utilities Comm	MN	Small City	1	0.69	8	$0.0800		$47.91	0.0193%	0.0182%	0.0185%
169	54784	NewPage Corporation	ME	Non-Small Company	1	1.01	14.47	$0.1447		$126.86	0.4372%	0.2741%	0.2785%
170	55807	Niagara Generation LLC	NY	Non-Small City	1	0.49	15.27	$0.1527		$64.95	0.0000%	0.0000%	0.0000%
171	35120	Norit Americas Inc	TX	Non-Small Company	1	0.02	10.73	$0.1073		$1.86	0.0813%	0.0768%	0.0781%
172	13695	North Carolina Power Holdings, LLC	NC	Non-Small Company	2	0.61	8.53	$0.0853		$45.16	0.0853%	0.0806%	0.0819%
173	13833	Suez Energy - Northeastern Power Co	PA	Non-Small Company	1	0.5	9.64	$0.0964		$41.84	0.6122%	0.5781%	0.5875%
174	13756	Northern Indiana Pub Serv Co	IN	Non-Small Company	3	35.73	7.62	$0.0762		$2,363.24	0.0552%	0.0484%	0.0491%
175	13781	Northern States Power Co	MN	Non-Small Company	5	73.7	8	$0.0800	$0.0830	$5,308.36	0.9683%	0.9546%	0.9584%
176		Northern States Power Co	WI				9.49	$0.0949					
177	7860	NRG Energy - Energy Center Dover LLC	DE	Non-Small Company	1	1.03	12.06	$0.1206		$107.82	0.2417%	0.2283%	0.2320%
178	13168	NRG Energy - Huntley Operations Inc	NY	Non-Small Company	1	7.15	15.27	$0.1527		$947.69	0.0000%	0.0000%	0.0000%
179	54888	NRG Energy - Texas LLC	TX	Non-Small Company	2	125.29	10.73	$0.1073		$11,669.06	0.0071%	0.0067%	0.0068%
180	14006	American Electric Power Co - Ohio	OH	Non-Small	4	57.13	8.55	$0.0855	$0.0759	$3,761.31	1.7867%	1.7527%	1.7621%

Exhibit M2
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		Power Co		Company									
181		American Electric Power Co - Ohio Power Co	WV				6.62	$0.0662					
182	14015	Ohio Valley Electric Corp	OH	Non-Small Company	1	9.52	8.55	$0.0855		$706.52	2.7698%	2.7523%	2.7571%
183	14063	Oklahoma Gas & Electric Co	OK	Non-Small Company	2	62.7	7.67	$0.0767		$4,174.29	0.0169%	0.0000%	0.0000%
184	14127	Omaha Public Power District	NE	Non-Small State	2	22.92	6.67	$0.0667		$1,326.97	0.0362%	0.0342%	0.0347%
185	14165	Orion Power Midwest LP	OH	Non-Small Company	5	31.19	8.55	$0.0855	$0.0920	$2,491.79	0.0493%	0.0011%	0.0011%
186		Orion Power Midwest LP	PA				9.64	$0.0964					
187	14610	Orlando Utilities Comm	FL	Non-Small City	1	11.4	11.89	$0.1189		$1,176.54	0.1774%	0.1676%	0.1703%
188	14232	Otter Tail Power Co	MN	Non-Small Company	3	10.48	8	$0.0800	$0.0716	$651.62	0.0742%	0.0701%	0.0712%
189		Otter Tail Power Co	SD				7.05	$0.0705					
190		Otter Tail Power Co	ND				6.44	$0.0644					
191	14354	PacifiCorp	UT	Non-Small Company	7	88.08	6.26	$0.0626	$0.0604	$4,619.97	0.9204%	0.8802%	0.8848%
192		PacifiCorp	WY				5.88	$0.0588					
193	14432	Constellation Energy - Panther Creek Partners	PA	Non-Small Company	1	0.82	9.64	$0.0964		$68.61	0.3071%	0.2900%	0.2947%
194	14645	Pella City of	IA	Small City	1	0.61	6.99	$0.0699		$37.01	0.0358%	0.0338%	0.0344%
195	14839	Peru City of	IN	Small City	1	0.32	7.62	$0.0762		$21.17	0.0567%	0.0535%	0.0544%
196	15143	Platte River Power Authority	CO	Non-Small State	1	5.78	7.8	$0.0780		$391.33	0.1549%	0.1523%	0.1530%
197	15248	Portland General Electric Co	OR	Non-Small Company	1	23.32	7.7	$0.0770		$1,558.62	0.0539%	0.0509%	0.0517%
198	15537	PPL - Brunner Island LLC	PA	Non-Small Company	1	13.73	9.64	$0.0964		$1,148.86	0.0000%	0.0000%	0.0000%
199	15298	PPL - Montana LLC	MT	Non-Small Company	2	26.46	7.26	$0.0726		$1,667.42	5.5709%	5.5019%	5.5209%
200	15534	PPL - Montour LLC	PA	Non-Small Company	1	14.38	9.64	$0.0964		$1,203.25	0.0000%	0.0000%	0.0000%
201	54708	Primary Energy of North Carolina LLC	NC	Non-Small Company	2	1.77	8.53	$0.0853		$131.05	0.1309%	0.0299%	0.0304%
202	3046	Progress Energy Carolinas Inc	NC	Non-Small Company	8	120.48	8.53	$0.0853	$0.0850	$8,892.94	0.7437%	0.7416%	0.7421%
203		Progress Energy Carolinas Inc	SC				8.32	$0.0832					
204	6455	Progress Energy Florida Inc	FL	Non-Small Company	1	95.44	11.89	$0.1189		$9,849.90	0.0022%	0.0021%	0.0021%
205	15147	PSEG Fossil LLC	NJ	Non-Small Company	2	77.94	14.45	$0.1445		$9,775.70	0.0137%	0.0000%	0.0000%
206	15452	PSEG Power Connecticut LLC	CT	Non-Small	1	9.12	17.55	$0.1755		$1,389.29	0.0094%	0.0000%	0.0000%

Exhibit M2
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				Company									
207	15466	Public Service Co of Colorado	CO	Non-Small Company	7	39.41	7.8	$0.0780		$2,668.21	0.0724%	0.0038%	0.0039%
208	15472	Public Service Co of NH	NH	Non-Small Company	2	10.38	15.5	$0.1550		$1,396.53	0.0379%	0.0017%	0.0017%
209	15473	Public Service Co of NM	NM	Non-Small Company	1	27.09	8.41	$0.0841		$1,977.54	0.4838%	0.4569%	0.4643%
210	15474	American Electric Power Co - Public Service Co of Oklahoma	OK	Non-Small Company	2	43.84	7.67	$0.0767	$0.0920	$3,500.89	0.0996%	0.0987%	0.0990%
211		American Electric Power Co - Public Service Co of Oklahoma	TX				10.73	$0.1073					
212	55768	RC Cape May Holdings LLC	NJ	Non-Small Company	1	4.24	14.45	$0.1445		$531.81	0.0054%	0.0000%	0.0000%
213	17235	NRG Energy - Reliant Energy Mid-Atlantic PH LLC	PA	Non-Small Company	3	17.19	9.64	$0.0964		$1,438.38	0.0116%	0.0110%	0.0111%
214	15998	NRG Energy - Reliant Energy Seward LLC	PA	Non-Small Company	1	7.04	9.64	$0.0964		$589.07	0.4252%	0.4015%	0.4080%
215	15873	NRG Energy - Reliant Engy NE Management Co	PA	Non-Small Company	2	33	9.64	$0.0964		$2,761.28	0.0579%	0.0547%	0.0556%
216	16061	Constellation Energy - Rio Bravo Jasmin	CA	Non-Small Company	1	0.33	12.45	$0.1245		$35.66	0.7842%	0.7406%	0.7526%
217	16002	Constellation Energy - Rio Bravo Poso	CA	Non-Small Company	1	0.33	12.45	$0.1245		$35.66	0.7683%	0.7256%	0.7374%
218	16183	Energy East Corporation - Rochester Gas & Electric Corp	NY	Non-Small Company	1	3.61	15.27	$0.1527		$478.48	0.0290%	0.0000%	0.0000%
219	16181	Rochester Public Utilities	MN	Non-Small City	1	1.67	8	$0.0800		$115.96	0.0249%	0.0236%	0.0239%
220	16233	Rocky Mountain Power Inc	MT	Non-Small Company	1	1.01	7.26	$0.0726		$63.65	0.0339%	0.0320%	0.0325%
221	16572	Salt River Project	AZ	Non-Small State	2	58.44	8.65	$0.0865		$4,387.79	0.5977%	0.5698%	0.5775%
222	16604	San Antonio City of	TX	Non-Small City	2	42.57	10.73	$0.1073		$3,964.82	0.0077%	0.0024%	0.0024%
223	16624	San Miguel Electric Coop, Inc	TX	Small Coop	1	3.59	10.73	$0.1073		$334.36	2.1589%	0.0000%	0.0000%
224	56190	Savannah River Nuclear Solutions LLC	SC	Non-Small Company	1	0.69	8.32	$0.0832		$49.83	0.0000%	0.0000%	0.0000%
225	16793	Schuylkill Energy Resource Inc	PA	Small Company	1	0.87	9.64	$0.0964		$72.80	1.0407%	0.9828%	0.9987%
226	21554	Seminole Electric Coop, Inc	FL	Non-Small Coop	1	20.38	11.89	$0.1189		$2,103.32	0.3157%	0.2979%	0.3027%
227	17166	Sierra Pacific Power Co	NV	Non-Small Company	1	12.53	9.56	$0.0956		$1,039.75	0.3230%	0.3050%	0.3099%
228	29878	Somerset Power LLC	MA	Small City	1	1.96	16.05	$0.1605		$273.06	0.0622%	0.0000%	0.0000%
229	17539	South Carolina Electric&Gas Co	SC	Non-Small Company	6	51.25	8.32	$0.0832		$3,701.15	0.2474%	0.2465%	0.2467%
230	17554	South Carolina Genertg Co, Inc	SC	Non-Small	1	6.01	8.32	$0.0832		$434.03	0.0000%	0.0000%	0.0000%

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				Company									
231	17543	South Carolina Pub Serv Auth	SC	Non-Small State	4	44.79	8.32	$0.0832		$3,234.63	0.1953%	0.1741%	0.1747%
232	17568	South Mississippi El Pwr Assn	MS	Non-Small Coop	1	10.26	8.98	$0.0898		$799.73	0.1820%	0.1719%	0.1747%
233	17632	Southern Illinois Power Coop	IL	Small Coop	1	3.7	9.34	$0.0934		$299.96	0.9464%	0.0000%	0.0000%
234	17633	Southern Indiana Gas & Elec Co	IN	Non-Small Company	2	11.26	7.62	$0.0762		$744.75	2.3710%	2.2704%	2.2744%
235	17698	American Electric Power Co - Southwestern Electric Power Co	AR	Non-Small Company	3	44.92	7.96	$0.0796	$0.0981	$3,823.67	0.3407%	0.3369%	0.3380%
236		American Electric Power Co - Southwestern Electric Power Co	TX				10.73	$0.1073					
237	17718	Southwestern Public Service Co	TX	Non-Small Company	2	39.52	10.73	$0.1073		$3,680.75	0.0000%	0.0000%	0.0000%
238	40307	Soyland Power Coop Inc	IL	Small Coop	1	1.58	9.34	$0.0934		$128.09	0.0866%	0.0818%	0.0831%
239	55740	Spruance Operating Services LLC	VA	Small Company	1	2.01	9.01	$0.0901		$157.20	0.5679%	0.0000%	0.0000%
240	18041	State Line Energy LLC	IN	Non-Small Company	1	5.38	7.62	$0.0762		$355.84	0.0318%	0.0000%	0.0000%
241	22001	Sunbury Generation LP	PA	Non-Small Company	1	4.3	9.64	$0.0964		$359.80	0.1748%	0.1014%	0.1029%
242	18315	Sunflower Electric Power Corp	KS	Non-Small Company	1	8.76	8.03	$0.0803		$610.58	0.1186%	0.1120%	0.1138%
243	21734	Sunnyside Cogeneration Assoc	UT	Non-Small City	1	0.51	6.26	$0.0626		$27.71	2.7001%	2.5498%	2.5913%
244	19194	Syracuse Energy Corp	NY	Non-Small City	1	0.89	15.27	$0.1527		$117.96	0.0000%	0.0000%	0.0000%
245	18454	Tampa Electric Co	FL	Non-Small City	2	52.3	11.89	$0.1189		$5,397.63	0.0540%	0.0513%	0.0520%
246	18642	Tennessee Valley Authority	AL	Non-Small Federal	11	321.26	8.87	$0.0887	$0.0849	$23,687.35	0.7736%	0.7627%	0.7641%
247		Tennessee Valley Authority	KY				6.63	$0.0663					
248		Tennessee Valley Authority	TN				8.92	$0.0892					
249	18414	TES Filer City Station LP	MI	Small Company	1	0.61	9.23	$0.0923		$48.87	0.0197%	0.0186%	0.0189%
250	18715	Texas Municipal Power Agency	TX	Small City	1	3.97	10.73	$0.1073		$369.75	0.0102%	0.0096%	0.0098%
251	19099	TransAlta Centralia Gen LLC	WA	Non-Small Company	1	15.62	6.98	$0.0698		$946.36	0.0624%	0.0589%	0.0598%
252	19145	Trigen-Cinergy Sol-Tuscola LLC	IL	Non-Small Company	1	0.16	9.34	$0.0934		$12.97	1.3790%	1.3022%	1.3234%
253	30151	Tri-State G & T Assn, Inc	NM	Non-Small Company	3	21.39	8.41	$0.0841	$0.0800	$1,485.94	0.4186%	0.2513%	0.2541%
254		Tri-State G & T Assn, Inc	CO				7.8	$0.0780					
255	24211	Tucson Electric Power Co	AZ	Non-Small City	2	18.01	8.65	$0.0865		$1,352.23	0.9718%	0.9151%	0.9300%
256	19323	TXU Generation Co LP	TX	Non-Small Company	4	128.13	10.73	$0.1073		$11,933.57	0.2197%	0.2184%	0.2188%
257	19391	UGI Development Co	PA	Non-Small Company	1	0.44	9.64	$0.0964		$36.82	0.0875%	0.0826%	0.0840%
258	19436	Union Electric Co	MO	Non-Small Company	4	105.42	6.46	$0.0646		$5,911.19	0.7558%	0.7447%	0.7453%
259	19578	Integrys Energy Group - Upper	MI	Non-Small	1	1	9.23	$0.0923		$80.12	0.0066%	0.0062%	0.0063%

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		Peninsula Power Co		Company									
260	14932	US Operating Services Company	NJ	Non-Small Company	6	12.47	14.45	$0.1445	$0.1199	$1,298.15	0.6009%	0.1424%	0.1447%
261		US Operating Services Company	FL				11.89	$0.1189					
262		US Operating Services Company	PA				9.64	$0.0964					
263	19856	Vineland City of	NJ	Non-Small City	1	0.85	14.45	$0.1445		$106.61	0.0999%	0.0943%	0.0959%
264	19876	Virginia Electric & Power Co	VA	Non-Small Company	11	169.16	9.01	$0.0901	$0.0858	$12,591.42	0.3844%	0.3494%	0.3508%
265		Virginia Electric & Power Co	WV				6.62	$0.0662					
266	22500	Westar Energy Inc	KS	Non-Small Company	3	35.26	8.03	$0.0803		$2,457.64	0.6923%	0.6850%	0.6870%
267	20447	Western Farmers Elec Coop, Inc	OK	Non-Small Coop	1	10.87	7.67	$0.0767		$723.68	0.1718%	0.1718%	0.1718%
268	20546	Western Kentucky Energy Corp	KY	Non-Small Company	5	17.95	6.63	$0.0663		$1,032.99	3.1296%	2.9692%	3.0134%
269	55808	Westmoreland Partners	NC	Small Company	2	2.1	8.53	$0.0853		$155.48	0.5146%	0.0395%	0.0401%
270	20541	Wheelabrator Environmental Systems	PA	Non-Small Company	1	7.82	9.64	$0.0964		$654.34	0.0475%	0.0449%	0.0456%
271	1951	White Pine Electric Power LLC	MI	Small Company	1	0.53	9.23	$0.0923		$42.46	0.0119%	0.0112%	0.0114%
272	20737	Willmar Municipal Utils Comm	MN	Small City	1	0.26	8	$0.0800		$18.05	0.0579%	0.0546%	0.0555%
273	20847	Wisconsin Electric Power Co	MI	Non-Small Company	5	48.11	9.23	$0.0923	$0.0944	$3,941.26	0.0040%	0.0038%	0.0038%
274		Wisconsin Electric Power Co	WI				9.49	$0.0949					
275	20856	Wisconsin Power & Light Co	WI	Non-Small Company	3	27.51	9.49	$0.0949		$2,266.09	0.0947%	0.0914%	0.0923%
276	20860	Wisconsin Public Service Corp	WI	Non-Small Company	2	13.19	9.49	$0.0949		$1,086.50	0.1040%	0.0982%	0.0998%
277	21025	Integrys Energy Group - WPS Power Developement	PA	Non-Small Company	1	2.62	9.64	$0.0964		$219.23	0.1369%	0.1292%	0.1313%
278	21048	Wyandotte Municipal Serv Comm	MI	Small City	1	0.69	9.23	$0.0923		$55.28	0.0152%	0.0143%	0.0146%
				TOTALS =	495	5,437.3				$423,565.22	**0.5369%**	**0.5118%**	**0.5137%**

Appendix N:

Minority & Low-Income Population Data
(Executive Order 12898, 2000 Census)

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Utility ID and Total Plant Count	Plant ID	Plant Name	State	Zip code	ZCTA popula-tion	ZCTA white popula-tion	% White	ZCTA housing units	Persons below poverty level	Census ZCTA % below poverty level	% of ZCTA code population below poverty level	State % below poverty level	If ZCTA > state poverty level	Census ZCTA % minority	ZCTA % that are minority	State % minority	If ZCTA > % state minority level % assign 1
986	79	Aurora Energy LLC Chena	AK	99701	17,555	11,720	66.8	8,122	2,232	13.00	13.00%	8.40%	1	33.20	33.20%	30.70%	1
7353	6288	Healy	AK	99743	997	904	90.7	663	52	5.20	5.20%	8.40%	0	9.30	9.30%	30.70%	0
2		**AK**		**2**	**18,552**	**12,624**	**68.0**	**8,785**	**2,284**	**12.31**	**12.31%**	**8.40%**	**1**	**31.95**	**31.95%**	**30.70%**	**1**
195	3	Barry	AL	35073	2,694	2,065	76.7	1,173	339	12.40	12.40%	14.70%	0	23.30	23.30%	28.90%	0
189	56	Charles R Lowman	AL	35186	3,870	3,634	93.9	1,702	345	8.90	8.90%	14.70%	0	6.10	6.10%	28.90%	0
18642	47	Colbert	AL	35580	4,563	4,105	90	2,174	697	14.80	14.80%	14.70%	1	10.00	10.00%	28.90%	0
195	26	E C Gaston	AL	35674	18,361	15,907	86.6	8,206	2,591	14.50	14.50%	14.70%	0	13.40	13.40%	28.90%	0
195	7	Gadsden	AL	35772	5,121	4,323	84.4	2,373	891	17.30	17.30%	14.70%	1	15.60	15.60%	28.90%	0
195	8	Gorgas	AL	35903	18,728	12,604	67.3	8,783	3,205	17.40	17.40%	14.70%	1	32.70	32.70%	28.90%	1
195	10	Greene County	AL	36512							0.00%	14.70%	0		0.00%	28.90%	0
195	6002	James H Miller Jr	AL	36548	1,067	671	62.9	449	178	17.10	17.10%	14.70%	1	37.10	37.10%	28.90%	1
34672	50407	Mobile Energy Services LLC	AL	36610	19,717	557	2.8	8,170	9,302	49.10	49.10%	14.70%	1	97.20	97.20%	28.90%	1
18642	50	Widows Creek	AL	36732	8,733	4,046	46.3	3,807	2,783	31.30	31.30%	14.70%	1	53.70	53.70%	28.90%	1
10		**AL**		**9**	**82,854**	**47,912**	**57.8**	**36,837**	**20,331**	**24.54**	**24.54%**	**14.70%**	**6**	**42.17**	**42.17%**	**28.90%**	**4**
814	6009	White Bluff	AR	72132	2,975	2,734	91.9	1,204	275	9.20	9.20%	15.80%	0	8.10	8.10%	20.00%	0
814	6641	Independence	AR	72562	2,081	2,023	97.2	909	256	12.20	12.20%	15.80%	0	2.80	2.80%	20.00%	0
17698	6138	Flint Creek	AR	72734	6,730	6,117	90.9	2,743	683	10.10	10.10%	15.80%	0	9.10	9.10%	20.00%	0
3		**AR**		**3**	**11,786**	**10,874**	**92.3**	**4,856**	**1,214**	**10.30**	**10.30%**	**15.80%**	**0**	**7.74**	**7.74%**	**20.00%**	**0**
796	160	Apache Station	AZ	85606	1,592	1,407	88.4	839	272	19.50	19.50%	13.50%	1	11.60	11.60%	24.50%	0
24211	126	H Wilson Sundt Generating Station	AZ	85714	14,549	6,306	43.3	4,798	4,388	30.60	30.60%	13.50%	1	56.70	56.70%	24.50%	1
16572	6177	Coronado	AZ	85936	4,115	3,249	79	1,668	599	16.70	16.70%	13.50%	1	21.00	21.00%	24.50%	0
24211	8223	Springerville	AZ	85938	4,263	3,578	83.9	1,977	546	12.50	12.50%	13.50%	0	16.10	16.10%	24.50%	0
803	113	Cholla	AZ	86032	173	98	56.6	66	23	18.40	18.40%	13.50%	1	43.40	43.40%	24.50%	1
16572	4941	Navajo	AZ	86040	10,249	5,033	49.1	3,836	1,605	16.10	16.10%	13.50%	1	50.90	50.90%	24.50%	1
6		**AZ**		**6**	**34,941**	**19,671**	**56.3**	**13,184**	**7,433**	**21.27**	**21.27%**	**13.50%**	**5**	**43.70**	**43.70%**	**24.50%**	**3**
13060	54626	Mt Poso Cogeneration	CA	93308	44,914	39,106	87.1	17,321	7,053	16.70	16.70%	14.00%	1	12.90	12.90%	40.50%	0
16061	10768	Rio Bravo Jasmin	CA	93308	44,914	39,106	87.1	17,321	7,053	16.70	16.70%	14.00%	1	12.90	12.90%	40.50%	0
16002	10769	Rio Bravo Poso	CA	93380							0.00%	14.00%	0		0.00%	40.50%	0
52	10002	ACE Cogeneration Facility	CA	93562	1,988	1,721	86.6	1,237	400	21.10	21.10%	14.00%	1	13.40	13.40%	40.50%	0
6811	54238	Port of Stockton District Energy Fac	CA	95203	16,344	7,514	46	5,919	4,579	29.00	29.00%	14.00%	1	54.00	54.00%	40.50%	1
353	10640	Stockton Cogen	CA	95206	49,649	13,505	27.2	13,462	12,717	25.90	25.90%	14.00%	1	72.80	72.80%	40.50%	1
6		**CA**		**4**	**112,895**	**61,846**	**54.8**	**37,939**	**24,749**	**21.92**	**21.92%**	**14.00%**	**5**	**45.22**	**45.22%**	**40.50%**	**2**
15466	469	Cherokee	CO	80216	10,701	4,543	42.5	2,939	2,718	26.10	26.10%	8.50%	1	57.50	57.50%	17.20%	1
15466	465	Arapahoe	CO	80223	18,721	11,646	62.2	7,103	3,648	19.50	19.50%	8.50%	1	37.80	37.80%	17.20%	1
15466	477	Valmont	CO	80302	29,795	26,804	90	11,994	6,800	27.20	27.20%	8.50%	1	10.00	10.00%	17.20%	0
19173	10003	Colorado Energy Nations Company	CO	80401	38,580	35,440	91.9	16,204	2,884	7.70	7.70%	8.50%	0	8.10	8.10%	17.20%	0
15143	6761	Rawhide	CO	80549	4,809	4,333	90.1	1,779	273	5.70	5.70%	8.50%	0	9.90	9.90%	17.20%	0
15466	6248	Pawnee	CO	80723	6,973	5,584	80.1	2,620	729	10.90	10.90%	8.50%	1	19.90	19.90%	17.20%	1
3989	8219	Ray D Nixon	CO	80817	16,113	12,145	75.4	5,577	1,364	8.40	8.40%	8.50%	0	24.60	24.60%	17.20%	1
3989	492	Martin Drake	CO	80903	15,091	11,897	78.8	6,985	2,768	20.30	20.30%	8.50%	1	21.20	21.20%	17.20%	1

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15466	470	Comanche	CO	81006	11,933	9,783	82	4,555	893	7.60	7.60%	8.50%	0	18.00	18.00%	17.20%	1
10633	508	Lamar Plant	CO	81052	10,897	8,568	78.6	4,453	1,916	18.00	18.00%	8.50%	1	21.40	21.40%	17.20%	1
19204	511	Trinidad	CO	81082	12,512	10,171	81.3	5,847	2,031	16.50	16.50%	8.50%	1	18.70	18.70%	17.20%	1
770	462	W N Clark	CO	81212	29,188	26,587	91.1	10,850	2,506	10.70	10.70%	8.50%	1	8.90	8.90%	17.20%	0
30151	527	Nucla	CO	81424	1,245	1,193	95.8	644	151	11.70	11.70%	8.50%	1	4.20	4.20%	17.20%	0
15466	468	Cameo	CO	81526	5,338	5,005	93.8	2,183	582	11.50	11.50%	8.50%	1	6.20	6.20%	17.20%	0
30151	6021	Craig	CO	81626							0.00%	8.50%	0		0.00%	17.20%	0
15466	525	Hayden	CO	81639	2,199	2,121	96.5	886	132	6.00	6.00%	8.50%	0	3.50	3.50%	17.20%	0
16		**CO**		**15**	**214,095**	**175,820**	**82.1**	**84,619**	**29,395**	**13.73**	**13.73%**	**8.50%**	**10**	**17.88**	**17.88%**	**17.20%**	**8**
42	10675	AES Thames	CT	06382	12,001	9,860	82.2	4,319	565	5.50	5.50%	7.70%	0	17.80	17.80%	18.40%	0
15452	568	Bridgeport Station	CT	06604	30,715	13,572	44.2	11,890	5,862	21.10	21.10%	7.70%	1	55.80	55.80%	18.40%	1
2		**CT**		**2**	**42,716**	**23,432**	**54.9**	**16,209**	**6,427**	**15.05**	**15.05%**	**7.70%**	**1**	**45.14**	**45.14%**	**18.40%**	**1**
4252	593	Edge Moor	DE	19809	14,586	11,799	80.9	6,667	794	5.50	5.50%	9.90%	0	19.10	19.10%	25.40%	0
7860	10030	NRG Energy Center Dover	DE	19904	27,676	17,430	63	10,423	2,785	11.10	11.10%	9.90%	1	37.00	37.00%	25.40%	1
9332	594	Indian River Generating Station	DE	19939	4,663	4,153	89.1	2,325	400	8.50	8.50%	9.90%	0	10.90	10.90%	25.40%	0
3		**DE**		**3**	**46,925**	**33,382**	**71.1**	**19,415**	**3,979**	**8.48**	**8.48%**	**9.90%**	**1**	**28.86**	**28.86%**	**25.40%**	**1**
14932	10672	Cedar Bay Generating Company LP	FL	32218	37,790	21,856	57.8	14,801	4,019	11.00	11.00%	12.10%	0	42.20	42.20%	22.00%	1
9617	667	Northside Generating Station	FL	32226	8,173	7,901	96.7	3,226	723	9.20	9.20%	12.10%	0	3.30	3.30%	22.00%	0
9617	207	St Johns River Power Park	FL	32226	8,173	7,901	96.7	3,226	723	9.20	9.20%	12.10%	0	3.30	3.30%	22.00%	0
7801	643	Lansing Smith	FL	32409	7,360	7,075	96.1	3,163	926	12.90	12.90%	12.10%	1	3.90	3.90%	22.00%	0
7801	642	Scholz	FL	32460	5,287	3,711	70.2	1,757	601	15.80	15.80%	12.10%	1	29.80	29.80%	22.00%	1
7801	641	Crist	FL	32514	34,837	28,391	81.5	15,724	3,574	10.90	10.90%	12.10%	0	18.50	18.50%	22.00%	0
6909	663	Deerhaven Generating Station	FL	32606	17,794	15,274	85.8	8,032	1,277	7.20	7.20%	12.10%	0	14.20	14.20%	22.00%	0
21554	136	Seminole	FL	32708	38,849	34,255	88.2	14,840	1,622	4.20	4.20%	12.10%	0	11.80	11.80%	22.00%	0
14610	564	Stanton Energy Center	FL	32831	57	48	84.2	22	0	0.00	0.00%	12.10%	0	15.80	15.80%	22.00%	0
18454	645	Big Bend	FL	33572	7,461	6,991	93.7	3,409	304	4.10	4.10%	12.10%	0	6.30	6.30%	22.00%	0
10623	676	C D McIntosh Jr	FL	33801	31,593	25,639	81.2	15,444	5,971	19.30	19.30%	12.10%	1	18.80	18.80%	22.00%	0
18454	7242	Polk	FL	33860	17,015	13,807	81.1	7,050	1,676	10.00	10.00%	12.10%	0	18.90	18.90%	22.00%	0
6455	628	Crystal River	FL	34428	9,294	8,573	92.2	4,621	1,199	13.40	13.40%	12.10%	1	7.80	7.80%	22.00%	0
3303	10333	Central Power & Lime	FL	34605							0.00%	12.10%	0		0.00%	22.00%	0
14932	50976	Indiantown Cogeneration LP	FL	34956	8,992	4,364	48.5	2,505	1,974	25.50	25.50%	12.10%	1	51.50	51.50%	22.00%	1
15		**FL**		**13**	**224,502**	**177,885**	**79.2**	**94,594**	**23,866**	**10.63**	**10.63%**	**12.10%**	**5**	**20.76**	**20.76%**	**22.00%**	**3**
7140	710	Jack McDonough	GA	30080	43,472	25,113	57.8	21,766	3,885	8.90	8.90%	12.50%	0	42.20	42.20%	34.90%	1
7140	703	Bowen	GA	30120	29,734	24,913	83.8	11,326	2,525	8.60	8.60%	12.50%	0	16.20	16.20%	34.90%	0
7140	708	Hammond	GA	30129							0.00%	12.50%	0		0.00%	34.90%	0
7140	6052	Wansley	GA	30170	2,681	2,451	91.4	1,071	235	7.90	7.90%	12.50%	0	8.60	8.60%	34.90%	0
7140	728	Yates	GA	30264							0.00%	12.50%	0		0.00%	34.90%	0
7140	6257	Scherer	GA	31046	2,839	2,350	82.8	1,116	150	5.50	5.50%	12.50%	0	17.20	17.20%	34.90%	0
7140	709	Harllee Branch	GA	31061	39,231	21,850	55.7	17,031	6,125	16.90	16.90%	12.50%	1	44.30	44.30%	34.90%	1
7140	6124	McIntosh	GA	31326	12,302	10,617	86.3	4,657	859	7.10	7.10%	12.50%	0	13.70	13.70%	34.90%	0
7140	733	Kraft	GA	31405	32,887	15,574	47.4	13,276	4,710	16.00	16.00%	12.50%	1	52.60	52.60%	34.90%	1
7140	727	Mitchell	GA	31705	38,667	12,731	32.9	14,719	10,703	29.30	29.30%	12.50%	1	67.10	67.10%	34.90%	1
4538	753	Crisp Plant	GA	31796	1,160	793	68.4	652	269	22.90	22.90%	12.50%	1	31.60	31.60%	34.90%	0

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11		**GA**		**9**	**202,973**	**116,392**	**57.3**	**85,614**	**29,461**	**14.51**	**14.51%**	**12.50%**	**4**	**42.66**	**42.66%**	**34.90%**	**4**
177	10673	AES Hawaii	HI	96707	25,054	5,470	21.8	7,877	1,150	4.60	4.60%	10.60%	0	78.20	78.20%	75.70%	1
8286	10604	Hawaiian Comm & Sugar Puunene Mill	HI	96784							0.00%	10.60%	0		0.00%	75.70%	0
2		**HI**		**1**	**25,054**	**5,470**	**21.8**	**7,877**	**1,150**	**4.59**	**4.59%**	**10.60%**	**0**	**78.17**	**78.17%**	**75.70%**	**1**
554	1122	Ames Electric Services Power Plant	IA	50010	24,991	22,020	88.1	11,234	3,626	14.70	14.70%	7.90%	1	11.90	11.90%	6.10%	1
9417	1077	Sutherland	IA	50158	30,316	26,708	88.1	12,552	3,251	11.30	11.30%	7.90%	1	11.90	11.90%	6.10%	1
14645	1175	Pella	IA	50219	12,745	12,333	96.8	4,693	715	6.10	6.10%	7.90%	0	3.20	3.20%	6.10%	0
3203	1131	Streeter Station	IA	50613	38,681	36,887	95.4	14,276	5,428	15.80	15.80%	7.90%	1	4.60	4.60%	6.10%	0
12341	1091	George Neal North	IA	51052	1,050	1,035	98.6	436	97	8.60	8.60%	7.90%	1	1.40	1.40%	6.10%	0
12341	7343	George Neal South	IA	51052	1,050	1,035	98.6	436	97	8.60	8.60%	7.90%	1	1.40	1.40%	6.10%	0
4363	1217	Earl F Wisdom	IA	51301	12,885	12,583	97.7	5,791	1,077	8.60	8.60%	7.90%	1	2.30	2.30%	6.10%	0
12341	1082	Walter Scott Jr Energy Center	IA	51501	34,258	32,091	93.7	14,158	3,758	11.20	11.20%	7.90%	1	6.30	6.30%	6.10%	1
9417	1046	Dubuque	IA	52004							0.00%	7.90%	0		0.00%	6.10%	0
9417	1047	Lansing	IA	52151	2,319	2,299	99.1	1,281	142	6.40	6.40%	7.90%	0	0.90	0.90%	6.10%	0
9417	1058	Sixth Street	IA	52402	39,913	37,029	92.8	17,034	2,239	5.90	5.90%	7.90%	0	7.20	7.20%	6.10%	1
9417	1073	Prairie Creek	IA	52404	32,016	29,829	93.2	14,066	2,985	9.50	9.50%	7.90%	1	6.80	6.80%	6.10%	1
9417	6254	Ottumwa	IA	52548	48	46	95.8	23	11	23.90	23.90%	7.90%	1	4.20	4.20%	6.10%	0
9417	1104	Burlington	IA	52601	30,847	28,508	92.4	13,752	3,576	11.80	11.80%	7.90%	1	7.60	7.60%	6.10%	1
12341	1081	Riverside	IA	52722	33,695	32,082	95.2	13,983	1,596	4.80	4.80%	7.90%	0	4.80	4.80%	6.10%	0
9417	1048	Milton L Kapp	IA	52733							0.00%	7.90%	0		0.00%	6.10%	0
3258	1218	Fair Station	IA	52761	30,286	27,856	92	12,333	2,933	9.90	9.90%	7.90%	1	8.00	8.00%	6.10%	1
12341	6664	Louisa	IA	52761	30,286	27,856	92	12,333	2,933	9.90	9.90%	7.90%	1	8.00	8.00%	6.10%	1
13143	1167	Muscatine Plant #1	IA	52761	30,286	27,856	92	12,333	2,933	9.90	9.90%	7.90%	1	8.00	8.00%	6.10%	1
19		**IA**		**14**	**324,050**	**301,306**	**93.0**	**135,612**	**31,434**	**9.70**	**9.70%**	**7.90%**	**13**	**7.02**	**7.02%**	**6.10%**	**9**
12384	883	Waukegan	IL	60087	23,530	15,409	65.5	8,291	1,400	6.00	6.00%	10.50%	0	34.50	34.50%	26.50%	1
12384	384	Joliet 29	IL	60436	16,184	10,632	65.7	6,611	1,986	12.60	12.60%	10.50%	1	34.30	34.30%	26.50%	1
12384	874	Joliet 9	IL	60436	16,184	10,632	65.7	6,611	1,986	12.60	12.60%	10.50%	1	34.30	34.30%	26.50%	1
12384	884	Will County	IL	60446	20,141	17,177	85.3	7,348	360	1.80	1.80%	10.50%	0	14.70	14.70%	26.50%	0
12384	886	Fisk Street	IL	60608	92,472	32,997	35.7	28,729	22,754	27.80	27.80%	10.50%	1	64.30	64.30%	26.50%	1
12384	867	Crawford	IL	60623	108,144	22,934	21.2	30,905	33,246	31.40	31.40%	10.50%	1	78.80	78.80%	26.50%	1
5517	892	Hennepin Power Station	IL	61327	1,190	1,151	96.7	511	46	4.10	4.10%	10.50%	0	3.30	3.30%	26.50%	0
49756	6016	Duck Creek	IL	61520	18,659	17,016	91.2	7,677	1,932	11.80	11.80%	10.50%	1	8.80	8.80%	26.50%	0
12384	879	Powerton	IL	61554	43,500	41,919	96.4	17,770	3,431	8.40	8.40%	10.50%	0	3.60	3.60%	26.50%	0
49756	856	E D Edwards	IL	61607	10,473	10,229	97.7	4,343	544	5.20	5.20%	10.50%	0	2.30	2.30%	26.50%	0
5517	897	Vermilion	IL	61858	2,833	2,814	99.3	1,195	251	8.70	8.70%	10.50%	0	0.70	0.70%	26.50%	0
19145	55245	Tuscola Station	IL	61953	6,285	6,165	98.1	2,651	276	4.50	4.50%	10.50%	0	1.90	1.90%	26.50%	0
5517	898	Wood River	IL	62002	34,062	25,644	75.3	15,472	5,420	16.30	16.30%	10.50%	1	24.70	24.70%	26.50%	0
520	861	Coffeen	IL	62017	1,287	1,270	98.7	603	212	15.90	15.90%	10.50%	1	1.30	1.30%	26.50%	0
5517	889	Baldwin Energy Complex	IL	62217	4,114	1,728	42	411	99	10.50	10.50%	10.50%	0	58.00	58.00%	26.50%	1
40307	6238	Pearl Station	IL	62361	555	545	98.2	318	71	12.70	12.70%	10.50%	1	1.80	1.80%	26.50%	0
520	863	Hutsonville	IL	62433	1,057	1,039	98.3	444	166	15.70	15.70%	10.50%	1	1.70	1.70%	26.50%	0
520	6017	Newton	IL	62448	6,063	6,016	99.2	2,657	608	9.90	9.90%	10.50%	0	0.80	0.80%	26.50%	0

Appendix N
Minority & Low-Income Population Data (2000)

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5269	876	Kincaid Generation LLC	IL	62540	1,392	1,372	98.6	643	145	10.10	10.10%	10.50%	0	1.40	1.40%	26.50%	0
5517	891	Havana	IL	62644	5,773	5,708	98.9	2,552	616	10.80	10.80%	10.50%	1	1.10	1.10%	26.50%	0
520	864	Meredosia	IL	62665	1,675	1,664	99.3	847	167	9.90	9.90%	10.50%	0	0.70	0.70%	26.50%	0
17828	963	Dallman	IL	62703	31,211	19,843	63.6	14,794	6,438	21.10	21.10%	10.50%	1	36.40	36.40%	26.50%	1
17828	964	Lakeside	IL	62703	31,211	19,843	63.6	14,794	6,438	21.10	21.10%	10.50%	1	36.40	36.40%	26.50%	1
5748	887	Joppa Steam	IL	62953	427	378	88.5	208	171	42.50	42.50%	10.50%	1	11.50	11.50%	26.50%	0
17632	976	Marion	IL	62959	24,807	23,214	93.6	11,035	3,068	12.90	12.90%	10.50%	1	6.40	6.40%	26.50%	0
25		**IL**		**23**	455,834	266,864	**58.5**	166,015	83,407	**18.30**	**18.30%**	**10.50%**	**14**	**41.46**	**41.46%**	**26.50%**	**8**
9273	991	Eagle Valley	IN	46151	32,420	31,999	98.7	12,651	2,342	7.50	7.50%	8.30%	0	1.30	1.30%	12.50%	0
9273	990	Harding Street	IN	46217	19,210	18,647	97.1	7,583	526	2.70	2.70%	8.30%	0	2.90	2.90%	12.50%	0
3599	992	CC Perry K	IN	46225	8,262	7,026	85	3,599	1,953	23.60	23.60%	8.30%	1	15.00	15.00%	12.50%	1
13756	995	Bailly	IN	46304	21,445	20,683	96.4	8,555	994	4.70	4.70%	8.30%	0	3.60	3.60%	12.50%	0
18041	981	State Line Energy	IN	46325							0.00%	8.30%	0		0.00%	12.50%	0
13756	997	Michigan City	IN	46360	46,107	35,405	76.8	20,359	4,738	10.90	10.90%	8.30%	1	23.20	23.20%	12.50%	1
13756	6085	R M Schahfer	IN	46392	6,410	6,273	97.9	2,275	322	5.00	5.00%	8.30%	0	2.10	2.10%	12.50%	0
13756	996	Dean H Mitchell	IN	46401							0.00%	8.30%	0		0.00%	12.50%	0
11142	1032	Logansport	IN	46947	30,180	27,886	92.4	12,368	2,520	8.70	8.70%	8.30%	1	7.60	7.60%	12.50%	0
14839	1037	Peru	IN	46970	25,373	23,383	92.2	11,002	2,174	9.20	9.20%	8.30%	1	7.80	7.80%	12.50%	0
9324	988	Tanners Creek	IN	47025	20,234	19,656	97.1	7,912	1,152	5.90	5.90%	8.30%	0	2.90	2.90%	12.50%	0
15470	1008	R Gallagher	IN	47200							0.00%	8.30%	0		0.00%	12.50%	0
9269	983	Clifty Creek	IN	47250	21,047	20,142	95.7	9,499	2,012	10.00	10.00%	8.30%	1	4.30	4.30%	12.50%	0
15989	1040	Whitewater Valley	IN	47375							0.00%	8.30%	0		0.00%	12.50%	0
15470	1004	Edwardsport	IN	47500							0.00%	8.30%	0		0.00%	12.50%	0
9667	6225	Jasper 2	IN	47547							0.00%	8.30%	0		0.00%	12.50%	0
9273	994	AES Petersburg	IN	47567	6,045	6,003	99.3	2,666	507	8.80	8.80%	8.30%	1	0.70	0.70%	12.50%	0
9267	1043	Frank E Ratts	IN	47567	6,045	6,003	99.3	2,666	507	8.80	8.80%	8.30%	1	0.70	0.70%	12.50%	0
17633	6137	A B Brown	IN	47620	14,158	13,762	97.2	5,921	1,300	9.30	9.30%	8.30%	1	2.80	2.80%	12.50%	0
17633	1012	F B Culley	IN	47630	27,376	26,332	96.2	10,378	980	3.60	3.60%	8.30%	0	3.80	3.80%	12.50%	0
261	6705	Warrick	IN	47630	27,376	26,332	96.2	10,378	980	3.60	3.60%	8.30%	0	3.80	3.80%	12.50%	0
9324	6166	Rockport	IN	47635	5,533	5,390	97.4	2,420	449	8.20	8.20%	8.30%	0	2.60	2.60%	12.50%	0
15470	6113	Gibson	IN	47665	3,340	3,300	98.8	1,363	204	5.90	5.90%	8.30%	0	1.20	1.20%	12.50%	0
9267	6213	Merom	IN	47882	8,524	8,393	98.5	3,887	897	11.10	11.10%	8.30%	1	1.50	1.50%	12.50%	0
15470	1001	Cayuga	IN	47900							0.00%	8.30%	0		0.00%	12.50%	0
15470	1010	Wabash River	IN	47900							0.00%	8.30%	0		0.00%	12.50%	0
4508	1024	Crawfordsville	IN	47933	27,659	26,555	96	11,547	2,390	9.00	9.00%	8.30%	1	4.00	4.00%	12.50%	0
27		**IN**		**17**	**323,323**	**300,835**	**93.0**	**133,985**	**25,460**	**7.87**	**7.87%**	**8.30%**	**10**	**6.96**	**6.96%**	**12.50%**	**2**
10000	1241	La Cygne	KS	66040	3,072	2,967	96.6	1,599	190	6.30	6.30%	10.50%	0	3.40	3.40%	13.90%	0
22500	1250	Lawrence Energy Center	KS	66049	20,338	17,926	88.1	8,506	2,440	11.90	11.90%	10.50%	1	11.90	11.90%	13.90%	0
9996	6064	Nearman Creek	KS	66104	27,452	8,844	32.2	11,870	4,363	16.10	16.10%	10.50%	1	67.80	67.80%	13.90%	1
9996	1295	Quindaro	KS	66104	27,452	8,844	32.2	11,870	4,363	16.10	16.10%	10.50%	1	67.80	67.80%	13.90%	1
22500	6068	Jeffrey Energy Center	KS	66536	3,064	2,927	95.5	1,046	377	12.60	12.60%	10.50%	1	4.50	4.50%	13.90%	0
22500	1252	Tecumseh Energy Center	KS	66542	2,913	2,756	94.6	1,062	113	3.90	3.90%	10.50%	0	5.40	5.40%	13.90%	0
5860	1239	Riverton	KS	66730							0.00%	10.50%	0		0.00%	13.90%	0
18315	108	Holcomb	KS	67851	2,678	2,216	82.7	830	235	9.10	9.10%	10.50%	0	17.30	17.30%	13.90%	1

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8		**KS**		**6**	**59,517**	**37,636**	**63.2**	**24,913**	**7,718**	**12.97**	**12.97%**	**10.50%**	**4**	**36.76**	**36.76%**	**13.90%**	**3**
11249	6071	Trimble County	KY	40006	4,831	4,704	97.4	1,986	709	14.70	14.70%	12.50%	1	2.60	2.60%	9.90%	0
11249	1363	Cane Run	KY	40216	39,924	30,505	76.4	17,542	4,254	10.70	10.70%	12.50%	0	23.60	23.60%	9.90%	1
11249	1364	Mill Creek	KY	40272	34,740	33,182	95.5	13,373	2,877	8.40	8.40%	12.50%	0	4.50	4.50%	9.90%	0
10171	1355	E W Brown	KY	40330	18,971	17,789	93.8	8,492	2,565	13.70	13.70%	12.50%	1	6.20	6.20%	9.90%	0
10171	1361	Tyrone	KY	40383	20,454	18,833	92.1	8,230	1,531	7.60	7.60%	12.50%	0	7.90	7.90%	9.90%	0
5580	1385	Dale	KY	40391	32,884	30,764	93.6	13,638	3,476	10.70	10.70%	12.50%	0	6.40	6.40%	9.90%	0
10171	1356	Ghent	KY	41045	1,154	1,088	94.3	453	68	5.50	5.50%	12.50%	0	5.70	5.70%	9.90%	0
5580	6041	H L Spurlock	KY	41056	13,861	12,492	90.1	6,487	2,356	17.40	17.40%	12.50%	1	9.90	9.90%	9.90%	1
55729	6018	East Bend	KY	41100							0.00%	12.50%	0		0.00%	9.90%	0
22053	1353	Big Sandy	KY	41230	11,283	11,168	99	4,996	3,317	29.20	29.20%	12.50%	1	1.00	1.00%	9.90%	0
18642	1379	Shawnee	KY	42086	3,744	3,569	95.3	1,670	277	8.10	8.10%	12.50%	0	4.70	4.70%	9.90%	0
14268	1374	Elmer Smith	KY	42303	35,321	33,268	94.2	15,166	4,237	12.30	12.30%	12.50%	0	5.80	5.80%	9.90%	0
20546	6823	D B Wilson	KY	42328	1,435	1,421	99	600	133	8.90	8.90%	12.50%	0	1.00	1.00%	9.90%	0
10171	1357	Green River	KY	42330	10,785	9,951	92.3	4,449	1,900	19.20	19.20%	12.50%	1	7.70	7.70%	9.90%	0
18642	1378	Paradise	KY	42337	2,145	1,955	91.1	930	575	26.20	26.20%	12.50%	1	8.90	8.90%	9.90%	0
20546	1381	Kenneth C Coleman	KY	42348	4,469	4,375	97.9	1,847	476	10.40	10.40%	12.50%	0	2.10	2.10%	9.90%	0
8449	1372	Henderson I	KY	42419							0.00%	12.50%	0		0.00%	9.90%	0
20546	1382	HMP&L Station Two Henderson	KY	42452	2,116	2,071	97.9	837	135	5.60	5.60%	12.50%	0	2.10	2.10%	9.90%	0
20546	6639	R D Green	KY	42452	2,116	2,071	97.9	837	135	5.60	5.60%	12.50%	0	2.10	2.10%	9.90%	0
20546	1383	Robert A Reid	KY	42452	2,116	2,071	97.9	837	135	5.60	5.60%	12.50%	0	2.10	2.10%	9.90%	0
5580	1384	Cooper	KY	42501	16,916	16,283	96.3	8,099	3,611	22.20	22.20%	12.50%	1	3.70	3.70%	9.90%	0
21		**KY**		**17**	**255,033**	**233,418**	**91.5**	**108,795**	**32,497**	**12.74**	**12.74%**	**12.50%**	**7**	**8.48**	**8.48%**	**9.90%**	**2**
55936	1393	R S Nelson	LA	70669	10,102	8,475	83.9	4,078	1,536	15.40	15.40%	18.50%	0	16.10	16.10%	36.10%	0
11252	6055	Big Cajun 2	LA	70760	7,589	2,699	35.6	3,055	2,264	31.50	31.50%	18.50%	1	64.40	64.40%	36.10%	1
3265	51	Dolet Hills	LA	71052	11,217	4,489	40	4,836	3,388	30.80	30.80%	18.50%	1	60.00	60.00%	36.10%	1
3265	6190	Rodemacher	LA	71447	1,473	997	67.7	707	358	22.20	22.20%	18.50%	1	32.30	32.30%	36.10%	0
4		**LA**		**4**	**30,381**	**16,660**	**54.8**	**12,676**	**7,546**	**24.84**	**24.84%**	**18.50%**	**3**	**45.16**	**45.16%**	**36.10%**	**2**
54895	1606	Mount Tom	MA	01040	39,838	26,197	65.8	16,210	10,082	26.40	26.40%	10.10%	1	34.20	34.20%	15.50%	1
50018	1626	Salem Harbor	MA	01970	40,407	34,497	85.4	18,175	3,787	9.70	9.70%	10.10%	0	14.60	14.60%	15.50%	0
50018	1619	Brayton Point	MA	02726	15,553	15,285	98.3	6,176	551	3.60	3.60%	10.10%	0	1.70	1.70%	15.50%	0
29878	1613	Somerset Station	MA	02726	15,553	15,285	98.3	6,176	551	3.60	3.60%	10.10%	0	1.70	1.70%	15.50%	0
4		**MA**		**3**	**95,798**	**75,979**	**79.3**	**40,561**	**14,420**	**15.05**	**15.05%**	**10.10%**	**1**	**20.69**	**20.69%**	**15.50%**	**1**
12628	1571	Chalk Point LLC	MD	20608	1,015	551	54.3	435	67	6.50	6.50%	7.30%	0	45.70	45.70%	36.00%	1
12653	1573	Morgantown Generating Plant	MD	20664	2,716	2,018	74.3	1,179	97	3.60	3.60%	7.30%	0	25.70	25.70%	36.00%	0
12653	1572	Dickerson	MD	20842	1,848	1,595	86.3	747	126	6.50	6.50%	7.30%	0	13.70	13.70%	36.00%	0
4161	1552	C P Crane	MD	21220	36,551	30,586	83.7	15,105	3,061	8.50	8.50%	7.30%	1	16.30	16.30%	36.00%	0
4161	602	Brandon Shores	MD	21226	6,720	5,865	87.3	2,985	1,047	16.10	16.10%	7.30%	1	12.70	12.70%	36.00%	0
4161	1554	Herbert A Wagner	MD	21226	6,720	5,865	87.3	2,985	1,047	16.10	16.10%	7.30%	1	12.70	12.70%	36.00%	0
35	10678	AES Warrior Run Cogeneration Facility	MD	21502	44,053	39,928	90.6	19,600	5,757	14.40	14.40%	7.30%	1	9.40	9.40%	36.00%	0
23279	1570	R Paul Smith Power Station	MD	21795	8,238	8,071	98	3,572	467	6.00	6.00%	7.30%	0	2.00	2.00%	36.00%	0
8		**MD**		**7**	**101,141**	**88,614**	**87.6**	**43,623**	**10,622**	**10.50**	**10.50%**	**7.30%**	**4**	**12.39**	**12.39%**	**36.00%**	**1**

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54784	10495	Rumford Cogeneration	ME	04276	6,748	6,660	98.7	3,405	1,037	15.7	15.70%	9.80%	1	**1.30**	1.30%	3.10%	0
1		**ME**		**1**	**6,748**	**6,660**	**98.7**	**3,405**	**1,037**	**15.37**	**15.37%**	**9.80%**	**1**	**1.30**	**1.30%**	**3.10%**	**0**
5109	1732	Marysville	MI	48040	9,684	9,508	98.2	4,180	445	4.60	4.60%	10.20%	0	1.80	1.80%	19.80%	0
5109	6034	Belle River	MI	48054	7,059	6,954	98.5	2,748	227	3.30	3.30%	10.20%	0	1.50	1.50%	19.80%	0
5109	1743	St Clair	MI	48054	7,059	6,954	98.5	2,748	227	3.30	3.30%	10.20%	0	1.50	1.50%	19.80%	0
4254	1723	J R Whiting	MI	48133	5,355	5,070	94.7	2,137	287	5.40	5.40%	10.20%	0	5.30	5.30%	19.80%	0
5109	1733	Monroe	MI	48161	25,412	23,414	92.1	10,419	2,986	11.90	11.90%	10.20%	1	7.90	7.90%	19.80%	0
5109	1745	Trenton Channel	MI	48183	40,891	38,633	94.5	16,647	2,069	5.10	5.10%	10.20%	0	5.50	5.50%	19.80%	0
21048	1866	Wyandotte	MI	48192	44,894	42,275	94.2	19,186	2,595	5.90	5.90%	10.20%	0	5.80	5.80%	19.80%	0
5109	1740	River Rouge	MI	48218	10,060	5,326	52.9	4,151	2,204	22.00	22.00%	10.20%	1	47.10	47.10%	19.80%	1
5109	1731	Harbor Beach	MI	48441	4,554	4,437	97.4	2,366	493	10.80	10.80%	10.20%	1	2.60	2.60%	19.80%	0
4254	1702	Dan E Karn	MI	48732	11,918	11,337	95.1	5,172	1,004	8.70	8.70%	10.20%	0	4.90	4.90%	19.80%	0
4254	1720	J C Weadock	MI	48732	11,918	11,337	95.1	5,172	1,004	8.70	8.70%	10.20%	0	4.90	4.90%	19.80%	0
56155	1831	Eckert Station	MI	48910	35,735	27,336	76.5	16,772	4,961	14.00	14.00%	10.20%	1	23.50	23.50%	19.80%	1
56155	1832	Erickson Station	MI	48917	31,366	26,230	83.6	14,336	1,807	5.90	5.90%	10.20%	0	16.40	16.40%	19.80%	0
12807	4259	Endicott Station	MI	49252	2,569	2,519	98.1	1,046	238	9.70	9.70%	10.20%	0	1.90	1.90%	19.80%	0
7483	1825	J B Sims	MI	49417	27,969	27,023	96.6	11,691	794	2.90	2.90%	10.20%	0	3.40	3.40%	19.80%	0
8723	1830	James De Young	MI	49423	46,804	38,385	82	17,184	3,882	8.90	8.90%	10.20%	0	18.00	18.00%	19.80%	0
4254	1695	B C Cobb	MI	49445	19,811	18,729	94.5	7,734	803	4.10	4.10%	10.20%	0	5.50	5.50%	19.80%	0
4254	1710	J H Campbell	MI	49460	7,697	7,041	91.5	2,686	348	5.00	5.00%	10.20%	0	8.50	8.50%	19.80%	0
18414	50835	TES Filer City Station	MI	49634	86	83	96.5	35	4	4.20	4.20%	10.20%	0	3.50	3.50%	19.80%	0
19578	1771	Escanaba	MI	49829	18,414	17,682	96	8,319	2,037	11.40	11.40%	10.20%	1	4.00	4.00%	19.80%	0
20847	1769	Presque Isle	MI	49855	32,378	30,224	93.3	13,755	3,486	12.10	12.10%	10.20%	1	6.70	6.70%	19.80%	0
11701	1843	Shiras	MI	49855	32,378	30,224	93.3	13,755	3,486	12.10	12.10%	10.20%	1	6.70	6.70%	19.80%	0
1951	10148	White Pine Electric Power	MI	49971	628	601	95.7	397	65	10.50	10.50%	10.20%	1	4.30	4.30%	19.80%	0
23		**MI**		**20**	**383,284**	**342,807**	**89.4**	**160,961**	**30,735**	**8.02**	**8.02%**	**10.20%**	**8**	**10.56**	**10.56%**	**19.80%**	**2**
13781	1915	Allen S King	MN	55003	3,162	2,306	72.9	789	64	3.70	3.70%	7.80%	0	27.10	27.10%	10.60%	1
13781	1904	Black Dog	MN	55101	21,969	10,736	48.9	8,830	5,220	24.50	24.50%	7.80%	1	51.10	51.10%	10.60%	1
13781	6090	Sherburne County	MN	55308	6,268	6,155	98.2	2,073	218	3.40	3.40%	7.80%	0	1.80	1.80%	10.60%	0
13781	1927	Riverside	MN	55401	3,649	2,905	79.6	2,865	499	14.50	14.50%	7.80%	1	20.40	20.40%	10.60%	1
12647	10075	Taconite Harbor Energy Center	MN	55613	187	175	93.6	210	14	6.60	6.60%	7.80%	0	6.40	6.40%	10.60%	0
12647	1891	Syl Laskin	MN	55705	3,385	3,329	98.3	1,599	329	9.80	9.80%	7.80%	1	1.70	1.70%	10.60%	0
12647	1893	Clay Boswell	MN	55721	2,867	2,783	97.1	1,397	153	5.40	5.40%	7.80%	0	2.90	2.90%	10.60%	0
12647	10686	Rapids Energy Center	MN	55744	19,799	19,199	97	9,241	1,757	9.00	9.00%	7.80%	1	3.00	3.00%	10.60%	0
8543	1979	Hibbing	MN	55746	18,129	17,656	97.4	8,679	2,036	11.50	11.50%	7.80%	1	2.60	2.60%	10.60%	0
19883	2018	Virginia	MN	55792	10,904	10,434	95.7	5,457	1,515	14.30	14.30%	7.80%	1	4.30	4.30%	10.60%	0
12647	1897	M L Hibbard	MN	55807	10,302	9,699	94.1	4,640	1,141	11.20	11.20%	7.80%	1	5.90	5.90%	10.60%	0
16181	2008	Silver Lake	MN	55903							0.00%	7.80%	0		0.00%	10.60%	0
1009	1961	Austin Northeast	MN	55912	28,012	26,122	93.3	12,095	2,817	10.30	10.30%	7.80%	1	6.70	6.70%	10.60%	0
13488	2001	New Ulm	MN	56073	17,199	16,903	98.3	7,051	975	5.90	5.90%	7.80%	0	1.70	1.70%	10.60%	0
20737	2022	Willmar	MN	56201	22,126	19,861	89.8	9,178	2,529	11.80	11.80%	7.80%	1	10.20	10.20%	10.60%	0
14232	1943	Hoot Lake	MN	56537	19,054	18,592	97.6	8,333	1,643	9.00	9.00%	7.80%	1	2.40	2.40%	10.60%	0
16		**MN**		**15**	**187,012**	**166,855**	**89.2**	**82,437**	**20,910**	**11.18**	**11.18%**	**7.80%**	**10**	**10.78**	**10.78%**	**10.60%**	**3**
19436	6155	Rush Island	MO	63028	23,221	22,328	96.2	8,894	1,707	7.60	7.60%	9.80%	0	3.80	3.80%	15.10%	0

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19436	2103	Labadie	MO	63055	1,767	1,753	99.2	690	71	4.00	4.00%	9.80%	0	0.80	0.80%	15.10%	0
19436	2104	Meramec	MO	63129	51,191	49,691	97.1	19,705	1,537	3.00	3.00%	9.80%	0	2.90	2.90%	15.10%	0
19436	2107	Sioux	MO	63386	598	593	99.2	298	41	7.40	7.40%	9.80%	0	0.80	0.80%	15.10%	0
17177	6768	Sikeston Power Station	MO	63801	23,779	19,338	81.3	10,101	4,422	19.00	19.00%	9.80%	1	18.70	18.70%	15.10%	1
924	2167	New Madrid	MO	63869	4,175	2,889	69.2	1,781	1,071	26.70	26.70%	9.80%	1	30.80	30.80%	15.10%	1
9231	2132	Blue Valley	MO	64056	15,357	13,749	89.5	5,651	1,496	9.90	9.90%	9.80%	1	10.50	10.50%	15.10%	0
9231	2171	Missouri City	MO	64072	133	131	98.5	53	17	14.50	14.50%	9.80%	1	1.50	1.50%	15.10%	0
770	2094	Sibley	MO	64088	1,443	1,401	97.1	517	63	4.40	4.40%	9.80%	0	2.90	2.90%	15.10%	0
10000	6065	Iatan	MO	64098	2,943	2,872	97.6	1,222	191	6.50	6.50%	9.80%	0	2.40	2.40%	15.10%	0
10000	2079	Hawthorn	MO	64120	481	413	85.9	278	37	8.50	8.50%	9.80%	0	14.10	14.10%	15.10%	0
770	2098	Lake Road	MO	64504	10,926	10,458	95.7	4,641	1,528	14.00	14.00%	9.80%	1	4.30	4.30%	15.10%	0
10000	2080	Montrose	MO	64735	12,910	12,403	96.1	6,064	1,790	14.20	14.20%	9.80%	1	3.90	3.90%	15.10%	0
5860	2076	Asbury	MO	64832	724	698	96.4	317	67	8.10	8.10%	9.80%	0	3.60	3.60%	15.10%	0
3242	2169	Chamois	MO	65024	1,200	1,185	98.8	599	142	13.10	13.10%	9.80%	1	1.20	1.20%	15.10%	0
4045	2123	Columbia	MO	65205							0.00%	9.80%	0		0.00%	15.10%	0
924	2168	Thomas Hill	MO	65244	442	426	96.4	213	64	14.90	14.90%	9.80%	1	3.60	3.60%	15.10%	0
11732	2144	Marshall	MO	65340	15,580	13,684	87.8	6,245	1,898	13.50	13.50%	9.80%	1	12.20	12.20%	15.10%	0
17833	2161	James River Power Station	MO	65804	35,482	33,574	94.6	17,525	3,104	8.80	8.80%	9.80%	0	5.40	5.40%	15.10%	0
17833	6195	Southwest Power Station	MO	65807	49,132	45,104	91.8	21,282	5,468	12.40	12.40%	9.80%	1	8.20	8.20%	15.10%	0
20		**MO**		**19**	**251,484**	**232,690**	**92.5**	**106,076**	**24,714**	**9.83**	**9.83%**	**9.80%**	**10**	**7.47**	**7.47%**	**15.10%**	**2**
7651	2062	Henderson	MS	38930	28,116	9,989	35.5	11,184	9,180	33.20	33.20%	15.50%	1	64.50	64.50%	38.60%	1
17568	6061	R D Morrow	MS	39475	9,539	8,704	91.2	3,646	1,074	11.40	11.40%	15.50%	0	8.80	8.80%	38.60%	0
12686	2049	Jack Watson	MS	39501	26,121	10,928	41.8	10,719	6,200	25.40	25.40%	15.50%	1	58.20	58.20%	38.60%	1
12686	6073	Victor J Daniel Jr	MS	39552							0.00%	15.50%	0		0.00%	38.60%	0
3593	55076	Red Hills Generating Facility	MS	39735	5,433	3,853	70.9	2,436	1,221	23.10	23.10%	15.50%	1	29.10	29.10%	38.60%	0
5		**MS**		**4**	**69,209**	**33,474**	**48.4**	**27,985**	**17,675**	**25.54**	**25.54%**	**15.50%**	**3**	**51.63**	**51.63%**	**38.60%**	**2**
16233	55749	Hardin Generator Project	MT	59034	4,726	3,161	66.9	1,968	882	19.60	19.60%	16.00%	1	33.10	33.10%	9.40%	1
15298	2187	J E Corette Plant	MT	59101	36,335	31,597	87	16,362	6,260	17.70	17.70%	16.00%	1	13.00	13.00%	9.40%	1
12199	6089	Lewis & Clark	MT	59270	7,054	6,776	96.1	3,316	781	11.20	11.20%	16.00%	0	3.90	3.90%	9.40%	0
15298	6076	Colstrip	MT	59323	2,440	2,059	84.4	976	163	6.80	6.80%	16.00%	0	15.60	15.60%	9.40%	1
4217	10784	Colstrip Energy LP	MT	59323	2,440	2,059	84.4	976	163	6.80	6.80%	16.00%	0	15.60	15.60%	9.40%	1
56110	56612	Thompson River Power LLC	MT	59873	2,654	2,566	96.7	1,442	355	13.30	13.30%	16.00%	0	3.30	3.30%	9.40%	0
6		**MT**		**5**	**53,209**	**46,159**	**86.8**	**24,064**	**8,441**	**15.86**	**15.86%**	**16.00%**	**2**	**13.25**	**13.25%**	**9.40%**	**4**
5416	8042	Belews Creek	NC	27052	10,380	8,889	85.6	4,407	934	9.00	9.00%	13.20%	0	14.40	14.40%	27.90%	0
5416	2723	Dan River	NC	27288	24,878	19,398	78	11,269	3,918	16.00	16.00%	13.20%	1	22.00	22.00%	27.90%	0
3046	2709	Lee	NC	27530	38,376	20,543	53.5	16,451	6,757	18.40	18.40%	13.20%	1	46.50	46.50%	27.90%	1
3046	2708	Cape Fear	NC	27559	2,149	1,510	70.3	954	138	6.50	6.50%	13.20%	0	29.70	29.70%	27.90%	1
3046	6250	Mayo	NC	27573	24,527	15,687	64	10,552	2,806	11.80	11.80%	13.20%	0	36.00	36.00%	27.90%	1
54708	10379	Primary Energy Roxboro	NC	27573	24,527	15,687	64	10,552	2,806	11.80	11.80%	13.20%	0	36.00	36.00%	27.90%	1
3046	2712	Roxboro	NC	27573	24,527	15,687	64	10,552	2,806	11.80	11.80%	13.20%	0	36.00	36.00%	27.90%	1
55739	10384	Edgecombe Genco LLC	NC	27809	5,162	2,035	39.4	2,218	802	16.20	16.20%	13.20%	1	60.60	60.60%	27.90%	1
55808	54035	Roanoke Valley Energy Fac. I	NC	27890	2,879	694	24.1	1,288	833	30.20	30.20%	13.20%	1	75.90	75.90%	27.90%	1
55808	54755	Roanoke Valley Energy Fac. II	NC	27890	2,879	694	24.1	1,288	833	30.20	30.20%	13.20%	1	75.90	75.90%	27.90%	1
5416	2718	G G Allen	NC	28012	19,024	16,956	89.1	7,917	1,324	7.20	7.20%	13.20%	0	10.90	10.90%	27.90%	0

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5416	2721	Cliffside	NC	28024							0.00%	13.20%	0		0.00%	27.90%	0
5416	2732	Riverbend	NC	28120	15,595	13,711	87.9	6,537	1,442	9.30	9.30%	13.20%	0	12.10	12.10%	27.90%	0
5416	2720	Buck	NC	28145							0.00%	13.20%	0		0.00%	27.90%	0
13695	10380	Elizabethtown Power LLC	NC	28337	9,225	4,817	52.2	4,932	2,042	23.30	23.30%	13.20%	1	47.80	47.80%	27.90%	1
54889	10381	Coastal Carolina Clean Power	NC	28349	3,472	1,913	55.1	1,260	566	16.60	16.60%	13.20%	1	44.90	44.90%	27.90%	1
3046	2716	W H Weatherspoon	NC	28358	36,671	18,269	49.8	15,105	7,888	22.70	22.70%	13.20%	1	50.20	50.20%	27.90%	1
13695	10382	Lumberton	NC	28359							0.00%	13.20%	0		0.00%	27.90%	0
3046	2713	L V Sutton	NC	28401	21,799	9,803	45	11,061	5,808	28.20	28.20%	13.20%	1	55.00	55.00%	27.90%	1
54708	10378	Primary Energy Southport	NC	28461	9,095	7,968	87.6	5,602	817	9.10	9.10%	13.20%	0	12.40	12.40%	27.90%	0
5416	2727	Marshall	NC	28682	860	838	97.4	587	53	6.40	6.40%	13.20%	0	2.60	2.60%	27.90%	0
3046	2706	Asheville	NC	28704	14,782	13,446	91	6,617	1,260	8.60	8.60%	13.20%	0	9.00	9.00%	27.90%	0
22		**NC**		**16**	**238,874**	**156,477**	**65.5**	**106,757**	**37,388**	**15.65**	**15.65%**	**13.20%**	**9**	**34.49**	**34.49%**	**27.90%**	**12**
1307	6469	Antelope Valley	ND	58523	3,886	3,737	96.2	1,904	296	7.90	7.90%	12.70%	0	3.80	3.80%	7.60%	0
14232	8222	Coyote	ND	58523	3,886	3,737	96.2	1,904	296	7.90	7.90%	12.70%	0	3.80	3.80%	7.60%	0
12658	2823	Milton R Young	ND	58530	1,374	1,330	96.8	613	164	11.80	11.80%	12.70%	0	3.20	3.20%	7.60%	0
12199	2790	R M Heskett	ND	58554	20,219	19,265	95.3	8,256	1,813	9.10	9.10%	12.70%	0	4.70	4.70%	7.60%	0
1307	2817	Leland Olds	ND	58571	557	538	96.6	337	33	5.80	5.80%	12.70%	0	3.40	3.40%	7.60%	0
7570	2824	Stanton	ND	58571	557	538	96.6	337	33	5.80	5.80%	12.70%	0	3.40	3.40%	7.60%	0
7570	6030	Coal Creek	ND	58576	1,051	1,024	97.4	504	134	13.30	13.30%	12.70%	1	2.60	2.60%	7.60%	0
7		**ND**		**5**	**27,087**	**25,894**	**95.6**	**11,614**	**2,440**	**9.01**	**9.01%**	**12.70%**	**1**	**4.40**	**4.40%**	**7.60%**	**0**
6779	2240	Lon Wright	NE	68025	29,200	27,896	95.5	12,676	2,384	8.40	8.40%	10.70%	0	4.50	4.50%	10.40%	0
14127	2291	North Omaha	NE	68112	12,092	9,140	75.6	4,692	1,672	14.20	14.20%	10.70%	1	24.40	24.40%	10.40%	1
13337	2277	Sheldon	NE	68368	497	472	95	212	19	3.50	3.50%	10.70%	0	5.00	5.00%	10.40%	0
14127	6096	Nebraska City	NE	68410	8,459	8,165	96.5	3,647	753	9.10	9.10%	10.70%	0	3.50	3.50%	10.40%	0
40606	59	Platte	NE	68801	27,389	22,998	84	11,096	4,028	15.00	15.00%	10.70%	1	16.00	16.00%	10.40%	1
8245	60	Whelan Energy Center	NE	68902							0.00%	10.70%	0		0.00%	10.40%	0
13337	6077	Gerald Gentleman	NE	69165	1,676	1,615	96.4	705	136	8.50	8.50%	10.70%	0	3.60	3.60%	10.40%	0
7		**NE**		**6**	**79,313**	**70,286**	**88.6**	**33,028**	**8,992**	**11.34**	**11.34%**	**10.70%**	**2**	**11.38**	**11.38%**	**10.40%**	**2**
15472	2364	Merrimack	NH	03301	31,744	30,239	95.3	13,177	2,436	8.50	8.50%	7.60%	1	4.70	4.70%	4.00%	1
15472	2367	Schiller	NH	03801	21,558	20,186	93.6	10,490	1,919	9.10	9.10%	7.60%	1	6.40	6.40%	4.00%	1
2		**NH**		**2**	**53,302**	**50,425**	**94.6**	**23,667**	**4,355**	**8.17**	**8.17%**	**7.60%**	**2**	**5.40**	**5.40%**	**4.00%**	**2**
15147	2403	PSEG Hudson Generating Station	NJ	07306	54,912	20,045	36.5	21,333	10,449	19.30	19.30%	8.10%	1	63.50	63.50%	27.40%	1
14932	10043	Logan Generating Company LP	NJ	08085	10,703	8,831	82.5	3,777	552	5.20	5.20%	8.10%	0	17.50	17.50%	27.40%	0
19856	2434	Howard Down	NJ	08360							0.00%	8.10%	0		0.00%	27.40%	0
15147	2408	PSEG Mercer Generating Station	NJ	08611	23,868	12,850	53.8	9,614	4,320	18.60	18.60%	8.10%	1	46.20	46.20%	27.40%	1
14932	10566	Chambers Cogeneration LP	NJ	08069	12,468	8,320	66.7	5,354	1,828	14.90	14.90%	8.10%	1	33.30	33.30%	27.40%	1
4158	2384	Deepwater	NJ	08070	12,951	12,516	96.6	5,515	648	5.00	5.00%	8.10%	0	3.40	3.40%	27.40%	0
55768	2378	B L England	NJ	08223	4,384	4,286	97.8	2,327	161	3.70	3.70%	8.10%	0	2.20	2.20%	27.40%	0
7		**NJ**		**6**	**119,286**	**66,848**	**56.0**	**47,920**	**17,958**	**15.05**	**15.05%**	**8.10%**	**3**	**43.96**	**43.96%**	**27.40%**	**3**
30151	87	Escalante	NM	87045	2,380	157	6.6	863	1,221	54.40	54.40%	19.30%	1	93.40	93.40%	33.20%	1
803	2442	Four Corners	NM	87416	5,086	576	11.3	1,545	1,765	34.10	34.10%	19.30%	1	88.70	88.70%	33.20%	1
15473	2451	San Juan	NM	87421	1,606	295	18.4	551	363	29.00	29.00%	19.30%	1	81.60	81.60%	33.20%	1

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15698	2468	Raton	NM	87740	8,419	6,717	79.8	4,041	1,289	15.60	15.60%	19.30%	0	20.20	20.20%	33.20%	0
4		**NM**		**4**	**17,491**	**7,745**	**44.3**	**7,000**	**4,638**	**26.52**	**26.52%**	**19.30%**	**3**	**55.72**	**55.72%**	**33.20%**	**3**
13407	2324	Reid Gardner	NV	89025	1,395	835	59.9	472	171	11.50	11.50%	10.10%	1	40.10	40.10%	24.80%	1
17609	2341	Mohave	NV	89029	7,076	6,302	89.1	4,127	652	9.60	9.60%	10.10%	0	10.90	10.90%	24.80%	0
17166	8224	North Valmy	NV	89438							0.00%	10.10%	0		0.00%	24.80%	0
3		**NV**		**2**	**8,471**	**7,137**	**84.3**	**4,599**	**823**	**9.72**	**9.72%**	**10.10%**	**1**	**15.75**	**15.75%**	**24.80%**	**1**
12792	2629	Lovett	NY	10986	1,739	1,631	93.8	614	58	3.30	3.30%	14.70%	0	6.20	6.20%	32.10%	0
5511	2480	Danskammer Generating Station	NY	12550	52,084	31,969	61.4	19,316	7,886	15.50	15.50%	14.70%	1	38.60	38.60%	32.10%	1
19194	50651	Trigen Syracuse Energy	NY	13204	20,826	13,071	62.8	10,288	7,210	34.60	34.60%	14.70%	1	37.20	37.20%	32.10%	1
1746	10464	Black River Generation	NY	13602	4,651	2,932	63	12	0	0.00	0.00%	14.70%	0	37.00	37.00%	32.10%	1
22122	2531	AES Jennison LLC	NY	13733	4,874	4,807	98.6	2,269	533	11.00	11.00%	14.70%	0	1.40	1.40%	32.10%	0
22146	2526	AES Westover	NY	13790	19,713	17,788	90.2	9,352	2,724	14.30	14.30%	14.70%	0	9.80	9.80%	32.10%	0
22129	6082	AES Somerset LLC	NY	14012	2,603	2,530	97.2	1,042	270	10.30	10.30%	14.70%	0	2.80	2.80%	32.10%	0
13579	2554	Dunkirk Generating Plant	NY	14048	16,097	13,676	85	7,457	3,104	20.10	20.10%	14.70%	1	15.00	15.00%	32.10%	0
13168	2549	C R Huntley Generating Station	NY	14150	44,535	42,871	96.3	19,624	3,419	7.70	7.70%	14.70%	0	3.70	3.70%	32.10%	0
55807	50202	WPS Power Niagara	NY	14302							0.00%	14.70%	0		0.00%	32.10%	0
25	2527	AES Greenidge LLC	NY	14441	344	326	94.8	197	19	5.40	5.40%	14.70%	0	5.20	5.20%	32.10%	0
16183	2642	Rochester 7	NY	14612	35,665	33,410	93.7	14,443	1,673	4.80	4.80%	14.70%	0	6.30	6.30%	32.10%	0
9645	2682	S A Carlson	NY	14702							0.00%	14.70%	0		0.00%	32.10%	0
39	2529	AES Hickling LLC	NY	14830	19,342	18,343	94.8	8,915	2,066	10.70	10.70%	14.70%	0	5.20	5.20%	32.10%	0
22125	2535	AES Cayuga	NY	14882	3,943	3,611	91.6	1,597	225	6.20	6.20%	14.70%	0	8.40	8.40%	32.10%	0
15		**NY**		**13**	**226,416**	**186,965**	**82.6**	**95,126**	**29,187**	**12.89**	**12.89%**	**14.70%**	**3**	**17.42**	**17.42%**	**32.10%**	**3**
4062	2843	Picway	OH	43137	2,453	2,364	96.4	978	140	6.20	6.20%	11.10%	0	3.60	3.60%	15.00%	0
6526	2878	Bay Shore	OH	43616	16,776	15,853	94.5	6,993	813	5.00	5.00%	11.10%	0	5.50	5.50%	15.00%	0
4062	2840	Conesville	OH	43811	850	846	99.5	372	54	6.00	6.00%	11.10%	0	0.50	0.50%	15.00%	0
3006	2828	Cardinal	OH	43913	1,728	1,712	99.1	829	226	13.10	13.10%	11.10%	1	0.90	0.90%	15.00%	0
6526	2864	R E Burger	OH	43947	5,356	5,320	99.3	2,518	441	8.60	8.60%	11.10%	0	0.70	0.70%	15.00%	0
6526	2866	W H Sammis	OH	43961	277	271	97.8	146	21	7.60	7.60%	11.10%	0	2.20	2.20%	15.00%	0
6526	2835	Ashtabula	OH	44004	35,631	31,821	89.3	15,759	5,678	16.00	16.00%	11.10%	1	10.70	10.70%	15.00%	0
14165	2836	Avon Lake	OH	44012	18,284	17,786	97.3	6,987	416	2.30	2.30%	11.10%	0	2.70	2.70%	15.00%	0
14381	2936	Painesville	OH	44077	50,412	45,469	90.2	20,132	3,938	7.90	7.90%	11.10%	0	9.80	9.80%	15.00%	0
6526	2837	Eastlake	OH	44095	35,298	34,466	97.6	14,878	1,684	4.80	4.80%	11.10%	0	2.40	2.40%	15.00%	0
6526	2838	Lake Shore	OH	44103	25,348	3,741	14.8	12,000	9,484	37.80	37.80%	11.10%	1	85.20	85.20%	15.00%	1
3762	2908	Lake Road	OH	44114	3,891	1,400	36	2,765	1,295	35.60	35.60%	11.10%	1	64.00	64.00%	15.00%	1
14165	2861	Niles	OH	44446	23,207	22,307	96.1	10,461	2,129	9.40	9.40%	11.10%	0	3.90	3.90%	15.00%	0
5336	2914	Dover	OH	44622	17,898	17,489	97.7	7,417	1,352	7.80	7.80%	11.10%	0	2.30	2.30%	15.00%	0
14194	2935	Orrville	OH	44667	13,744	12,820	93.3	5,291	981	7.30	7.30%	11.10%	0	6.70	6.70%	15.00%	0
17043	2943	Shelby Municipal Light Plant	OH	44875	14,882	14,530	97.6	6,110	1,239	8.60	8.60%	11.10%	0	2.40	2.40%	15.00%	0
7977	2917	Hamilton	OH	45011	55,358	48,221	87.1	20,783	5,980	11.00	11.00%	11.10%	0	12.90	12.90%	15.00%	0
3542	2832	Miami Fort	OH	45100							0.00%	11.10%	0		0.00%	15.00%	0
4922	2850	J M Stuart	OH	45101	2,540	2,473	97.4	1,211	455	18.60	18.60%	11.10%	1	2.60	2.60%	15.00%	0
4922	6031	Killen Station	OH	45144	4,269	4,176	97.8	2,055	882	20.60	20.60%	11.10%	1	2.20	2.20%	15.00%	0
3542	6019	W H Zimmer	OH	45200							0.00%	11.10%	0		0.00%	15.00%	0
3542	2830	Walter C Beckjord	OH	45200							0.00%	11.10%	0		0.00%	15.00%	0

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4922	2848	O H Hutchings	OH	45342	31,540	29,532	93.6	13,838	1,578	5.10	5.10%	11.10%	0	6.40	6.40%	15.00%	0
14006	8102	General James M Gavin	OH	45620	1,242	1,212	97.6	576	116	9.90	9.90%	11.10%	0	2.40	2.40%	15.00%	0
14015	2876	Kyger Creek	OH	45620	1,242	1,212	97.6	576	116	9.90	9.90%	11.10%	0	2.40	2.40%	15.00%	0
14006	2872	Muskingum River	OH	45715	2,501	2,474	98.9	1,150	211	8.90	8.90%	11.10%	0	1.10	1.10%	15.00%	0
40577	7286	Richard Gorsuch	OH	45750	28,220	27,469	97.3	12,422	3,129	11.70	11.70%	11.10%	1	2.70	2.70%	15.00%	0
27		**OH**		**23**	**391,705**	**343,752**	**87.8**	**165,671**	**42,242**	**10.78**	**10.78%**	**11.10%**	**7**	**12.24**	**12.24%**	**15.00%**	**2**
14063	6095	Sooner	OK	73061	1,308	1,174	89.8	550	153	11.90	11.90%	14.10%	0	10.20	10.20%	23.80%	0
15474	2963	Northeastern	OK	74053	2,628	2,043	77.7	1,034	258	9.60	9.60%	14.10%	0	22.30	22.30%	23.80%	0
7490	165	GRDA	OK	74337	4,841	3,885	80.3	2,139	737	16.30	16.30%	14.10%	1	19.70	19.70%	23.80%	0
14063	2952	Muskogee	OK	74401	18,018	8,580	47.6	8,125	4,200	24.40	24.40%	14.10%	1	52.40	52.40%	23.80%	1
20447	6772	Hugo	OK	74735	1,840	1,436	78	877	392	21.80	21.80%	14.10%	1	22.00	22.00%	23.80%	0
21	10671	AES Shady Point LLC	OK	74951	1,722	1,448	84.1	772	377	22.30	22.30%	14.10%	1	15.90	15.90%	23.80%	0
6		**OK**		**6**	**30,357**	**18,566**	**61.2**	**13,497**	**6,117**	**20.15**	**20.15%**	**14.10%**	**4**	**38.84**	**38.84%**	**23.80%**	**1**
15248	6106	Boardman	OR	97818	3,884	2,362	60.8	1,312	596	15.40	15.40%	12.90%	1	39.20	39.20%	13.40%	1
1		**OR**		**1**	**3,884**	**2,362**	**60.8**	**1,312**	**596**	**15.35**	**15.35%**	**12.90%**	**1**	**39.19**	**39.19%**	**13.40%**	**1**
14165	3098	Elrama Power Plant	PA	15038	291	282	96.9	137	0	0.00	0.00%	9.80%	0	3.10	3.10%	14.60%	0
142	10676	AES Beaver Valley Partners Beaver Valley	PA	15061	13,828	13,354	96.6	5,840	882	6.50	6.50%	9.80%	0	3.40	3.40%	14.60%	0
23279	3181	Mitchell Power Station	PA	15067	2,272	2,204	97	1,073	211	9.30	9.30%	9.80%	0	3.00	3.00%	14.60%	0
6526	6094	Bruce Mansfield	PA	15077							0.00%	9.80%	0		0.00%	14.60%	0
14165	8226	Cheswick Power Plant	PA	15204	9,502	6,948	73.1	4,176	1,390	14.60	14.60%	9.80%	1	26.90	26.90%	14.60%	1
23279	3179	Hatfields Ferry Power Station	PA	15461	4,605	4,293	93.2	2,134	1,078	24.30	24.30%	9.80%	1	6.80	6.80%	14.60%	0
12384	3122	Homer City Station	PA	15748	7,073	7,014	99.2	3,112	641	9.10	9.10%	9.80%	0	0.80	0.80%	14.60%	0
15873	3136	Keystone	PA	15774	3,234	3,203	99	1,301	377	11.60	11.60%	9.80%	1	1.00	1.00%	14.60%	0
9379	10143	Colver Power Project	PA	15927	1,199	1,194	99.6	501	236	21.30	21.30%	9.80%	1	0.40	0.40%	14.60%	0
2884	10641	Cambria Cogen	PA	15931	9,667	9,365	96.9	3,572	726	8.40	8.40%	9.80%	0	3.10	3.10%	14.60%	0
5670	10603	Ebensburg Power	PA	15931	9,667	9,365	96.9	3,572	726	8.40	8.40%	9.80%	0	3.10	3.10%	14.60%	0
15873	3118	Conemaugh	PA	15944	3,487	3,456	99.1	1,543	504	13.90	13.90%	9.80%	1	0.90	0.90%	14.60%	0
15998	3130	Seward	PA	15944	3,487	3,456	99.1	1,543	504	13.90	13.90%	9.80%	1	0.90	0.90%	14.60%	0
14165	3138	New Castle Plant	PA	16160	960	944	98.3	427	125	12.60	12.60%	9.80%	1	1.70	1.70%	14.60%	0
23279	3178	Armstrong Power Station	PA	16210	1,181	1,174	99.4	684	181	16.10	16.10%	9.80%	1	0.60	0.60%	14.60%	0
4129	54144	Piney Creek Project	PA	16214	10,449	9,993	95.6	4,218	2,426	28.30	28.30%	9.80%	1	4.40	4.40%	14.60%	0
14932	50974	Scrubgrass Generating Company LP	PA	16374	1,622	1,589	98	1,529	211	13.00	13.00%	9.80%	1	2.00	2.00%	14.60%	0
17235	3131	Shawville	PA	16873							0.00%	9.80%	0		0.00%	14.60%	0
15537	3140	PPL Brunner Island	PA	17370	4,992	4,857	97.3	2,018	260	5.20	5.20%	9.80%	0	2.70	2.70%	14.60%	0
49889	10343	Foster Wheeler Mt Carmel Cogen	PA	17832	755	750	99.3	381	43	5.90	5.90%	9.80%	0	0.70	0.70%	14.60%	0
22001	3152	Sunbury Generation LP	PA	17876							0.00%	9.80%	0		0.00%	14.60%	0
15534	3149	PPL Montour	PA	17884	257	250	97.3	125	70	24.40	24.40%	9.80%	1	2.70	2.70%	14.60%	0
7199	10113	John B Rich Memorial Power Station	PA	17931	8,631	6,685	77.5	2,674	413	7.50	7.50%	9.80%	0	22.50	22.50%	14.60%	1
20541	50879	Wheelabrator Frackville Energy	PA	17931	8,631	6,685	77.5	2,674	413	7.50	7.50%	9.80%	0	22.50	22.50%	14.60%	1
16793	54634	St Nicholas Cogen Project	PA	17976	7,864	7,703	98	4,387	1,199	15.60	15.60%	9.80%	1	2.00	2.00%	14.60%	0

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21025	50611	WPS Westwood Generation LLC	PA	17981	2,738	2,716	99.2	1,161	259	10.30	10.30%	9.80%	1	0.80	0.80%	14.60%	0
14932	50888	Northampton Generating Company LP	PA	18067	15,953	15,688	98.3	6,608	512	3.30	3.30%	9.80%	0	1.70	1.70%	14.60%	0
13833	50039	Kline Township Cogen Facility	PA	18237	3,189	3,165	99.2	1,622	380	11.90	11.90%	9.80%	1	0.80	0.80%	14.60%	0
14432	50776	Panther Creek Energy Facility	PA	18240	3,898	3,818	97.9	1,920	315	8.40	8.40%	9.80%	0	2.10	2.10%	14.60%	0
17235	3113	Portland	PA	18351	579	569	98.3	247	34	6.00	6.00%	9.80%	0	1.70	1.70%	14.60%	0
19391	3176	Hunlock Power Station	PA	18621	5,885	5,409	91.9	2,140	491	9.50	9.50%	9.80%	0	8.10	8.10%	14.60%	0
6035	3161	Eddystone Generating Station	PA	19022	3,906	3,400	87	1,720	679	17.60	17.60%	9.80%	1	13.00	13.00%	14.60%	0
6035	3159	Cromby Generating Station	PA	19460	32,944	30,016	91.1	13,557	1,440	4.50	4.50%	9.80%	0	8.90	8.90%	14.60%	0
17235	3115	Titus	PA	19506	6,293	6,167	98	2,452	416	6.50	6.50%	9.80%	0	2.00	2.00%	14.60%	0
34		**PA**		**28**	**167,254**	**156,206**	**93.4**	**71,259**	**15,499**	**9.27**	**9.27%**	**9.80%**	**15**	**6.61**	**6.61%**	**14.60%**	**3**
17539	7210	Cope	SC	29038	2,543	1,662	65.4	2,543	318	12.80	12.80%	12.00%	1	34.60	34.60%	32.80%	1
17539	3297	Wateree	SC	29044	5,937	2,068	34.8	2,417	1,077	18.30	18.30%	12.00%	1	65.20	65.20%	32.80%	1
17539	3287	McMeekin	SC	29212	28,029	22,710	81	11,209	1,214	4.40	4.40%	12.00%	0	19.00	19.00%	32.80%	0
17539	7737	Cogen South	SC	29423	791	565	71.4	10	0	(X)	#VALUE!	12.00%	#VALUE!	28.60	28.60%	32.80%	0
17539	3280	Canadys Steam	SC	29433							0.00%	12.00%	0		0.00%	32.80%	0
17543	130	Cross	SC	29436	4,451	1,600	35.9	2,143	1,207	27.50	27.50%	12.00%	1	64.10	64.10%	32.80%	1
17543	6249	Winyah	SC	29440	28,875	13,706	47.5	12,123	5,537	19.70	19.70%	12.00%	1	52.50	52.50%	32.80%	1
17554	3298	Williams	SC	29445	48,628	35,249	72.5	16,894	4,313	9.50	9.50%	12.00%	0	27.50	27.50%	32.80%	0
17543	3319	Jefferies	SC	29461	24,081	15,718	65.3	9,652	2,974	12.80	12.80%	12.00%	1	34.70	34.70%	32.80%	1
17543	3317	Dolphus M Grainger	SC	29526	30,392	24,807	81.6	12,967	3,624	12.50	12.50%	12.00%	1	18.40	18.40%	32.80%	0
3046	3251	H B Robinson	SC	29550	31,313	21,163	67.6	13,829	6,035	19.60	19.60%	12.00%	1	32.40	32.40%	32.80%	0
5416	3264	W S Lee	SC	29697	10,592	9,336	88.1	4,408	1,224	11.40	11.40%	12.00%	0	11.90	11.90%	32.80%	0
56190	7652	US DOE Savannah River Site (D Area)	SC	29808							0.00%	12.00%	0		0.00%	32.80%	0
17539	3295	Urquhart	SC	29842	6,782	3,999	59	2,820	1,223	17.90	17.90%	12.00%	1	41.00	41.00%	32.80%	1
14		**SC**		**12**	**222,414**	**152,583**	**68.6**	**91,015**	**28,746**	**12.92**	**12.92%**	**12.00%**	**8**	**31.40**	**31.40%**	**32.80%**	**6**
14232	6098	Big Stone	SD	57216	1,133	1,124	99.2	744	156	13.40	13.40%	9.40%	1	0.80	0.80%	11.30%	0
19545	3325	Ben French	SD	57702	29,375	27,690	94.3	12,678	1,607	5.50	5.50%	9.40%	0	5.70	5.70%	11.30%	0
2		**SD**		**2**	**30,508**	**28,814**	**94.4**	**13,422**	**1,763**	**5.78**	**5.78%**	**9.40%**	**1**	**5.55**	**5.55%**	**11.30%**	**0**
18642	3399	Cumberland	TN	37050	1,786	1,675	93.8	830	238	13.70	13.70%	13.40%	1	6.20	6.20%	19.80%	0
18642	3403	Gallatin	TN	37066	34,155	28,292	82.8	13,774	3,783	11.30	11.30%	13.40%	0	17.20	17.20%	19.80%	0
18642	3406	Johnsonville	TN	37134	3,018	2,951	97.8	1,407	260	8.70	8.70%	13.40%	0	2.20	2.20%	19.80%	0
18642	3419	Watts Bar Fossil	TN	37381	7,850	7,572	96.5	3,937	1,258	16.40	16.40%	13.40%	1	3.50	3.50%	19.80%	0
18642	3396	Bull Run	TN	37716	24,422	23,561	96.5	10,692	3,007	12.50	12.50%	13.40%	0	3.50	3.50%	19.80%	0
18642	3407	Kingston	TN	37763	14,572	14,046	96.4	6,613	1,522	10.20	10.20%	13.40%	0	3.60	3.60%	19.80%	0
18642	3405	John Sevier	TN	37857	20,063	19,453	97	9,243	3,246	16.50	16.50%	13.40%	1	3.00	3.00%	19.80%	0
18642	3393	Allen Steam Plant	TN	38109	52,401	1,558	3	18,768	13,258	25.50	25.50%	13.40%	1	97.00	97.00%	19.80%	1
8		**TN**		**8**	**158,267**	**99,108**	**62.6**	**65,264**	**26,572**	**16.79**	**16.79%**	**13.40%**	**4**	**37.38**	**37.38%**	**19.80%**	**1**
19323	6147	Monticello	TX	75455	24,737	16,904	68.3	9,242	4,409	18.30	18.30%	14.90%	1	31.70	31.70%	29.00%	1
17698	7902	Pirkey	TX	75650	7,699	6,949	90.3	3,007	781	9.70	9.70%	14.90%	0	9.70	9.70%	29.00%	0
17698	6139	Welsh	TX	75686	11,285	7,750	68.7	5,058	2,182	19.80	19.80%	14.90%	1	31.30	31.30%	29.00%	1
19323	6146	Martin Lake	TX	75691	3,687	2,622	71.1	1,529	578	16.20	16.20%	14.90%	1	28.90	28.90%	29.00%	0

Appendix N
Minority & Low-Income Population Data (2000)

Utility ID and Total Plant Count	Plant ID	Plant Name	State	Zip code	ZCTA popula-tion	ZCTA white popula-tion	% White	ZCTA housing units	Persons below poverty level	Census ZCTA % below poverty level	% of ZCTA code population below poverty level	State % below poverty level	If ZCTA > state poverty level	Census ZCTA % minority	ZCTA % that are minority	State % minority	If ZCTA > % state minority level % assign 1
19323	3497	Big Brown	TX	75840	6,622	5,155	77.8	3,056	918	14.20	14.20%	14.90%	0	22.20	22.20%	29.00%	0
54888	298	Limestone	TX	75846	2,645	2,260	85.4	1,495	469	16.90	16.90%	14.90%	1	14.60	14.60%	29.00%	0
15474	127	Oklaunion	TX	76373	194	167	86.1	93	46	21.30	21.30%	14.90%	1	13.90	13.90%	29.00%	0
19323	6648	Sandow No 4	TX	76567	9,238	7,130	77.2	4,087	1,419	15.80	15.80%	14.90%	1	22.80	22.80%	29.00%	0
54891	7030	Twin Oaks Power One	TX	76629	1,926	1,622	84.2	1,013	382	20.40	20.40%	14.90%	1	15.80	15.80%	29.00%	0
54888	3470	W A Parish	TX	77481	184	99	53.8	86	44	23.00	23.00%	14.90%	1	46.20	46.20%	29.00%	1
18715	6136	Gibbons Creek	TX	77830	2,290	1,895	82.8	1,115	262	11.40	11.40%	14.90%	0	17.20	17.20%	29.00%	0
54865	6178	Coleto Creek	TX	77960	125	114	91.2	59	0	0.00	0.00%	14.90%	0	8.80	8.80%	29.00%	0
16624	6183	San Miguel	TX	78012	526	421	80	220	194	36.40	36.40%	14.90%	1	20.00	20.00%	29.00%	0
16604	7097	J K Spruce	TX	78263	4,147	3,582	86.4	1,507	154	3.80	3.80%	14.90%	0	13.60	13.60%	29.00%	0
16604	6181	J T Deely	TX	78263	4,147	3,582	86.4	1,507	154	3.80	3.80%	14.90%	0	13.60	13.60%	29.00%	0
11269	6179	Fayette Power Project	TX	78945	10,041	8,347	83.1	4,834	994	10.10	10.10%	14.90%	0	16.90	16.90%	29.00%	0
17718	6193	Harrington	TX	79108	11,876	10,466	88.1	4,496	1,124	10.00	10.00%	14.90%	0	11.90	11.90%	29.00%	0
17718	6194	Tolk	TX	79371	1,180	867	73.5	515	191	16.50	16.50%	14.90%	1	26.50	26.50%	29.00%	0
35120	54972	Norit Americas Marshall Plant	TX	1							0.00%	14.90%	0		0.00%	29.00%	0
19		**TX**		**17**	**98,402**	**76,350**	**77.6**	**41,412**	**14,147**	**14.38**	**14.38%**	**14.90%**	**10**	**22.41**	**22.41%**	**29.00%**	**3**
40230	7790	Bonanza	UT	84078	19,591	18,708	95.5	7,054	2,120	10.90	10.90%	8.10%	1	4.50	4.50%	10.80%	0
14354	6165	Hunter	UT	84513	1,880	1,796	95.5	679	151	8.30	8.30%	8.10%	1	4.50	4.50%	10.80%	0
14354	3644	Carbon	UT	84526	3,909	3,613	92.4	2,069	543	13.90	13.90%	8.10%	1	7.60	7.60%	10.80%	0
14354	8069	Huntington	UT	84528	2,742	2,574	93.9	998	330	12.20	12.20%	8.10%	1	6.10	6.10%	10.80%	0
21734	50951	Sunnyside Cogen Associates	UT	84539	408	369	90.4	200	62	14.70	14.70%	8.10%	1	9.60	9.60%	10.80%	0
11208	6481	Intermountain Power Project	UT	84624	5,679	5,365	94.5	1,967	679	12.00	12.00%	8.10%	1	5.50	5.50%	10.80%	0
6		**UT**		**6**	**34,209**	**32,425**	**94.8**	**12,967**	**3,885**	**11.36**	**11.36%**	**8.10%**	**6**	**5.22**	**5.22%**	**10.80%**	**0**
12588	3788	Potomac River	VA	22314	24,921	17,897	71.8	14,163	2,550	10.50	10.50%	8.10%	1	28.20	28.20%	27.70%	1
1735	54304	Birchwood Power	VA	22485	15,805	12,287	77.7	6,599	871	5.60	5.60%	8.10%	0	22.30	22.30%	27.70%	0
19876	3796	Bremo Bluff	VA	23022	656	275	41.9	296	69	11.40	11.40%	8.10%	1	58.10	58.10%	27.70%	1
55740	54081	Spruance Genco LLC	VA	23234	38,100	16,620	43.6	15,370	4,556	11.90	11.90%	8.10%	1	56.40	56.40%	27.70%	1
19876	3803	Chesapeake	VA	23323	31,336	18,456	58.9	10,887	2,179	7.00	7.00%	8.10%	0	41.10	41.10%	27.70%	1
19876	3809	Yorktown	VA	23690	2,577	1,060	41.1	963	592	26.30	26.30%	8.10%	1	58.90	58.90%	27.70%	1
3901	10071	Cogentrix Virginia Leasing Corporation	VA	23703	27,625	15,397	55.7	10,176	1,961	7.80	7.80%	8.10%	0	44.30	44.30%	27.70%	1
19876	3797	Chesterfield	VA	23831	24,798	20,589	83	9,593	1,174	4.80	4.80%	8.10%	0	17.00	17.00%	27.70%	0
19876	10774	Southampton Power Station	VA	23851	13,397	6,816	50.9	5,993	2,356	18.00	18.00%	8.10%	1	49.10	49.10%	27.70%	1
19876	10771	Hopewell Power Station	VA	23860	27,173	17,353	63.9	11,602	3,694	13.70	13.70%	8.10%	1	36.10	36.10%	27.70%	1
9628	10377	James River Cogeneration	VA	23860	27,173	17,353	63.9	11,602	3,694	13.70	13.70%	8.10%	1	36.10	36.10%	27.70%	1
19876	52007	Mecklenburg Power Station	VA	23927	4,456	3,020	67.8	3,030	347	7.70	7.70%	8.10%	0	32.20	32.20%	27.70%	1
733	3776	Glen Lyn	VA	24093	338	334	98.8	120	30	12.50	12.50%	8.10%	1	1.20	1.20%	27.70%	0
733	3775	Clinch River	VA	24225	2,017	2,001	99.2	1,008	456	22.90	22.90%	8.10%	1	0.80	0.80%	27.70%	0
19876	10773	Altavista Power Station	VA	24517	5,431	4,131	76.1	2,522	603	11.30	11.30%	8.10%	1	23.90	23.90%	27.70%	0
19876	7213	Clover	VA	24534	2,170	1,153	53.1	1,051	384	17.80	17.80%	8.10%	1	46.90	46.90%	27.70%	1
16		**VA**		**15**	**220,800**	**137,389**	**62.2**	**93,373**	**21,822**	**9.88**	**9.88%**	**8.10%**	**11**	**37.78**	**37.78%**	**27.70%**	**11**
19099	3845	Transalta Centralia Generation	WA	98531	21,842	19,759	90.5	9,337	3,394	15.80	15.80%	9.50%	1	9.50	9.50%	18.20%	0
1		**WA**		**1**	**21,842**	**19,759**	**90.5**	**9,337**	**3,394**	**15.54**	**15.54%**	**9.50%**	**1**	**9.54**	**9.54%**	**18.20%**	**0**
20847	4041	South Oak Creek	WI	53154	28,659	26,377	92	11,842	915	3.20	3.20%	9.00%	0	8.00	8.00%	11.10%	0

Appendix N
Minority & Low-Income Population Data (2000)

Utility ID and Total Plant Count	Plant ID	Plant Name	State	Zip code	ZCTA popula-tion	ZCTA white popula-tion	% White	ZCTA housing units	Persons below poverty level	Census ZCTA % below poverty level	% of ZCTA code population below poverty level	State % below poverty level	If ZCTA > state poverty level	Census ZCTA % minority	ZCTA % that are minority	State % minority	If ZCTA > % state minority level % assign 1
20847	6170	Pleasant Prairie	WI	53158	11,339	10,676	94.2	4,131	269	2.40	2.40%	9.00%	0	5.80	5.80%	11.10%	0
20847	7549	Milwaukee County	WI	53226	18,835	17,678	93.9	8,578	830	4.60	4.60%	9.00%	0	6.10	6.10%	11.10%	0
20847	4042	Valley	WI	53233	15,485	8,327	53.8	5,713	4,697	47.30	47.30%	9.00%	1	46.20	46.20%	11.10%	1
11479	3992	Blount Street	WI	53703	26,715	23,125	86.6	13,097	10,385	43.80	43.80%	9.00%	1	13.40	13.40%	11.10%	1
20856	4050	Edgewater	WI	53802							0.00%	9.00%	0		0.00%	11.10%	0
12435	4146	E J Stoneman Station	WI	53806	2,003	1,992	99.5	967	334	16.80	16.80%	9.00%	1	0.50	0.50%	11.10%	0
20856	4054	Nelson Dewey	WI	53806	2,003	1,992	99.5	967	334	16.80	16.80%	9.00%	1	0.50	0.50%	11.10%	0
20856	8023	Columbia	WI	53954	6,480	6,346	97.9	2,656	319	5.10	5.10%	9.00%	0	2.10	2.10%	11.10%	0
11571	4125	Manitowoc	WI	54221							0.00%	9.00%	0		0.00%	11.10%	0
20860	4072	Pulliam	WI	54303	27,638	23,827	86.2	12,534	2,860	10.50	10.50%	9.00%	1	13.80	13.80%	11.10%	1
20860	4078	Weston	WI	54474	3,728	3,563	95.6	1,504	155	4.20	4.20%	9.00%	0	4.40	4.40%	11.10%	0
4716	4140	Alma	WI	54610	1,877	1,841	98.1	902	175	9.60	9.60%	9.00%	1	1.90	1.90%	11.10%	0
4716	4271	John P Madgett	WI	54610	1,877	1,841	98.1	902	175	9.60	9.60%	9.00%	1	1.90	1.90%	11.10%	0
4716	4143	Genoa	WI	54632	1,226	1,212	98.9	597	92	7.50	7.50%	9.00%	0	1.10	1.10%	11.10%	0
13781	3982	Bay Front	WI	54806	11,793	10,392	88.1	5,148	1,273	11.50	11.50%	9.00%	1	11.90	11.90%	11.10%	1
12298	4127	Menasha	WI	54952	22,927	21,903	95.5	9,898	1,273	5.60	5.60%	9.00%	0	4.50	4.50%	11.10%	0
17		**WI**		**13**	**178,705**	**157,259**	**88.0**	**77,567**	**23,577**	**13.19**	**13.19%**	**9.00%**	**8**	**12.00**	**12.00%**	**11.10%**	**4**
733	3936	Kanawha River	WV	25086	1,118	1,102	98.6	503	133	11.20	11.20%	15.80%	0	1.40	1.40%	5.00%	0
733	3935	John E Amos	WV	25213	4,754	4,696	98.8	2,062	255	5.50	5.50%	15.80%	0	1.20	1.20%	5.00%	0
733	6264	Mountaineer	WV	25265	1,657	1,631	98.4	759	222	13.40	13.40%	15.80%	0	1.60	1.60%	5.00%	0
733	3938	Philip Sporn	WV	25265	1,657	1,631	98.4	759	222	13.40	13.40%	15.80%	0	1.60	1.60%	5.00%	0
14006	3947	Kammer	WV	26041	16,781	16,469	98.1	7,233	3,204	19.70	19.70%	15.80%	1	1.90	1.90%	5.00%	0
14006	3948	Mitchell	WV	26041	16,781	16,469	98.1	7,233	3,204	19.70	19.70%	15.80%	1	1.90	1.90%	5.00%	0
23279	6004	Pleasants Power Station	WV	26134	1,216	1,200	98.7	484	234	20.00	20.00%	15.80%	1	1.30	1.30%	5.00%	0
12796	3946	Willow Island	WV	26134	1,216	1,200	98.7	484	234	20.00	20.00%	15.80%	1	1.30	1.30%	5.00%	0
23279	3944	Harrison Power Station	WV	26366	142	140	98.6	61	60	36.80	36.80%	15.80%	1	1.40	1.40%	5.00%	0
12949	10743	Morgantown Energy Facility	WV	26505	32,418	28,809	88.9	14,879	10,166	36.20	36.20%	15.80%	1	11.10	11.10%	5.00%	1
12796	3942	Albright	WV	26519	1,413	1,402	99.2	639	291	19.50	19.50%	15.80%	1	0.80	0.80%	5.00%	0
12796	3943	Fort Martin Power Station	WV	26541	845	833	98.6	341	134	16.20	16.20%	15.80%	1	1.40	1.40%	5.00%	0
563	10151	Grant Town Power Plant	WV	26574	712	652	91.6	342	160	22.40	22.40%	15.80%	1	8.40	8.40%	5.00%	1
12796	3945	Rivesville	WV	26588	2,541	2,517	99.1	1,176	550	21.30	21.30%	15.80%	1	0.90	0.90%	5.00%	0
19876	7537	North Branch	WV	26707	356	341	95.8	206	64	18.70	18.70%	15.80%	1	4.20	4.20%	5.00%	0
19876	3954	Mt Storm	WV	26739	818	800	97.8	630	104	12.40	12.40%	15.80%	0	2.20	2.20%	5.00%	0
16		**WV**		**13**	**64,771**	**60,592**	**93.5**	**29,315**	**15,577**	**24.05**	**24.05%**	**15.80%**	**11**	**6.45**	**6.45%**	**5.00%**	**2**
1307	6204	Laramie River Station	WY	82070	16,376	15,104	92.2	7,759	2,854	18.70	18.70%	11.10%	1	7.80	7.80%	7.90%	0
14354	4158	Dave Johnston	WY	82637	3,758	3,575	95.1	1,805	388	10.30	10.30%	11.10%	0	4.90	4.90%	7.90%	0
14354	6101	Wyodak	WY	82716	14,749	14,080	95.5	6,206	1,550	10.50	10.50%	11.10%	0	4.50	4.50%	7.90%	0
19545	4150	Neil Simpson	WY	82718	15,835	15,234	96.2	5,804	721	4.60	4.60%	11.10%	0	3.80	3.80%	7.90%	0
19545	7504	Neil Simpson II	WY	82718	15,835	15,234	96.2	5,804	721	4.60	4.60%	11.10%	0	3.80	3.80%	7.90%	0
19545	55479	Wygen 1	WY	82718	15,835	15,234	96.2	5,804	721	4.60	4.60%	11.10%	0	3.80	3.80%	7.90%	0
19545	4151	Osage	WY	82723	359	350	97.5	208	29	8.20	8.20%	11.10%	0	2.50	2.50%	7.90%	0
14354	8066	Jim Bridger	WY	82942	62	58	93.5	36	0	0.00	0.00%	11.10%	0	6.50	6.50%	7.90%	0
14354	4162	Naughton	WY	83101	2,762	2,673	96.8	1,292	176	6.40	6.40%	11.10%	0	3.20	3.20%	7.90%	0
9		**WY**		**8**	**69,736**	**66,308**	**95.1**	**28,914**	**6,439**	**9.23**	**9.23%**	**11.10%**	**1**	**4.92**	**4.92%**	**7.90%**	**0**

Appendix O:

Child Population Data
(Executive Order 13045, 2000 Census)

Appendix O
Child Population Data (2000)

ZCTA data 1=yes	Utility ID Total Plant Count	Row Number	Plant ID	Plant Name	State	ZIPS Unique Zips that Have Census Data	Total ZCTA popula-tion	Total Population 18 years old and older	Number of Children Under 18 Years Old	Percentage of ZCTA Population under 18 Years Old	Statewide % of children	If ZCTA > state children 1=Yes
1	986	28	79	Aurora Energy LLC Chena	AK	99701	17,555	12,646	4,909	27.96%	27.0%	1
1	7353	200	6288	Healy	AK	99743	997	718	279	27.98%	27.0%	1
2	**2**			**AK**		**2**	**18,552**	**13,364**	**5,188**	**27.96%**	**27.0%**	**2**
1	195	233	6002	James H Miller Jr	AL	35073	2,694	2,148	546	20.27%	24.4%	0
1	195	136	26	E C Gaston	AL	35186	3,870	2,947	923	23.85%	24.4%	0
1	195	179	8	Gorgas	AL	35580	4,563	3,503	1,060	23.23%	24.4%	0
1	18642	95	47	Colbert	AL	35674	18,361	14,137	4,224	23.01%	24.4%	0
1	18642	493	50	Widows Creek	AL	35772	5,121	3,870	1,251	24.43%	24.4%	1
1	195	168	7	Gadsden	AL	35903	18,728	14,251	4,477	23.91%	24.4%	0
	195	35	3	Barry	AL	36512					24.4%	0
1	189	79	56	Charles R Lowman	AL	36548	1,067	773	294	27.55%	24.4%	1
1	34672	307	50407	Mobile Energy Services LLC	AL	36610	19,717	13,059	6,658	33.77%	24.4%	1
1	195	183	10	Greene County	AL	36732	8,733	6,188	2,545	29.14%	24.4%	1
9	**10**			**AL**		**9**	**82,854**	**60,876**	**21,978**	**26.53%**	24.4%	**4**
1	814	490	6009	White Bluff	AR	72132	2,975	2,177	798	26.82%	24.8%	1
1	814	218	6641	Independence	AR	72562	2,081	1,540	541	26.00%	24.8%	1
1	17698	162	6138	Flint Creek	AR	72734	6,730	4,710	2,020	30.01%	24.8%	1
3	**3**			**AR**		**3**	**11,786**	**8,427**	**3,359**	**28.50%**	24.8%	**3**
1	796	22	160	Apache Station	AZ	85606	1,592	1,226	366	22.99%	26.4%	0
1	24211	186	126	H Wilson Sundt Generating Station	AZ	85714	14,549	9,787	4,762	32.73%	26.4%	1
1	16572	108	6177	Coronado	AZ	85936	4,115	2,796	1,319	32.05%	26.4%	1
1	24211	435	8223	Springerville	AZ	85938	4,263	2,903	1,360	31.90%	26.4%	1
1	803	84	113	Cholla	AZ	86032	173	101	72	41.62%	26.4%	1
1	16572	322	4941	Navajo	AZ	86040	10,249	6,602	3,647	35.58%	26.4%	1
6	**6**			**AZ**		**6**	**34,941**	**23,415**	**11,526**	**32.99%**	26.4%	**5**
1	13060	316	54626	Mt Poso Cogeneration	CA	93308	44,914	32,526	12,388	27.58%	25.9%	1
1	16061	391	10768	Rio Bravo Jasmin	CA	93308	44,914	32,526	12,388	27.58%	25.9%	1
	16002	392	10769	Rio Bravo Poso	CA	93380					25.9%	0
1	52	2	10002	ACE Cogeneration Facility	CA	93562	1,988	1,385	603	30.33%	25.9%	1
1	6811	362	54238	Port of Stockton District Energy Fac	CA	95203	16,344	11,281	5,063	30.98%	25.9%	1
1	353	443	10640	Stockton Cogen	CA	95206	49,649	31,418	18,231	36.72%	25.9%	1
5	**6**			**CA**		**4**	**112,895**	**76,610**	**36,285**	**32.14%**	25.9%	**5**
1	15466	80	469	Cherokee	CO	80216	10,701	7,031	3,670	34.30%	24.7%	1
1	15466	23	465	Arapahoe	CO	80223	18,721	13,589	5,132	27.41%	24.7%	1
1	15466	468	477	Valmont	CO	80302	29,795	26,986	2,809	9.43%	24.7%	0

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1	19173	97	10003	Colorado Energy Nations Company	CO	80401	38,580	30,226	8,354	21.65%	24.7%	0
1	15143	386	6761	Rawhide	CO	80549	4,809	3,393	1,416	29.44%	24.7%	1
1	15466	350	6248	Pawnee	CO	80723	6,973	4,951	2,022	29.00%	24.7%	1
1	3989	387	8219	Ray D Nixon	CO	80817	16,113	10,621	5,492	34.08%	24.7%	1
1	3989	285	492	Martin Drake	CO	80903	15,091	12,535	2,556	16.94%	24.7%	0
1	15466	103	470	Comanche	CO	81006	11,933	8,780	3,153	26.42%	24.7%	1
1	10633	265	508	Lamar Plant	CO	81052	10,897	7,684	3,213	29.49%	24.7%	1
1	19204	461	511	Trinidad	CO	81082	12,512	9,412	3,100	24.78%	24.7%	1
1	770	476	462	W N Clark	CO	81212	29,188	23,212	5,976	20.47%	24.7%	0
1	30151	341	527	Nucla	CO	81424	1,245	925	320	25.70%	24.7%	1
1	15466	66	468	Cameo	CO	81526	5,338	4,019	1,319	24.71%	24.7%	1
	30151	110	6021	Craig	CO	81626					24.7%	0
1	15466	199	525	Hayden	CO	81639	2,199	1,541	658	29.92%	24.7%	1
15	**16**			**CO**		**15**	**214,095**	**164,905**	**49,190**	**22.98%**	24.7%	**11**
1	42	12	10675	AES Thames	CT	06382	12,001	9,364	2,637	21.97%	23.7%	0
1	15452	57	568	Bridgeport Station	CT	06604	30,715	22,609	8,106	26.39%	23.7%	1
2	**2**			**CT**		**2**	**42,716**	**31,973**	**10,743**	**25.15%**	23.7%	**1**
1	4252	147	593	Edge Moor	DE	19809	14,586	11,277	3,309	22.69%	23.9%	0
1	7860	340	10030	NRG Energy Center Dover	DE	19904	27,676	20,800	6,876	24.84%	23.9%	1
1	9332	219	594	Indian River Generating Station	DE	19939	4,663	3,679	984	21.10%	23.9%	0
3	**3**			**DE**		**3**	**46,925**	**35,756**	**11,169**	**23.80%**	23.9%	**1**
1	14932	74	10672	Cedar Bay Generating Company LP	FL	32218	37,790	27,109	10,681	28.26%	22.3%	1
1	9617	339	667	Northside Generating Station	FL	32226	8,173	6,229	1,944	23.79%	22.3%	1
1	9617	438	207	St Johns River Power Park	FL	32226	8,173	6,229	1,944	23.79%	22.3%	1
1	7801	267	643	Lansing Smith	FL	32409	7,360	5,393	1,967	26.73%	22.3%	1
1	7801	415	642	Scholz	FL	32460	5,287	4,308	979	18.52%	22.3%	0
1	7801	114	641	Crist	FL	32514	34,837	27,788	7,049	20.23%	22.3%	0
1	6909	128	663	Deerhaven Generating Station	FL	32606	17,794	13,718	4,076	22.91%	22.3%	1
1	21554	417	136	Seminole	FL	32708	38,849	28,335	10,514	27.06%	22.3%	1
1	14610	441	564	Stanton Energy Center	FL	32831	57	39	18	31.58%	22.3%	1
1	18454	41	645	Big Bend	FL	33572	7,461	6,102	1,359	18.21%	22.3%	0
1	10623	62	676	C D McIntosh Jr	FL	33801	31,593	24,426	7,167	22.69%	22.3%	1
1	18454	361	7242	Polk	FL	33860	17,015	12,294	4,721	27.75%	22.3%	1
1	6455	117	628	Crystal River	FL	34428	9,294	7,195	2,099	22.58%	22.3%	1
	3303	75	10333	Central Power & Lime	FL	34605					22.3%	0

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1	14932	220	50976	Indiantown Cogeneration LP	FL	34956	8,992	6,541	2,451	27.26%	22.3%	1
14	**15**			**FL**		**13**	**224,502**	**169,477**	**55,025**	**24.51%**	22.3%	**11**
1	7140	230	710	Jack McDonough	GA	30080	43,472	35,423	8,049	18.52%	26.5%	0
1	7140	53	703	Bowen	GA	30120	29,734	21,375	8,359	28.11%	26.5%	1
	7140	188	708	Hammond	GA	30129					26.5%	0
1	7140	481	6052	Wansley	GA	30170	2,681	1,931	750	27.97%	26.5%	1
	7140	505	728	Yates	GA	30264					26.5%	0
1	7140	413	6257	Scherer	GA	31046	2,839	2,085	754	26.56%	26.5%	1
1	7140	192	709	Harllee Branch	GA	31061	39,231	29,745	9,486	24.18%	26.5%	0
1	7140	289	6124	McIntosh	GA	31326	12,302	8,553	3,749	30.47%	26.5%	1
1	7140	256	733	Kraft	GA	31405	32,887	25,210	7,677	23.34%	26.5%	0
1	7140	304	727	Mitchell	GA	31705	38,667	26,825	11,842	30.63%	26.5%	1
1	4538	113	753	Crisp Plant	GA	31796	1,160	862	298	25.69%	26.5%	0
9	**11**			**GA**		**9**	**202,973**	**152,009**	**50,964**	**25.11%**	26.5%	**5**
1	177	6	10673	AES Hawaii	HI	96707	25,054	16,896	8,158	32.56%	22.3%	1
	8286	197	10604	Hawaiian Comm & Sugar Puunene Mill	HI	96784					22.3%	0
1	**2**			**HI**		**1**	**25,054**	**16,896**	**8,158**	**32.56%**	22.3%	**1**
1	554	20	1122	Ames Electric Services Power Plant	IA	50010	24,991	20,021	4,970	19.89%	23.9%	0
1	9417	447	1077	Sutherland	IA	50158	30,316	22,789	7,527	24.83%	23.9%	1
1	14645	352	1175	Pella	IA	50219	12,745	9,643	3,102	24.34%	23.9%	1
1	3203	444	1131	Streeter Station	IA	50613	38,681	31,574	7,107	18.37%	23.9%	0
1	12341	172	1091	George Neal North	IA	51052	1,050	742	308	29.33%	23.9%	1
1	12341	173	7343	George Neal South	IA	51052	1,050	742	308	29.33%	23.9%	1
1	4363	141	1217	Earl F Wisdom	IA	51301	12,885	9,780	3,105	24.10%	23.9%	1
1	12341	480	1082	Walter Scott Jr Energy Center	IA	51501	34,258	25,007	9,251	27.00%	23.9%	1
	9417	133	1046	Dubuque	IA	52004					23.9%	0
1	9417	266	1047	Lansing	IA	52151	2,319	1,737	582	25.10%	23.9%	1
1	9417	429	1058	Sixth Street	IA	52402	39,913	30,292	9,621	24.10%	23.9%	1
1	9417	368	1073	Prairie Creek	IA	52404	32,016	24,356	7,660	23.93%	23.9%	1
1	9417	346	6254	Ottumwa	IA	52548	48	33	15	31.25%	23.9%	1
1	9417	61	1104	Burlington	IA	52601	30,847	23,313	7,534	24.42%	23.9%	1
1	12341	395	1081	Riverside	IA	52722	33,695	24,816	8,879	26.35%	23.9%	1
	9417	300	1048	Milton L Kapp	IA	52733					23.9%	0
1	3258	159	1218	Fair Station	IA	52761	30,286	22,239	8,047	26.57%	23.9%	1

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1	12341	277	6664	Louisa	IA	52761	30,286	22,239	8,047	26.57%	23.9%	1
1	13143	318	1167	Muscatine Plant #1	IA	52761	30,286	22,239	8,047	26.57%	23.9%	1
17	**19**			**IA**		**14**	**324,050**	**246,342**	**77,708**	**23.98%**	23.9%	**15**
1	12384	485	883	Waukegan	IL	60087	23,530	16,806	6,724	28.58%	25.1%	1
1	12384	245	384	Joliet 29	IL	60436	16,184	12,009	4,175	25.80%	25.1%	1
1	12384	246	874	Joliet 9	IL	60436	16,184	12,009	4,175	25.80%	25.1%	1
1	12384	494	884	Will County	IL	60446	20,141	14,126	6,015	29.86%	25.1%	1
1	12384	161	886	Fisk Street	IL	60608	92,472	64,971	27,501	29.74%	25.1%	1
1	12384	111	867	Crawford	IL	60623	108,144	69,175	38,969	36.03%	25.1%	1
1	5517	203	892	Hennepin Power Station	IL	61327	1,190	901	289	24.29%	25.1%	0
1	49756	134	6016	Duck Creek	IL	61520	18,659	14,821	3,838	20.57%	25.1%	0
1	12384	365	879	Powerton	IL	61554	43,500	33,176	10,324	23.73%	25.1%	0
1	49756	137	856	E D Edwards	IL	61607	10,473	8,081	2,392	22.84%	25.1%	0
1	5517	469	897	Vermilion	IL	61858	2,833	2,131	702	24.78%	25.1%	0
1	19145	462	55245	Tuscola Station	IL	61953	6,285	4,677	1,608	25.58%	25.1%	1
1	5517	499	898	Wood River	IL	62002	34,062	25,574	8,488	24.92%	25.1%	0
1	520	92	861	Coffeen	IL	62017	1,287	975	312	24.24%	25.1%	0
1	5517	34	889	Baldwin Energy Complex	IL	62217	4,114	3,869	245	5.96%	25.1%	0
1	40307	351	6238	Pearl Station	IL	62361	555	399	156	28.11%	25.1%	1
1	520	216	863	Hutsonville	IL	62433	1,057	827	230	21.76%	25.1%	0
1	520	331	6017	Newton	IL	62448	6,063	4,540	1,523	25.12%	25.1%	1
1	5269	253	876	Kincaid Generation LLC	IL	62540	1,392	1,034	358	25.72%	25.1%	1
1	5517	196	891	Havana	IL	62644	5,773	4,406	1,367	23.68%	25.1%	0
1	520	294	864	Meredosia	IL	62665	1,675	1,252	423	25.25%	25.1%	1
1	17828	121	963	Dallman	IL	62703	31,211	22,743	8,468	27.13%	25.1%	1
1	17828	264	964	Lakeside	IL	62703	31,211	22,743	8,468	27.13%	25.1%	1
1	5748	247	887	Joppa Steam	IL	62953	427	306	121	28.34%	25.1%	1
1	17632	282	976	Marion	IL	62959	24,807	19,263	5,544	22.35%	25.1%	0
25	**25**			**IL**		**23**	**455,834**	**326,062**	**129,772**	**28.47%**	25.1%	**14**
1	9273	140	991	Eagle Valley	IN	46151	32,420	23,884	8,536	26.33%	25.1%	1
1	9273	191	990	Harding Street	IN	46217	19,210	14,184	5,026	26.16%	25.1%	1
1	3599	73	992	CC Perry K	IN	46225	8,262	6,141	2,121	25.67%	25.1%	1
1	13756	33	995	Bailly	IN	46304	21,445	15,618	5,827	27.17%	25.1%	1
	18041	442	981	State Line Energy	IN	46325					25.1%	0
1	13756	298	997	Michigan City	IN	46360	46,107	34,921	11,186	24.26%	25.1%	0

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1	13756	381	6085	R M Schahfer	IN	46392	6,410	4,475	1,935	30.19%	25.1%	1
	13756	126	996	Dean H Mitchell	IN	46401					25.1%	0
1	11142	275	1032	Logansport	IN	46947	30,180	22,459	7,721	25.58%	25.1%	1
1	14839	353	1037	Peru	IN	46970	25,373	18,997	6,376	25.13%	25.1%	1
1	9324	450	988	Tanners Creek	IN	47025	20,234	14,685	5,549	27.42%	25.1%	1
	15470	379	1008	R Gallagher	IN	47200					25.1%	0
1	9269	87	983	Clifty Creek	IN	47250	21,047	16,002	5,045	23.97%	25.1%	0
	15989	492	1040	Whitewater Valley	IN	47375					25.1%	0
	15470	150	1004	Edwardsport	IN	47500					25.1%	0
	9667	236	6225	Jasper 2	IN	47547					25.1%	0
1	9267	166	1043	Frank E Ratts	IN	47567	6,045	4,680	1,365	22.58%	25.1%	0
1	9273	9	994	AES Petersburg	IN	47567	6,045	4,680	1,365	22.58%	25.1%	0
1	17633	1	6137	A B Brown	IN	47620	14,158	10,375	3,783	26.72%	25.1%	1
1	261	482	6705	Warrick	IN	47630	27,376	19,607	7,769	28.38%	25.1%	1
1	17633	158	1012	F B Culley	IN	47630	27,376	19,607	7,769	28.38%	25.1%	1
1	9324	403	6166	Rockport	IN	47635	5,533	4,097	1,436	25.95%	25.1%	1
1	15470	177	6113	Gibson	IN	47665	3,340	2,440	900	26.95%	25.1%	1
1	9267	295	6213	Merom	IN	47882	8,524	6,458	2,066	24.24%	25.1%	0
	15470	72	1001	Cayuga	IN	47900					25.1%	0
	15470	478	1010	Wabash River	IN	47900					25.1%	0
1	4508	112	1024	Crawfordsville	IN	47933	27,659	20,706	6,953	25.14%	25.1%	1
19	**27**			**IN**		**17**	**323,323**	**239,729**	**83,594**	**25.85%**	25.1%	**14**
1	10000	259	1241	La Cygne	KS	66040	3,072	2,291	781	25.42%	25.2%	1
1	22500	269	1250	Lawrence Energy Center	KS	66049	20,338	15,491	4,847	23.83%	25.2%	0
1	9996	323	6064	Nearman Creek	KS	66104	27,452	19,529	7,923	28.86%	25.2%	1
1	9996	375	1295	Quindaro	KS	66104	27,452	19,529	7,923	28.86%	25.2%	1
1	22500	238	6068	Jeffrey Energy Center	KS	66536	3,064	1,934	1,130	36.88%	25.2%	1
1	22500	451	1252	Tecumseh Energy Center	KS	66542	2,913	2,144	769	26.40%	25.2%	1
	5860	397	1239	Riverton	KS	66730					25.2%	0
1	18315	207	108	Holcomb	KS	67851	2,678	1,596	1,082	40.40%	25.2%	1
7	**8**			**KS**		**6**	**59,517**	**42,985**	**16,532**	**27.78%**	25.2%	**6**
1	11249	460	6071	Trimble County	KY	40006	4,831	3,488	1,343	27.80%	23.9%	1
1	11249	68	1363	Cane Run	KY	40216	39,924	30,762	9,162	22.95%	23.9%	0
1	11249	299	1364	Mill Creek	KY	40272	34,740	25,771	8,969	25.82%	23.9%	1
1	10171	139	1355	E W Brown	KY	40330	18,971	14,370	4,601	24.25%	23.9%	1

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1	10171	464	1361	Tyrone	KY	40383	20,454	15,157	5,297	25.90%	23.9%	1
1	5580	120	1385	Dale	KY	40391	32,884	24,718	8,166	24.83%	23.9%	1
1	10171	175	1356	Ghent	KY	41045	1,154	800	354	30.68%	23.9%	1
1	5580	185	6041	H L Spurlock	KY	41056	13,861	10,575	3,286	23.71%	23.9%	0
	55729	142	6018	East Bend	KY	41100					23.9%	0
1	22053	44	1353	Big Sandy	KY	41230	11,283	8,449	2,834	25.12%	23.9%	1
1	18642	419	1379	Shawnee	KY	42086	3,744	2,821	923	24.65%	23.9%	1
1	14268	152	1374	Elmer Smith	KY	42303	35,321	26,280	9,041	25.60%	23.9%	1
1	20546	119	6823	D B Wilson	KY	42328	1,435	1,065	370	25.78%	23.9%	1
1	10171	182	1357	Green River	KY	42330	10,785	8,430	2,355	21.84%	23.9%	0
1	18642	349	1378	Paradise	KY	42337	2,145	1,567	578	26.95%	23.9%	1
1	20546	250	1381	Kenneth C Coleman	KY	42348	4,469	3,217	1,252	28.02%	23.9%	1
	8449	202	1372	Henderson I	KY	42419					23.9%	0
1	20546	206	1382	HMP&L Station Two Henderson	KY	42452	2,116	1,547	569	26.89%	23.9%	1
1	20546	376	6639	R D Green	KY	42452	2,116	1,547	569	26.89%	23.9%	1
1	20546	401	1383	Robert A Reid	KY	42452	2,116	1,547	569	26.89%	23.9%	1
1	5580	106	1384	Cooper	KY	42501	16,916	13,004	3,912	23.13%	23.9%	0
19	**21**			**KY**		**17**	**255,033**	**192,021**	**63,012**	**24.71%**	23.9%	**15**
1	55936	383	1393	R S Nelson	LA	70669	10,102	7,290	2,812	27.84%	25.4%	1
1	11252	43	6055	Big Cajun 2	LA	70760	7,589	5,463	2,126	28.01%	25.4%	1
1	3265	130	51	Dolet Hills	LA	71052	11,217	7,931	3,286	29.29%	25.4%	1
1	3265	404	6190	Rodemacher	LA	71447	1,473	1,080	393	26.68%	25.4%	1
4	**4**			**LA**		**4**	**30,381**	**21,764**	**8,617**	**28.36%**	25.4%	**4**
1	54895	314	1606	Mount Tom	MA	01040	39,838	28,098	11,740	29.47%	22.5%	1
1	50018	409	1626	Salem Harbor	MA	01970	40,407	32,250	8,157	20.19%	22.5%	0
1	29878	430	1613	Somerset Station	MA	02726	15,553	12,372	3,181	20.45%	22.5%	0
1	50018	55	1619	Brayton Point	MA	02726	15,553	12,372	3,181	20.45%	22.5%	0
4	**4**			**MA**		**3**	**95,798**	**72,720**	**23,078**	**24.09%**	22.5%	**1**
1	12628	76	1571	Chalk Point LLC	MD	20608	1,015	762	253	24.93%	24.4%	1
1	12653	313	1573	Morgantown Generating Plant	MD	20664	2,716	2,046	670	24.67%	24.4%	1
1	12653	129	1572	Dickerson	MD	20842	1,848	1,426	422	22.84%	24.4%	0
1	4161	63	1552	C P Crane	MD	21220	36,551	27,013	9,538	26.10%	24.4%	1
1	4161	54	602	Brandon Shores	MD	21226	6,720	5,033	1,687	25.10%	24.4%	1
1	4161	204	1554	Herbert A Wagner	MD	21226	6,720	5,033	1,687	25.10%	24.4%	1
1	35	13	10678	AES Warrior Run Cogeneration	MD	21502	44,053	34,893	9,160	20.79%	24.4%	0

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				Facility								
1	23279	382	1570	R Paul Smith Power Station	MD	21795	8,238	6,439	1,799	21.84%	24.4%	0
8	**8**			**MD**		**7**	**101,141**	**77,612**	**23,529**	**23.26%**	24.4%	**5**
1	54784	406	10495	Rumford Cogeneration	ME	04276	6,748	5,187	1,561	23.13%	21.5%	1
1	**1**			**ME**		**1**	**6,748**	**5,187**	**1,561**	**23.13%**	21.5%	**1**
1	5109	287	1732	Marysville	MI	48040	9,684	7,324	2,360	24.37%	24.6%	0
1	5109	39	6034	Belle River	MI	48054	7,059	5,318	1,741	24.66%	24.6%	1
1	5109	437	1743	St Clair	MI	48054	7,059	5,318	1,741	24.66%	24.6%	1
1	4254	228	1723	J R Whiting	MI	48133	5,355	3,882	1,473	27.51%	24.6%	1
1	5109	309	1733	Monroe	MI	48161	25,412	18,545	6,867	27.02%	24.6%	1
1	5109	458	1745	Trenton Channel	MI	48183	40,891	30,657	10,234	25.03%	24.6%	1
1	21048	502	1866	Wyandotte	MI	48192	44,894	34,596	10,298	22.94%	24.6%	0
1	5109	393	1740	River Rouge	MI	48218	10,060	6,929	3,131	31.12%	24.6%	1
1	5109	189	1731	Harbor Beach	MI	48441	4,554	3,338	1,216	26.70%	24.6%	1
1	4254	122	1702	Dan E Karn	MI	48732	11,918	9,077	2,841	23.84%	24.6%	0
1	4254	223	1720	J C Weadock	MI	48732	11,918	9,077	2,841	23.84%	24.6%	0
1	56155	145	1831	Eckert Station	MI	48910	35,735	27,286	8,449	23.64%	24.6%	0
1	56155	155	1832	Erickson Station	MI	48917	31,366	24,244	7,122	22.71%	24.6%	0
1	12807	154	4259	Endicott Station	MI	49252	2,569	1,924	645	25.11%	24.6%	1
1	7483	222	1825	J B Sims	MI	49417	27,969	20,559	7,410	26.49%	24.6%	1
1	8723	232	1830	James De Young	MI	49423	46,804	34,255	12,549	26.81%	24.6%	1
1	4254	31	1695	B C Cobb	MI	49445	19,811	14,365	5,446	27.49%	24.6%	1
1	4254	225	1710	J H Campbell	MI	49460	7,697	5,251	2,446	31.78%	24.6%	1
1	18414	452	50835	TES Filer City Station	MI	49634	86	60	26	30.23%	24.6%	1
1	19578	157	1771	Escanaba	MI	49829	18,414	14,018	4,396	23.87%	24.6%	0
1	11701	424	1843	Shiras	MI	49855	32,378	26,151	6,227	19.23%	24.6%	0
1	20847	369	1769	Presque Isle	MI	49855	32,378	26,151	6,227	19.23%	24.6%	0
1	1951	491	10148	White Pine Electric Power	MI	49971	628	511	117	18.63%	24.6%	0
23	**23**			**MI**		**20**	**383,284**	**288,290**	**94,994**	**24.78%**	24.6%	**13**
1	13781	16	1915	Allen S King	MN	55003	3,162	2,772	390	12.33%	24.5%	0
1	13781	47	1904	Black Dog	MN	55101	21,969	14,808	7,161	32.60%	24.5%	1
1	13781	423	6090	Sherburne County	MN	55308	6,268	4,048	2,220	35.42%	24.5%	1
1	13781	396	1927	Riverside	MN	55401	3,649	3,515	134	3.67%	24.5%	0
1	12647	449	10075	Taconite Harbor Energy Center	MN	55613	187	152	35	18.72%	24.5%	0
1	12647	448	1891	Syl Laskin	MN	55705	3,385	2,673	712	21.03%	24.5%	0

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1	12647	85	1893	Clay Boswell	MN	55721	2,867	2,140	727	25.36%	24.5%	1
1	12647	384	10686	Rapids Energy Center	MN	55744	19,799	15,040	4,759	24.04%	24.5%	0
1	8543	205	1979	Hibbing	MN	55746	18,129	14,015	4,114	22.69%	24.5%	0
1	19883	471	2018	Virginia	MN	55792	10,904	8,767	2,137	19.60%	24.5%	0
1	12647	280	1897	M L Hibbard	MN	55807	10,302	7,911	2,391	23.21%	24.5%	0
	16181	427	2008	Silver Lake	MN	55903					24.5%	0
1	1009	29	1961	Austin Northeast	MN	55912	28,012	21,285	6,727	24.01%	24.5%	0
1	13488	330	2001	New Ulm	MN	56073	17,199	13,037	4,162	24.20%	24.5%	0
1	20737	496	2022	Willmar	MN	56201	22,126	16,270	5,856	26.47%	24.5%	1
1	14232	209	1943	Hoot Lake	MN	56537	19,054	14,371	4,683	24.58%	24.5%	1
15	**16**			**MN**		**15**	**187,012**	**140,804**	**46,208**	**24.71%**	24.5%	**5**
1	19436	407	6155	Rush Island	MO	63028	23,221	16,919	6,302	27.14%	24.4%	1
1	19436	260	2103	Labadie	MO	63055	1,767	1,281	486	27.50%	24.4%	1
1	19436	293	2104	Meramec	MO	63129	51,191	37,998	13,193	25.77%	24.4%	1
1	19436	428	2107	Sioux	MO	63386	598	436	162	27.09%	24.4%	1
1	17177	426	6768	Sikeston Power Station	MO	63801	23,779	17,292	6,487	27.28%	24.4%	1
1	924	329	2167	New Madrid	MO	63869	4,175	3,013	1,162	27.83%	24.4%	1
1	9231	50	2132	Blue Valley	MO	64056	15,357	10,474	4,883	31.80%	24.4%	1
1	9231	303	2171	Missouri City	MO	64072	133	91	42	31.58%	24.4%	1
1	770	425	2094	Sibley	MO	64088	1,443	1,053	390	27.03%	24.4%	1
1	10000	217	6065	Iatan	MO	64098	2,943	2,191	752	25.55%	24.4%	1
1	10000	198	2079	Hawthorn	MO	64120	481	374	107	22.25%	24.4%	0
1	770	261	2098	Lake Road	MO	64504	10,926	7,987	2,939	26.90%	24.4%	1
1	10000	311	2080	Montrose	MO	64735	12,910	9,902	3,008	23.30%	24.4%	0
1	5860	25	2076	Asbury	MO	64832	724	552	172	23.76%	24.4%	0
1	3242	78	2169	Chamois	MO	65024	1,200	880	320	26.67%	24.4%	1
	4045	100	2123	Columbia	MO	65205					24.4%	0
1	924	453	2168	Thomas Hill	MO	65244	442	337	105	23.76%	24.4%	0
1	11732	283	2144	Marshall	MO	65340	15,580	11,819	3,761	24.14%	24.4%	0
1	17833	235	2161	James River Power Station	MO	65804	35,482	28,795	6,687	18.85%	24.4%	0
1	17833	434	6195	Southwest Power Station	MO	65807	49,132	40,006	9,126	18.57%	24.4%	0
19	**20**			**MO**		**19**	**251,484**	**191,400**	**60,084**	**23.89%**	24.4%	**12**
1	7651	201	2062	Henderson	MS	38930	28,116	19,491	8,625	30.68%	26.3%	1
1	17568	377	6061	R D Morrow	MS	39475	9,539	6,768	2,771	29.05%	26.3%	1
1	12686	231	2049	Jack Watson	MS	39501	26,121	19,083	7,038	26.94%	26.3%	1

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	12686	470	6073	Victor J Daniel Jr	MS	39552					26.3%	0
1	3593	388	55076	Red Hills Generating Facility	MS	39735	5,433	4,000	1,433	26.38%	26.3%	1
4	**5**			**MS**		**4**	**69,209**	**49,342**	**19,867**	**28.71%**	26.3%	**4**
1	16233	190	55749	Hardin Generator Project	MT	59034	4,726	3,288	1,438	30.43%	23.2%	1
1	15298	224	2187	J E Corette Plant	MT	59101	36,335	27,024	9,311	25.63%	23.2%	1
1	12199	272	6089	Lewis & Clark	MT	59270	7,054	5,131	1,923	27.26%	23.2%	1
1	4217	99	10784	Colstrip Energy LP	MT	59323	2,440	1,607	833	34.14%	23.2%	1
1	15298	98	6076	Colstrip	MT	59323	2,440	1,607	833	34.14%	23.2%	1
1	56110	454	56612	Thompson River Power LLC	MT	59873	2,654	2,044	610	22.98%	23.2%	0
6	**6**			**MT**		**5**	**53,209**	**39,094**	**14,115**	**26.53%**	23.2%	**5**
1	5416	38	8042	Belews Creek	NC	27052	10,380	7,896	2,484	23.93%	24.4%	0
1	5416	123	2723	Dan River	NC	27288	24,878	19,169	5,709	22.95%	24.4%	0
1	3046	270	2709	Lee	NC	27530	38,376	28,585	9,791	25.51%	24.4%	1
1	3046	69	2708	Cape Fear	NC	27559	2,149	1,664	485	22.57%	24.4%	0
1	3046	288	6250	Mayo	NC	27573	24,527	18,724	5,803	23.66%	24.4%	0
1	3046	405	2712	Roxboro	NC	27573	24,527	18,724	5,803	23.66%	24.4%	0
1	54708	370	10379	Primary Energy Roxboro	NC	27573	24,527	18,724	5,803	23.66%	24.4%	0
1	55739	148	10384	Edgecombe Genco LLC	NC	27809	5,162	3,705	1,457	28.23%	24.4%	1
1	55808	399	54035	Roanoke Valley Energy Facililty I	NC	27890	2,879	2,076	803	27.89%	24.4%	1
1	55808	400	54755	Roanoke Valley Energy Facility II	NC	27890	2,879	2,076	803	27.89%	24.4%	1
1	5416	167	2718	G G Allen	NC	28012	19,024	14,661	4,363	22.93%	24.4%	0
	5416	86	2721	Cliffside	NC	28024					24.4%	0
1	5416	394	2732	Riverbend	NC	28120	15,595	11,956	3,639	23.33%	24.4%	0
	5416	59	2720	Buck	NC	28145					24.4%	0
1	13695	151	10380	Elizabethtown Power LLC	NC	28337	9,225	6,947	2,278	24.69%	24.4%	1
1	54889	91	10381	Coastal Carolina Clean Power	NC	28349	3,472	2,737	735	21.17%	24.4%	0
1	3046	474	2716	W H Weatherspoon	NC	28358	36,671	26,587	10,084	27.50%	24.4%	1
	13695	279	10382	Lumberton	NC	28359					24.4%	0
1	3046	258	2713	L V Sutton	NC	28401	21,799	17,163	4,636	21.27%	24.4%	0
1	54708	371	10378	Primary Energy Southport	NC	28461	9,095	7,325	1,770	19.46%	24.4%	0
1	5416	284	2727	Marshall	NC	28682	860	713	147	17.09%	24.4%	0
1	3046	26	2706	Asheville	NC	28704	14,782	11,238	3,544	23.98%	24.4%	0
19	**22**			**NC**		**16**	**238,874**	**181,146**	**57,728**	**24.17%**	24.4%	**6**
1	1307	21	6469	Antelope Valley	ND	58523	3,886	2,703	1,183	30.44%	22.5%	1
1	14232	109	8222	Coyote	ND	58523	3,886	2,703	1,183	30.44%	22.5%	1

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1	12658	301	2823	Milton R Young	ND	58530	1,374	1,014	360	26.20%	22.5%	1
1	12199	380	2790	R M Heskett	ND	58554	20,219	14,705	5,514	27.27%	22.5%	1
1	1307	271	2817	Leland Olds	ND	58571	557	433	124	22.26%	22.5%	0
1	7570	440	2824	Stanton	ND	58571	557	433	124	22.26%	22.5%	0
1	7570	90	6030	Coal Creek	ND	58576	1,051	821	230	21.88%	22.5%	0
7	**7**			**ND**		**5**	**27,087**	**19,676**	**7,411**	**27.36%**	22.5%	**4**
1	6779	276	2240	Lon Wright	NE	68025	29,200	22,189	7,011	24.01%	25.3%	0
1	14127	335	2291	North Omaha	NE	68112	12,092	8,693	3,399	28.11%	25.3%	1
1	13337	422	2277	Sheldon	NE	68368	497	373	124	24.95%	25.3%	0
1	14127	324	6096	Nebraska City	NE	68410	8,459	6,215	2,244	26.53%	25.3%	1
1	40606	358	59	Platte	NE	68801	27,389	19,771	7,618	27.81%	25.3%	1
	8245	489	60	Whelan Energy Center	NE	68902					25.3%	0
1	13337	174	6077	Gerald Gentleman	NE	69165	1,676	1,219	457	27.27%	25.3%	1
6	**7**			**NE**		**6**	**79,313**	**58,460**	**20,853**	**26.29%**	25.3%	**4**
1	15472	296	2364	Merrimack	NH	03301	31,744	24,766	6,978	21.98%	23.1%	0
1	15472	414	2367	Schiller	NH	03801	21,558	17,823	3,735	17.33%	23.1%	0
2	**2**			**NH**		**2**	**53,302**	**42,589**	**10,713**	**20.10%**	23.1%	**0**
1	15147	372	2403	PSEG Hudson Generating Station	NJ	07306	54,912	42,215	12,697	23.12%	24.0%	0
1	14932	77	10566	Chambers Cogeneration LP	NJ	08069	12,468	9,122	3,346	26.84%	24.0%	1
1	4158	127	2384	Deepwater	NJ	08070	12,951	9,967	2,984	23.04%	24.0%	0
1	14932	274	10043	Logan Generating Company LP	NJ	08085	10,703	7,382	3,321	31.03%	24.0%	1
1	55768	32	2378	B L England	NJ	08223	4,384	3,172	1,212	27.65%	24.0%	1
	19856	211	2434	Howard Down	NJ	8360					24.0%	0
1	15147	373	2408	PSEG Mercer Generating Station	NJ	08611	23,868	17,622	6,246	26.17%	24.0%	1
6	**7**			**NJ**		**6**	**119,286**	**89,480**	**29,806**	**24.99%**	24.0%	**4**
1	30151	156	87	Escalante	NM	87045	2,380	1,341	1,039	43.66%	25.6%	1
1	803	165	2442	Four Corners	NM	87416	5,086	3,091	1,995	39.23%	25.6%	1
1	15473	410	2451	San Juan	NM	87421	1,606	1,061	545	33.94%	25.6%	1
1	15698	385	2468	Raton	NM	87740	8,419	6,342	2,077	24.67%	25.6%	0
4	**4**			**NM**		**4**	**17,491**	**11,835**	**5,656**	**32.34%**	25.6%	**3**
1	13407	389	2324	Reid Gardner	NV	89025	1,395	865	530	37.99%	25.8%	1
1	17609	308	2341	Mohave	NV	89029	7,076	5,779	1,297	18.33%	25.8%	0
	17166	336	8224	North Valmy	NV	89438					25.8%	0
2	**3**			**NV**		**2**	**8,471**	**6,644**	**1,827**	**21.57%**	25.8%	**1**
1	12792	278	2629	Lovett	NY	10986	1,739	1,274	465	26.74%	23.2%	1

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1	5511	124	2480	Danskammer Generating Station	NY	12550	52,084	36,576	15,508	29.77%	23.2%	1
1	19194	459	50651	Trigen Syracuse Energy	NY	13204	20,826	14,150	6,676	32.06%	23.2%	1
1	1746	48	10464	Black River Generation	NY	13602	4,651	4,638	13	0.28%	23.2%	0
1	22122	8	2531	AES Jennison LLC	NY	13733	4,874	3,632	1,242	25.48%	23.2%	1
1	22146	14	2526	AES Westover	NY	13790	19,713	15,534	4,179	21.20%	23.2%	0
1	22129	11	6082	AES Somerset LLC	NY	14012	2,603	1,849	754	28.97%	23.2%	1
1	13579	135	2554	Dunkirk Generating Plant	NY	14048	16,097	12,260	3,837	23.84%	23.2%	1
1	13168	64	2549	C R Huntley Generating Station	NY	14150	44,535	34,708	9,827	22.07%	23.2%	0
	55807	500	50202	WPS Power Niagara	NY	14302					23.2%	0
1	25	5	2527	AES Greenidge LLC	NY	14441	344	276	68	19.77%	23.2%	0
1	16183	402	2642	Rochester 7	NY	14612	35,665	26,589	9,076	25.45%	23.2%	1
	9645	408	2682	S A Carlson	NY	14702					23.2%	0
1	39	7	2529	AES Hickling LLC	NY	14830	19,342	14,617	4,725	24.43%	23.2%	1
1	22125	4	2535	AES Cayuga	NY	14882	3,943	2,701	1,242	31.50%	23.2%	1
13	**15**			**NY**		**13**	**226,416**	**168,804**	**57,612**	**25.45%**	23.2%	**9**
1	4062	355	2843	Picway	OH	43137	2,453	1,793	660	26.91%	24.2%	1
1	6526	37	2878	Bay Shore	OH	43616	16,776	12,764	4,012	23.92%	24.2%	0
1	4062	105	2840	Conesville	OH	43811	850	634	216	25.41%	24.2%	1
1	3006	71	2828	Cardinal	OH	43913	1,728	1,336	392	22.69%	24.2%	0
1	6526	378	2864	R E Burger	OH	43947	5,356	4,264	1,092	20.39%	24.2%	0
1	6526	473	2866	W H Sammis	OH	43961	277	228	49	17.69%	24.2%	0
1	6526	27	2835	Ashtabula	OH	44004	35,631	26,609	9,022	25.32%	24.2%	1
1	14165	30	2836	Avon Lake	OH	44012	18,284	13,006	5,278	28.87%	24.2%	1
1	14381	347	2936	Painesville	OH	44077	50,412	37,507	12,905	25.60%	24.2%	1
1	6526	143	2837	Eastlake	OH	44095	35,298	27,318	7,980	22.61%	24.2%	0
1	6526	263	2838	Lake Shore	OH	44103	25,348	17,162	8,186	32.29%	24.2%	1
1	3762	262	2908	Lake Road	OH	44114	3,891	3,386	505	12.98%	24.2%	0
1	14165	332	2861	Niles	OH	44446	23,207	17,965	5,242	22.59%	24.2%	0
1	5336	132	2914	Dover	OH	44622	17,898	13,533	4,365	24.39%	24.2%	1
1	14194	344	2935	Orrville	OH	44667	13,744	9,758	3,986	29.00%	24.2%	1
1	17043	421	2943	Shelby Municipal Light Plant	OH	44875	14,882	10,901	3,981	26.75%	24.2%	1
1	7977	187	2917	Hamilton	OH	45011	55,358	38,680	16,678	30.13%	24.2%	1
	3542	297	2832	Miami Fort	OH	45100					24.2%	0
1	4922	227	2850	J M Stuart	OH	45101	2,540	1,853	687	27.05%	24.2%	1
1	4922	252	6031	Killen Station	OH	45144	4,269	3,236	1,033	24.20%	24.2%	0

Appendix O Child Population Data (2000)												
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	3542	475	6019	W H Zimmer	OH	45200					24.2%	0
	3542	479	2830	Walter C Beckjord	OH	45200					24.2%	0
1	4922	342	2848	O H Hutchings	OH	45342	31,540	23,743	7,797	24.72%	24.2%	1
1	14006	170	8102	General James M Gavin	OH	45620	1,242	921	321	25.85%	24.2%	1
1	14015	257	2876	Kyger Creek	OH	45620	1,242	921	321	25.85%	24.2%	1
1	14006	319	2872	Muskingum River	OH	45715	2,501	1,916	585	23.39%	24.2%	0
1	40577	390	7286	Richard Gorsuch	OH	45750	28,220	21,939	6,281	22.26%	24.2%	0
24	**27**			**OH**		**23**	**391,705**	**290,452**	**101,253**	**25.85%**	24.2%	**14**
1	14063	431	6095	Sooner	OK	73061	1,308	935	373	28.52%	24.9%	1
1	15474	338	2963	Northeastern	OK	74053	2,628	1,816	812	30.90%	24.9%	1
1	7490	181	165	GRDA	OK	74337	4,841	3,534	1,307	27.00%	24.9%	1
1	14063	320	2952	Muskogee	OK	74401	18,018	12,945	5,073	28.16%	24.9%	1
1	20447	212	6772	Hugo	OK	74735	1,840	1,381	459	24.95%	24.9%	1
1	21	10	10671	AES Shady Point LLC	OK	74951	1,722	1,233	489	28.40%	24.9%	1
6	**6**			**OK**		**6**	**30,357**	**21,844**	**8,513**	**28.04%**	24.9%	**6**
1	15248	51	6106	Boardman	OR	97818	3,884	2,506	1,378	35.48%	23.2%	1
1	**1**			**OR**		**1**	**3,884**	**2,506**	**1,378**	**35.48%**	23.2%	**1**
1	14165	153	3098	Elrama Power Plant	PA	15038	291	237	54	18.56%	22.6%	0
1	142	3	10676	AES Beaver Valley Partners Beaver Valley	PA	15061	13,828	10,759	3,069	22.19%	22.6%	0
1	23279	306	3181	Mitchell Power Station	PA	15067	2,272	1,780	492	21.65%	22.6%	0
	6526	58	6094	Bruce Mansfield	PA	15077					22.6%	0
1	14165	83	8226	Cheswick Power Plant	PA	15204	9,502	7,089	2,413	25.39%	22.6%	1
1	23279	195	3179	Hatfields Ferry Power Station	PA	15461	4,605	3,517	1,088	23.63%	22.6%	1
1	12384	208	3122	Homer City Station	PA	15748	7,073	5,517	1,556	22.00%	22.6%	0
1	15873	251	3136	Keystone	PA	15774	3,234	2,448	786	24.30%	22.6%	1
1	9379	102	10143	Colver Power Project	PA	15927	1,199	908	291	24.27%	22.6%	1
1	2884	65	10641	Cambria Cogen	PA	15931	9,667	7,639	2,028	20.98%	22.6%	0
1	5670	144	10603	Ebensburg Power	PA	15931	9,667	7,639	2,028	20.98%	22.6%	0
1	15873	104	3118	Conemaugh	PA	15944	3,487	2,680	807	23.14%	22.6%	1
1	15998	418	3130	Seward	PA	15944	3,487	2,680	807	23.14%	22.6%	1
1	14165	328	3138	New Castle Plant	PA	16160	960	783	177	18.44%	22.6%	0
1	23279	24	3178	Armstrong Power Station	PA	16210	1,181	882	299	25.32%	22.6%	1
1	4129	356	54144	Piney Creek Project	PA	16214	10,449	8,966	1,483	14.19%	22.6%	0
1	14932	416	50974	Scrubgrass Generating Company LP	PA	16374	1,622	1,271	351	21.64%	22.6%	0

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	17235	420	3131	Shawville	PA	16873					22.6%	0
1	15537	366	3140	PPL Brunner Island	PA	17370	4,992	3,651	1,341	26.86%	22.6%	1
1	49889	164	10343	Foster Wheeler Mt Carmel Cogen	PA	17832	755	610	145	19.21%	22.6%	0
	22001	445	3152	Sunbury Generation LP	PA	17876					22.6%	0
1	15534	367	3149	PPL Montour	PA	17884	257	186	71	27.63%	22.6%	1
1	7199	240	10113	John B Rich Memorial Power Station	PA	17931	8,631	7,545	1,086	12.58%	22.6%	0
1	20541	488	50879	Wheelabrator Frackville Energy	PA	17931	8,631	7,545	1,086	12.58%	22.6%	0
1	16793	439	54634	St Nicholas Cogen Project	PA	17976	7,864	6,355	1,509	19.19%	22.6%	0
1	21025	501	50611	WPS Westwood Generation LLC	PA	17981	2,738	2,130	608	22.21%	22.6%	0
1	14932	337	50888	Northampton Generating Company LP	PA	18067	15,953	12,428	3,525	22.10%	22.6%	0
1	13833	255	50039	Kline Township Cogen Facility	PA	18237	3,189	2,549	640	20.07%	22.6%	0
1	14432	348	50776	Panther Creek Energy Facility	PA	18240	3,898	3,147	751	19.27%	22.6%	0
1	17235	363	3113	Portland	PA	18351	579	447	132	22.80%	22.6%	1
1	19391	213	3176	Hunlock Power Station	PA	18621	5,885	4,656	1,229	20.88%	22.6%	0
1	6035	146	3161	Eddystone Generating Station	PA	19022	3,906	2,845	1,061	27.16%	22.6%	1
1	6035	115	3159	Cromby Generating Station	PA	19460	32,944	25,005	7,939	24.10%	22.6%	1
1	17235	455	3115	Titus	PA	19506	6,293	4,643	1,650	26.22%	22.6%	1
31	**34**			**PA**		**28**	**167,254**	**130,673**	**36,581**	**21.87%**	22.6%	**13**
1	17539	107	7210	Cope	SC	29038	2,543	1,831	712	28.00%	24.2%	1
1	17539	483	3297	Wateree	SC	29044	5,937	4,231	1,706	28.74%	24.2%	1
1	17539	290	3287	McMeekin	SC	29212	28,029	20,162	7,867	28.07%	24.2%	1
1	17539	93	7737	Cogen South	SC	29423	791	787	4	0.51%	24.2%	0
	17539	67	3280	Canadys Steam	SC	29433					24.2%	0
1	17543	116	130	Cross	SC	29436	4,451	3,198	1,253	28.15%	24.2%	1
1	17543	498	6249	Winyah	SC	29440	28,875	20,784	8,091	28.02%	24.2%	1
1	17554	495	3298	Williams	SC	29445	48,628	34,495	14,133	29.06%	24.2%	1
1	17543	237	3319	Jefferies	SC	29461	24,081	17,500	6,581	27.33%	24.2%	1
1	17543	131	3317	Dolphus M Grainger	SC	29526	30,392	23,197	7,195	23.67%	24.2%	0
1	3046	184	3251	H B Robinson	SC	29550	31,313	23,253	8,060	25.74%	24.2%	1
1	5416	477	3264	W S Lee	SC	29697	10,592	7,804	2,788	26.32%	24.2%	1
	56190	466	7652	US DOE Savannah River Site (D Area)	SC	29808					24.2%	0
1	17539	465	3295	Urquhart	SC	29842	6,782	4,781	2,001	29.50%	24.2%	1
12	**14**			**SC**		**12**	**222,414**	**162,023**	**60,391**	**27.15%**	24.2%	**10**

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1	14232	45	6098	Big Stone	SD	57216	1,133	852	281	24.80%	24.8%	1
1	19545	40	3325	Ben French	SD	57702	29,375	22,146	7,229	24.61%	24.8%	0
2	**2**			**SD**		**2**	**30,508**	**22,998**	**7,510**	**24.62%**	24.8%	**1**
1	18642	118	3399	Cumberland	TN	37050	1,786	1,331	455	25.48%	24.1%	1
1	18642	169	3403	Gallatin	TN	37066	34,155	25,523	8,632	25.27%	24.1%	1
1	18642	244	3406	Johnsonville	TN	37134	3,018	2,280	738	24.45%	24.1%	1
1	18642	484	3419	Watts Bar Fossil	TN	37381	7,850	6,193	1,657	21.11%	24.1%	0
1	18642	60	3396	Bull Run	TN	37716	24,422	18,797	5,625	23.03%	24.1%	0
1	18642	254	3407	Kingston	TN	37763	14,572	11,443	3,129	21.47%	24.1%	0
1	18642	243	3405	John Sevier	TN	37857	20,063	15,508	4,555	22.70%	24.1%	0
1	18642	17	3393	Allen Steam Plant	TN	38109	52,401	36,510	15,891	30.33%	24.1%	1
8	**8**			**TN**		**8**	**158,267**	**117,585**	**40,682**	**25.70%**	24.1%	**4**
	35120	333	54972	Norit Americas Marshall Plant	TX	1					27.7%	0
1	19323	310	6147	Monticello	TX	75455	24,737	17,158	7,579	30.64%	27.7%	1
1	17698	357	7902	Pirkey	TX	75650	7,699	5,363	2,336	30.34%	27.7%	1
1	17698	486	6139	Welsh	TX	75686	11,285	8,236	3,049	27.02%	27.7%	0
1	19323	286	6146	Martin Lake	TX	75691	3,687	2,649	1,038	28.15%	27.7%	1
1	19323	42	3497	Big Brown	TX	75840	6,622	4,877	1,745	26.35%	27.7%	0
1	54888	273	298	Limestone	TX	75846	2,645	1,951	694	26.24%	27.7%	0
1	15474	343	127	Oklaunion	TX	76373	194	139	55	28.35%	27.7%	1
1	19323	412	6648	Sandow No 4	TX	76567	9,238	6,595	2,643	28.61%	27.7%	1
1	54891	463	7030	Twin Oaks Power One	TX	76629	1,926	1,410	516	26.79%	27.7%	0
1	54888	472	3470	W A Parish	TX	77481	184	143	41	22.28%	27.7%	0
1	18715	176	6136	Gibbons Creek	TX	77830	2,290	1,757	533	23.28%	27.7%	0
1	54865	96	6178	Coleto Creek	TX	77960	125	97	28	22.40%	27.7%	0
1	16624	411	6183	San Miguel	TX	78012	526	342	184	34.98%	27.7%	1
1	16604	226	7097	J K Spruce	TX	78263	4,147	3,004	1,143	27.56%	27.7%	0
1	16604	229	6181	J T Deely	TX	78263	4,147	3,004	1,143	27.56%	27.7%	0
1	11269	160	6179	Fayette Power Project	TX	78945	10,041	7,627	2,414	24.04%	27.7%	0
1	17718	193	6193	Harrington	TX	79108	11,876	8,747	3,129	26.35%	27.7%	0
1	17718	456	6194	Tolk	TX	79371	1,180	836	344	29.15%	27.7%	1
18	**19**			**TX**		**17**	**98,402**	**70,931**	**27,471**	**27.92%**	27.7%	**7**
1	40230	52	7790	Bonanza	UT	84078	19,591	12,849	6,742	34.41%	30.9%	1
1	14354	214	6165	Hunter	UT	84513	1,880	1,180	700	37.23%	30.9%	1
1	14354	70	3644	Carbon	UT	84526	3,909	2,855	1,054	26.96%	30.9%	0

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1	14354	215	8069	Huntington	UT	84528	2,742	1,757	985	35.92%	30.9%	1
1	21734	446	50951	Sunnyside Cogen Associates	UT	84539	408	300	108	26.47%	30.9%	0
1	11208	221	6481	Intermountain Power Project	UT	84624	5,679	3,499	2,180	38.39%	30.9%	1
6	**6**			**UT**		**6**	**34,209**	**22,440**	**11,769**	**34.40%**	30.9%	**4**
1	12588	364	3788	Potomac River	VA	22314	24,921	21,795	3,126	12.54%	23.9%	0
1	1735	46	54304	Birchwood Power	VA	22485	15,805	11,480	4,325	27.36%	23.9%	1
1	19876	56	3796	Bremo Bluff	VA	23022	656	514	142	21.65%	23.9%	0
1	55740	436	54081	Spruance Genco LLC	VA	23234	38,100	27,591	10,509	27.58%	23.9%	1
1	19876	81	3803	Chesapeake	VA	23323	31,336	21,883	9,453	30.17%	23.9%	1
1	19876	506	3809	Yorktown	VA	23690	2,577	1,833	744	28.87%	23.9%	1
1	3901	94	10071	Cogentrix Virginia Leasing Corporation	VA	23703	27,625	20,667	6,958	25.19%	23.9%	1
1	19876	82	3797	Chesterfield	VA	23831	24,798	18,059	6,739	27.18%	23.9%	1
1	19876	433	10774	Southampton Power Station	VA	23851	13,397	9,979	3,418	25.51%	23.9%	1
1	9628	234	10377	James River Cogeneration	VA	23860	27,173	19,938	7,235	26.63%	23.9%	1
1	19876	210	10771	Hopewell Power Station	VA	23860	27,173	19,938	7,235	26.63%	23.9%	1
1	19876	291	52007	Mecklenburg Power Station	VA	23927	4,456	3,570	886	19.88%	23.9%	0
1	733	178	3776	Glen Lyn	VA	24093	338	270	68	20.12%	23.9%	0
1	733	88	3775	Clinch River	VA	24225	2,017	1,578	439	21.76%	23.9%	0
1	19876	19	10773	Altavista Power Station	VA	24517	5,431	4,186	1,245	22.92%	23.9%	0
1	19876	89	7213	Clover	VA	24534	2,170	1,633	537	24.75%	23.9%	1
16	**16**			**VA**		**15**	**220,800**	**164,976**	**55,824**	**25.28%**	23.9%	**10**
1	19099	457	3845	Transalta Centralia Generation	WA	98531	21,842	16,328	5,514	25.24%	23.9%	1
1	**1**			**WA**		**1**	**21,842**	**16,328**	**5,514**	**25.24%**	23.9%	**1**
1	20847	432	4041	South Oak Creek	WI	53154	28,659	21,574	7,085	24.72%	23.8%	1
1	20847	359	6170	Pleasant Prairie	WI	53158	11,339	8,059	3,280	28.93%	23.8%	1
1	20847	302	7549	Milwaukee County	WI	53226	18,835	14,993	3,842	20.40%	23.8%	0
1	20847	467	4042	Valley	WI	53233	15,485	13,746	1,739	11.23%	23.8%	0
1	11479	49	3992	Blount Street	WI	53703	26,715	25,623	1,092	4.09%	23.8%	0
	20856	149	4050	Edgewater	WI	53802					23.8%	0
1	12435	138	4146	E J Stoneman Station	WI	53806	2,003	1,497	506	25.26%	23.8%	1
1	20856	327	4054	Nelson Dewey	WI	53806	2,003	1,497	506	25.26%	23.8%	1
1	20856	101	8023	Columbia	WI	53954	6,480	4,810	1,670	25.77%	23.8%	1
	11571	281	4125	Manitowoc	WI	54221					23.8%	0
1	20860	374	4072	Pulliam	WI	54303	27,638	20,784	6,854	24.80%	23.8%	1

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1	20860	487	4078	Weston	WI	54474	3,728	2,756	972	26.07%	23.8%	1
1	4716	18	4140	Alma	WI	54610	1,877	1,451	426	22.70%	23.8%	0
1	4716	242	4271	John P Madgett	WI	54610	1,877	1,451	426	22.70%	23.8%	0
1	4716	171	4143	Genoa	WI	54632	1,226	893	333	27.16%	23.8%	1
1	13781	36	3982	Bay Front	WI	54806	11,793	8,913	2,880	24.42%	23.8%	1
1	12298	292	4127	Menasha	WI	54952	22,927	17,178	5,749	25.08%	23.8%	1
15	**17**			**WI**		**13**	**178,705**	**142,277**	**36,428**	**20.38%**	23.8%	**10**
1	733	249	3936	Kanawha River	WV	25086	1,118	887	231	20.66%	21.5%	0
1	733	241	3935	John E Amos	WV	25213	4,754	3,605	1,149	24.17%	21.5%	1
1	733	315	6264	Mountaineer	WV	25265	1,657	1,280	377	22.75%	21.5%	1
1	733	354	3938	Philip Sporn	WV	25265	1,657	1,280	377	22.75%	21.5%	1
1	14006	248	3947	Kammer	WV	26041	16,781	13,075	3,706	22.08%	21.5%	1
1	14006	305	3948	Mitchell	WV	26041	16,781	13,075	3,706	22.08%	21.5%	1
1	12796	497	3946	Willow Island	WV	26134	1,216	939	277	22.78%	21.5%	1
1	23279	360	6004	Pleasants Power Station	WV	26134	1,216	939	277	22.78%	21.5%	1
1	23279	194	3944	Harrison Power Station	WV	26366	142	105	37	26.06%	21.5%	1
1	12949	312	10743	Morgantown Energy Facility	WV	26505	32,418	28,709	3,709	11.44%	21.5%	0
1	12796	15	3942	Albright	WV	26519	1,413	1,094	319	22.58%	21.5%	1
1	12796	163	3943	Fort Martin Power Station	WV	26541	845	620	225	26.63%	21.5%	1
1	563	180	10151	Grant Town Power Plant	WV	26574	712	563	149	20.93%	21.5%	0
1	12796	398	3945	Rivesville	WV	26588	2,541	2,001	540	21.25%	21.5%	0
1	19876	334	7537	North Branch	WV	26707	356	286	70	19.66%	21.5%	0
1	19876	317	3954	Mt Storm	WV	26739	818	661	157	19.19%	21.5%	0
16	**16**			**WV**		**13**	**64,771**	**53,825**	**10,946**	**16.90%**	21.5%	**10**
1	1307	268	6204	Laramie River Station	WY	82070	16,376	13,334	3,042	18.58%	24.0%	0
1	14354	125	4158	Dave Johnston	WY	82637	3,758	2,679	1,079	28.71%	24.0%	1
1	14354	504	6101	Wyodak	WY	82716	14,749	10,467	4,282	29.03%	24.0%	1
1	19545	325	4150	Neil Simpson	WY	82718	15,835	10,612	5,223	32.98%	24.0%	1
1	19545	326	7504	Neil Simpson II	WY	82718	15,835	10,612	5,223	32.98%	24.0%	1
1	19545	503	55479	Wygen 1	WY	82718	15,835	10,612	5,223	32.98%	24.0%	1
1	19545	345	4151	Osage	WY	82723	359	292	67	18.66%	24.0%	0
1	14354	239	8066	Jim Bridger	WY	82942	62	49	13	20.97%	24.0%	0
1	14354	321	4162	Naughton	WY	83101	2,762	1,959	803	29.07%	24.0%	1
9	**9**			**WY**		**8**	**69,736**	**50,004**	**19,732**	**28.30%**	24.0%	**6**

Appendix P:

UMRA Written Statement

I. Introduction

Title II of the 1995 Unfunded Mandates Reform Act (UMRA; 2 U.S.C. 1531-1538), requires Federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Specifically, Section 202 of UMRA generally requires Federal agencies to prepare a written statement, including a cost-benefit analysis, for each proposed and final rule with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Section 202 requires that "Written Statements" contain five elements of information:

1. An identification of the provision of Federal law under which the rule is being promulgated;
2. A qualitative and quantitative assessment of the anticipated costs and benefits of the Federal mandate, including the costs and benefits to State, local, and tribal governments or the private sector, as well as the effect of the Federal mandate on health, safety, and the natural environment;
3. Estimates by the agency, if and to the extent that the agency determines that accurate estimates are reasonably feasible, of—
   (A) the future compliance costs of the Federal mandate; and
   (B) any disproportionate budgetary effects of the Federal mandate upon any particular regions of the nation or particular State, local, or tribal governments, urban or rural or other types of communities, or particular segments of the private sector;
4. Estimates by the agency of the effect on the national economy, such as the effect on productivity, economic growth, full employment, creation of productive jobs, and international competitiveness of United States goods and services, if and to the extent that the agency in its sole discretion determines that accurate estimates are reasonably feasible and that such effect is relevant and material; and
5. Description of the extent of the agency's prior consultation with elected representatives (under section 204) of the affected State, local, and tribal governments, including a summary of the comments and concerns that were presented by State, local, or tribal governments either orally or in writing to the agency; and a summary of the agency's evaluation of those comments and concerns.

This document constitutes the "Written Statement" to meet this requirement for the CCR proposed rule. The Environmental Protection Agency (EPA) has conducted a cost-benefit analysis for this action, which has been submitted in the docket entitled "Regulatory Impact Analysis" (RIA).

II. Summary of Proposed Rule

As stated in the Federal Register notice for the proposed rule, EPA is proposing to list coal combustion residues (CCR) generated by electric utility plants as "K179 hazardous wastes" under the Resource Conservation and Recovery Act (RCRA). Currently CCRs are exempt from RCRA hazardous waste regulation under the RCRA "Bevill exclusion"(40 CFR 261.4(b)(4)). The proposed rule will remove the Bevill exclusion for CCR which dates back to 1980, but maintain the existing RCRA Bevill exclusion from hazardous waste regulation for CCRs that are "beneficially used" by at least 14 other industries (e.g., cement and concrete manufacturing, construction fill, wall board manufacturing, waste stabilization, blasting grit, roofing granules, filler for asphalt, agricultural soil amendment, snow/ice control).[16] This rulemaking also proposes as a sub-option to require the treatment of CCR prior to disposal by dewatering so that CCR may be managed as dry waste in landfills rather than as wet (watery) waste in surface

[16] This proposed rulemaking does not apply to CCRs that are used for mine filling. EPA is working in conjunction with the U.S. Department of the Interior's Office of Surface Mining to develop separate requirements for the use of CCRs in mine filling operations.

impoundments (i.e., ponds, lagoons, dams, embankments). The proposed rule presents three regulatory options plus a sub-option for regulating CCR disposal, as identified below:

- *Subtitle C haz waste:* RCRA Subtitle C regulation (i.e., listing CCR as K179 "hazardous waste") based on RCRA 3004(x) custom-tailored technical standards similar to EPA's 1999 CKD cement kiln dust proposed rule. (proposed rule lead option).
- *Subtitle D Version 1:* RCRA Subtitle D non-hazardous waste regulation; technical standards same as Subtitle C haz waste.
- *Hybrid C & D:* Hybrid approach #2: RCRA Subtitle C regulation for wet CCR disposal; Subtitle D for dry CCR disposal.
- *Suboption:*Treatment of wet CCR by dewatering 95% so that is may be disposed as dry waste in landfill rather than as wet (watery) waste in surface impoundments; this sub-option may be applied to any of the four options above.

III. Legal Authority of Proposed Rule

As stated in its Federal Register notice, the electric utility industry CCR disposal proposed rule is being taken under EPA's authorities under 42 U.S.C. 6912 which authorizes the EPA Administrator to prescribe, in consultation with Federal, State, and regional authorities, such regulations as are necessary to carry out the functions under Federal solid waste disposal laws; 42 U.S.C. 6944 and 6945 which prohibit open dumping; Section 2002(a) of RCRA which provides the EPA Administrator the authority to prescribe such regulations as are necessary to carry out his or her functions under the Act; Section 3001(b)(3)(A) of RCRA which required EPA to conduct a study of fly ash waste, bottom ash waste, slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels and make a determination whether these wastes should be regulated as hazardous wastes; Sections 3004(c) and (d) which prohibit free liquids in hazardous wastes in landfills, and prohibit land disposal of specified wastes. Additionally, Section 4004(a) of RCRA which requires EPA, after consultation with the States, and after notice and public hearings, to promulgate regulations containing criteria for determining which facilities shall be classified as sanitary landfills and which shall be classified as open dumps within the meaning of RCRA. At a minimum, such criteria are to provide that a facility may be classified as a sanitary landfill and not an open dump only if there is no reasonable probability of adverse effects on health or the environment from disposal of solid waste at such facility.

IV. Summary of Cost-Benefit Assessment

IV.A. Cost to State, local, and Tribal Governments and the Private Sector

As estimated in the RIA, the proposed rule may affect 495 coal-fired electric utility plants, and may have a nationwide average annualized cost between $492 million per year (for Subtitle D Version 1 without land treatment sub-option) and $2,274 million per year (for Subtitle C haz waste with land treatment sub-option). Of this amount, average annualized costs to State/local governments total between $56 million (Subtitle D Version 1 w/out sub-option) and $97 million (Subtitle C haz waste with sub-option), consisting of estimated regulatory compliance costs for State/local governments that currently own or operate affected coal-fired electric utility plant(s), plus $3 million for State/local government implementation of the proposed rule. The respective estimated average annualized cost to the private sector ranges between $415 million to $1,999 million per year.

Although three of the 495 coal-fired electric utility plants are located on Tribal land, none of the plants are Tribally-owned; therefore, EPA dose not expect this proposed rule will impose costs on tribal governments.

UMRA and Federalism Tests for CCR Disposal Regulatory Options ($millions average annualized costs @7% discount rate over 50-years 2012 to 2061, 2009$)			
Type of Direct Compliance Cost	**Subtitle C haz waste (Preferred Option)** • Subtitle C hazardous waste	**Subtitle D Version 1** • Subtitle D non-hazardous waste	**Option 3** • Subtitle C for impoundments • Subtitle D for landfills
A. Without land treatment disposal sub-option:	**$598**	**$492**	**$500**
UMRA Test:			
1. Private sector $100 million direct cost threshold test	$512.7	$415.3	$422.1
2. State/local government $100 million direct cost threshold test*	$67.3	$55.9	$57.9
Federalism Test:			
1. $25 million threshold test: sub-total State/Local govt cost	$67.3	$55.9	$57.9
2. 1% Test: State/local govt cost as percentage of State/Local government electric utility annual revenues	0.158%	0.131%	0.136%
B. With land treatment disposal sub-option:	**$2,274**	**$2,168**	**$2,176**
UMRA Test:			
1. Private sector $100 million direct cost threshold test	$1,999.4	$1,902.0	$1,908.8
2. State/local government $100 million direct cost threshold test*	$96.7	$85.3	$91.6
Federalism Test:			
1. $25 million threshold test: sub-total State/Local govt cost	$96.7	$85.3	$91.6
2. 1% Test: State/local govt cost as percentage of State/Local government electric utility annual revenues	0.227%	0.200%	0.215%
* Note: Remainder Federal government costs represent costs associated with Federally-owned electric utility plants (i.e., Tennessee Valley Authority) which are not subject to either the UMRA or Federalism tests. Therefore, the sub-total private sector direct cost plus the state/local government direct cost does not add-up to the total annual cost estimate under each option; the remainder cost is for the Federally-owned plants.			

IV.B. Extent To Which Costs To State, Local, And Tribal Governments May Be Paid By EPA Or Other Federal Agencies, Or To Which There Are Available Federal/EPA Resources To Carry Out A Federal Intergovernmental Mandate

As of 2008, EPA provides states with $101 million per year in funding for implementation of RCRA-authorized programs in 50 states (AK and IA do not have authorized RCRA programs). In comparison this EPA annual funding level, a recent (2007) survey study[17] of State government RCRA Subtitle C programs estimated that state governments annually spend 2.5 times more (i.e., $255 million per year) in RCRA program implementation cost, consisting of (1) disposal site closure costs, (2) facility investigation costs, (3) site remediation costs, (4) corrective action costs, (5) permitting costs, (6) site/facility inspection costs, (7) regulatory enforcement costs, and (8) program development costs. This federal funding deficit indicates that it is not likely that the federal government may provide state/local governments with additional resources to cover the implementation cost of the proposed rule.

[17] Source: Association of State & Territorial Solid Waste Management Officials (ASTSWMO), "State RCRA Subtitle C Core Hazardous Waste Management Program Implementation Costs: Final Report", January 2007, 94 pages: http://www.astswmo.org/files/publications/hazardouswaste/Final%20Report%20-%20RCRA%20Subtitle%20C%20Core%20Project.pdf

IV.C. Estimates Of Future Compliance Costs And Budgetary Effects On Particular Regions Of The Country, Or Particular State, Local, Or Tribal Governments Or Communities, Or Particular Segments Of The Private Sector

The RIA (Chapter 5) assessed a number of potential distributional effects of the proposed rule cost impacts on:

(a) Future electricity prices on a state-by-state and on a national aggregate basis
(b) A state-by-state regulatory cost sub-total basis
(c) Small entity cost sub-total basis
(d) Minority and low-income population basis living near affected electric utility plants
(e) Child populations living near affected electric utility plants
(f) State/local government cost sub-total basis

IV.D. Estimate of the Potential Effect on the National Economy

The RIA for this proposed rule does not include either qualitative or quantitative estimation of the potential effects of the proposed rule on economic productivity, economic growth, employment, job creation, or international economic competitiveness. These potential effects are identified as factors in both the 1993 Executive Order "Regulatory Planning and Review" (section 3(f)(1)) and in the 1995 Unfunded Mandates Reform Act (section 202(a)(4)). These other potential economic effects are excluded from the RIA because the upper-end of the range in average annualized regulatory cost across all four regulatory options as estimated in the RIA, does not exceed the 0.25% to 0.5% of Gross Domestic Product (GDP) threshold identified in OMB's 1995 guidance[18] for attempting to measure such national economic effects for purpose of UMRA economic analysis compliance. Based on the 2008 US GDP of $14.42 trillion,[19] the 0.25% to 0.5% threshold is equal to $36 billion to $72 billion.

IV.E. Extent of EPA's Prior Consultation With Affected State, Local, and Tribal Governments

In developing the regulatory options described in today's proposed rulemaking, EPA consulted with small governments according to EPA's UMRA interim small government consultation plan developed pursuant to section 203 of UMRA. EPA's interim plan provides for two types of possible small government input: technical input and administrative input. According to this plan, and consistent with section 204 of UMRA, early in EPA's 2009 process for developing the proposed rule, EPA implemented a small government consultation process consisting of two consultation components:

1. The following series of year 2009 meetings for purpose of acquiring small government technical input: (1) February 27 with the Association of State and Territorial Solid Waste Management Officials (ASTSWMO) Coal Ash Workgroup (Washington DC), (2) March 22-24 with the Environmental Council of States (ECOS) Spring Meeting (Alexandria VA), (3) April 15-16 with the ASTSWMO Mid-Year Meeting (Columbus OH), (4) May 12-13 with the EPA Region IV State Directors Meeting (Atlanta, GA), (5) June 17-18 with the ASTSWMO Solid

[18] Source: Section 4.B(3) of OMB's 31 March 1995 guidance for implementing the UMRA (http://www.whitehouse.gov/omb/memoranda_1998/#1995) state that "We would note that such macro-economic effects tend to be measurable, in nation-wide econometric models, only if the economic impact of the regulation reaches 0.25 percent to 0.5 percent of Gross Domestic Product. A regulation with a smaller aggregate effect is highly unlikely to have any measurable impact in macro-economic terms unless it is highly focuses on a particular geographic region or economic sector."

[19] Source: 2008 3rd quarter estimate of 2008 US GDP as reported in "TABLE B–8.—Gross domestic product by major type of product, 1959–2008" of the 2009 Economic Report of the President at http://www.gpoaccess.gov/eop/tables09.html

Waste Managers Conference (New Orleans, LA), (6) July 21-23 with the ASTSWMO Board of Directors Meeting (Seattle, WA), and (7) August 12 with the ASTSWMO Hazardous Waste Subcommittee Meeting (Washington DC). ASTSWMO is an organization with a mission to work closely with the EPA to ensure that its state government members are aware of the most current developments related to their state waste management programs. ECOS is a national non-profit, non-partisan association of state and territorial environmental agency leaders. As a result of these meetings EPA received letters in mid-2009 from 22 state governments as well as a letter from ASTSWMO expressing their stance on CCR disposal regulatory options.

2. Contact letters mailed August 24, 2009 to the following 10 organizations representing small government elected officials, to inform them and seek their input for the proposed rule development, as well as to invite them to a meeting held September 16, 2009 in Washington DC: (1) National Governors Association, (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) County Executives of America, (7) National Association of Counties, (8) International City/County Management Association, (9) National Association of Towns and Townships, and (10) Environmental Council of the States. These 10 organizations of small government elected officials are identified in EPA's November 2008 Federalism guidance as the "Big 10" organizations appropriate to contact for purpose of consultation with small government elected office.

Appendix Q

Documentation for EPA's Social Cost Estimate Assigned in this RIA to the TVA-Kingston 2008 CCR Impoundment Failure Event

Purpose of this Appendix

This appendix provides documentation of how EPA derived the preliminary $3 billion social cost estimate assigned as the main value in this RIA to the CCR impoundment structural failure event in December 2008 at the Tennessee Valley Authority (TVA) Kingston TN coal-fired electricity plant. TVA's August 2009 estimate of its eventual total cleanup cost (i.e., $933 million to $1.2 billion) constitutes less than 40% of the $3 billion social cost estimate assigned in this RIA, and represents one of four cost elements (i.e., **Cost Element #1**) included in EPA's $3 billion cost estimate derived in this Appendix. The 60% remainder of EPA's $3 billion social cost estimate consists of three additional cost elements documented and calculated below in this Appendix:

- **Cost Element #2**: Emergency response and cleanup oversight costs to local agencies, state agencies, and other Federal agencies
- **Cost Element #3**: Ecological (natural resource) damages
- **Cost Element #4**: Local (community) socio-economic damages

These three additional social cost elements are not actual costs that TVA will eventually pay, but which represent opportunity costs to society. According to EPA's economic analysis guidance,[20] opportunity costs are the value of goods and services lost by society resulting from interrupted or diverted uses of resources from other purposes, and from temporary or permanent reductions in economic output.

This Appendix begins by summarizing TVA's most recent published cleanup cost estimate (i.e., Cost Element #1), followed by documentation and supporting calculations for each of the three additional cost elements listed above (i.e., Cost Elements #2, #3, #4).

[20] Source: Chapter 8: Analyzing Social Costs (page 113) of EPA's "Guidelines for Preparing Economic Analyses," report nr. EPA-240-R-00-003, Sept 2000 at: http://yosemite.epa.gov/EE/epa/eed.nsf/webpages/Guidelines.html/$file/Guidelines.pdf

Cost Element #1: TVA's Cleanup Cost

In February 2009, TVA initially published an estimate for the Kingston TN site cleanup cost (time critical + non-time critical) of between $525 million and $825 million.[21] On 18 August 2009, TVA published a revised estimate of cleanup cost:

> "*Due to the uncertainty at this time of the final methods of remediation, a range of reasonable estimates has been developed by cost category and either the known amounts, most likely scenarios, or the low end of the range for each category has been accumulated to determine the total estimate. The range of estimated costs varies from approximately $933 million to approximately $1.2 billion.*"[22]

TVA provided the following additional detailed explanation[23] for its $933 million to $1.2 billion cleanup cost estimate range:

> "*The $933 million estimate currently includes, among other things, a reasonable estimate of costs related to ash dredging and processing, ash disposition, infrastructure repair, dredge cell repair, root cause analysis, certain legal and settlement costs, environmental impact studies and remediation, human health assessments, community outreach and support, regulatory oversight, cenosphere recovery, skimmer wall installation, construction of temporary ash storage areas, dike reinforcement, project management, and certain other remediation costs associated with the clean up. If the actual amount of ash removed is more or less than the estimate, the expense could change significantly as this affects the largest cost components of the estimate. The cost of the removal of the ash is in large part dependent on the final disposal plan, which is still in development by TVA and regulatory authorities.*
>
> *Due to the uncertainty at this time of the final methods of disposal, a range of reasonable estimates has been developed by cost category and either the known amounts, most likely scenarios, or low end of the range for each category has been accumulated and evaluated to determine the total estimate. The costs related to loading, transport, and disposal of all time critical ash and final disposition of dredge cell closures are the ones most subject to change. It is not currently known exactly how much ash will need to be removed. The range of estimated costs varies from approximately $933 million to approximately $1.2 billion.*"

On 15 January 2010, TVA provided an estimate of $272 million to $744 million for non-time critical removal of 2.4 million of the 5.4 million cubic yards of CCR from the Swan Pond Embankment.[24] This RIA assumes the non-time critical cost estimate is represented in TVA's $933 million to $1.2 billion cleanup cost estimate.

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[21] Source: Waste & Recycling News, 13 Feb 2009, http://www.wasterecyclingnews.com/email.html?id=1234543579
[22] Source: Page 13 of "TVA 10Q Filing for Q3 FY2009", 18 Aug 2009 at http://www.tva.gov/kingston/admin_record/pdf/51.pdf
[23] Source: Page 15 of "Form 10-Q Quarterly Report" filed 03 Feb 2010 by TVA with the US Securities & Exchange Commission (SEC), available at: http://investor.shareholder.com/tva/secfiling.cfm?filingID=1376986-10-5
[24] Source: Pages 69-70 of "Kingston Ash Recovery Project Non-Time Critical Removal Action Embayment/ Dredge Cell Engineering Evaluation/ Cost Analysis" at http://www.tva.gov/kingston/eeca/NTCRA-EE-CA-2010-01-14.pdf

TVA noted that a yet-to-be-estimated cost for non-time critical removal of residual CCR in the river system will be prepared at a later date following further sampling and analysis of biotic and abiotic media which TVA will use to assess potential human health and ecological risks for the river system.[25] This RIA assumes this yet-to-be-estimated cost is represented in TVA's $933 million to $1.2 billion cleanup cost estimate, which is probably a cost under-estimating assumption applied in this RIA, because TVA also identifies the following other possible costs:

> "*TVA has not included the following categories of costs in the above estimate since it has determined that these costs are currently either not probable, not reasonably estimable, or not appropriately accounted for as part of the estimate accrual: fines or regulatory directives, outcome of lawsuits, future claims, long-term environmental impact costs, final long-term disposition of ash processing area, associated capital asset purchases, ash handling and disposition from current plant operations, costs of remediating any discovered mixed waste during ash removal process, and other costs not meeting the recognition criteria. As ash removal continues, it is possible that other environmentally sensitive material potentially in the river sediment before the ash spill may be uncovered. If other materials are identified, additional remediation not included in the above estimates may be required. On January 26, 2010, the owners of the landfill in Perry County, Alabama that is receiving the ash dredged from the Emory River filed for Chapter 11 bankruptcy. At this time it is unclear whether this filing will cause TVA to incur any additional costs.*"[26]

Regardless of the above cost uncertainties identified by TVA, this RIA Appendix applies the midpoint of TVA's August 2009 $933 million to $1.2 billion cleanup cost estimate range (i.e., **$1.07 billion**) to represent the value of Cost Element #1, for addition below in this Appendix to the other three cost elements.

Cost Element #2: Costs to Local/State/Other Federal Agencies

As identified in information published[27] by the Roane County Government (Tennessee), this cost element involves opportunity costs for emergency response, cleanup and administrative oversight, and ancillary activities, associated with at least three categories of at least nine other agencies and organizations, in addition to TVA:

- Local agencies: Example agencies are:
  - Roane County TN Community Advisory Group
  - Roane County Long Term Recovery Committee
  - Roane County Sheriff Office
- State agencies: Example agencies are:

[25] Source: Page viii of "Kingston Ash Recovery Project Non-Time Critical Removal Action Embayment/ Dredge Cell Engineering Evaluation/ Cost Analysis," TVA, 15 January 2010 at http://www.tva.gov/kingston/eeca/NTCRA-EE-CA-2010-01-14.pdf
[26] Source: Page 16 of "Form 10-Q Quarterly Report" filed 03 Feb 2010 by TVA with the US Securities & Exchange Commission (SEC), available at: http://investor.shareholder.com/tva/secfiling.cfm?filingID=1376986-10-5
[27] Source: Example agencies for these three categories other organizations and agencies are provided on the Roane County Government's "Emory River Ash Spill Information Page" website at: http://www.roanegov.org/id16.html

- o Tennessee Emergency Management Agency
- o Tennessee Department of Environment & Conservation
- o Tennessee Department of Health
- o Tennessee Wildlife Resources Agency
- Other Federal government agencies: Example agencies are:
  - o EPA's Region 4 Office
  - o Agency for Toxic Substances & Disease Registry

This cost element is not separately estimated in this RIA, but is assumed included in the socio-economic cost estimate (Cost Element #4) below.

Cost Element #3: Ecological Damage Cost

The harmful effects (i.e., injuries) of chemical substances and industrial chemical materials/waste releases on ecological systems are often referred to as natural resource damages. EPA's Superfund program defines natural resource damages as damages to land, ground water, habitat, fish and other wildlife, and other environmental resources.[28] Natural resources can also be viewed as assets that provide flows of services over time to other natural resources and to the economy. When natural resources are damaged, the flows of ecological and human services provided by those natural resources (and thus the ecological, economic, and social values they provide) may be interrupted for some time. Thus, the public (i.e., society) incurs interim losses from natural resource damages.

According to EPA's Superfund program, there are four categories of benefits which ecosystems provide, which hypothetically could constitute social costs if damaged by environmental releases of industrial chemical materials/wastes (e.g., environmental releases from CCR impoundment structural failures):

1. Direct market benefits: Primary products produced by nature that can be bought and sold either as factors of production or as final consumption products. Relevant examples include commercial fish species, which can be harmed by releases of industrial waste into aquatic ecosystems. Includes recreational activities for which access fees are charged.
2. Direct non-market benefits: Recreational opportunities and aesthetic qualities provided by ecosystems. Non-market benefits can include both consumptive uses (e.g., recreational fishing and hunting) and non-consumptive uses (e.g., scenic vistas, wildlife viewing, hiking, and boating) for which access fees are not charged.
3. Indirect benefits: Ecosystem services that do not directly provide a market or non-market good or opportunity, but which are still valued by humans because they support off-site ecological resources or maintain the biological and biochemical processes required to support life on this planet. For example, wetlands recharge ground water, mitigate flooding, and trap sediments. Rivers provide spawning locations for fish. Terrestrial ecosystems provide habitat for natural pollinators. All of these ecosystems support biodiversity.

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[28] Additional information about the Superfund program and environmental effects of industrial contamination of the environment and natural resources is available at EPA's Superfund "Environmental Effects" website at http://www.epa.gov/superfund/health/environment.htm

4. Non-use benefits: Not associated with any direct or indirect use by individuals or society but arise when people value an ecological resource without using it. Non-use values are associated by people who either have knowledge that (a) the resource could be used by the individual making the valuation (option value), (b) the resource exists in an undisturbed state (existence value), or (c) future generations could use the natural resource (bequest value).

For site-specific ecological assets and damages, the process of monetizing can take several years and cost several million dollars. Consequently, this Appendix applies a "benefit transfer" method to estimate ecological damages associated with the TVA Kingston CCR impoundment release. The benefit transfer method is defined in EPA's economic analysis guidelines[29] as an approach involving transferring information and cost estimates contained in prior studies on related topics and subject matter:

> "*Rather than collecting primary data, the benefit transfer approach relies on information from existing studies that have applied other [estimation] methods…. [The benefit transfer approach involves] the transfer of existing estimates … to a new study which is different from the study for which the values were originally estimated. The case from which the existing estimates were obtained is often referred to as the 'study case,' while the case under consideration for a new policy is termed the 'policy case'…. The advantages of benefit transfer are clear. Original studies are time consuming and expensive; benefit transfer can reduce both the time and financial resources needed to develop benefits estimates of a proposed policy. Given the demands of the regulatory process, these considerations may be extremely important…. However … estimates derived using benefit transfer techniques are unlikely to be as accurate as primary research tailored specifically to the new policy case.*"

EPA's economic analysis guidelines (ibid, page 87) identifies four methods for actually transferring numerical (quantitative) results from existing studies using the "transfer method":

1. Point estimate approach: Involves applying the mean value or range of values from the 'study case' directly to the 'policy case.'
2. Mathematical function approach: Involves substituting applicable numerical values of key variables in the 'study case' which are relevant to the 'policy case' (e.g., mean or median household income, racial or age distribution).
3. Meta-analysis approach: Involves statistically combining the numerical results contained in multiple study cases.
4. Bayesian techniques approach: Involves exploratory approaches to incorporating 'study case' information with 'policy case' information.

A 2004 study prepared for EPA's Oil Spill Response Program estimated oil spill cleanup costs, as well as separately estimated associated ecological and socio-economic damages.[30] The study separately estimated these three types of costs for two separate categories of oil spills by spill source: (a) industrial facilities, and (b) all sources (i.e., facilities and vessels). The study (ibid, Table 2, page 8) defines "facility" as:

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[29] Source: Section 7.5.4 Benefits Transfer (pages 85-87) of EPA's "Guidelines for Preparing Economic Analyses," report nr. EPA-240-R-00-003, Sept 2000 at: http://yosemite.epa.gov/EE/epa/eed.nsf/webpages/Guidelines.html/$file/Guidelines.pdf

[30] Source: "Analysis Of Benefits of EPA Oil Program" by Dagmar Schmidt Etkin, Environmental Research Consulting (presented at the 6-8 April 2004 EPA Freshwater Spills Symposium), available at http://www.environmental-research.com/erc_reports/ERC_report_9.pdf. The study used the EPA "Basic Oil Spill Cost Estimation Model" (BOSCEM) for estimating oil spill costs including response costs, ecological damage costs, and socio-economic damage costs for actual or hypothetical oil spills. Additional information about BOSCEM is available in the document "Modeling Oil Spill Response and Damage Costs" by Dagmar Schmidt Etkin, Environmental Research Consulting, Cortlandt Manor, NY at: http://www.epa.gov/emergencies/docs/oil/fss/fss04/etkin2_04.pdf

"Any mobile or fixed, onshore or offshore building, structure, installation, equipment, pipe, or pipeline (other than a vessel) used in oil well drilling operations, production, refining, storage, gathering, processing, transfer, distribution, and waste treatment, or in which oil is used."

We believe it is feasible and reasonable to use the EPA oil spill cost study as a 'study case' according to the transfer method; however, we take comment on this assumption and provide an alternative preliminary method below. For this purpose, the costs reported in the study which involved "facility oil spills into inland navigable waters (Table 5, p.14) are relevant as a 'study case.' This cost 'study case' represents historical oil spill events with the following characteristics:

- Facility spill location: Based on the "open water/shore" location category (from Table 4, p.11 of the study); other oil spill locations not included in the cost estimates for the historical spill events selected as a 'study case' are (a) soil/sand, (b) pavement/rock, (c) wetland, (d) mudflat, (e) grassland, (f) forest, (g) taiga, (h) tundra
- Cleanup method: Cleanup costs involved mechanical removal of land and surface water contamination at industrial facilities not including vessel spills (from Table 6, page 12 of the study); other cleanup methods not represented in the cleanup cost estimates for the historical spill events are (a) dispersants, and (b) in situ burning.
- Ecological sensitivity: Surrounding ecological habitat and wildlife sensitivity categories for determining associated ecological damages are based on "river/stream" facility oil spill locations (from Table 8, p.13 of the study); other ecological sensitivity categories not represented in the ecological damage estimates for the historical spill events selected as a 'study case' are (a) urban/industrial, (b) roadside/suburb, (c) wetland, (d) agricultural, (e) dry grassland, (f) lake/pond, (g) estuary, (h) forest, (i) taiga, (j) tundra.
- Freshwater vulnerability: Non-specific freshwater vulnerability category (i.e., cost estimates for the historical spill events represent, in aggregate, average freshwater vulnerability spill locations across the five vulnerability categories of (a) wildlife use, (b) drinking water use, (c) recreation use, (d) industrial use, and (e) tributaries to drinking and recreation use; from Table 7, p.13 of the study).

These characteristics are relevant to transfer of the 'study case' cost results to the CCR impoundment failure 'policy case' because the 'study case' largely comports with the location characteristics of coal-fired electric utility plants, which are mostly located near surface waters according to the US Geological Survey.[31]

The "point estimate" transfer approach may be applied to the oil spill cleanup cost study. Based on that study, the ratio of ecological damage (as numerator) compared to cleanup cost (as denominator) for the fraction of the analysis pertaining to industrial facility spills involving inland navigable waters, based on the 41,068 historical facility oil spill events involving 500 gallons or more, spanning the years 1982-2002 (from Table 5, p.14 of the analysis) are:

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[31] Source: US Geological Survey (USGS) webpage titled "Thermoelectric Power Water Use" at http://ga.water.usgs.gov/edu/wupt.html which indicates that production of electrical power results in one of the largest uses of water because water for thermoelectric power is used in generating electricity with steam-driven turbine generators. On this website the USGS reports that in 2000, 195,000 million gallons of water per-day were used to produce electricity (excluding hydroelectric power), and that surface water was the source for more than 99% of total thermoelectric-power withdrawals.

($13.811 billion cumulative ecological damages from spills) / ($8.681 billion cumulative cleanup costs for spills) = 1.591 (i.e., **159%**)

Based on this cost factor, this RIA estimates this cost element is 159% of the TVA cleanup cost, as follows:

($933 million to $1.2 billion) x 159% = $1.48 billion to $1.91 billion (midpoint = **$1.70 billion**).

- **Alternative Approach for Cost Element #3:**

In addition to the oil spill cost study, an alternative estimate of ecological damages may be made based on a benefits transfer using a different damage scenario. This alternative estimate is based on an assessment of the ecological and human use service losses resulting from the contamination of sediments in Lower Watts Bar Reservoir from the Department of Energy's (DOE) Oak Ridge Reservation.

In DOE's August 1994 Remedial Investigation/Feasibility Study Report[32], DOE estimated the costs of removing the contaminated sediments at $38 billion. By comparison, TVA's estimated cost of Kingston cleanup is $933 million to $1.2 billion (which includes, in addition to actual removal costs, payments to other agencies, payments of $43 million to the local community for economic development impacts, and the cost of purchasing affected properties). A recently completed natural resource damage assessment (NRDA)[33] found the ecological and human use services provided by transfer of a conservation easement over 2,965.95 acres of forested upland, together with annual payments for management and operations having a present value of $730,000, was sufficient to compensate for the ecological and human use service losses caused by the Oak Ridge contamination. Assuming the cost of a conservation easement over such forested upland would be $10,000 per acre, which may be a conservative estimate, the total ecological and human service cost of the Oak Ridge contamination would be about $30 million.

TVA's high-end Kingston estimate of $1.2 billion is three percent of the estimated $38 billion costs of removing the DOE-contaminated sediments. Applying this adjustment factor to the Kingston cleanup cost estimate yields $900,000 (3% of $30 million). This would imply that the original cleanup estimate of $933 to $1.2 billion is very close to the social cost of the Kingston failure.

Due to the wide range of estimates presented in this appendix, EPA specifically requests comments on the best way to estimate the ecological damages associated with coal ash surface impoundment failures. For example, should EPA use the oil spill analysis as the primary estimate, or does the estimate based on the Oak Ridge contamination provide a better starting off point since it involves the same type of remedy (sediment removal) in the same reservoir. EPA also requests comment on other examples, analogies, or approaches that we should consider when estimating such damages in the final rule.

[32] Source: Department of Energy/Oak Ridge National Laboratory, "Remedial Investigation/Feasibility Study Report for Lower Watts Bar Reservoir Operable Unit," August 1994 (DOE/OR/01-1282&D1).
[33] Prepared by Industrial Economics, Inc. for the Watts Bar Reservoir Trustee Council (Department of Energy, Department of Interior, State of Tennessee, and TVA). Available at http://www.oakridge.doe.gov/External/LinkClick.aspx?fileticket=8aTfl--QCLk%3D&tabid=325&mid=1118

Cost Element #4: Socio-Economic Damage Cost

Depending upon the particular location of any given coal-fired electric utility plant and the associated CCR impoundment location(s) at or near each plant, socio-economic damages from CCR impoundment environmental releases may include one or more of the following damages and costs (listed in random order below not in order of cost magnitude). Based on the reference source of information, this particular list of potential socio-economic damages are relevant to industrial facilities (i.e., industrial spills and other types of environmental releases of industrial chemical materials) located near surface water resources (e.g., lakes, streams, rivers, estuaries):[34]

- Damages to and lost local and regional tourism (tourist visitation and tourist sales/services revenues)
- Damages to and lost commercial fishing
- Damages to and lost-use of recreational facilities and parks
- Damages to and lost use of boat and water sports marinas
- Damages to and lost use of private property
- Waterway and port closures

The same oil spill cost study referenced for derivation of Cost Element #3 above, provides an estimate of socio-economic damages associated with oil spills. Socio-economic damages are defined in a companion report[35] to the study as including impacts to local and regional tourism, commercial fishing, lost-use of recreational facilities and parks, marinas, private property, and waterway closure. Socio-economic damages in the study do not include human health effects. Adjusting the socio-economic cost estimate (also displayed in Table 5, p.14 of the study) by a multiplier of 0.429 (i.e., 0.3/0.7) -- which assumes that the physical location of coal-fired electric utility plants are "predominated by areas with small amount of

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[34] Source: Page 2 of "Modeling Oil Spill Response and Damage Costs," presentation at the 6-8 April 2004 EPA Freshwater Spills Symposium by Dagmar Schmidt Etkin, Environmental Research Consulting, Cortlandt Manor, NY at: http://www.epa.gov/emergencies/docs/oil/fss/fss04/etkin2_04.pdf. These types of socio-economic damages are included in the EPA "Basic Oil Spill Cost Estimation Model" (BOSCEM). The Etkin reference document derived this list of example socio-economic damages from historical case studies of damage settlements and costs, as well as methods employed in the following five studies:

- Pulsipher, Tootle, and Pincomb "Economic and Social Consequences of the Oil Spill in Lake Barre, Louisiana, Louisiana State University Center for Energy Studies, Louisiana Applied and Educational Oil Spill Research and Development Program/Minerals Management, Technical Report Series 98-009, 27 pp.
- Dunford, R.W. and M.L. Freeman "A Statistical Model for Estimating Natural Resource Damages from Oil Spills" in the Proceedings of the 2001 International Oil Spill Conference: pp. 225-229, 2001
- US Army Corps of Engineers "Civil Works Construction Cost Index System" document nr. EM 1110-2-1304, Washington, DC, 2000.
- US Army Corps of Engineers "Economic Guidance Memorandum 01-01: Unit Day Values for REC, Fiscal Year 2001"Washington, DC. November 2001. 10 pp.
- US Army Corps of Engineers "Planning Guidance Document. Appendix D: Economic and Social Considerations" document nr. ER 1105-2-100, Washington, DC. 22 April 2000. 43 pp.

[35] Source: Page 2 of "Modeling Oil Spill Response and Damage Costs" by Dagmar Schmidt Etkin, Environmental Research Consulting (presentation at the 6-9 April 2004 EPA Freshwater Spills Symposium), available at http://www.environmental-research.com/erc_reports/ERC_report_10.pdf

socioeconomic value that may potentially experience short-term impact" if a spill occurs (cost modifier value = 0.3) rather than predominated by areas with medium value (cost modifier value = 0.7) as applied in the 2004 cost study[36] – and comparing it to spill cleanup cost implies a ratio of:

> ($4.854 billion cumulative socio-economic damages from spills) x (0.3/0.7 cost modifier ratio for power plant locations) / ($8.681 billion cumulative cleanup costs for spills) = 0.240 (i.e., **24%**)

Based on this factor, this RIA Appendix estimates this cost element is 24% of the TVA cleanup cost, as follow:

> ($933 million to $1.2 billion) x 24% = $224 million to $288 million (midpoint = **$256 million**).

Summary of All Four Cost Elements

The Exhibit below provides a summary and addition of all four cost elements documented above in this Appendix. These four cost elements, three of which are separately estimated above, sum to $3 billion.

Summary of the Four Cost Elements
of EPA's $3 Billion Social Cost Estimate
Assigned in this RIA to the TVA-Kingston 2008 CCR Impoundment Failure Event

Cost Element	Cost Element Description	Estimated Cost	
		Range	Range midpoint
#1	TVA cleanup costs	$933 million to $1.2 billion	$1.077 billion
#2	Response, oversight, and ancillary costs to local/state/other Federal agencies	Not separately estimated; assumed included in #4	Not separately estimated
#3	Ecological (natural resource) damages	$1.48 billion to $1.91 billion	$1.70 billion
#4	Socio-economic damages	$224 million to $288 million	$256 million
	Column totals =	$2.6 billion to $3.4 billion	**$3.0 billion**

[36] The "cost modifier values" of 0.3 and 0.7, respectively, are defined in Table 5, p.12 of "Modeling Oil Spill Response and Damage Costs" by Dagmar Schmidt Etkin, Environmental Research Consulting (presentation at the 6-9 April 2004 EPA Freshwater Spills Symposium), available at http://www.environmental-research.com/erc_reports/ERC_report_10.pdf