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Cost Analysis of Proposed National Regulation of Coal Combustion Residuals from the Electric Generating Industry

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Final Report, November 2010

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NOTE

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ABSTRACT

This analysis quantifies the potential cost to the coal-fired electric generation industry from EPA's proposed rule on the disposal of coal combustion residuals. It includes an assessment of the incremental compliance costs of the Subtitle C proposed regulatory option. Costs for this analysis were developed at the individual generating unit and plant level and aggregated to develop a national industry cost estimate.[1] The analytical model used to estimate the costs utilizes a Monte Carlo framework to account for parameter uncertainty in input cost components and uncertainty in disposal decision by individual coal-fired plants. The total incremental cost to the industry over a 20-year period for the proposed Subtitle C option is estimated between $54.66 billion and $76.84 billion present value (at a discount rate of seven percent). This estimate represents only the incremental cost due to Subtitle C regulation over baseline costs and does not include disposal site construction and operation costs.

Keywords
Coal combustion residuals
Disposal regulation
Compliance cost
Subtitle C

[1] [1] This analysis includes 377 plants. Plants with a generating capacity less than 100 MW were not included.

ACRONYMS USED IN THIS REPORT

ACAA	American Coal Ash Association
CCP	coal combustion product
CCR	coal combustion residual
CWA	Clean Water Act
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization
GAO	Government Accountability Office
GW	gigawatt
GWh	gigawatt-hour
LDR	land disposal restrictions
MW	megawatt
MWh	megawatt hour
NAICS	North American Industry Classification System
NPDES	National Pollutant Discharge Elimination System
NPV	net present value
O&M	operations and maintenance
OMB	Office of Management and Budget
OSHA	Occupational Safety and Health Administration
RCRA	Resource Conservation and Recovery Act
RIA	regulatory impact analysis
TVA	Tennessee Valley Authority
USWAG	Utility Solid Waste Activities Group

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1
INTRODUCTION

On June 21, 2010 the United States Environmental Protection Agency (EPA) published a proposed rule for the disposal of coal combustion residuals (CCRs) generated by electric utilities (75 *Fed. Reg*. 35127–35264). EPA co-proposed two regulatory options: listing CCRs destined for disposal as a special listed waste under Subtitle C of the Resource Conservation and Recovery Act (RCRA), or regulating CCRs under Subtitle D of RCRA by issuing national criteria for the disposal of CCRs. Both regulatory approaches require the phase out of surface impoundments that do not meet minimum design and performance standards. EPA also proposed a D Prime option, which would allow continued use of surface impoundments until the end of their useful life. These regulatory requirements, particularly under Subtitle C, will necessitate technological changes at the generating unit and plant level related to CCR handling, management and disposal. Due to the abundance of coal-fired generation in the United States, the proposed rule could have significant financial impacts on the electricity generation sector overall.

This analysis quantifies the potential financial (cost) impacts on the electric utility industry. It includes an incremental cost assessment for the Subtitle C proposed regulatory option. The analysis quantifies the incremental cost for the additional compliance requirements under the Subtitle C option, compared to the baseline, or current operations. Costs for this analysis were developed at the individual generating unit and plant level, and aggregated to develop the national industry cost estimate. Because the requirements for any individual power plant or generating unit would be a function of the current technical systems and operating practices, costs will vary across units and plants. Thus, this analysis draws on site-specific data obtained through utility interviews and survey responses to assess compliance costs as accurately as possible.

Further, this study attempts to quantify several costs that have been previously difficult to estimate, including the "upstream" costs associated with collection, handling, and storage of CCRs from the point of generation to disposal. In the proposal, EPA specifically requested supporting data on these upstream costs (75 *Fed. Reg*. 35159). These costs pertain only to the Subtitle C option, which would regulate CCRs from the point of generation to final disposition (i.e., cradle to grave).

Regulatory Background

The EPA has previously considered regulating CCRs under Subtitle C of RCRA on multiple occasions. In 1978, EPA published the first set of hazardous waste standards which exempted wastes from the combustion of fossil fuels from Subtitle C regulations until further study could be completed. In 1988, EPA submitted the report *Wastes from the Combustion of Coal by*

Electric Utility Power Plants to Congress, with the determination that the large-volume wastes did not warrant regulation under Subtitle C. In August 1993, the EPA issued a tentative determination stating that large volume coal combustion wastes produced at electric utility and independent power-producing facilities did not warrant regulation as hazardous material when managed alone. Regulation of such wastes under Subtitle C of the RCRA was deemed inappropriate "because of the limited risks posed by them and the existence of generally adequate State and Federal regulatory programs" (58 *Fed. Reg*. 42466). In March 1999, the EPA issued a second Report to Congress on the remaining wastes subject to RCRA Sections 3001(b) and 8002(n). The EPA tentatively concluded that disposal of such wastes should remain exempt from Subtitle C of the RCRA, but did not make a recommendation regarding minefill use of CCRs. Then on May 22, 2000, the EPA issued a regulatory determination concluding that the remaining wastes "do not warrant regulation under Subtitle C of the RCRA" (Elcock and Ranek 2006; EPA 2000a, 2009a).

On December 22, 2008, a breach in an ash surface impoundment caused a large coal ash spill at a Tennessee Valley Authority facility in Kingston, Tennessee. Following the Kingston spill, the EPA sent letters in March, April, and December 2009 to plant owners with surface impoundments or similar impoundments containing coal-combustion products. The Information Requests solicited information about the number of impoundments, types of waste stored, and structural integrity of those impoundments. EPA published a proposed rule on June 21, 2010, which contained two regulatory options: regulation of CCRs under either Subtitle C or Subtitle D of RCRA. EPA has requested comments and data pertaining to both regulatory options.

Proposed Subtitle C Regulatory Option

Under the Subtitle C proposal, EPA would list CCRs destined for disposal under a new waste category as a "special waste" under RCRA. The Subtitle C proposal would reverse the Bevill exemption for CCRs destined for disposal, but retain the exemption for CCRs that are beneficially used. Coal combustion products destined for disposal "would be regulated from the point of their generation to the point of their final disposition, including during and after closure of any disposal unit" (75 *Fed. Reg*. 35133). The requirements of RCRA Subtitle C include disposal unit siting requirements, design requirements for liners, groundwater monitoring, and dust control; financial assurance, facility-wide corrective action, unit closure and post-closure care; generator permits, monitoring and reporting; as well as secondary containment for tanks and structural requirements for storage buildings. All impoundments that do not meet the minimum technology criteria would need to cease receiving CCRs within five years of the state implementation of the rules, and close within seven years. The "combined requirements under subtitle C would effectively phase-out all wet handling of CCRs and prohibit the disposal of CCRs in surface impoundments" (75 *Fed. Reg*. 35157).

Proposed Subtitle D Regulatory Option

Under the Subtitle D proposal, EPA would establish national criteria for impoundments and landfills including location standards, liner requirements, stability criteria, groundwater monitoring, closure and post-closure requirements. Existing impoundments that do not meet the minimum technology and siting requirements would be required to cease receiving CCRs within five years and close within seven years. Landfills in unstable areas would be required to demonstrate the structural integrity of the disposal unit. Under the Subtitle D option, coal-fired stations could continue to use impoundments for CCR disposal and storage as long as the impoundment met minimum technology and siting criteria. The economic analysis presented in this report did not quantify the incremental costs of the Subtitle D (or D Prime) options.

Overview of Cost Analysis

This report presents the methodology and data sources used to estimate the costs to the electric utility industry under the co-proposed regulatory options. Since compliance costs such as conversion to dry handling include large capital expenditures, the study horizon should extend well into the future to capture the expected lifetime of newly constructed disposal facilities and capitalized equipment. The 20-year timeframe employed in this study is consistent with industry-developed cost estimates and capital cost recovery for conversion to dry handling and landfill construction. Further, this time frame reflects the vintage of the coal-fired generation fleet, with a mean age of 42 years. In analyzing the costs to industry, a relevant parameter is the expected lifetime of the generating units. This analysis includes plants in the electric generating industry that burn coal as a primary or secondary fuel source and are over 100 megawatts (MW) in size. This is further discussed in Section 2, Characterization of Regulated Units and Compliance Costs.

The cost estimates provided are discounted at seven percent, consistent with guidance from the Office of Management and Budget (OMB) Circular A-4, which recommends seven percent discounting for regulatory impact analyses. However, the implications of alternate discount rates are discussed in Section 4.

The analysis assumes 2012 final rule promulgation, with a five-year impoundment phase out. Under Subtitle C, states are expected to adopt the rules within 2 years, so an impoundment phase out date of 2019 is used. The analysis further assumes that capital expenditures on wet-to-dry conversion, wastewater treatment systems, and engineering upgrades would need to commence prior to the date when impoundments must stop receiving CCRs, to allow plants time to complete the retrofits.

The analytical model used to develop the cost to industry utilizes a Monte Carlo statistical model to account for parameter uncertainty in input cost components, and uncertainty in disposal decision by individual coal-fired plants. Generating unit- and plant-specific compliance costs and disposal costs are calculated for each of the regulated facilities. Cost assignments are based on unit and plant characteristics and configurations, ascertained from publicly available data supplemented with plant-specific data derived from utility surveys. The plant compliance estimates are then aggregated to develop the total cost to the industry. Compliance costs for individual units or plants are not presented. This analysis quantifies the incremental costs associated with Subtitle C regulation; that is the costs attributable to regulation which are incremental to the baseline cost. Due to the permitting, reporting, handling, storage, and disposal requirements for RCRA listed wastes, the costs incurred under Subtitle C are expected to be substantially different than the costs incurred under the Subtitle D option.

Summary of Results: Cost to Industry of Proposed Rule

Table 1-1 summarizes the *incremental* costs of the proposed rule under the proposed Subtitle C regulatory option and the cost impacts of alternative beneficial use scenarios. The costs presented for the Subtitle C option are the incremental cost of the regulation (i.e. increased cost over baseline cost). The ranges in Table 1-1 represent the 90 percent confidence interval of the cost model results, which reflect uncertainty in cost estimates and in compliance decisions at the plant level. Table 1-1 also presents the costs for alternative scenarios in which the proposed rule has an induced effect on beneficial use. The effect on beneficial use was incorporated as a change in the amount of CCRs that must be disposed. This analysis did not quantify and include the incremental change in revenues from beneficial use under the alternate scenarios.

As Table 1-1 indicates, the results of the cost analysis show that the costs to the electric generation industry could range from $55.31 billion to $74.53 billion under the Subtitle C option. The costs for the Subtitle C option are significantly higher than EPA's estimate of $20.35 billion. This is due to the inclusion of "upstream" costs such as wastewater treatment upgrades, in-plant engineering upgrades (i.e. tanks and secondary containment), and additional maintenance staff. In addition, this cost study analyzed the implications of Subtitle C siting requirements on disposal costs, and the probability for increased off-site and commercial disposal.

Table 1-1
Comparison of Incremental Subtitle C Costs under Alternative Beneficial Use Scenarios
($Billions present value at 7% discount rate and 20-year study horizon)

Scenario	Subtitle C Option*
Scenario #1: Encapsulated Use Rate Unchanged	$55.31 – $74.53
Scenario #2: Encapsulated Use Decreases 18%	$56.45 – $76.84
Scenario #3: Encapsulated Use Increases 11%	$54.66 – $73.20

*Incremental costs over baseline. These do not include costs for landfill construction and operation costs, with the exception of specific upgrades required under Subtitle C

Report Overview

The remainder of this report is organized as follows. Section 2 provides a description of the data sources used to compile the database of regulated coal-fired generating units, characterization of the regulated facilities, and the potential compliance costs. This section includes a discussion of the data collected from an EPRI survey of the potentially regulated facilities. Section 3 presents an overview of methodology used to assess the costs of the proposed rule. Section 3 details the methods for incorporating uncertainty in compliance costs and disposal choice, how site-specific information is utilized, and assumptions that are made in the absence of site-specific data. Section 4 presents the results of the cost model and the discussion of alternative beneficial use scenarios and discounting rates. A discussion of the implications for defining "point of generation" is also provided.

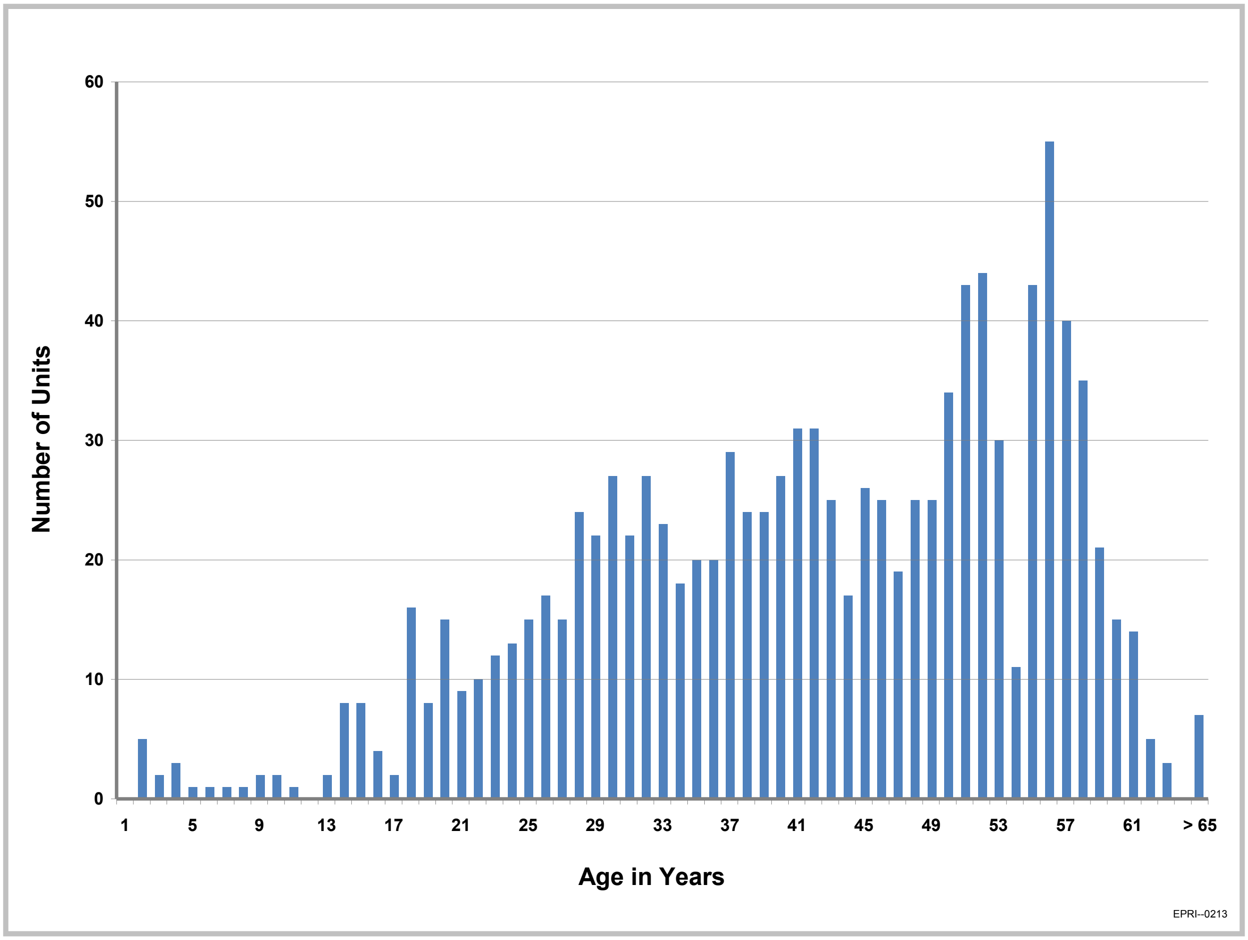
Appendix A contains summary tables of the input engineering cost estimates for Subtitle C regulation used in the analysis.

2
CHARACTERIZATION OF REGULATED UNITS AND COMPLIANCE COSTS

To estimate the national costs of the proposed CCR regulatory options, a variety of publicly available and site-specific information was collected to develop a generating-unit level database that contained data on the relevant characteristics that would impact compliance costs. The universe of regulated facilities was identified by paralleling EPA's assumptions. Cost assignments were made based on information from national databases supplemented with plant-specific information provided by electric utilities. This section details the methodology for developing the regulated unit database, and the potential compliance costs that coal-fired generating units would incur under the Subtitle C proposal.

The proposed CCR rule would potentially affect a significant percentage of the electric generating industry. Coal-fired electric generation accounted for 1,764,486 (GWh) of the 3,953,111 GWh produced in the U.S. in 2009—or 44.6 percent of all electricity generated (Energy Information Administration [EIA] 2009). Figure 2-1 shows the age of the coal-fired generating units. As can be seen in Figure 2-1, the coal-fired fleet contains a large number of generating units over 40 years old (mean age 42 years). Thus, in selecting a study horizon for this analysis, a 20-year horizon was deemed appropriate to capture the costs over the expected operating lifetime of the majority of the units.

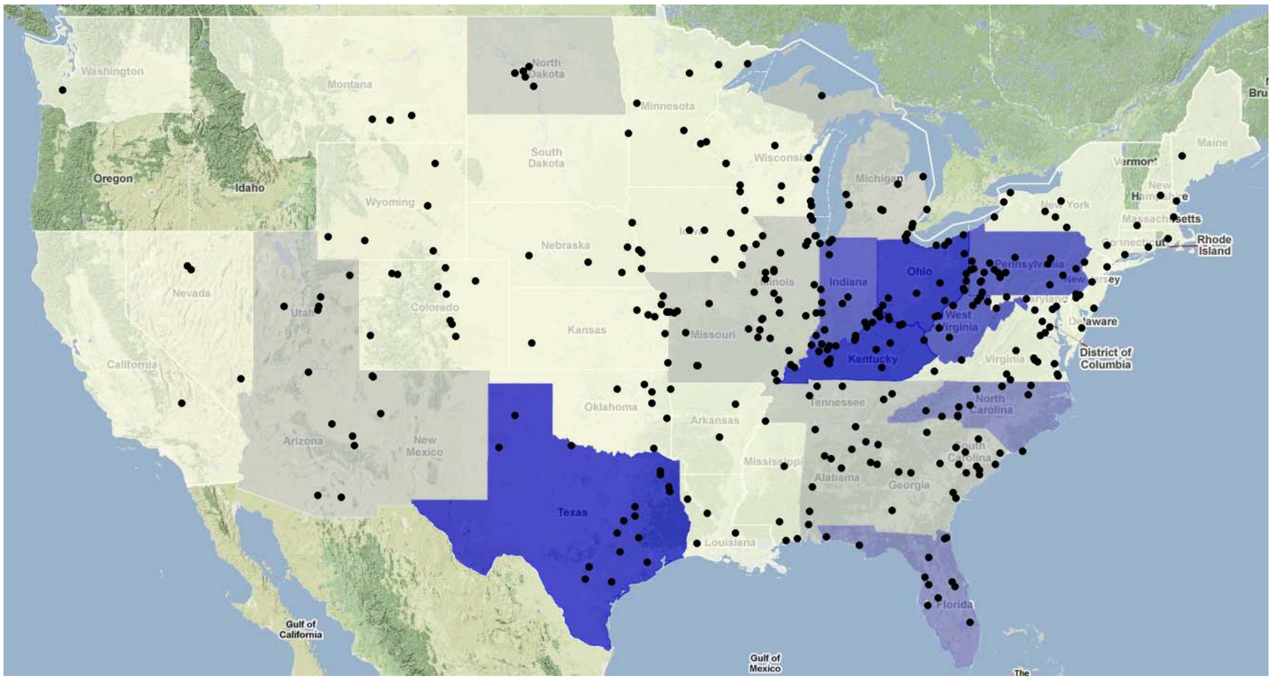
The amount of CCRs generated annually by a unit is a function of the efficiency (reflected as the heat rate) of the unit, the type and ash content of the coal(s) burned, and the amount the unit runs, or its annual generation. Figure 2-2 shows the location of the coal-fired plants and the amount of total CCRs (fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) byproducts) generated annually by state. As Figure 2-2 shows, coal-fired generating units are distributed across the U.S., but are concentrated in some geographic regions. Texas, Indiana, Ohio and Pennsylvania are among the states with the highest generated volume of CCRs. Over 95 percent of the electricity produced in Indiana is from coal-fired generators (EIA Electric Power Monthly, March 2009). The proposed CCR regulations would increase the costs of electricity production at coal-fired generating units due to increased capital, operation and maintenance, and disposal costs.



Source: EIA Form 860 (2008).

Figure 2-1
Age of Coal-Fired Units Included in This Analysis

Legend: CCR Produced (1,000 tons)	Color
0 to 1,999	Cream
2,000 to 3,999	Light gray
4,000 to 5,999	Light purple
6,000 to 7,999	Not applicable
8,000 to 10,999	Medium purple
11,000 to 12,999	Dark purple



Source: EIA Form 860/923 (2008).

Figure 2-2
Geographic Distribution of Coal-Fired Electric Generating Plants and Annual Production of CCRs by State

Public Data Sources

The following public data sources were used for constructing the generating unit database and for obtaining compliance cost information:

1. EIA Form 860—Annual Electric Generator Report: EIA 860 is a generating unit-level data file that includes specific information about generators at electric power plants owned and operated by electric utilities and non-utilities. The file contains generator-specific information such as date of operation, prime movers, generating capacity, energy sources, operating status, county and state location, and ownership. Form EIA-860 also includes data on boiler air emission standards, design parameters and emission controls, cooling system design parameters, flue gas particulate collector information, flue gas desulfurization (FGD) unit design parameters, and stack and flue design parameters. Data for the year 2008 were used to construct the generating unit dataset.

2. EIA Form 923—Power Plant Operations Report: This new form (starting 2008) combines EIA Form 906 (Power Plant Report), EIA Form 920 (Combined Heat and Power Plant Report), EIA Form 423 (Monthly Cost and Quality of Fuels for Electric Plants), FERC Form 423 (Monthly Report of Cost and Quality of Fuels for Electric Plants) and EIA Form 767 (Steam-Electric Plant Operation and Design Report). The report contains data on plant-level operations and equipment design, including boilers, generators, cooling systems, flue gas desulfurization systems, flue gas particulate collectors, and stacks. The Form 767 also contains data on end disposition of fly ash, bottom ash, FGD gypsum, and other FGD byproducts by disposal (landfill, pond, or offsite), use (onsite, offsite), storage (onsite, offsite), or sold. Facilities are required to report only end disposition and not the CCR collection or handling methods.
3. *Engineering and Cost Assessment of Hazardous Waste Designation of Coal Combustion Residuals: Technical Update 1020557* (EPRI, 2010). This EPRI report details the engineering cost estimates EPRI developed for the changes that would be required at coal-fired plants in order to comply with the Subtitle C proposal. The report provides estimates of the incremental operational and capital costs of Subtitle C requirements above and beyond current practice and beyond the requirements under Subtitle D in the proposed rules. These engineering cost estimates were used as input in this analysis, and were applied to individual generating units and plants depending on their relevant characteristics and configuration.
4. *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal-Fired Electric Utilities* (USWAG 2010). This report provided by USWAG gives cost estimates for conversion to dry fly ash handling, dry bottom ash handling, and FGD dewatering. The wastewater treatment and total cost estimates for each of the regulatory options were not used in this analysis.
5. American Coal Ash Association (ACAA) 2008 Coal Combustion Product (CCP) Production and Use Survey Report (ACAA 2009): ACAA compiles statistics on production and beneficial use of CCPs by type, use category, and application. This information was used to calculate the percentage of encapsulated usage of fly ash, bottom ash, and gypsum for beneficial use markets.
6. EPA Coal Ash Survey Results (EPA 2009b): The responses to EPA's March and April 2009 Information Request Letters include a table compilation of survey results, covering 629 surface impoundments, as well as individual generator written responses. The reported age and size of the impoundments were used to develop the stranded costs associated with early pond closure under the proposed rule.
7. PC*MILER (ALK Technologies Inc. 2010): ALK Technologies' PC*MILER is the transportation industry's leading software for mapping, routing, and mileage calculations, and is used by the Department of Defense and the General Services Administration because of its reliability and accuracy. PC*MILER is used to calculate distances from each plant to the nearest commercial Subtitle C landfill. It was also used to confirm distances between plants and regional generator landfills.

In addition to the data sources above, other supplemental data were obtained from literature and publicly available reports. This includes EPA, DOE, U.S. Army Corps of Engineers, and state data on hazardous waste transportation costs, commercial hazardous waste landfill locations and tipping fees. These sources are provided in the reference section of this report.

EPRI CCR Survey

An important component of this analysis was the use of non-public information gained from an EPRI survey on CCR handling, management and disposal practices sent to companies that own coal-fired generating units. The goal of the survey was obtain site-specific information about plant configuration and CCR disposal practices, as this information would be used to improve the accuracy of the cost assignments. Survey questions requested information on the temporary storage of CCRs, wastewater treatment systems, the number of units with wet/dry bottom ash and fly ash handling, and restrictions on siting Subtitle C landfill capacity. Table 2-1 provides an overview of the survey questions.

Survey respondents were asked to indicate whether they would choose on-site disposal, disposal at a company-owned off-site landfill, or commercial landfill disposal under a Subtitle C rule. This is an important compliance decision, as the costs to dispose of CCRs at an on-site landfill will differ significantly from disposal costs if a plant was forced to transport CCRs to another landfill for disposal. In conversations with utilities, and from survey data, several companies indicated that landfill siting restrictions under Subtitle C could preclude them from disposing of CCRs in on-site landfills. In such cases, these plants would have to dispose of CCRs in an off-site or commercial landfill. “Off-site” disposal could be either a company-owned regional landfill that serves multiple plants or a nearby plant that has available landfill capacity. In this respect, off-site disposal is differentiated from disposal in a commercial hazardous waste landfill that would require a tipping fee.

Table 2-1
Overview of EPRI CCR Survey Questions

CCR Handling	CCR Disposal	Plant Facilities
• Number of units with wet (dry) bottom ash handling • Number of units with wet (dry) fly ash handling • Wet FGD solids separation • Temporary storage of CCRs (buildings, sheds, stacker pads)	• Current disposal in on-site ponds and landfills • Current use of commercial landfills • Land availability for additional landfill capacity • Subtitle C landfill siting restrictions (seismic, fault, floodplain, wetlands, state-level restrictions • Disposal choice under Subtitle C (on-site, off-site company owned or commercial)	• Wastewater treatment for FGD blowdown/purge • Wastewater treatment for CCR contact water • Buildings and enclosures for ESPs/baghouses and FGD dewatering equipment • CCR solids conveyance to storage

A total of 39 companies provided survey data. These survey responses covered 561 coal-fired units at 225 plants. This represents site-specific data for 60.3 percent of the coal-fired generating capacity in the United States subject to proposed CCR rule, and 60.2 percent of the annual net coal-fired generation. Respondents included large utilities with many coal-fired plants, as well as smaller, municipal-owned facilities. The survey data constitute a statistically representative sample of the coal-fired generating fleet.

Data gathered from surveys was used to update the generating unit database with site-specific information. The site-specific data allowed for accurate assignment of compliance costs at the generating units and plants covered by the interviews. Further, survey data was used to develop the cost assignment logic for non-surveyed plants. Cost component assignments were allocated across all units and plants based on logic developed from the surveys. Further, the survey data was used to quantify uncertainty in disposal decision for non-surveyed plants. Because a disposal decision is dependent on a number of site-specific characteristics including land availability and siting restrictions, a multinomial regression was used to calculate Subtitle C disposal choice probabilities for non-surveyed plants. This process is detailed in Section 3.

Characterization of Regulated Facilities

In the Regulatory Impact Analysis (RIA) of the proposed rule, EPA has identified generating units that would be regulated as those in the electric utility industry that burn coal as their primary or secondary fuel source. EPA identified regulated plants as those with a North American Industry Classification System (NAICS) code of 22 as reported in EIA data. EIA classifies power plants into energy-use sectors. Plants with a NAICS code of 22 are assigned to the Electric Power Sector. This analysis utilized EIA Form 860 for the year 2008 as the primary information source to generate the regulated unit database. EIA 860 includes information on electric generating units, their status, fuel sources, capacity, and annual generation, as well as NAICS code.

This analysis first identified units at plants with an EIA NAICS designation of 22, and that burn anthracite, bituminous, subbituminous, lignite, synthetic or waste coal as a primary or secondary fuel source. The second step was to only include units with a status of “operating” or “standby.” This excluded retired and out-of-service units. In addition, any units or plants that had recently (2009-2010) announced retirements or repowering (which would not be reflected in EIA data) were also excluded (M.J. Bradley & Associates, 2010). These data filters resulted in 1104 regulated coal-fired units at 472 plants.

The next data filter was to identify plants with CCR disposition data in EIA Form 923 for 2008. Only plants with an installed capacity greater than 100 MW are required to submit data on Form 923. This results in 377 plants (947 units) that have 923 disposition data. Because smaller plants without disposition data (95 in total) would represent a small percentage of the total CCRs generated, and because of the lack of available data on their CCR handling and disposal practices, they were excluded from this cost analysis. Thus, the total costs to the industry could be higher than reported, if these smaller plants continue to burn coal and incur compliance costs associated with the rule. Of the 377 plants in the database, site-specific survey data was collected for 59.7 percent (225 of the 377 plants).

Components of Compliance Costs

The Subtitle C option of the proposed rule would effectively phase out the use of surface impoundments for the disposal or storage of CCRs. Under Subtitle C, facilities would have to convert to dry handling of CCRs, with disposal in landfills. Units that currently manage CCRs wet would incur capital costs to convert to dry handling systems. At many coal-fired plants, surface impoundments serve a primary role in wastewater handling and treatment before discharge in accordance with effluent limitations specified in National Pollutant Discharge Elimination System (NPDES) permits. This analysis assumes that the Subtitle C proposal effectively eliminates surface impoundments even for these purposes. To replace the wastewater treatment function that impoundments currently serve, facilities would require additional tank-based wastewater treatment systems. The wastewater treatment systems would treat CCR contact water and other low volume plant wastewaters before discharge. Even many facilities that currently manage CCRs dry continue to use settling or clarifying ponds for these low volume CCR contact wastewater streams, and would require partial wastewater treatment upgrades.

In addition to wet-to-dry conversion and associated wastewater treatment, many plants would require engineering modifications to their mechanical systems to comply with Subtitle C requirements for secondary containment, tank and building structural integrity, and materials handling (i.e. accumulation, storage, and spill prevention). Subtitle C regulation would present coal-fired facilities with additional administrative costs including permit applications, reporting, waste analysis, groundwater monitoring, personnel training, and RCRA facility investigations. Many of these administrative cost components include an initial cost followed by recurring annual costs. Estimates of these engineering and RCRA administrative costs are provided in the EPRI report *Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act* (EPRI 2010).

Disposal costs will be a major component of a generating unit's total compliance costs, and are highly site-specific due to a number of factors including amount of CCRs produced annually, whether the facility currently has landfill and its remaining capacity, the possibility of siting additional disposal capacity on-site, and the proximity to other disposal facilities (whether company-owned or commercial landfills). The estimation of disposal costs is discussed in detail in Section 3.

Thus, Subtitle C compliance costs for an individual coal-fired generating station would be dependent on the plant's current mechanical systems, and would be a function of:

- Current CCR handling and disposal practices—wet versus dry handling, disposal in ponds or landfill
- Annual generation, boiler heat rate, and type of coal burned (annual ash production)
- Installed flue gas desulfurization (FGD) technologies—type of FGD system if any and byproducts produced (gypsum or sulfite), dewatering equipment (wet FGD systems), and FGD effluent treatment technologies
- Current wastewater treatment technology—use of tank-based systems and/or ponds
- Site-specific restrictions for siting new land disposal units, including land availability, seismic restrictions, fault line restrictions, karst zone restrictions, floodplain or watershed restrictions, or state restrictions
- Proximity to commercial hazardous waste landfills.

Figure 2-3 presents a graphical representation of the cost components that were included in this analysis. These costs include capital, one-time initial costs, and annual O&M costs. A listing of the costs included and excluded in the study is provided in Table 2-2. Each of the components is an incremental cost that would be incurred as a result of the regulation (i.e. increase in costs relative to baseline costs). There are several real costs that would be incurred by companies which were not included in this analysis. This includes land acquisition costs, because quantifying that cost would require data on available on-site acreage as well as nearby acreage and the corresponding price per acre. Further, this analysis did not include the cost of new landfill construction. The assumption was made that all utilities would eventually have to build new disposal capacity even in the baseline scenario (i.e. without the rule). This assumption is further discussed below in the subsection on disposal costs. Therefore, the actual compliance costs for any individual plant or company would include these excluded costs, and would therefore affect the electricity production costs and profitability of that generating station. Section 3 provides a discussion of the methodology used to assign costs to the individual generating unit and plant, and aggregating those costs to develop a national industry estimate.

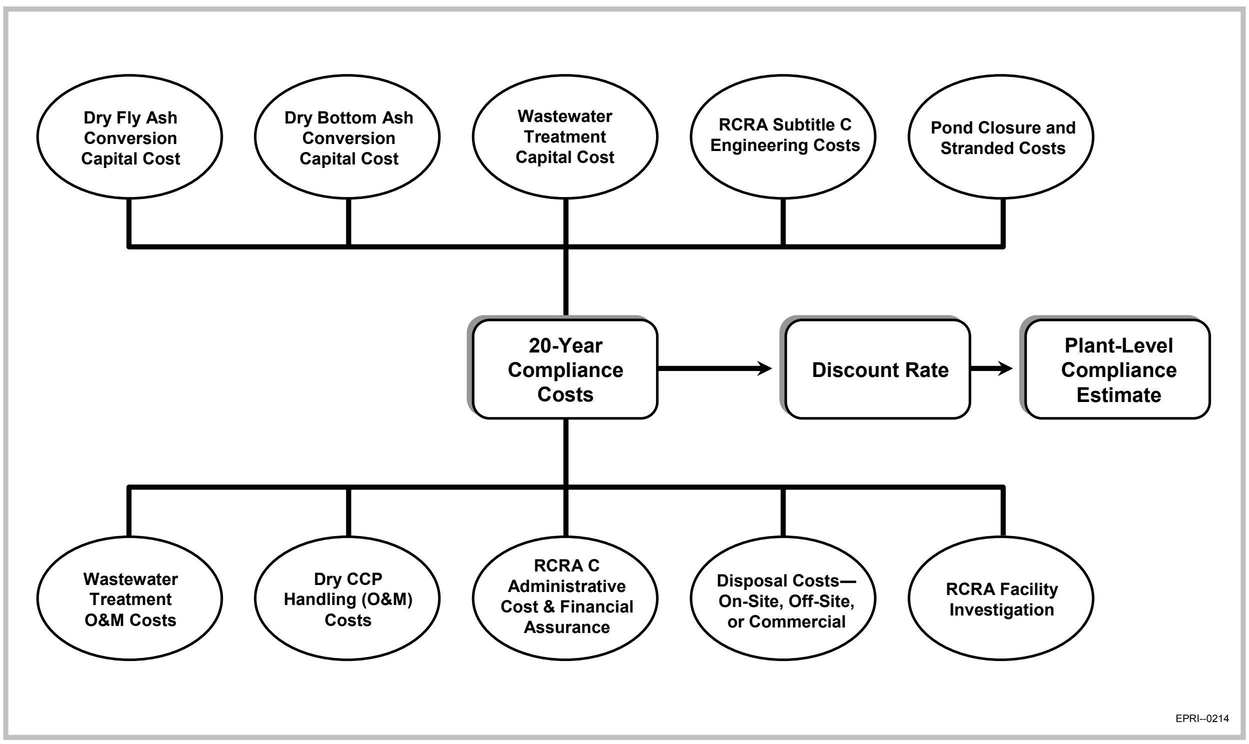


Figure 2-3
Calculation of Generating Unit Compliance Costs for Subtitle C Regulation

Table 2-2
Compliance Costs Included and Excluded in Analysis

Included Capital Costs	Included O&M Costs	Excluded Costs
• Conversion to dry fly ash and bottom ash handling • FGD solids dewatering for all-ponded systems • Install tank-based wastewater treatment system (to replace impoundment function) • Facility engineering to meet Subtitle C requirements (e.g., secondary containment, truck loading facilities with dust control, CCR storage buildings) • RCRA Facility Investigation costs • Financial assurance costs for closure and post-closure • Financial assurance for third party liability coverage • Incremental impoundment closure costs under Subtitle C regulation • RCRA C closure of legacy impoundments • Stranded costs associated with early pond closure	• Incremental costs for dry CCR handling • O&M costs for wastewater treatment system • RCRA reporting • Personnel training • General waste analysis and plan • Groundwater monitoring and sampling • Increased O&M costs associated with Subtitle C regulation (e.g. spill prevention and response) • Off-site disposal costs—transportation costs and tipping fees for commercial disposal	• RCRA Remediation costs—extremely facility-specific and would be dependent on RCRA Facility Investigation findings • Land acquisition costs • Landfill construction costs • Cost of replacement power during outages or to compensate for early retirements • Changes in revenue due to impacts to beneficial use markets • State generator fees • Cost of capital • Additional compliance costs due to planned (future) FGD systems

Dry Conversion Costs

Industry-average costs for conversion to dry bottom ash management, dry fly ash management, and FGD dewatering have been developed by USWAG (2010). Conversion to dry bottom ash management could be accomplished by installing a submerged scraper chain to wet bottom boilers or by directing sluiced ash to dewatering tanks (hydrobins) and recirculating reclaimed water. USWAG provides a point estimate of $20 million per generating unit for conversion to dry bottom ash handling. A number of plants have recently converted to dry fly ash handling, and a range of costs along with a mean based on actual cost experience from several utilities was developed. Dry fly ash systems typically have pneumatic conveyance from the electrostatic precipitator (ESP) or baghouse to a storage silo. Costs for dry fly ash conversion range from $6 million to $56 million, with a mean of $23 million per generating unit.

Based on EIA data, only 18 plants currently manage their FGD wastes wet and dispose of their FGD effluent in ponds. These plants would incur the cost of constructing dewatering facilities (hydroclones or thickeners, belt filters, etc.) to separate FGD solids from the water effluent. This cost is estimated at $35 million per plant. Costs for managing CCRs dry (rather than wet sluicing) are incurred on a dollar per ton basis. USWAG estimates the incremental cost of dry handling (cost increase over wet handling) as $2 per ton. This cost is applied per plant and is a function of the annual CCRs produced each year. However, the cost is only applied to plants that currently manage their CCRs wet in impoundments. Plants that are currently dry do not incur these costs. Table 2-3 presents a summary of the capital cost inputs for dry conversion.

Table 2-3
Capital Cost Components for Conversion to Dry CCR Handling

Cost Component	Mean Capital Cost ($)	Applied Per:
Dry bottom ash conversion	20,000,000	Generating unit
Dry fly ash conversion	23,000,000	Generating unit
Dewatering of FGD solids	35,000,000	Plant

Wastewater Treatment

Surface impoundments are used as part of the overall wastewater treatment process at the majority of plants. Plants that currently use impoundments for disposal of FGD effluent (solids along with purge) typically do not have a tank-based wastewater treatment system, and would require new treatment capacity to replace ponds. Further, many facilities use impoundments for settling of suspended solids. Solids are then dredged from ponds for beneficial reuse or dry disposal. This analysis assumes that Subtitle C regulation will preclude the continued use of ponds even for these purposes. Plants that currently manage their scrubber effluent in ponds would incur capital and O&M costs for FGD wastewater treatment. The cost for wastewater treatment of FGD blowdown/purge is dependent on the type of coal burned. Wastewater treatment for higher sulfur content coals (i.e. eastern bituminous) would require more expensive treatment, and would also be a function of the flowrate (i.e. size of the plant).

Plants will also need to treat low volume CCR contact wastewater, such as air preheater wash, leachate from landfills, and floor/yard drain wastewaters in a tank-based system to replace this function that impoundments currently serve. A 1997 EPRI survey found that 80 percent of facilities co-managed low volume wastes and high volume CCRs (EPRI 1997). Even plants that currently use dry collection and management of CCRs rely on impoundments for low volume wastewater treatment. This analysis assumes that all plants would require an upgraded tank-based wastewater treatment system for these low volume wastes. Further, plants that currently use ponds for CCR disposal also co-manage non-CCR effluent, such as cooling tower blowdown. These plants would require replacement pond capacity for non-CCR wastewaters. Capital and O&M costs from EPRI (2010) for wastewater treatment are presented in Table 2-4. Wastewater treatment costs for ash contact water is dependent on the station capacity. Wastewater treatment O&M costs are applied at the plant level.

Table 2-4
Capital and O&M Costs for Wastewater Treatment

Cost Component	Mean Capital Cost ($)	Annual O&M Cost ($)
FGD Wastewater Treatment:		
All Lignite, Subbituminous, Western Bituminous Plants and Eastern Bituminous Plants < 250 MW	23,000,000	1,400,000
Eastern Bituminous Plants ≤ 250 MW ≤ 1500 MW	36,000,000	2,800,000
Eastern Bituminous Plants > 1500 MW	61,000,000	10,400,000
Low Volume CCR Wastewater Treatment:		
Plants < 200 MW	6,000,000	800,000
Plants 200 – 1000 MW	10,000,000	1,000,000
Plants > 1000 MW	22,500,000	1,700,000
Replacement 10-Acre Pond for Non-CCR Wastewaters	2,400,000	—

Source: EPRI (2010)

RCRA C Compliance Costs – Plant Modifications

EPRI has developed engineering cost estimates to comply with Subtitle C requirements, undertaken in a separate project (EPRI 2010). These costs were developed by site visits to five facilities to determine system upgrades and technological changes that would be required to comply with a Subtitle C rule. These cost estimates were based on two model plants – a 400 MW plant and a 1600 MW plant. A discussion of why these model plant sizes were chosen is included in EPRI 2010. Estimated costs for upgrades were developed according to the following subsystems:

- Bottom ash management system: upgrade area around boiler, area surrounding dewatering bins, and construction of a truck loading facility from dewatering bins.
- Economizer/fly ash management system: upgrade area surrounding ESP/baghouse, provide negative pressure ESP enclosure building, construct truck loading facility from silos, and add redundant pneumatic transfer line if required.
- FGD by-product/gypsum management system: upgrade area around dewatering equipment, provide negative pressure truck loading enclosure, upgrade or construct FGD solids storage buildings, and install closed FGD solids conveyance lines.
- Land storage/landfill upgrades to RCRA C standards: landfill security upgrades, leachate collection tank, construct RCRA waste pile, and incremental landfill O&M costs. Incremental disposal costs do not include the cost of landfill construction.

These subsystem upgrade costs are dependent on the size and configuration of the coal-fired station, and are detailed in EPRI (2010) and provided in Tables A-1 through A-6 in Appendix A of this report.

RCRA C Compliance Costs – Administrative Costs

Regulation under Subtitle C will present plants with additional costs compared with Subtitle D regulation or baseline operations. These costs include:

- Notification Requirements
- Part A Permit Application
- Part B Permit Application
- Permit Fees
- General Waste Analysis, Land Disposal Restriction (LDR) Waste Analysis, and Written Waste Analysis Plan
- Written Inspection Schedule
- Personnel Training
- Emergency Response Plan
- Contingency Plan
- Biennial Report Preparation
- Operating Record
- Groundwater Monitoring Plan
- Groundwater Sampling
- Closure and Post-Closure Plans
- Closure Certification
- Financial Assurance for Closure and Post-Closure
- Financial Assurance for Third Party Liability Coverage
- Corrective Action Schedule
- RCRA Facility Assessments/Investigations
- Additional personnel focused on maintenance, spill prevention and response.

These costs are applied per plant to every coal-fired station. Costs are dependent on plant size, and are detailed in EPRI (2010) and provided in Table A-6 in Appendix A of this report.

Incremental Pond Closure Costs and Stranded Costs

Under the Subtitle C rule, facilities will have to close their active ponds that currently receive CCR waste streams within 7 years of rule adoption. Closure under Subtitle C has slightly different requirements than closure under Subtitle D. The costs to close the active ponds include elimination of free liquids, stabilization of waste to a bearing capacity sufficient to support final cover, and a combination landfill cover system[2]. EPRI (2010) estimates the incremental cost of closure under the Subtitle C rule as $65,000 per acre. This cost per acre was applied to the number of acres of active ponds as reported to EPA for their 2009 Information Request (IR). EPA has compiled the survey results into an Excel file. The total number of acres times the incremental closure cost is calculated as $2.06 billion (before discounting). Plant-specific incremental pond closure costs were not calculated.

In addition to the closure of active ponds, Subtitle C would also require closure of inactive ponds. For the purposes of this analysis, EPRI assumes inactive ponds are those with no free liquids that have stopped receiving CCRs and exist with moderate vegetation growing over the cap. EPRI (2010) assumes that these ponds will need a composite cap with a permeability less than or equal to the proposed liner system in the Subtitle C option, and continued groundwater monitoring to demonstrate compliance with the closure standards in 40 *CFR* 264.228 and subpart G of 40 *CFR* 264. The cost for inactive pond closure under Subtitle C is estimated at $221,000 per acre. A USWAG survey of inactive ponds was used to identify a range in costs for inactive pond closure. A mean number of inactive acres/plant and inactive ponds/plant was calculated from survey data. Estimates of inactive pond closure costs based on these two metrics yielded costs ranging from $2.67 billion to $3.82 billion (before discounting). These estimates are aggregate costs for the coal-fired industry.

The proposed rule requirement that surface impoundments stop receiving CCRs within 5 years of the promulgation of the final rule also present an additional cost – the stranded capital cost associated with foregone impoundment capacity. Surface impoundments are constructed with a certain useful life expectancy. Based on discussions with utilities, this analysis assumes an expected life expectancy of 40 years (mirroring EPA's assumption). If a plant has to stop using a pond with remaining capacity, the cost to replace that stranded capacity represents an incremental cost of the regulation. Because facilities would have to replace the impoundment capacity with landfill capacity under the Subtitle C rule, the stranded cost is calculated based on the cost per acre for landfill construction. Based on publicly available data, the cost for Subtitle C landfill construction is assumed the same as Subtitle D landfill construction and ranges from $4 to $24 per ton (Iowa Department of Natural Resources 2005; Moose 2005; USWAG 2010; Van Eaton 1991). There are economies of scale in landfill construction, ranging from approximately 75,000 tons CCR/acre on up to 190,000 tons CCR/acre. For this analysis, a mean estimate of $780,000 per acre was used to calculate stranded cost.

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[2] EPRI (2010) characterizes the combination landfill cover as being designed to provide long-term minimization of liquids, function with minimal maintenance, promote drainage and minimize erosion, accommodate settling/subsidence and have a permeability less than or equal to the permeability of any bottom liner system (or natural subsoils).

The results of the EPA Information Request were used to calculate stranded cost. Assuming an expected lifetime of 40 years and a 2019 date to stop receiving CCRs, the year each impoundment was built or the latest expansion date was used to calculate the number of years of remaining capacity in each impoundment. The remaining years of capacity divided by 40 years yields the percentage of the impoundment capacity remaining. This percentage multiplied by the total acreage yields an estimate of the stranded acreage. At a cost of $780,000 per acre, the total industry stranded cost is calculated as $5.11 billion (not discounted). This was consistent with USWAG estimated stranded cost of $5.2 billion, utilizing a different methodology to calculate stranded costs. They assumed a uniform rate of replacement and 20.5 years average remaining capacity for the industry.

Disposal Costs

Incremental disposal costs from Subtitle C regulation are dependent on where a plant will dispose of CCRs. Since facilities will have to build additional disposal unit capacity eventually even in the baseline (without the rule), landfill construction costs were not included as an incremental cost of the regulation. It is important to note that certain landfill upgrades to meet Subtitle C requirements (security, leachate collection tank, RCRA waste pile) would be incremental and have been included as part of the engineering costs described above. Because this analysis focuses on quantifying *incremental* costs of regulation, it is not a total compliance cost assessment, and thus some real costs that would be borne by companies (such as landfill construction and fully loaded costs) are not included in this analysis as an incremental cost. Companies may need to invest capital for landfill construction sooner as a result of the rule, and the accelerated cost of that expenditure relative to the baseline is not quantified. However, if a plant cannot build new landfill capacity on-site due to Subtitle C siting restrictions, then the cost to transport CCRs off-site (and pay a commercial tipping fee if applicable) would be incremental costs due to regulation. The baseline costs of disposal (as reported to EIA 923) are subtracted from the calculated off-site and commercial disposal costs, to arrive at incremental disposal costs.

This analysis quantified costs associated with three disposal choices: on-site disposal, off-site disposal at a company-owned landfill, and commercial disposal. On-site disposal costs include only the security, leachate collection tank, and RCRA waste pile upgrades. As discussed above, landfill construction costs are not incremental. Off-site disposal costs including transportation costs associated with a RCRA listed waste. To ascertain a cost per mile, various publicly available reports were consulted to obtain a range in costs (New York State DEC 2010b; WWPI 2003; U.S. EPA RCRA Enforcement Division 1997). Based on these sources, estimated costs for transportation of hazardous waste range from $0.256 per ton-mile to $0.380 per ton-mile[3]. These costs are inclusive, and would include manifesting, fuel surcharges, and liner/dust control.

Similarly, disposal of CCRs in commercial hazardous waste landfills would incur similar transportation costs. However, commercial landfills would also charge a tipping fee for disposal. A survey of current tipping fees was conducted to ascertain a reasonable distribution in costs associated with commercial disposal of CCRs. Metals-contaminated wastes (including metals-

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[3] Assuming a full net load of 12 tons CCPs.

laden soils, air pollution control system residues, filter cake from wastewater treatment, etc.) are usually treated to stabilize metals to meet EPA Land Disposal Restrictions (EPA 2010). This could occur at the plant or at the commercial disposal facility. Since the concentration of metals in CCR waste would vary by facility, the type of treatment would affect overall cost. The cost distribution captures a range in *current* tipping fees for hazardous waste treatment and disposal for similar type wastes (i.e. metals-contaminated soils, RCRA listed waste with metals, cement kiln dust). This analysis did not attempt to quantify potential increases in tipping fees due to CCR regulation. However, should CCRs be regulated under RCRA Subtitle C, the volume of CCRs generated annually would cause a shortage of available landfill capacity and would subsequently place upward pressure on tipping fees. These implications for regulation of CCRs under Subtitle C are further discussed in Section 4. Tipping fees for stabilization and disposal of similar wastes currently range from $62/ton to $410/ton[4]. The mean tipping fee was $158/ton. A distribution on tipping fee was used in the analysis, and is shown in Figure 2-4.

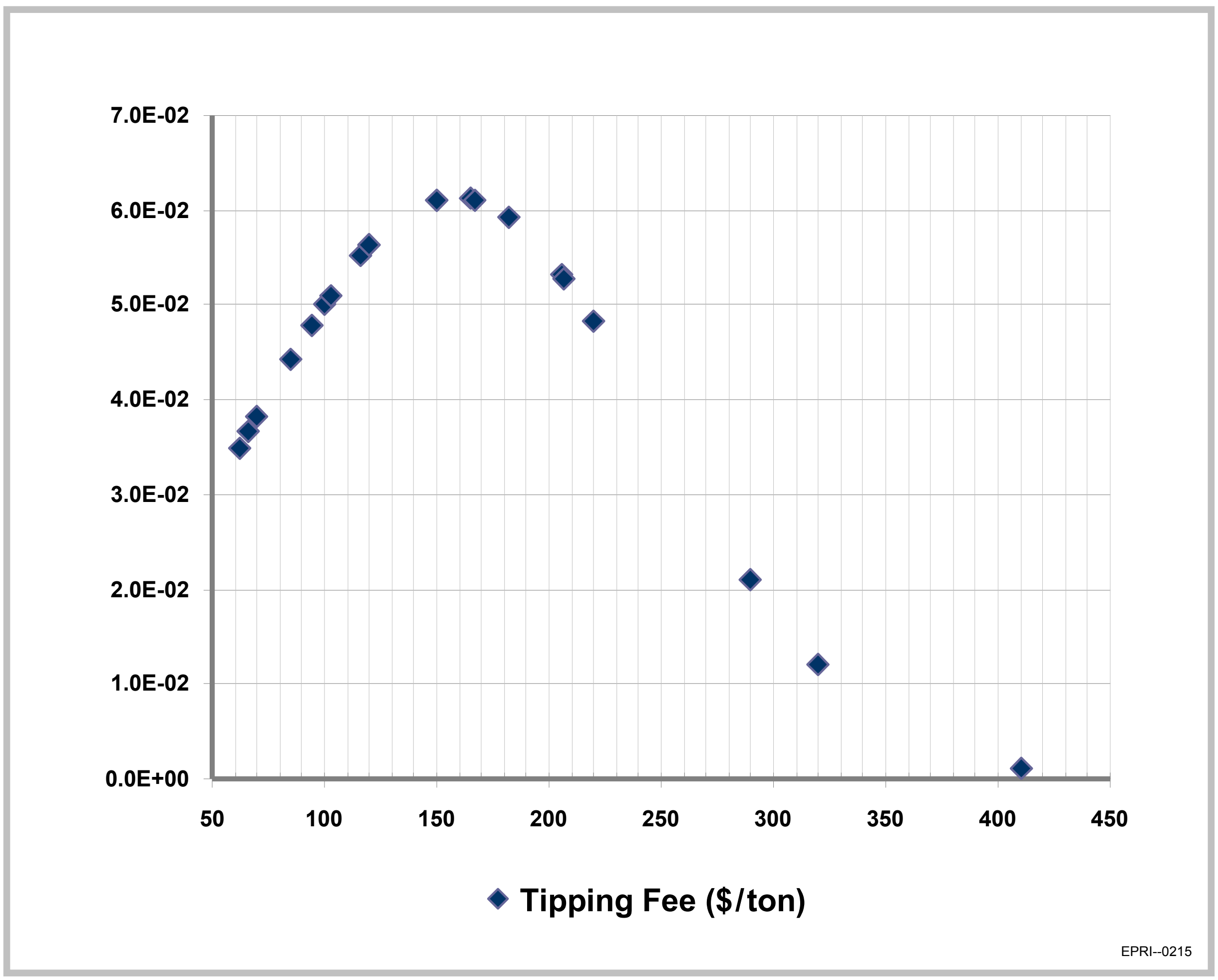


Figure 2-4
Tipping Fees at Commercial Hazardous Waste Landfills. Y-Axis is Probability of Occurrence.

[4] See references [5], [7], [9], [29], [31], [35], [41], [43], [44], [76].

Disposal costs will be highly site-specific, due to potential landfill siting restrictions, land availability, and proximity to alternate disposal capacity. In addition to the uncertainty regarding the cost inputs such as transportation costs and tipping fee, there is uncertainty on the disposal decision (on-site disposal, off-site disposal in company-owned landfill, or commercial disposal). In order to estimate disposal costs for each plant, it is necessary to first identify the probability that a generator would dispose of CCRs on-site, transport to an off-site company-owned landfill (either at another plant or in a regional landfill), or use commercial disposal facilities. This decision depends on the amount of CCRs produced annually, current disposal practices, available landfill capacity on-site, landfill siting restrictions, and the relative location of the plant to other disposal facilities (company-owned or commercial). Section 3 discusses how survey data was used to develop probabilities for each disposal option, and thus estimate disposal costs for each coal-fired plant.

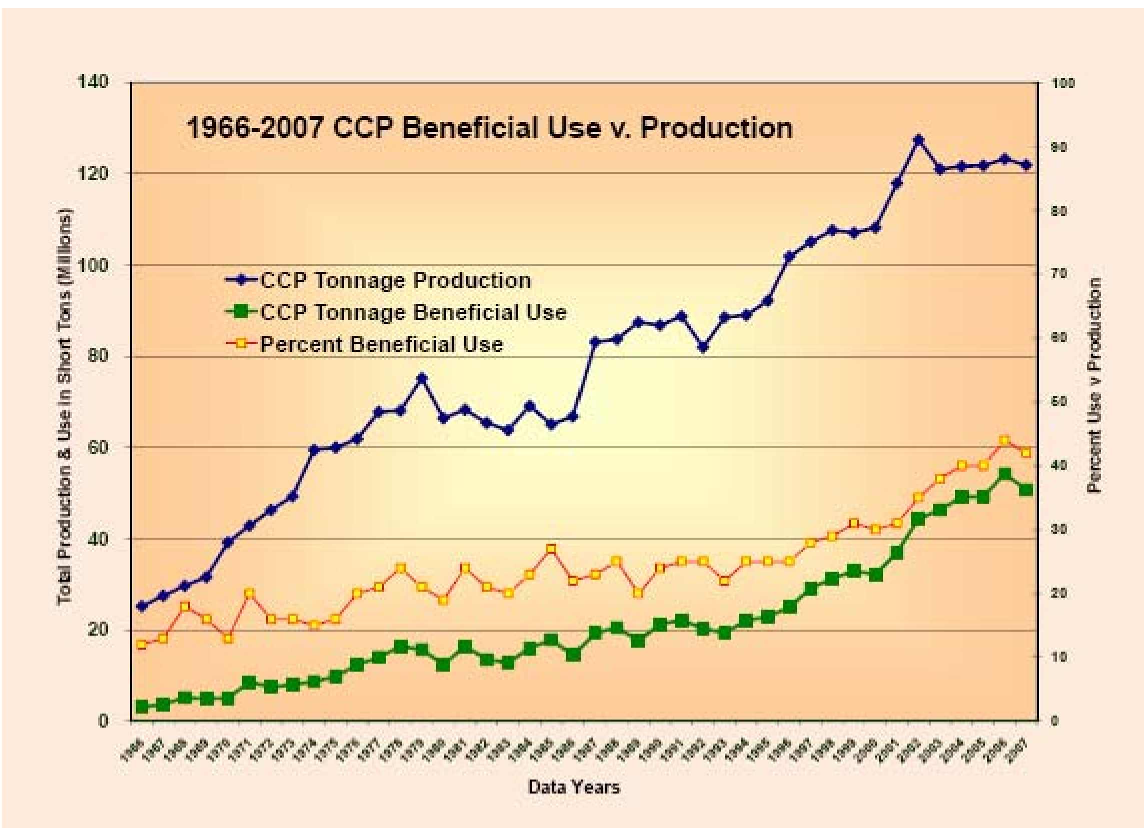
State hazardous waste generator fees were not included in the disposal costs due to the complexity of state rules. Many states have a complicated fee structure that is calculated based on the RCRA listing of the waste, an annual permitting fee, and a scaled fee structure based on the annual amount generated and where it is disposed (on-site or off-site). Still other states have a flat rate, some states have no generator fees, and others impose a cap on the maximum generator fee that can be assessed. For example, New York levies a $27 per ton fee for hazardous waste that is landfilled; Alabama assesses a fee of $41.60 per ton for RCRA listed waste sent to commercial disposal; Arizona charges $4 per ton to generators of waste that dispose on-site or in a company-owned off-site landfill; and Illinois charges a maximum fee of $30,000 for hazardous waste that is produced and landfilled on-site (New York State Department of Environmental Conservation 2010; FindLaw 2010; U.S. Army Corps of Engineers 2005; Hoerner 1998; U.S. EPA National Center for Environmental Economics 2001, 2010). If the Subtitle C option is promulgated, it is expected that states with authorized RCRA C programs would have to adjust their fee structures to reflect the increase in permit applications, and the voluminous nature of the CCR waste stream. This analysis does not speculate on the legislative changes at the state level that would be required to administer the proposed rules, although some states may increase their fees.

Impact of Regulation on Beneficial Use

In order to calculate disposal costs, the amount of CCRs destined for disposal would be impacted by any changes to beneficial use rates. Figure 2-5 shows the beneficial uses of CCRs from 1966 to 2007. Nearly 45 percent of all CCRs produced were beneficially used in 2008. These uses included concrete and cement products, structural fill and other geotechnical applications, and wallboard products, as delineated in Table 2-5. In the proposal, EPA has expressed concerns about "unencapsulated" uses, such as large-scale structural fill, road embankments, sand and gravel pits, and agricultural uses (75 *Fed. Reg*. 35155, 35160). In addition, since some stakeholders have raised concerns about a stigma on beneficial uses associated with Subtitle C regulation, EPA has included a sensitivity analysis in the RIA to address potential impacts to beneficial use rates. The RIA assumed a reduction rate for unencapsulated uses of 80 percent and only a small decrease in encapsulated uses (RIA page 176). Unencapsulated uses identified by EPA include:

- structural fill/embankments
- road base/sub-base
- soil modification/stabilization
- snow and ice control
- aggregate
- agricultural uses, and
- miscellaneous/other.

Thus, this analysis recognizes that unencapsulated uses may be eliminated through future regulation or severely curtailed due to liability concerns and stigma. For the purposes of calculating the amount of CCRs that must be disposed, the analysis reduces the total CCR production by the encapsulated use rate (thereby assuming no reduction in encapsulated uses). Regulation that restricts the beneficial use of CCRs will have significant impacts to the generation industry by increasing the amount of CCRs that must be disposed.



Source: American Coal Ash Association (2009)

Figure 2-5
Beneficial Use of Coal Combustion Products

Table 2-5
Beneficial Use Rates (tons) by Category for 2008

CCP Use Category	Fly Ash	Bottom Ash	Boiler Slag	FGD Gypsum	FGD Wet Scrubbers	FGD Dry Scrubbers	FGD Other	FBC Ash	
Total Produced	**72,454,230**	**18,431,297**	**2,028,455**	**17,754,939**	**12,980,588**	**1,399,258**	**1,537,283**	**9,487,057**	**136,073,107**
Concrete/Concrete Products/Grout	12,592,245	720,948	0	675,505	0	22,577	0	4,341	
Blended Cement/Raw Feed for Clinker	3,174,264	610,194	0	413,740	0	0	0	0	
Flowable Fill	74,794	0	0	0	0	18,338	0	0	
Structural Fills/Embankments	8,012,825	2,996,388	178,363	0	0	130,566	106,526	76,579	
Road Base/Sub-base	1,027,568	767,013	0	0	0	0	0	7,444	
Soil Modification/Stabilization	627,810	431,664	0	0	0	60,115	0	132,379	
Mineral Filler in Asphalt	7,781	247,806	0	0	0	0	0	0	
Snow and Ice Control	0	699,561	1,352	0	0	0	0	0	
Blasting Grit/Roofing Granules	84,881	66,670	1,486,316	0	0	0	0	0	
Mining Applications	960,911	63,648	3,021	0	685,104	109,641	0	8,643,947	
Gypsum Panel Products	0	0	0	8,533,732	0	0	0	0	
Waste Stabilization/Solidification	2,923,592	84,901	0	744,592	0	1,221	30,240	0	
Agriculture	35,340	3,771	0	278,875	0	2,877	0	0	
Aggregate	154,992	727,048	19,422	0	0	0	0	0	
Miscellaneous/Other	465,271	646,643	1,418	6,900	0	0	0	0	
Total Allowed Encapsulated Use	19,743,674	1,794,167	1,489,337	10,367,569	685,104	133,439	30,240	8,648,288	42,891,818
Encapsulated Uses Decrease -18%	16,189,813	1,471,217	1,221,256	8,501,407	561,785	109,420	24,797	7,091,596	
Encapsulated Uses Increase + 11%	21,915,478	1,991,525	1,653,164	11,508,002	760,465	148,117	33,566	9,599,600	

Source: American Coal Ash Association 2008 Coal Combustion Product (CCP) Production & Use Survey Report

3
COSTING METHODOLOGY AND INCORPORATION OF UNCERTAINTY

The section discusses the methodology for assigning compliance costs to each generating unit and plant, and how uncertainty in cost components and disposal decision is incorporated. The assumptions that were used in the absence of site-specific data are detailed. The section concludes with a discussion of the limitations of the results as a consequence of these assumptions and uncertainty in cost estimates.

Cost Assignment Methodology

Based on the compiled unit-level characteristics, the relevant components of compliance costs were assigned to each unit. Some cost components were assigned on a generating unit basis, and therefore are allocated based on plant configuration. Other cost components apply at the plant-level, depending on size of the plant. Compliance costs for the engineering upgrades needed to meet Subtitle C requirements were developed for two model plant sizes – a 400 MW plant and a 1600 MW plant. Due to the nonlinear nature of many of the cost components, costs developed for the smaller model plant were assigned to plants with a total installed capacity of less than 500 MW. Plants greater than 500 MW were assigned the costs developed for the larger model plant; however, certain costs were applied for plants larger than 800 MW, and plants larger than 1600 MW. This is discussed below. For units where site-specific information was available from survey data, the assignment of costs was based on what the generator specifically reported. For units at plants where site-specific information was not available, assignments were based on the following logic:

1. Plants that reported disposing of their fly ash in ponds in EIA Form 923 were assumed to have wet fly ash handling and were assigned dry fly ash conversion costs on a per unit basis. If survey data was available, the conversion cost was applied to the number of reported wet units.
2. Plants that reported disposing of their bottom ash in ponds, using bottom ash on-site, or storing on-site in EIA 923 were assumed to have wet bottom ash handling and were assigned dry bottom ash conversion costs on a per unit basis. This assumption resulted in 50 percent of facilities being assigned wet-to-dry bottom ash conversion costs, which matched the surveyed percentage of plants with wet bottom ash units. If survey data was available, the conversion cost was applied to the number of reported wet units.
3. Capital costs to convert to dry handling begin in 2016, prior to the date that impoundments must be closed, to allow time for the conversion.

4. Plants that currently utilize dual wet/dry fly ash handling (i.e. use wet sluicing as a backup when the pneumatic system is down) were assigned costs to install a redundant pneumatic transfer line. This cost was only assessed to plants whose survey data indicated dual handling.
5. Plants that report disposing of FGD gypsum or FGD other byproducts in ponds in EIA 923 were assumed to require the installation of FGD dewatering systems.
6. Plants that currently dispose of fly ash or bottom ash in ponds were also assigned an incremental dry handling O&M cost per ton of CCR disposed in ponds (from EIA 923).
7. Wastewater treatment capital and O&M costs for FGD systems are dependent on the type of coal burned, and for high sulfur eastern bituminous coals, the size of the plant. FGD information from EIA 860 and 923 was used to determine the primary coal type burned, and FGD type (dry, gypsum producer, or sulfite producer), and disposal method. Plants that have dry FGD systems were not assessed costs for FGD wastewater treatment systems. Only operating FGD systems were included for analysis, and not planned FGDs. Plants that reported pond disposal for FGD wastes were assigned FGD wastewater treatment costs. If survey data indicated a plant did not have a wastewater treatment system for FGD, it was assigned the cost.
8. The default assumption is that all plants will require upgrades for low volume CCR wastewater treatment, unless survey data indicated that they had a tank-based system that did not use settling ponds. Costs for the ash contact wastewater treatment systems are dependent on plant size. In addition, all plants that currently use disposal ponds for CCRs would require replacement pond capacity for non-CCR wastewater, such as cooling tower blowdown.
9. The amount of CCRs produced annually for each plant was calculated from EIA 923 disposition data. CCR production over the 20-year study horizon was used to calculate disposal and dry handling O&M costs.
10. Restrictions on beneficial use were evaluated by calculating the percentage of encapsulated uses for each CCR category (fly ash, bottom ash, FGD gypsum, FGD wet scrubbers, etc.). The amount of CCRs to be disposed of annually for each plant was reduced by the corresponding percentage for encapsulated beneficial uses. In essence, each plant was assumed to find a market for encapsulated uses. This is an analytical simplification, as secondary markets for CCRs vary by location and are subject to fluctuations. To assess the sensitivity of total costs to the amount beneficially used, two additional scenarios were also examined—one in which encapsulated use rate decreases 18 percent, and one in which encapsulated use increases 11 percent.
11. All plants were assumed to require upgrades surrounding their boilers and dewatering bins.
12. All wet FGD systems would require upgrade to the area under their dewatering equipment. Dry FGD systems (i.e. spray dryers) were not assigned these upgrade costs.
13. Plants would need to upgrade their ESPs/baghouse area to meet Subtitle C requirements, unless they were in southern states (defined as TX, OK, AR, LA, MS, TN, AL, GA, SC, NC, FL), in which case they were assigned the cost for a new containment area under the ESP.

14. Plants in southern states were assumed to have no enclosure for their ESPs/baghouses and CCR storage, unless survey data indicated otherwise. Thus these plants would require new enclosures and storage buildings. All other plants (i.e. northern plants) are assessed costs to upgrade their enclosures to Subtitle C standards. If site-specific data indicated a southern plant had an ESP enclosure, it was assigned the upgrade cost, and not the new enclosure cost.
15. Plants with gypsum-producing FGD systems in northern states were assumed to have a storage building which would require upgrades to meet Subtitle C requirements. Plants with gypsum-producing FGD systems in southern states were assumed to use primarily stacker pads and require a new building enclosure. If survey data indicated otherwise, then costs were assigned based on the survey responses. Since the byproduct of sulfite-producing FGDs are not typically marketed for beneficial uses, plants with these systems were assumed to require a new storage building to replace outdoor storage of stabilized material prior to disposal, unless site-specific data indicated the plant had enclosed storage.
16. All plants would require upgrades to truck loading facilities for bottom ash, fly ash, and FGD solids. The number of truck loading facilities required is dependent on plant size or configuration. For bottom ash handling, one truckloading facility was assumed to serve up to three units on average. Thus, plants with 4 or greater units would require a second truck loading facility. For fly ash handling, plants less than 800 MW would only require one truck loading facility. Plants over 800 MW would require a redundant truckloading facility, and plants over 1600 MW would require a total of 3 loading stations. These assumptions were based on a calculation of truck loading time from silo relative to fly ash production. Plants with both gypsum and sulfite-producing FGD systems were assigned the cost for two truck loading facilities.
17. Part A permit costs would be incurred upon adoption of the federal rules by the authorized states. Part B permit costs would start to be incurred thereafter. All plants would incur RCRA administrative costs.
18. The increase in O&M personnel dedicated to maintenance, spill prevention and response is dependent on plant size (MW).

Limitations Arising from Assumptions

While site-specific data enabled the accurate assignment of compliance costs, there are limitations to the publicly available data and the assumptions that can be drawn from those data for plants without survey data. Publicly available information for each of the surveyed plants and units was reviewed to assess the assumptions that would have been made without site-specific information. This was integral to refinement of the cost specifications and derivation of cost assignment logic. There were some units for which assumptions from publicly available information would have been incorrect. There are several conditions for which the publicly available data could not capture the nuances of ash handling practices and plant configuration:

- EIA 923 only provides *final* disposition data, and not treatment. Therefore, plants that use ponds for settling of solids following by dredging and reuse may appear to not use impoundments when in fact they have wet systems. This is particularly true for bottom ash handling, where approximately 50 percent of surveyed plants had wet bottom ash units, whereas from EIA data only 30 percent of plants report disposing of bottom ash in ponds.

- Recent conversion to dry ash handling: Units that were recently converted to dry ash handling would not have updated information reflected in EIA databases.
- A subset of the units at a plant has dry ash handling: In cases where some units utilize wet sluicing and other units have dry handling capability, some percentage of ash is often reported to ponds in the EIA 923 data. Further, these facilities typically report surface impoundments for fly ash even though only a subset of the units directs CCRs to ponds. Without site-specific information, which generating units have dry ash handling cannot be discerned.
- Dual dry/wet handling capability: Several generators had the capability to switch between wet sluicing and dry handling. In some circumstances, facilities would routinely sluice fly ash to ponds, but had the capability for dry ash handling when selling fly ash for beneficial uses. In other cases, wet sluicing was used as backup when the pneumatic lines encountered problems or required maintenance. In such cases, the units would not incur costs of converting to dry ash handling, but would appear from the publicly available data to have wet systems.
- Surface impoundments are used by many facilities as an integral part of their wastewater treatment process (i.e. settling of suspended solids), even facilities with partial tank-based systems. This information is impossible to discern from EIA 923, since the data only includes the final disposition. Thus, the assumption was made that all plants would require some upgrade for wastewater treatment, unless survey data indicated otherwise, since using disposition data would likely underestimate the number of facilities requiring treatment to replace impoundment function.
- Publicly available data does not have information on temporary storage of CCRs, including the use of stacker pads, semi-enclosed buildings, and open or closed solids conveyance to storage. Thus, plants without surveys were assumed to be configured depending on their location (northern versus southern states), with the assumption that ESPs/baghouses and gypsum containment are generally enclosed for northern plants, and open for southern plants. This assumption was based on site visits and best professional judgment (EPRI 2010).
- The analysis did not consider retirements or repowering as an alternative to compliance with the new rules. Plants with low capacity factors may choose to retire rather than comply. For other plants, compliance costs may exceed the costs of repowering. Thus, every plant is assumed to incur the costs to comply with the proposed rule.

Monte Carlo Analysis to Account for Parameter Uncertainty

The uncertainty in estimating costs of the proposed Subtitle C rule represents an analytical challenge. Accounting for the various cost uncertainties is an important component of evaluating the potential financial impacts of the proposed rule. To address uncertainty, this study employs a Monte Carlo analysis that incorporates the uncertainty in individual cost components and uncertainty in disposal decision into the cost estimation framework. The statistical cost model was developed in Analytica, a graphical programming interface that incorporates Intelligent Arrays™ to manage multidimensional tables. Figure 3-1 provides an overview of the cost model (this is an actual screen shot from the model).

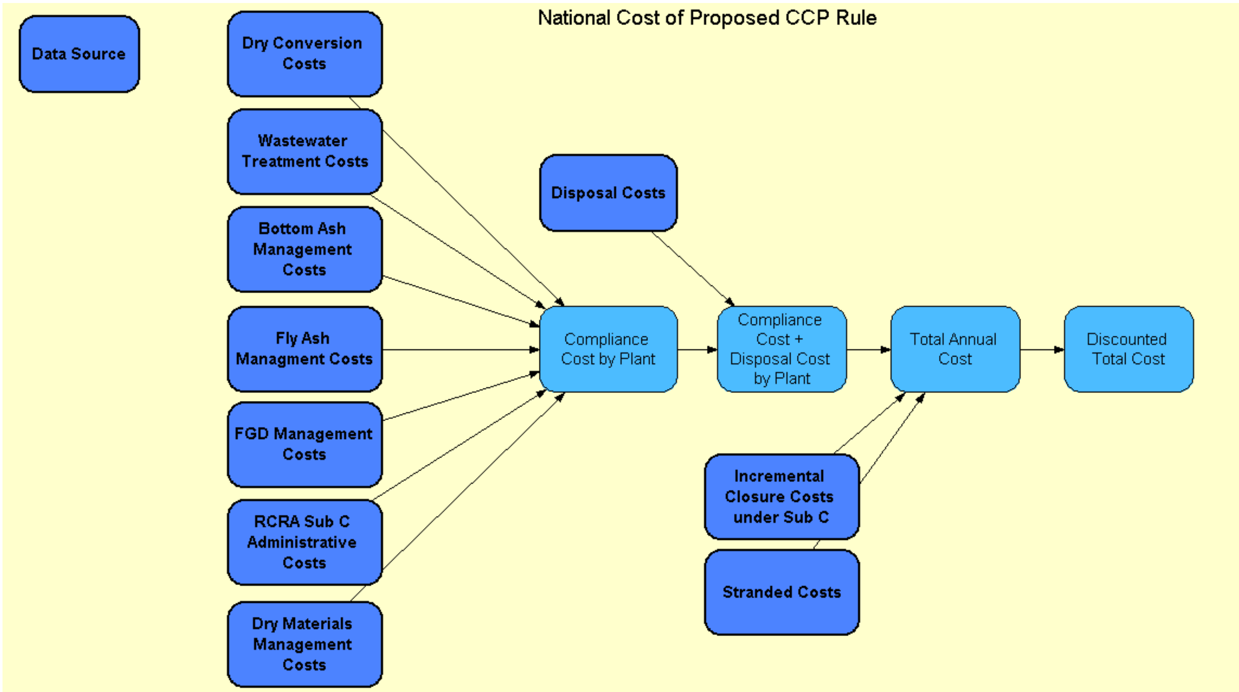


Figure 3-1
Overview of National Cost Model (Screen Shot)

Some cost components were developed as point estimates using best professional judgment and utilizing a contingency factor (EPRI 2010). Other cost components such as transportation costs and tipping fees are distributions based on a range of estimates from publicly available data (see Section 2). The statistical cost model takes distributions for each cost input, randomly selects a value from each distribution, and then combines the estimates. The resulting combination of the various inputs creates an estimate of total compliance cost for each generating plant. Once the compliance cost estimate is calculated for each generating plant per iteration, the costs for all regulated plants are summed to calculate the total cost to industry. This process is repeated 1,000 times. Each repetition produces a different estimate of total compliance costs for each plant. The resulting distribution of outcomes from the 1,000 draws produces the range of potential compliance costs that explicitly addresses relevant parameter uncertainty for each plant. Probability bands from the distribution of costs (5%, 50%, 95%) are used to determine the 90 percent confidence interval and mean of the results.

By contrast, if an analysis was conducted using the low end of the range for each cost component applied to every generating unit, it would produce unrealistically low compliance cost estimates. Similarly, applying the high end of cost range for each cost component to every generating unit would produce an equally unlikely result. Further, an assumption that every plant would be able to build a new landfill on-site ignores the requirements under Subtitle C and the reality that some plants will be unable to meet these requirements. Similarly, it is unrealistic to assume every plant will use commercial Subtitle C landfills for disposal, which would overestimate the regulatory costs. Therefore, this analysis attempted to quantify this uncertainty by utilizing survey data to develop realistic probabilities for disposal decisions of non-surveyed plants (discussed in the following subsection).

Quantifying Uncertainty in Disposal Decisions

Under a full Subtitle C regulatory scenario, generators would have to dispose of their CCRs in landfills that meet the new design, monitoring and performance standards. If a plant does not currently have a landfill on-site (or has limited capacity), that facility would be faced with a decision to permit and site a new landfill on-site, transport CCRs for disposal at an off-site company-owned landfill, or transport CCRs to a commercial hazardous waste landfill for disposal. Lacking site-specific data, disposal choice and possible landfill siting restrictions are difficult to assess. There are conditions for which generators would be restricted from constructing landfills on-site or would not choose to landfill on-site, that are dependent on site-specific information. These conditions include seismic, fault line, floodplain or watershed restrictions; state-specific permitting issues; lack of available land; intent to build regional or other offsite landfill facilities; concerns about public involvement/comment process; and potential legal ramifications and costs. Facilities that cannot or would choose not to build an on-site landfill that would meet new design standards would incur the cost of transporting to an off-site company-owned landfill or commercial Subtitle C landfill.

Results of the EPRI CCR survey confirm that not all facilities would be able to site a new landfill under the Subtitle C rules. Of the 225 plants with survey data, 104 reported they did not have available land on-site (within 5 miles) for a new landfill (46 percent). Six plants indicated they were aware of seismic restrictions, and three plants were aware of fault line restrictions. These numbers likely underestimate the number of plants subject to seismic or fault line restrictions as many answered “Unknown” to these questions. Thirty-four (34) of the 225 surveyed plants (15 percent) indicated they were aware of floodplain, wetlands, or watershed restrictions under Subtitle C. In addition, 39 plants (17 percent) indicated that other state-level siting restrictions may prevent them from building an on-site Subtitle C landfill. This would include restrictions such as in Florida and Kansas, whose state statutes are more restrictive than federal rules and prohibit the land disposal of hazardous waste (2010 Florida Statutes, sec. 403.7222, *Prohibition of hazardous waste landfills*; ASTSWMO 2009).

Companies also cited other reasons why they would not choose to build an on-site landfill. This included liability concerns, legal issues, or anticipation of a lengthy public involvement process; a decision to build a centrally located regional landfill that served several plants; or plants that were too small/low capacity factor to justify the time and expense of permitting an on-site landfill. Due to these restrictions and other factors, survey responses indicated that 95 plants would choose on-site disposal (42 percent), 66 plants (29 percent) would choose to transport CCRs off-site to another company-owned landfill, and 64 plants (28 percent) would choose commercial landfill disposal. In terms of percentage of CCRs, 67 percent of CCRs produced by the surveyed plants would be disposed on-site, 21 percent of CCRs would be disposed off-site, and 12 percent of CCRs would be disposed of in commercial hazardous waste landfills.

Survey data on disposal decision was used to assign the disposal costs for surveyed plants. For the remaining 40 percent of plants without survey data, the probabilities for on-site, off-site, and commercial disposal were calculated by employing a statistical regression. The analysis evaluated the statistical relationship between the characteristics of the surveyed facilities with their disposal decision using a multinomial logistic regression. It is important to note that the regression can only include variables for which data exists for non-surveyed plants. So although "land availability" was a survey question, those data do not exist for non-surveyed plants. Therefore, other parameters that would serve as a proxy for unknown variables were selected.

The characteristics in the regression include:

- Annual generation in MWh: the annual generation is a proxy for the capacity factor and ash production at the plant.
- Population density: population density would affect nearby land availability and the possibility for legal hurdles regarding siting landfills.
- Whether the plant currently has ponds or landfills: a plant that currently has ponds or landfills may be more likely to have land availability for new disposal units.
- Distance to nearest commercial hazardous waste landfill: transportation costs are a function of distance to landfill, and thus would influence the disposal decision.

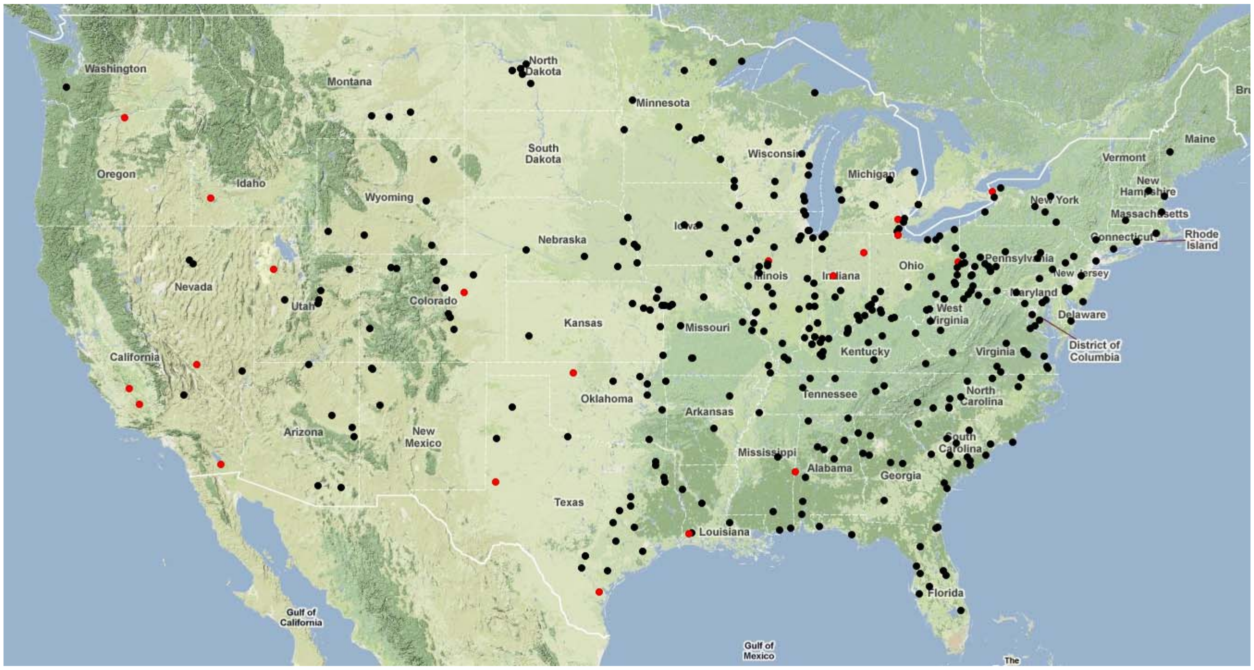
The regression showed a strong positive correlation between annual generation and on-site disposal. In other words, the more electricity a plant produces (in MWh), the more likely the plant was to dispose of CCRs on-site. Plants that produce more electricity are typically larger, have a lower heat rate (i.e. are more efficient), have a higher capacity factor, and thus produce more CCRs. Thus, the economical decision would be to build an on-site landfill. In addition, these plants have a larger footprint and are more likely to have land available for siting a landfill.

Population density (City-Data 2010) inversely correlated with on-site disposal. The more populous an area, the more likely the plant was to choose off-site or commercial disposal. This is likely due to land availability and potential permitting delays because of the public participation process (i.e. larger number of stakeholders could affect the permitting process).

If the plant currently had a landfill or pond on-site, it was more likely to choose on-site disposal. This variable is a proxy for land availability. Distance to commercial landfill correlated with a higher probability for disposal in an on-site or company-owned landfill.

The statistical model estimates a probability of each disposal choice for each plant. The disposal costs associated with each disposal decision are applied to each plant based on these probabilities. From survey data, the mean distance to a company-owned off-site landfill was 81 miles. This mean value was used as the distance to an off-site landfill for non-surveyed plants. If a surveyed plant indicated a specific distance to a company-owned off-site landfill, the specified distance was used.

For commercial disposal, each plant was assigned a distance to the nearest commercial hazardous waste landfill and that distance was used in the calculation of disposal cost. Figure 3-2 shows the location of commercial hazardous waste landfills in the U.S. (red dots) relative to the location of coal-fired generating plants included in this analysis (black dots). The distances from each plant to each commercial Subtitle C landfill were calculated, and the shortest distance was used. All distances were calculated using PC*Miler.



Commercial hazardous waste landfills are represented by red dots, and coal-fired power plants are represented by black dots.

Figure 3-2
Location of Commercial Hazardous Waste Landfills

Cost distributions were developed to account for the actual distance to off-site or commercial landfills from each plant, as well as the probability for on-site disposal versus off-site and commercial disposal. The cost distributions accounted for the range in transportation costs (trucking cost per mile per ton) and tipping fee at commercial landfills. The regression approach allows for development of range in disposal costs specific to each plant, thus quantifying the uncertainty in disposal decision and allowing development of a cost scenario that is based on a representative sample of the regulated plants.

Although an off-site and commercial disposal cost was calculated for every plant, the off-site cost would only be assigned based on disposal decision probability. In other words, within the Monte Carlo simulation, if the regression predicted a 30 percent probability of on-site disposal, a 50 percent probability of off-site disposal, and a 20 percent probability of commercial disposal, the cost associated with commercial disposal would be assigned in 200 of the 1000 iterations. Thus, the regression probabilities in the Monte Carlo framework allow the estimation of a likely range of disposal costs for each plant.

Since disposal costs are a key cost driver of the regulation, this analytical method allows a reasonable estimation of the range of incremental costs that could be incurred with Subtitle C regulation. The baseline disposal costs were subtracted from the off-site and commercial disposal costs to estimate the incremental cost. It is important to note that incremental off-site and commercial disposal costs would not be incurred under Subtitle D regulation, since the assumption is made that all facilities that currently dispose of CCRs on-site would continue to do so under a Subtitle D rule.

A sudden spike in the demand for commercial hazardous waste landfill capacity resulting from a Subtitle C regulation on CCRs could cause tipping fees to increase significantly. The estimation of potential fee increases was beyond the scope of this analysis, however. The implications of the Subtitle C rule on the amount of CCRs destined for commercial disposal is discussed in the next section.

4

NATIONAL COST ESTIMATE AND SCENARIO ANALYSIS

This analysis quantifies the potential range in costs to the coal-fired electric generating industry as a result of Subtitle C regulation on CCR disposal. A Monte Carlo analysis was utilized to quantify the uncertainty in total costs that arise from uncertainty in input cost components as well as uncertainty in disposal decision by individual plants. The incremental costs of Subtitle C regulation are estimated at $5.32 billion to $7.62 billion annually. Over a 20-year horizon and seven percent discount rate, the total incremental costs are $55.31 to $74.53 billion, with a mean of $63.85 billion.

The inclusion of site-specific data gathered from the EPRI CCR survey greatly increased the accuracy of cost assignments and the overall cost estimates. Fifty percent of the coal-fired units (and plants) subject to regulation under the proposal provided survey data (representing over 60 percent of the coal-fired capacity). This statistically representative sample was used to refine cost assumptions and estimate probabilities for plant-specific disposal decisions. This information was then used to quantify the uncertainty in disposal costs.

Key Cost Drivers of Subtitle C Regulation

The cost model developed for the analysis also allows the examination of the total industry costs for the different compliance cost components. This is helpful in identifying key cost drivers and comparing the results of this analysis with other estimates of the cost of the regulation. Table 4-1 presents a total (20-year) estimate for the major cost components. The costs presented are the present value of the mean of those cost components. As can be seen from Table 4-1, wastewater treatment, RCRA Subtitle C administrative costs, and disposal costs comprise a large percentage of the total costs. By comparison, EPA estimates the incremental cost of the Subtitle C proposal as $20.35 billion present value (discounted by 7% over 50 years). In the present analysis, the cost of conversion to dry handling, dry materials management, and RCRA administrative costs (including O&M) totals $23.79 billion present value (discounting by 7% over 20 years). EPA estimates do not include wastewater treatment system costs to replace impoundments, the "upstream" costs of bottom ash, fly ash, and FGD solids management to meet RCRA standards, increased plant O&M costs to stay in compliance (i.e. maintenance, spill prevention and response), or off-site (and commercial) disposal costs except for those plants that currently dispose of CCRs off-site. The inclusion of these cost components accounts for the difference between EPA's estimate and EPRI's estimate.

Table 4-1
Key Cost Drivers of Subtitle C Regulation

($Billions present value at 7% discount rate and 20-year study horizon)

Cost Component	Mean Estimate
Conversion to Dry Handling (Bottom Ash, Fly Ash and FGD)	$12.65
Wastewater Treatment Systems	$6.24
Bottom Ash Management Systems (RCRA Subtitle C requirements)	$0.54
Fly Ash Management Systems (RCRA Subtitle C requirements)	$2.07
FGD Management Systems (RCRA Subtitle C requirements)	$1.25
Dry Materials Management	$0.36
RCRA C Administrative Costs (including maintenance, spill prevention and response O&M)	$10.78
Disposal Costs	$23.90
Stranded Costs for Early Pond Closure	$2.97
Incremental Pond Closure Costs Under Subtitle C	$3.09

Impacts of Beneficial Use Assumptions

This analysis assumed that encapsulated uses continue at their current rate, and that every plant can find a market for their CCRs. The analysis assumes that unencapsulated uses will not continue, either due to reversal of the Bevill amendment for these uses, or from liability concerns and/or stigma. However, in order to examine the impacts of a decrease or increase in encapsulated use rate as a result of Subtitle C regulation, this study analyzed two additional scenarios: encapsulated beneficial use decreasing by 18 percent, and encapsulated beneficial use increasing by 11 percent. These scenarios were intended to parallel EPA scenarios. The amount of CCRs that would be required to be disposed of by each plant was increased or decreased by the corresponding scenario percentage. For example, for the increase in usage scenario, the percentage of fly ash currently used in encapsulated applications (27.2 percent) was increased by 11 percent to 30.2 percent. Thus, for any given plant, 69.8 percent of the fly ash produced annually was assumed to be disposed. Conversely for the decreased beneficial use scenario, the percent of fly ash going to encapsulated uses is 22.3 percent (a decrease of 18 percent). It is important to note that mining applications were included as continued beneficial uses in this analysis because regulations concerning mine placement would be addressed separately by the Office of Surface Mining.

Table 4-2 shows the impact of alternate beneficial use scenarios. As can be seen in the table, a moderate increase or decrease in encapsulated beneficial use does not affect total costs significantly. This is because encapsulated uses are only 31.5 percent of the total CCRs produced annually. The majority of CCRs will still require disposal under the Subtitle C rule, regardless of impacts to encapsulated beneficial uses. This analysis did not consider or quantify impacts to revenue from changes in beneficial use rates.

Table 4-2
Comparison of Incremental Subtitle C Costs under Alternative Beneficial Use Scenarios

($Billions present value at 7% discount rate and 20-year study horizon)

Scenario	Mean*	90% Confidence Interval*
Scenario #1: Encapsulated Use Rate Unchanged	$63.85	$55.31 – $74.53
Scenario #2: Encapsulated Use Decreases 18%	$65.52	$56.45 – $76.84
Scenario #3: Encapsulated Use Increases 11%	$62.82	$54.66 – $73.20

*Incremental costs over baseline. These do not include costs for landfill construction and operation costs, with the exception of specific upgrades required under Subtitle C

Interpreting "Point of Generation"

Under Subtitle C, CCRs destined for disposal would be regulated from the "point of generation." The proposed rules are ambiguous as to where point of generation is located. Because plant configurations, operations, and CCR handling practices can vary widely, it is expected that point of generation would be subject to interpretation on a case-by-case basis. For example, if a coal-fired plant was co-located with a wallboard manufacturing facility, and the gypsum conveyed directly from the power plant to its intended market, that CCR stream would be exempted from the Subtitle C regulation since the gypsum is being handled as a commodity and destined for an encapsulated use. However, if a plant stores fly ash in silos and a percentage of that ash is sold into encapsulated use markets, while the remainder is disposed, the point of generation could conceivably be considered the silo or even earlier in the process. Thus, EPRI undertook a separate study to determine the engineering costs associated with upgrading facilities to Subtitle C compliance (EPRI 2010).

In the analysis of point of generation for that study, the EPRI team applied concepts codified by EPA. More specifically, when one makes the determination to discard or dispose of materials that are not subject to exclusion or variance from solid waste, those materials are regulated as solid wastes under RCRA; further a solid waste that is a listed RCRA waste is a hazardous waste under RCRA (40 *CFR* 261.2(a)(1) and 40 *CFR* 261.3). Further, 40 *CFR* 260.10 defines disposal as "the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste or hazardous waste into or on any land or water so that such solid waste or hazardous waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters." Therefore, disposal may be an active decision (e.g., placing materials in a landfill for disposal) or passive (e.g., discharge, spilling, leaking solid waste or constituents of solid waste into the environment, air or water). If CCRs are contained, the point of generation occurs at the point when the decision is made to discard or dispose of the CCRs. However, if the CCRs are spilled, leaked, or discharged, then the point of generation occurs at the place of the discharge.

Thus, if point of generation were interpreted at the truck loading facility (trucks headed for landfill), then most of the Subtitle C costs included in this analysis still apply. Namely, RCRA administrative costs, wet-to-dry conversion costs, wastewater treatment costs, truck loading facility costs, and disposal costs would still apply. Some costs would possibly be eliminated, including:

- Upgrading area surrounding boilers and dewatering bins;
- Upgrading or building ESP/baghouse enclosures and concrete containment under ESPs;
- Upgrading area under FGD dewatering equipment; and
- Upgrading or building FGD solids containment building.

The additional personnel dedicated to maintenance, spill prevention, and response would still be required even with a point of generation at the truck loading facility. This is because prevention of spills would be paramount to demonstrating that downstream point of generation. This analysis examined the implications for a point of generation located at the truck loading facility. The results are shown in Table 4-3. As the table shows, the interpretation of point of generation does not make a significant difference in total costs.

Table 4-3
Interpretation of Point of Generation and Impact on Total Costs

($Billions present value at 7% discount rate and 20-year study horizon)

Scenario	Mean Cost	90% Confidence Interval
Point of Generation in plant	$63.85	$55.31 – $74.53
Point of Generation at truck loading	$60.91	$52.37 – $71.59

Effect of Discount Rate on Total Costs

The effect of alternate discount rates on the calculation of total present value cost is shown in Table 4-4. This analysis assumed a seven percent (7 %) discount rate, as suggested in OMB guidance for regulatory impact analysis (OMB 2003). This rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy[5]. However, OMB notes that "the effects of regulation do not always fall exclusively or primarily on the allocation of capital. When regulation primarily and directly affects private consumption (e.g., through higher consumer prices for goods and services), a lower discount rate is appropriate" (OMB Circular A-4, page 33). This is true for regulatory costs that could be passed onto consumers in the form of higher electricity prices through rate cases. Following the guidance in Circular A-4, an alternate discount rate of 3 percent was also analyzed.

[5] Per OMB, the seven percent rate approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector.

Table 4-4
Effect of Alternate Discount Rates on Costs

Discount Rate	Mean Cost	95% Confidence Interval
3% over 20 years	$92.70	$78.92 – $110.00
7% over 20 years	$63.85	$55.31 – $74.53

Implications of Subtitle C Rule for Commercial Disposal

As discussed in Section 3, this analysis used survey responses to calculate probabilities for alternate disposal decisions at non-surveyed plants. For each iteration of the simulation, the Monte Carlo cost model assigns a disposal decision (based on site-specific probabilities) to each coal-fired plant, and calculates the disposal costs associated with that decision. The model also sums the total quantity of CCRs by disposal location (on-site, off-site, and commercial). Across all the iterations, this summation yields a range of total CCRs destined for commercial disposal. The regression predicts between 14,970,000 and 20,550,000 tons of CCRs would be sent to commercial hazardous waste landfills each year. This volume of waste would exceed the entire current capacity of the commercial hazardous waste market, estimated at 34,000,000 tons (Brown 2009; U.S. EPA 2008a) within two years.

The implications for compliance deadlines can exacerbate this situation. Siting, designing, permitting, and constructing landfill capacity to replace impoundments that must close under the rule is expected to take at least five to seven years (and possibly longer for Subtitle C landfills or where state agencies are confronted with a large number of permit applications). Further, due to potentially lengthy public participation process, landfill permitting could take much longer in some areas. These timelines will affect compliance costs, particularly for plants that currently utilize only surface impoundments for disposal. Delays in landfill permitting and construction would force the early shipment of additional CCRs (increase from estimated volumes) to commercial landfills. Further, due to the regulatory uncertainty in adoption of the rules in states with more restrictive criteria (i.e. Florida, Kansas, Wisconsin), it is uncertain whether plants in those states could even use existing landfill capacity for CCR disposal. As a result of these difficulties, compliance costs could be substantial. However, this analysis did not include the increased costs associated with these permitting and disposal issues.

Non-Quantified Factors That Could Affect Compliance Costs

This analysis did not attempt to quantify the effect of multiple regulations on potential compliance costs, although there are other proposed rules that could increase costs associated with the CCR proposed rules. Revisions to EPA's Effluent Limitation Guidelines for the steam electric power generating industry could potentially affect wastewater treatment technologies installed. Further, the analysis does not consider the addition of future FGD systems, although many plants may need to retrofit with scrubber systems as EPA moves forward with their proposed Transport Rule for sulfur dioxide (SO_2) and nitrogen oxides (NO_x). The installation of scrubbers at plants would increase compliance costs because of the additional technical systems required to meet Subtitle C requirements.

This analysis does not take into account the increase in CCR volumes that may occur due to fixation/stabilization to meet land disposal restrictions. In such cases, handling, treatment and disposal costs could increase. While the analysis considered a scenario in which encapsulated use decreases, the analysis included minefill applications as an allowable use. If the Office of Surface Mining promulgates rules which restrict CCRs for minefill use, this would increase the volume of CCRs which must be disposed by seven percent.

As discussed above, delays in landfill permitting and siting could significantly increase total costs of the rule because plants without landfill capacity would be forced to use commercial disposal until landfill construction is complete. When regulatory approvals have been characterized by contested case hearings, the permitting process has been prone to delays. This analysis assumes that the permit process goes smoothly without delays, and new landfill capacity can be sited by the effective date of pond closures. Further, this analysis does not speculate on restrictions or limitations imposed by individual states in their adoption of the rule (rather, it assumes states adopt the federal rules in 2 years and are not more restrictive than the EPA regulations). However, if some states continue to prohibit hazardous waste landfills, then plants in those states would be forced to dispose off-site, increasing the total cost of the rule.

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A
COST SUMMARIES

The following tables are excerpted from the EPRI report *Engineering and Cost Assessment of Hazardous Waste Designation of Coal Combustion.* 1020557. EPRI, Palo Alto, CA, 2010. The costs in the tables were applied as specified in Section 3, Costing Methodology and Incorporation of Uncertainty.

Table A-1
Summary of Capital Costs for Work Item 1: Bottom Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Bottom Ash Management System: 800-MW Unit					
1a	Area Under Boiler	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	200' x 150' area with 700 linear (lin.) ft. curb	$640,000	Per unit
1b	Area Surrounding Dewatering Bins	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	40' x 80' area with 240 lin. ft. curb	$100,000	Per unit
1c	Truck Loading from Dewatering Bins	Construct truck loading building consisting of 1 truck bay, with mezzanine level to access top of truck, closed at either end by sealed doors. Truck will be loaded from Dewatering Bin in the center of building.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; curbed and coated concrete floor with rollover curbs; 230 lin. ft. curb	$410,000	Per station
Bottom Ash Management System: 200-MW Unit					
1a	Area Under Boiler	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	120' x 90' area with 420 lin. ft. curb	$260,000	Per Unit
1b	Area Surrounding Dewatering Bins	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	30' x 50' area with 160 lin. ft. curb	$60,000	Per Unit
1c	Truck Loading from Dewatering Bins	Construct truck loading building consisting of 1 truck bay, with mezzanine level to access top of truck, closed at either end by sealed doors. Truck will be loaded from Dewatering Bin in the center of building.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; curbed and coated concrete floor with rollover curbs; 230 lin. ft. curb	$410,000	Per Station

Table A-2
Summary of Capital Costs for Work Item 2: Economizer Ash/Fly Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Economizer / Fly Ash Management System: 800-MW Unit					
2a	Coat and Seal Area Under ESP	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	100' x 140' area with 480 lin. ft. curb	$330,000	Per Unit
2b	ESP Enclosure	(Existing enclosure around ESP hoppers, i.e. northern plant location) Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Tighten and seal enclosure building.	Enclosure measuring 140' long x 100' wide x 32' high from grade to bottom of existing ESP enclosure; 1 roll-up door; 2 personnel doors; one 22,400 acfm fan with filter housing and 40 horsepower (HP) motor.	$1,120,000	Per Unit
2c	Fly Ash Truck Loading	Construct truck loading building consisting of 1 truck bay, with mezzanine level to access top of truck, closed at either end by sealed doors. Truck will be loaded from storage silo in the center of building with a telescoping double wall chute. Provide ventilating fan with bag house filter to maintain negative pressure in loading bay and annulus on chute.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 lin. ft. curb.	$830,000	Per Station

Table A-2 (continued)
Summary of Capital Costs for Work Item 2: Economizer Ash/Fly Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Economizer / Fly Ash Management System: 800-MW Unit (continued)					
2-Option 1	ESP Enclosure	(No existing enclosure around ESP hoppers, i.e. southern plant location) Build a sealed enclosure around ESP hopper area. Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Provide sealed and curbed concrete floor.	Enclosure measuring 140' long x 100' wide x 32' high from grade to bottom of existing ESP enclosure; 1 roll-up door; 2 personnel doors; (1) 22,400 CFM fan with filter housing and 40 HP motor; curbed and coated concrete floor with rollover curbs; 480 lin. ft.	$3,770,000	Per Unit
2- Option 2	Concrete Containment Area Under ESP	Remove existing surface material (gravel, asphalt, etc.) and replace with curbed and coated concrete containment area.	100' x 140' area with 480 lin. ft. curb.	$520,000	Per Unit
2- Option 3	Redundant Pneumatic Transfer Line	Install redundant transfer line from ESP area to fly ash storage/loading facility	600' of 10" line	$1,500,000	Per Station
2 - Option 4	Redundant Ash Storage/Truck Loading Facility	Install silo with baghouse, building similar to Item 2c above	100-ton silo with 1000 acfm baghouse, 1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 lin. ft. curb.	$3,610,000	Per Station

Table A-2 (continued)
Summary of Capital Costs for Work Item 2: Economizer Ash/Fly Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Economizer / Fly Ash Management System: 200 MW Unit					
2a	Coat and Seal Area Under ESP	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	50' x 110' area with 320 lin. ft. curb	$150,000	Per Unit
2b	ESP Enclosure	(Existing enclosure around ESP hoppers, i.e. northern plant location) Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Tighten and seal enclosure building.	Enclosure measuring 110' long x 50' wide x 32' high from grade to bottom of existing ESP enclosure; 1 roll-up door; 2 personnel doors; (1) 8,800 acfm fan with filter housing and 20 HP motor.	$590,000	Per Unit
2c	Fly Ash Truck Loading	Construct truck loading building consisting of 1 truck bay, with mezzanine level to access top of truck, closed at either end by sealed doors. Truck will be loaded from storage silo in the center of building with a telescoping double wall chute. Provide ventilating fan with bag house filter to maintain negative pressure in loading bay and annulus on chute.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 linear ft curb.	$830,000	Per Station

Table A-2 (continued)
Summary of Capital Costs for Work Item 2: Economizer Ash/Fly Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Economizer / Fly Ash Management System: 200 MW Unit (continued)					
Option 1	ESP Enclosure	(No existing enclosure around ESP hoppers, i.e. southern plant location) Build a sealed enclosure around ESP hopper area. Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Provide sealed and curbed concrete floor.	Enclosure measuring 110' long x 50' wide x 32' high from grade to bottom of existing ESP enclosure; 1 roll-up door; 2 personnel doors; one 8,800 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 320 lin. ft. curb.	$1,740,000	Per Unit
2- Option 2	Concrete Containment Area Under ESP	Remove existing surface material (gravel, asphalt, etc) and replace with curbed and coated concrete containment area.	50' x 110' area with 320 lin. ft. curb.	$220,000	Per Unit
2- Option 3	Redundant Pneumatic Transfer Line	Install redundant transfer line from ESP area to fly ash storage/loading facility	600' of 10" line	$1,500,000	Per Station

Table A-3
Summary of Capital Costs for Work Item 3: FGD By-product/Gypsum Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Flue Gas Desulfurization By-product/Gypsum Management System: 800-MW Unit					
3a	Area Under Dewatering Equipment	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	100' x 120' area with 440 lin. ft. curb.	$290,000	Based on 2 100% 50 TPH belt filters; Per Station
3b	Dewatering Equipment Building	(Existing enclosure around dewatering equipment) Provide ventilating fan with bag house filter to maintain negative pressure in building. Tighten and seal enclosure building.	1 building measuring 120' long x 100' wide x 50' high; 1 roll-up door; 2 personnel doors; one 30,000 acfm fan with filter housing and 60 HP motor.	$1,430,000	Based on 2 100% 50 TPH belt filters; Per Station
3c	Gypsum Containment Building	(Existing enclosure around gypsum storage) Provide ventilating fan with bag house filter to maintain negative pressure in building. Tighten and seal storage building.	1 building measuring 425' long x 100' wide x 50' high; 2 roll-up doors; 2 personnel doors; one 106,250 acfm fan with filter housing and 200 HP motor.	$6,050,000	Per Station
3d	Gypsum Containment Building Floor	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	425' x 100' area with 1050 lin. ft. curb.	$920,000	Per Station
3e	Truck Loading from Storage	Construct truck loading building consisting of 1 truck bay, with mezzanine to access top to truck, closed at either end by sealed doors. Truck will be loaded from gypsum storage building. Provide ventilating fan with bag house filter to maintain negative pressure in loading bay.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 lin. ft curb.	$820,000	Per Station

Table A-3 (continued)
Summary of Capital Costs for Work Item 3: FGD By-product/Gypsum Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Flue Gas Desulfurization By-product/Gypsum Management System: 800-MW Unit (continued)					
3 – Option 1	Gypsum Containment Building Floor	Remove existing surface material in gypsum storage area and replace with curbed and coated concrete containment area.	425' x 100' area with 1050 lin. ft. curb.	$1,540,000	Per Station
3 – Option 2	New Gypsum Containment Building	(No existing enclosure around gypsum storage) Build a sealed enclosure around gypsum storage area. Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Provide sealed and curbed concrete floor.	1 building measuring 425' long x 100' wide x 50' high; 400' long 50 TPH conveyor with travelling tripper; 1 roll-up door; 2 personnel doors; one 106,250 acfm fan with filter housing and 200 HP motor; curbed and coated concrete floor with rollover curbs; 1050 lin. ft. curb.	$16,850,000	Per Station
3 – Option 3	Conveying to Storage	Demolish existing conveyor from dewatering building to gypsum storage area and replace with pipe conveyor.	250 linear feet of existing conveyor replaced with pipe conveyor.	$850,000	Per Station; Use $2500/ft new conveyor cost
3 – Option 4	Redundant Conveying to Storage	Add second pipe conveyor	250 linear feet of new pipe conveyor parallel to new conveyor installed in Option 3 above	$760,000	Per Station; Use $2250/ft new conveyor cost
3 - Option 5	Sulfite producing FGD System	Assume Items 3a, 3b, 3e, and 3 - option 2 above will apply. Includes upgrades to area under dewatering and pug mill equipment, upgrades to dewatering/pug mill building, new stabilized byproduct RCRA storage building, and new enclosed truck loading facility.	See above	$19,390,000	Total Cost Per Station

Table A-3 (continued)
Summary of Capital Costs for Work Item 3: FGD By-product/Gypsum Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
FGD By-product/Gypsum Management System: 200-MW Unit					
3a	Area Under Dewatering Equipment	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	60' x 90' area with 300 lin. ft. curb.	$150,000	Based on 2 100% 50 TPH belt filters; Per Station
3b	Dewatering Equipment building	(Existing enclosure around dewatering equipment) Provide ventilating fan with bag house filter to maintain negative pressure in building. Tighten and seal enclosure building.	1 building measuring 100' long x 80' wide x 50' high; 1 roll-up door; 2 personnel doors; one 20,000 acfm fan with filter housing and 40 HP motor.	$1,040,000	Based on 2 100% 50 TPH belt filters; Per Station
3c	Gypsum Containment Building	(Existing enclosure around gypsum storage) Provide ventilating fan with bag house filter to maintain negative pressure in building. Tighten and seal storage building.	1 building measuring 250' long x 100' wide x 50' high; 2 roll-up doors; 2 personnel doors; one 62,500 acfm fan with filter housing and 125 HP motor.	$4,100,000	Per Station
3d	Gypsum Containment Building Floor	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	250' x 100' area with 700 lin. ft. curb.	$560,000	Per Station
3e	Truck Loading from Storage	Construct truck loading building consisting of 1 truck bay, with mezzanine to access top to truck, closed at either end by sealed doors. Truck will be loaded from gypsum storage building. Provide ventilating fan with bag house filter to maintain negative pressure in loading bay.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 lin. Ft. curb.	$820,000	Per Station

Table A-3 (continued)
Summary of Capital Costs for Work Item 3: FGD By-product/Gypsum Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
FGD By-product/Gypsum Management System: 200-MW Unit (continued)					
3 - Option 1	Gypsum Containment Building Floor	Remove existing surface material in gypsum storage area and replace with curbed and coated concrete containment area.	250' x 100' area with 700 lin. ft. curb.	$910,000	Per Station
3 - Option 2	New Gypsum Containment Building	(No existing enclosure around gypsum storage) Build a sealed enclosure around gypsum storage area. Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Provide sealed and curbed concrete floor.	1 building measuring 250' long x 100' wide x 50' high; 225' long 50 TPH conveyor with travelling tripper; 1 roll-up door; 2 personnel doors; one 62,500 acfm fan with filter housing and 125 HP motor; curbed and coated concrete floor with rollover curbs; 700 lin. ft. curb.	$10,120,000	Per Station
3 - Option 3	Conveying to Storage	Demolish existing conveyor from dewatering building to gypsum storage area and replace with pipe conveyor.	250 linear feet of existing conveyor replaced with pipe conveyor.	$850,000	Per Station; Use $2500/ft replacement cost.
3 - Option 4	Redundant Conveying to Storage	Add second pipe conveyor	250 linear feet of new pipe conveyor parallel to new conveyor installed in Option 3 above	$760,000	Per Station; Use $2250/ft new conveyor cost
3 - Option 5	Sulfite producing FGD System	Assume Items 3a, 3b, 3f, and 3 - option 2 above will apply. Includes upgrades to area under dewatering equipment, upgrades to dewatering/pug mill building, new stabilized byproduct RCRA storage building, and new enclosed truck loading facility.	See above	$12,130,000	Total Cost Per Station

Table A-4
Summary of Costs for Work Item 5: Land Storage/Landfill Upgrades to RCRA Standards*

General Work Description	Cost Estimate			
	400 MW Station	800 MW Station	1600 MW Station	3200 MW Station
Landfill Security	$733,000	$890,000	$1,100,000	$1,370,000
Leachate Tank (RCRA tank standards)	$1,410,000	$1,410,000	$2,810,000	$4,220,000
RCRA Waste Pile (Constructed at landfill)	$3,480,000	$3,480,000	$3,480,000	$3,480,000
Item 5 Total Estimated Cost for Landfills & RCRA Waste Pile Per Station	$5,630,000	$5,780,000	$7,390,000	$9,070,000
Landfill O&M (Increase over impoundment O&M - additional Subtitle C requirements)	$161,000	$161,000	$322,000	$322,000

* Numbers in Table A-4 have been rounded up to three significant digits.

Table A-5
Summary of Costs for Work Item 6 Wastewater Treatment System*

General Work Description	Estimated Cost	Cost Basis
Active Pond Closures [Ponds that are currently receiving CCR slurry streams and will be operational when rules become effective]:		
Active pond closure - per Subtitle D requirements	$192,000	$/acre
Active pond closure - per Subtitle C requirements	$275,000	$/acre
Active pond closure - Incremental cost to close an active pond per Subtitle C relative to Subtitle D	$65,000	$/acre
Mean acreage of active ponds/plant: 148 acres	$9,620,000	Per Station
Inactive Ponds Closure [Ponds that have stopped receiving CCRs and exist with moderate vegetation growing over the cap.]:		
For Subtitle D requirements of the proposed rules - not required to close inactive ponds.	0	$/acre
Closure of an inactive pond per Subtitle C Requirements	$221,000	$/acre
Incremental cost to close an active pond per Subtitle C relative to Subtitle D	$221,000	$/acre
Mean acreage of inactive ponds/plant: 48 acres	$10,700,000	Per Station
Wastewater Treatment:		
Water treatment system for CCR contact water (0.1 to 2.0 mgd)	$6,000,000 to $22,500,000	Per Station
Water treatment system for FGD wastewater (0.1 to 2.0 mgd)	$22,800,000 to $60,800,000	Per Station with FGD
Replacement ponds for other streams (non-CCR contact water) (10-acre pond with 2 foot recompacted clay liner. Includes contingency)	$2,400,000	1 or 2 Per station with ash ponds

* Numbers in Table A-5 have been rounded up to three significant digits.

Table A-6
Summary of Costs for Work Item 7 Miscellaneous Operational/Administrative Upgrades

General Work Description	Initial (one-time) Cost Estimate		Annual Cost Estimate
	2x200 MW Units	2x800 MW Units	
Notification Requirements	$328	$329	$110
Pt A Permit Application	$12,100	$17,300	Not estimated
Pt B Permit Application	$721,000	$1,020,000	Not estimated
Permit Fees	$15,000	$549,000	Not estimated
General Waste Analysis, LDR Waste Analysis, and Written Waste Analysis Plan	$14,800	$14,800	$13,000
Written Inspection Schedule	$1,320	$1,320	$1,390
Personnel Training	$18,600	$48,000	$15,900 to $48,000
Emergency Response Plan	$2,630	$2,630	Not estimated
Contingency Plan	$2,630	$2,630	Not estimated
Biennial Report Preparation	--	--	$875
Operating Record	$41,000	$47,000	$7,230
Groundwater Monitoring Plan	$20,000	$30,000	$5,400
Groundwater Sampling	$347,000	$445,000	$29,100 to $146,000
Closure and Post-closure Plans	$125,000	$143,000	$1,750
Closure Certification	$108,000	$147,000	0
Financial Assurance for Closure and Post-Closure	$68,000	$68,000	$56,100
Financial Assurance for Third Party Liability Coverage	$109,000	$109,000	$102,000
Corrective Action Schedule	$1,320	$1,320	$656
Corrective Action: Facility Assessments/Investigations	$750,000	$3,500,000	Not estimated
Additional O&M Staff focused on CCR maintenance, spills and response	$1,290,000	$4,190,000	$1,290,000 to $4,190,000

* Numbers in this table have been rounded up to three significant figures.

Program:

Coal Combustion Products - Environmental Issues

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