Hart Exhibit 33
Docket No. E-7, Sub 1214

OFFICIAL COPY

North Carolina Department of Environment and Natural Resources
Division of Water Quality
Coleen H. Sullins
Director

Beverly Eaves Perdue
Governor

Dee Freeman
Secretary

March 3, 2009

Mr. Allen Stowe
Water Management
Duke Energy Corporation
EC 13K / PO Box 1006
Charlotte, NC 28201-1006

Dear Mr. Stowe:

Duke Energy and the Division of Water Quality have been in discussions concerning your company's participation in a voluntary utility industry groundwater monitoring program. The purpose of this monitoring as we understand it is to help determine the environmental impact of coal ash storage in on-site ash ponds. Over the past two years, we have received one or more reports containing data from seven of your facilities that operate under NPDES permits: Allen Steam, Belews Creek Steam, Buck Steam, Cliffside Steam, Dan River Steam, Marshall Steam, and Riverbend Steam Power Plants.

Although most of the data for parameters sampled did not exceed standards, all of the reports included some standard exceedances or pH values outside the allowable range. Due to concern about the relevance of these exceedances, we need additional information regarding well locations, parameter lists, and sampling schedules for the facilities involved. Please submit the following additional information by April 30, 2009:

- A list of all North Carolina facilities, indicating which facilities are expected to submit voluntary groundwater monitoring data at any point in the future. Include the pre-determined parameter list and sampling schedule (months) for each participating facility.
- Maps for each facility that is performing voluntary monitoring.
    - Include appropriate markings for property boundaries, water supply wells etc.
    - Show locations of all monitoring wells associated with the permitted ash ponds (voluntary or permit related wells) in relation to the Waste Boundary, Compliance Boundary, and Review Boundary, as defined in 15A NCAC 2L .0102, .0107, and .0108 respectively.
    - Identify each well as a background or downgradient well as applicable.
    - Show the location of any waste disposal areas and other potential sources of contamination at the site.
- Electronic copies in Excel of all data collected previously in the attached format. Submit future data in the same format according to the pre-determined schedule. (Attached format can be provided electronically).
- Copies of well construction records (Form GW-1) for all voluntary monitoring wells.
- An evaluation of the groundwater standard exceedances at each facility to determine if the facility is in compliance. Include the following:
    - Well locations in relation to the Waste Boundary, Review Boundary, and Compliance Boundary.
    - Determination of exceedances relative to groundwater quality standards.
    - Planned action as a result of the exceedances. This should be done in accordance with the applicable sections of 15A NCAC 2L .0106.

AQUIFER PROTECTION SECTION
1636 Mail Service Center, Raleigh, North Carolina 27699-1636
Location: 2728 Capital Boulevard, Raleigh, North Carolina 27604
Phone: 919-733-3221 \ FAX 1: 919-715-0588; FAX 2: 919-715-6048 \ Customer Service: 1-877-623-6748
Internet: www.ncwaterquality.org

Hart Exhibit 34
Docket No. E-7. Sub

I/A

CORPORATE EHS SERVICES

Duke Energy Corporation
526 South Church St.
Charlotte, NC 28202

Mailing Address:
EC13K / PO Box 1006
Charlotte, NC 28201-1006

April 30, 2009

Mr. Ted Bush
State of North Carolina
Department of Environment and Natural Resources
Division of Water Quality
Aquifer Protection Section
1636 Mail Service Center
Raleigh, North Carolina 27699-1636

Subject: Duke Energy Carolinas, LLC
Voluntary Utility Industry Groundwater Monitoring Program

Dear Mr. Bush:

Attached is the information that you requested in your letter dated March 3, 2009 concerning the groundwater monitoring programs at the ash ponds for our North Carolina facilities. This information is stored electronically on a compact disc. Additionally, three hard copies of the facility maps are also enclosed.

Duke Energy Carolinas, LLC proactively embarked upon instituting voluntary groundwater monitoring programs around our ash ponds in late 2004. Groundwater monitoring around the ash ponds at our seventh and final North Carolina coal fired facility was completed in December 2008. The Aquifer Protection Section was consulted for guidance at various stages of this implementation process.

We would like to arrange a meeting with your staff to discuss this information in greater detail at a later date. Should you have questions regarding this submittal, please contact me at (704) 382-4309.

Sincerely,

Allen Stowe
Water Management

Attachments

J.A. Stowe/DWQ Information Request 04302009

bc w: George Everett
Allen Stowe

bc wo: Patrick Gratton
Bill McCabel
Dave Mitchell
Debbie Nispel
Garry Rice
Ed Sullivan

Record Number: 497585
Certified Mail: 7008 1140 0002 2718 5394

The North Carolina Department of Environment and Natural Resources Aquifer Protection Section sent Duke Energy Carolinas, LLC a letter dated March 3, 2009 requesting information by April 30, 2009 on the voluntary groundwater action plan for the Duke Energy Carolinas, LLC ash ponds. The following bullets address the information requested and our response.

- A list of all North Carolina facilities, indicating which facilities are expected to submit voluntary groundwater monitoring data at any point in the future. Include the pre-determined parameter list and sampling schedule (months) for each participating facility.

All of the Duke Energy Carolinas, LLC fossil plants are currently monitoring the groundwater at their ash ponds on a semi-annual basis. See attached electronic records for all facility information, parameter list and sampling schedule.

- Maps for each facility that is performing voluntary monitoring.
    - Include appropriate markings for property boundaries, water supply wells, etc.
    - Show locations of all monitoring well associated with the permitted ash ponds (voluntary or permit related wells) in relation to the Waste Boundary, Compliance Boundary, and Review Boundary, as defined in 15A NCAC 2L .0102, .0107, and .0108 respectively.
    - Identify each well as a background or downgradient well as applicable.
    - Show the location of any waste disposal areas and other potential sources of contamination at the site.

Please see attached maps for Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, and Riverbend Steam Stations which show the requested information. As this request was directed at ash ponds containing coal combustion products (CCPs), these maps show location of active and inactive CCP disposal, reuse, and storage areas.

- Electronic copies in Excel of all data collected previously in the attached format. Submit future data in the same format according to the pre-determined schedule. (Attached format can be provided electronically).

Included with this submittal is a compact disc containing Excel spreadsheet groundwater data for Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, and Riverbend Steam Stations which has been collected for the utility voluntary Action Plan. Note that Dan River Steam Station has conducted groundwater monitoring as required by its NPDES permit (NC0003468) since 1993. Additional wells have recently been added to the Dan River Steam Station groundwater monitoring program as part of the voluntary action plan.

All groundwater data gathered from these ash pond monitoring well locations have been promptly forwarded to the Aquifer Protection Section since 2005. Each semi-annual submittal package contained a topographical map with monitoring well locations, data tables with complete analytical results and water elevations, laboratory chain of custody

sheets, and a cover letter highlighting exceedances from the NCAC 2L groundwater standards.

- Copies of well construction records (Form GW-1) for all voluntary monitoring wells.

See attached electronic records for all voluntary action plan groundwater monitoring well construction records.

- An evaluation of the groundwater standard exceedances at each facility to determine if the facility is in compliance. Include the following:
    - Well locations in relation to the Waste Boundary, Review Boundary and Compliance Boundary
    - Determination of exceedances relative to groundwater quality standards
    - Planned action as a result of the exceedances. This should be done in accordance with the applicable sections of 15A NCAC 2L .0106

The attached figures include the waste boundary, review boundary and compliance boundary for Allen, Belews Creek, Buck, Cliffside, Dan River, Marshall, and Riverbend Steam Stations.

Duke Energy Carolinas, LLC is currently reviewing the various groundwater monitoring systems and investigating options to make these systems more robust. Locating monitoring wells more precisely along the review and/or compliance boundaries is anticipated. To date, there have been no observed exceedances at the compliance boundary. Duke Energy Carolinas, LLC would like to consult with the Aquifer Protection Section regarding these enhanced groundwater monitoring networks.

Sampling Schedule and Pre-determined Parameter List

Duke Energy Carolinas LLC
NC Facility List
Groundwater Voluntary Action Plan (VAP)

Site	Permit/Program Name	Permit #	Sample Months (performed semi-annually)
Allen	Ash Basin	VAP	May
Allen	Ash Basin	VAP	November
Belews Creek	Ash Basin	VAP	May
Belews Creek	Ash Basin	VAP	November
Buck	Ash Basin	VAP	May
Buck	Ash Basin	VAP	November
Cliffside	Ash Basin	VAP	February
Cliffside	Ash Basin	VAP	August
Dan River	Ash Basin - NPDES	NC0003468	April
Dan River	Ash Basin - NPDES	NC0003468	October
Marshall	Ash Basin	VAP	February
Marshall	Ash Basin	VAP	August
Riverbend	Ash Basin	VAP	June
Riverbend	Ash Basin	VAP	December

Note: Voluntary ash basin groundwater monitoring programs have been established at all Duke Energy coal fired sites in North Carolina. These seven facilities are listed in the table above.

Groundwater Parameter List

Parameter	Units	Certificate Codes
Field pH	Std. Units	5193
Field Spec. Conductance	umho/cm	5193
Temperature	C	5193
Top Casing	msl-feet	
Depth to Water	feet	
Water Elevation	msl-feet	
Well Depth	feet	
Arsenic	mg/l	248
Barium	mg/l	248
BOD	mg/l	12
Boron	mg/l	248
Cadmium	mg/l	248
Chemical Oxygen Demand	mg/l	12
Chloride	mg/l	248
Chromium	mg/l	248
Copper	mg/l	248
Fluoride	mg/l	248
Iron	mg/l	248
Lead	mg/l	248
Manganese	mg/l	248
Mercury	mg/l	248
Nickel	mg/l	248
Nitrate (as Nitrogen)	mg-N/l	248
Selenium	mg/l	248
Silver	mg/l	248
Sulfate	mg/l	248
Total Dissolved Solids	mg/l	12
Total Organic Carbon	mg/l	248
Total Organic Halogen	mg/l	12
Zinc	mg/l	248

Voluntary Action Plan Facility Maps

ALLEN STEAM STATION

PLANT ALLEN ROAD

AB-1

FACILITY BOUNDARY

LIMIT OF WASTE (STRUCTURAL FILL)

ASH STORAGE

INACTIVE ASH BASIN (APPROXIMATE)

SOUTH POINT ROAD (NC 273)

STRUCTURAL FILL

STRUCTURAL FILL

INACTIVE ASH BASIN ASH LANDFILL PERMIT NO. 36-12

ASH STORAGE

AB2-D

AB2

AB-8

LOWER ARMSTRONG ROAD

WILDLIFE ROAD

AB4-D

AB4

LAKE WYLIE

ACTIVE ASH BASIN

AB-6R
AB-6A

AB-5

REVIEW BOUNDARY

COMPLIANCE BOUNDARY

REESE WILSON ROAD

SOUTH POINT ROAD (NC 273)

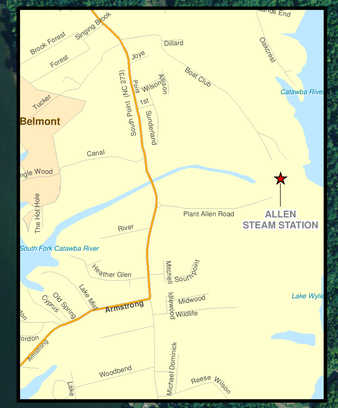
N

W E

S

300 150 0 300 600 900 1200

Feet



SITE LOCATION MAP

SCALE: 1" = 2,000'

Legend

- Duke Property Boundary
- Waste Boundary
- Monitoring Well
- Topographic Contour
- Review Boundary
- Compliance Boundary
- Compliance Boundary Coincident with Property Line
- Inactive Ash Basin, Structural Fill or Ash Storage

NOTES:

PARCEL DATA FOR THE SITE WAS OBTAINED FROM GASTON COUNTY GEOGRAPHIC INFORMATION SYSTEMS (GIS) DEPARTMENT (OCTOBER 2008) AND IS APPROXIMATE.

WASTE BOUNDARY IS APPROXIMATE.

MONITORING WELL LOCATIONS PROVIDED BY DUKE.

TOPOGRAPHY DATA FOR THE SITE WAS OBTAINED FROM NCDOT GEOGRAPHIC INFORMATION SYSTEMS (GIS) DEPARTMENT WEB SITE.

ORTHO-PHOTOGRAPHY WAS OBTAINED FROM NC ONEMAP (FLY DATE, 2007).

THE COMPLIANCE BOUNDARY IS ESTABLISHED ACCORDING TO THE DEFINITION FOUND IN 15A NCAC 02L .0107 (a).

THE REVIEW BOUNDARY IS ESTABLISHED ACCORDING TO THE DEFINITION FOUND IN 15A NCAC 02L .0108.

Duke Energy®

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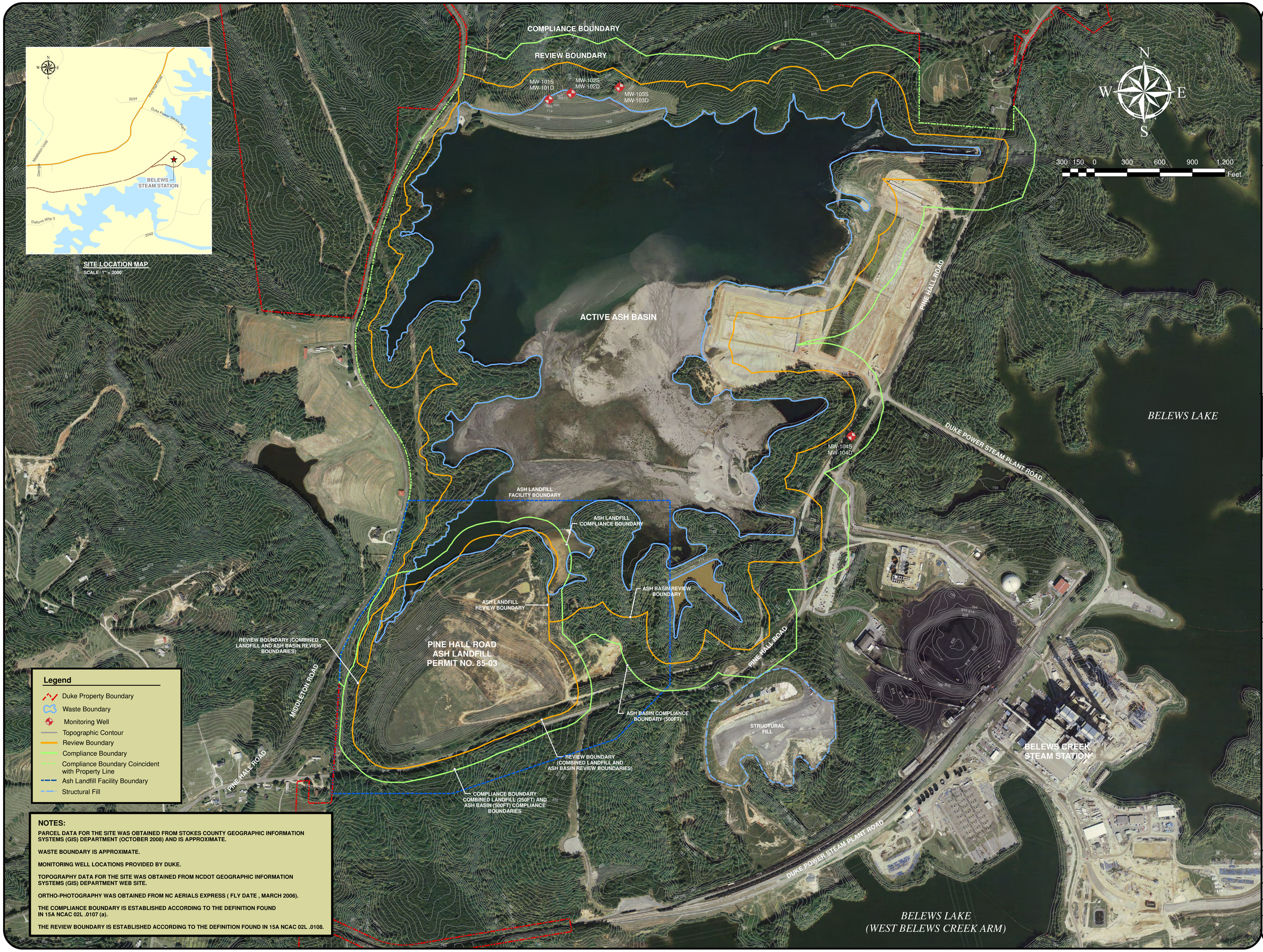
NORTH CAROLINA PROFESSIONAL ENGINEER SEAL 17661 WILLIAM M. MCDONALD

NO.	DATE	DESCRIPTION	BY
0	04/27/2009	RELEASED FOR SUBMITTAL TO NCDENR	WMM

ALLEN ASH BASIN
NPDES PERMIT NC0004979
WASTE, REVIEW, AND COMPLIANCE BOUNDARY

DUKE ENERGY - ALLEN STEAM STATION
GASTON COUNTY, NORTH CAROLINA

DRAWN BY: R. POWERS	CHECKED BY: WMM
DESIGNED BY:	APPROVED BY: LTA
PROJECT NO: 1411-08-092	
SCALE: 1"=300'	DATE: 04/27/2009
DRAWING: 1	OF: 1



SITE LOCATION MAP
SCALE: 1" = 2000'

Legend

- Duke Property Boundary
- Waste Boundary
- Monitoring Well
- Topographic Contour
- Review Boundary
- Compliance Boundary
- Compliance Boundary Coincident with Property Line
- Ash Landfill Facility Boundary
- Structural Fill

NOTES:

PARCEL DATA FOR THE SITE WAS OBTAINED FROM STOKES COUNTY GEOGRAPHIC INFORMATION SYSTEMS (GIS) DEPARTMENT (OCTOBER 2008) AND IS APPROXIMATE.

WASTE BOUNDARY IS APPROXIMATE.

MONITORING WELL LOCATIONS PROVIDED BY DUKE.

TOPOGRAPHY DATA FOR THE SITE WAS OBTAINED FROM NCDOT GEOGRAPHIC INFORMATION SYSTEMS (GIS) DEPARTMENT WEB SITE.

ORTHO-PHOTOGRAPHY WAS OBTAINED FROM NC AERIALS EXPRESS (FLY DATE , MARCH 2006).

THE COMPLIANCE BOUNDARY IS ESTABLISHED ACCORDING TO THE DEFINITION FOUND IN 15A NCAC 02L .0107 (a).

THE REVIEW BOUNDARY IS ESTABLISHED ACCORDING TO THE DEFINITION FOUND IN 15A NCAC 02L .0108.

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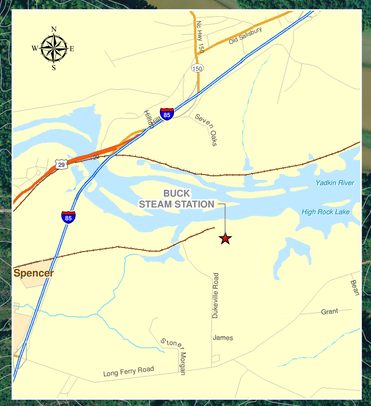
NORTH CAROLINA PROFESSIONAL ENGINEER SEAL 17661 WILLIAM M. MCDONALD

NO.	DATE	DESCRIPTION	BY
0	04/27/2009	RELEASED FOR SUBMITTAL TO NCDENR	WMM

BELEWS CREEK ASH BASIN NPDES PERMIT NC0024406 WASTE, REVIEW, AND COMPLIANCE BOUNDARY

DUKE ENERGY - BELEWS CREEK STEAM STATION STOKES COUNTY, NORTH CAROLINA

DRAWN BY: R. POWERS	CHECKED BY: WMM
DESIGNED BY:	APPROVED BY: LTA
PROJECT NO: 1411-08-092	
SCALE: 1"=300'	DATE: 04/27/2009
DRAWING: 1	OF: 1



SITE LOCATION MAP
SCALE: 1" = 3000'

YADKIN RIVER

BUCK
STEAM STATION

SITE
WATER WELL

COMPLIANCE BOUNDARY

REVIEW BOUNDARY

MW-3S; MW-3D

MW-4S; MW-4D

MW-5S; MW-5D

MW-1S; MW-1D

MW-6S; MW-6D

ACTIVE ASH BASIN
SECONDARY CELL

ACTIVE ASH BASIN
OLD PRIMARY CELL

ACTIVE ASH BASIN
ADDTIONAL
PRIMARY CELL

LEONARD ROAD

DUKEVILLE ROAD

LONG FERRY ROAD

N
W E
S

300 150 0 300 600 900 1,200
Feet

Legend

- Duke Property Boundary
- Waste Boundary
- Monitoring Well
- Topographic Contour
- Review Boundary
- Compliance Boundary
- Compliance Boundary Coincident with Property Line

NOTES:

PARCEL DATA WAS OBTAINED FROM ROWAN COUNTY AND MONITORING WELL LOCATIONS WERE OBTAINED FROM DUKE ENERGY AND ARE APPROXIMATE.

WASTE BOUNDARY IS APPROXIMATE.

TOPOGRAPHY DATA FOR THE SITE WAS OBTAINED FROM ROWAN COUNTY GEOGRAPHIC INFORMATION SYSTEMS (GIS) DEPARTMENT WEB SITE.

ORTHO-PHOTOGRAPHY WAS OBTAINED FROM AERIALS EXPRESS (FLY DATE, MARCH 2007).

THE COMPLIANCE BOUNDARY IS ESTABLISHED ACCORDING TO THE DEFINITION FOUND IN 15A NCAC 02L .0107 (a).

THE REVIEW BOUNDARY IS ESTABLISHED ACCORDING TO THE DEFINITION FOUND IN 15A NCAC 02L .0108.

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NORTH CAROLINA
PROFESSIONAL ENGINEER
SEAL
17661
WILLIAM M. MCKINNEY

NO.	DATE	DESCRIPTION	BY
0	04/27/2009	RELEASED FOR SUBMITTAL TO NCDENR	WMM

BUCK ASH BASIN
NPDES PERMIT NC0004774
WASTE, REVIEW, AND COMPLIANCE BOUNDARY

DUKE ENERGY - BUCK STEAM STATION
ROWAN COUNTY, NORTH CAROLINA

DRAWN BY: R. POWERS	CHECKED BY: WMM
DESIGNED BY:	APPROVED BY: LTA
PROJECT NO: 1411-08-092	
SCALE: 1"=300'	DATE: 04/27/2009
DRAWING: 1	OF: 1

Duke Energy's Position on the Regulation of Surface Impoundments and Landfills Used to Manage Coal Combustion Residues

Duke Energy is committed to the continued management of its coal combustion residues (CCR) in a manner that is protective of human health and the environment.

Duke Energy believes that the development of additional federal and state regulation of CCR management is appropriate. Specifically, Duke Energy supports the regulation of CCR as a non-hazardous waste under a Resource Conservation and Recovery Act (RCRA) Subtitle D program that can be implemented by the states. Duke Energy also supports the development of structural integrity standards for surface impoundments. Duke Energy is, however, adamantly opposed to the regulation of CCR as a RCRA Subtitle C hazardous waste. That option is not legally authorized and would result in significant adverse consequences; including devastating the CCR beneficial use market, imposing excessive and costly controls on power plant operations, and creating a serious short-fall in disposal capacity. Furthermore, the incremental cost to the electric utility industry from regulating CCR under Subtitle C, costs that would ultimately be paid by consumers, would be significantly greater than the cost of a properly designed Subtitle D program, yet would provide no additional protection to human health and the environment.

EPA's final regulation should adhere to the following fundamental principles.

- Retain unchanged the EPA's determination in 2000 that CCR do not warrant regulation as hazardous waste.
- Employ performance based non-hazardous waste standards for landfills and surface impoundments managing CCR.
- No mandatory phase out of wet handling of CCR or associated low volume wastewaters managed in surface impoundments meeting applicable dam integrity and ground water performance standards.
- State groundwater performance standards should guide any corrective action for CRR landfills and surface impoundments.
- Continue to support the beneficial use of CCR.

The following is Duke Energy's recommended approach to regulating **CCR under RCRA Subtitle D per comments to the EPA dated November 19, 2010.**

- The regulatory program would include a mechanism under which the states would administer the performance based ground water standards and dam integrity standards.
- All CCR landfills and surface impoundments would be required to obtain a permit from the state to insure compliance with ground water protection standards, and dam integrity standards for surface impoundments.
- Ground water monitoring wells would be required at all existing CCR landfills and surface impoundments to determine compliance with applicable state ground water performance standards. Any unit not in compliance would be required to take appropriate steps to come into compliance or to implement a closure plan, under a schedule determined by the state permitting authority.
- The horizontal expansion of existing CCR units or the construction of new CCR units would be required to use composite liner systems or an equivalent alternative systems approved by the state.
- All active CCR surface impoundments would be required to comply with dam integrity standards modeled after Mine Safety and Health Administration standards with appropriate adjustments, or be closed.
- Owners of CCR landfills and surface impoundments would be required to develop closure and post-closure plans, allowing for in-place closure for all active and inactive surface impoundments. The closure schedule would be established based on best engineering management practices.
- Location restrictions would not apply to existing CCR surface impoundments and landfills.
- Where performance criteria standards are satisfied, legitimate beneficial use of CCR should be allowed in encapsulated applications, and in unencapsulated applications that include gypsum use in agricultural applications and coal ash use in engineered structural fills such as road sub base and embankments.

Duke Energy
526 South Church Street
Charlotte, NC 28202
800-521-2232
www.duke-energy.com

[redacted]

Duke Energy

Regulated Utility Operations

Environmental Regulatory Issues

April 2013

[redacted]

Table of Contents

[redacted]

Acronym Listing

AFUDC	Allowance for Funds Used During Construction
ANPR	Advanced Notice of Proposed Rulemaking
BACT	Best Available Control Technology
BMP	Best Management Practices
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCB	Coal Combustion Byproducts
CCR	Coal Combustion Residuals
CCW	Condenser Cooling Water
CEM	Continuous Emission Monitor
CMP	Carbon Mitigation Plan
CSAPR	Cross-State Air Pollution Rule
DAQ	Division of Air Quality
DBA	Dibasic Acid
ESP	Electrostatic Precipitator
FDEP	Florida Department of Environmental Protection
FGD	Flue Gas Desulfurization
GHG	Greenhouse Gases
HAPs	Hazardous Air Pollutants
IDEM	Indiana Department of Environmental Management
ICR	Information Collection Request
LAER	Lowest Achievable Emissions Rate
LNB	Low NO_X Burners
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxic Standards
MSA	Metropolitan Statistical Area
MTR	Mountain Top Removal
NAAQS	National Ambient Air Quality Standards
NCCSA	North Carolina Clean Smokestack Act

[redacted]

Acronym Listing (cont'd)

NCDENR	North Carolina Department of Environment and Natural Resources
NODA	Notice of Data Availability
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review
PM	Particulate Matter
OFA	Over-fired Air
ORSANCO	Ohio River Valley Sanitation Commission
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
RACT	Reasonably Achievable Control Technology
SBS	Sodium Bi-Sulfate
SCDHEC	South Carolina Department of Health and Environmental Control
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SOFA	Separated Over-fired Air
TR	Transport Rule
USWAG	Utilities Solid Waste Activities Group
316(a)	Clean Water Act Thermal Discharge Regulation
316(b)	Clean Water Act Cooling Water Intake Regulation

[redacted]

Executive Summary

The primary purpose of the Environmental Regulatory Issues document is to support Regulated Generation's and other utility operation's overall environmental issues management, business planning and budgeting needs. The goal is to help fulfill their significant current and future environmental regulatory requirements (e.g., air, water, waste and climate) both cost effectively and at the appropriate time, while considering the variety of business impacts. In addition, the document is intended to assist other corporate strategic planning and financial planning functions in their evaluation of regulated assets due to projected environmental implications.

The various issues described in this document are designed to represent potential environmental requirements that may result from rulemaking or legislative initiatives. Many uncertainties exist regarding future environmental regulations, including the scope and timing of compliance obligations. The issues described in this document are highly dependent on the assumptions made, and are to be used as an internal planning tool to allow Duke Energy to develop diversified, long-term and cost-effective environmental compliance options intended to satisfy reliably the electricity demands of customers located within a service territory. The pollution equipment installations described herein are not meant to represent Best Available Control Technology ("BACT") or Lowest Achievable Emissions Rates ("LAER"), etc. Furthermore, the pollution equipment installations described are based on high-level engineering and cost estimating. Any decision to install specific pollution controls at an existing facility will require more extensive engineering and cost estimating. Finally, due to the uncertainties regarding the timing of future environmental regulations, the possibility of unit retirements must be considered; however, specific decisions regarding unit retirements would need to be made based on multiple factors in a separate engineering study.

New environmental regulations now final or expected to be finalized over the next few years will have a significant effect on the planning and operations of Duke Energy's regulated generation fleet. While the specific regulatory requirements and timing of many of the regulations are still uncertain, the current expectation is that several new regulatory requirements will likely significantly impact coal-fired generation in the 2013 to 2020 timeframe. New requirements will target SO_2, NO_X, HAPs, PM, and CO_2 emissions, station cooling water intakes and surface and groundwater impacts as well as the handling, use and storage of coal combustion residuals. Until there are final rules in place, the uncertainty surrounding the details of these expected new requirements will require thoughtful planning to most effectively comply with these requirements, given the array of scenarios that may occur. Decisions around installation of new controls, retirement of units, NSR considerations, deployment of renewable energy sources and other replacement generation sources are all likely to be involved in addressing these requirements. The environmental issues that are expected to create the greatest impact to Duke Energy's operations over the next several years are:

[redacted]

1. Mercury and Air Toxics Standard (also Utility Boiler MACT) - The final rule was published in the Federal Register on February 16, 2012. The rule establishes emission limits for mercury, acid gases, and non-mercury metals from coal-fired power plants. It allows for the control of SO_2 emissions as a surrogate for acid gases and filterable particulate matter as a surrogate for non-mercury metals. The rule requires compliance within 3 years of the effective date of the rule (April 16, 2012). The rule allows (but does not guarantee) permitting authorities to grant up to a one-year extension of the compliance period on a case-by-case basis if more time is needed to install controls, where replacement generation is being installed at the same site as the source being retired, or for addressing transmission reliability associated with retirement of a unit. These standards will require significant new or modified air emission controls and systems (e.g., SCR, activated carbon, sorbent injection) to be added to certain existing units. Requirements to install new controls to meet the various standards will potentially cause some units to be retired, in lieu of making the investment to add controls.

2. Clean Water Act 316 (b) – EPA is developing new regulations for cooling water intake structures for existing facilities to address fish impingement and entrainment concerns. The final rule is expected to be published in June 2013. If the rule is finalized as proposed, initial submittals, station details, study plans, etc. for some facilities would be due in the March/April 2014 timeframe. If required, modifications to the intakes to comply with the impingement requirements could be required as early as mid to late 2016. Under the proposed rule, all nuclear, coal and possibly some combined cycle combustion turbine stations are at risk for some type of modification requirements. EPA's proposed regulation was published on April 20, 2011 and does not mandate closed-cycle cooling but requires closed-cycle cooling to be evaluated as best technology available for entrainment reduction.

3. Coal combustion residuals (CCR) rules – New CCR regulations, when finalized, are expected to significantly impact operations relative to handling, disposal and re-use of CCR. There remains risk that CCR may be regulated as a hazardous waste. If so, the historic means of disposing of and re-using CCR, including both coal ash and synthetic gypsum, would be significantly altered and would be much more costly. Even if CCR remain non-hazardous, it is anticipated that new regulations will likely affect the way CCR are handled and disposed of on-site (dry handling of flyash and bottom ash), will require additional groundwater monitoring and closure of ash ponds, and will increase the need for additional landfills and alternative wastewater treatment systems. When the rule is finalized, expected to occur in 2014, compliance requirements could begin 5 years or less from when the rule is promulgated. The likelihood is low of federal legislation blocking EPA from finalizing its hazardous proposal and instead directing states to regulate CCR as non-hazardous.

[redacted]

4. NAAQS - The 75 ppb ozone standard will remain in place until it is revised under the next 5-year review, which is expected to be completed in 2014. EPA finalized area designations in May 2012 under the current ozone standard. With regard to the $PM_{2.5}$ standards, EPA finalized a revision in December 2012. The annual standard was changed from 15 micrograms per cubic meter (ug/m^3) to 12 ug/m^3, and EPA retained the current 24-hour standard of 35 ug/m^3. The 1-hour SO_2 standard is also in place. EPA plans to make final area designations with this standard in June 2013.

In addition to the new and major issues already described, some of the other regulatory risks addressed in this document that are likely to impact operations include:

- Steam Electric Effluent Limitation Guidelines - EPA plans to revise the Steam Electric Effluent Limitation Guidelines which are federally established technology-based effluent limits for NPDES discharges in the steam electric industrial category. The guidelines are expected to target primarily ash handling, landfill leachate, and FGD wastewater treatment system operations. New regulations from these guidelines are expected to be proposed in April 2013 and to become final, under consent decree by April 28, 2014 with compliance beginning as early as mid-2017 for some facilities.

- Climate Change - Federal climate change cap-and-trade or carbon tax legislation is not likely to be enacted through 2013. However, on the regulatory front, EPA finalized a number of rules including the Tailoring Rule which subjects any GHG emitting generating unit that undergoes a modification that will result in a net increase of 75,000 tons/year of GHG to NSR/PSD permitting requirements. Challenges to the Tailoring and other rules were dismissed in June 2012 but have been appealed to the Supreme Court. EPA proposed New Source Performance Standards (NSPS) for GHGs for new electric generating units in March 2012. It is possible that EPA will re-propose the rule in 2013, delaying a final rule until 2014. The schedule for EPA to propose GHG emission guidelines for existing (and potentially modified) EGUs will be influenced by EPA's schedule for the new source NSPS rule.

- Lower NPDES permit limits and groundwater standards - EPA is evaluating establishing surface water quality criteria for selenium. Various states are also targeting stricter limits for nitrates, mercury, boron, bromides and other constituents. Potential strategies to address new, stricter limits on these constituents are likely to focus on converting wet-sluiced ash handling systems to dry ash handling and on requirements for enhancement of FGD wastewater treatment systems. Lower groundwater standards and increased focus on the threat of groundwater impacts from ash basin operations will require the monitoring of groundwater around Duke Energy's ash basins. This requirement creates additional risk for corrective actions, including conversion to dry ash handling systems and landfill development, due to groundwater impacts.

[redacted]

- PCB Phase-out - A proposed rule from EPA is expected in 2013 or 2014, focused on registration requirements for PCB transformers and Large Capacitors (≥ 500 ppm) and marking requirements for regulated PCB-containing (≥ 50 ppm PCB) equipment that has been removed from service. EPA had also been considering the phase-out of PCB use by 2025.

- CCR Storage Area Closures –Active and inactive CCR storage areas (ash basins) will be impacted by final federal and state CCR rules. Storage areas are likely to require a state or federally approved plan for addressing closure/post closure care along with a financial mechanism to address any remediation and groundwater monitoring following their closure. Closure will have to consider continued management of other low volume wastewater streams and limitations (loss of Bevill exemption) once units cease producing CCR. Consideration is being given to how these plants are operated and prepared for closure (waste volumes and disposal) before retirement.

[redacted]

1.0 Introduction

Environmental obligations have significantly impacted planning and operations for Duke Energy's regulated utility operations. The expectation is that Duke Energy's operations will continue to provide reliable and affordable electricity while meeting or exceeding all environmental regulatory requirements. Also, some of Duke Energy's greatest sustainability risks and opportunities are in the environmental focus area. One element of Duke Energy's systematic approach to managing environmental challenges, opportunities and impacts is to anticipate, identify, prevent and mitigate risks and impacts to protect people, the environment, the business and customers. A significant component of environmental risk and opportunity has been Duke Energy's strategy to comply with laws, regulations and permits. A related component has been Duke Energy's process to assure our day-to-day compliance obligations are met. Strategic plans and responses have included a variety of approaches:

- pollution control equipment (e.g., SCRs, scrubbers, baghouses);
- emissions allowance management;
- fuel specification changes;
- unit dispatch changes;
- unit retirements;
- cooling towers and wastewater treatment (e.g., Flue Gas Desulfurization (FGD)); and
- Coal Combustion Residual (CCR) handling changes and reuse and disposal of byproducts.

Responding effectively to environmental regulatory requirements has demanded a coordinated and systematic approach. Examples of past major requirements include the NC Clean Smokestacks Act and EPA's Clean Air Interstate Rule (CAIR). To comply with these and other environmental regulatory challenges, Duke Energy's coal-fired generation businesses, primarily, have spent approximately $7.5 billion since 1999. Similar challenges are expected from the current wave of environmental regulations under development. For planning purposes, it has been estimated that Duke Energy could potentially spend an additional $5 to $6 billion, excluding allowance for funds used during construction (AFUDC) over the next 10 years to address the environmental issues that will be discussed in greater detail in this document.

The complexity of challenges facing Duke Energy continues to increase as new federal environmental laws and regulations become more stringent, as state environmental agencies address concerns over the interactions between air pollution controls, wastewater streams and waste management, and as requirements related to greenhouse gas emissions, coal mining techniques, renewable energy demands and energy efficiency continue to evolve. Recent lower natural gas prices have also added to the complexity. Upcoming challenges for Duke Energy and the industry both in the near-term and long-term are likely to include:

- current and potentially more stringent National Ambient Air Quality Standards (NAAQS) for ozone, SO_2 and fine particles ($PM_{2.5}$)and potentially revised CSAPR that takes into account lower ozone and $PM_{2.5}$ NAAQS;
- potentially revised CSAPR to address interstate emissions transport;

[redacted]

- compliance with the Mercury and Air Toxics Standards (MATS) rule for mercury, acid gases, metals and organics;
- new or more stringent groundwater standards (e.g., arsenic);
- 316(b) cooling water intake structures and systems;
- new regulations for CCR handling, re-use and disposal practices;
- fuel procurement and operating concerns due to potential limitations imposed on mountain top removal mining restrictions and other regulatory requirements;
- revised steam electric effluent limitation guidelines that may require stricter technology-based wastewater treatment systems to meet effluent requirements;
- actual and potential generation unit retirements; and
- further regulation of greenhouse gas (GHG) emissions.

The primary purpose of the Environmental Regulatory Issues document is to support regulated utility operations' overall issues management, business planning and budgeting needs to help fulfill their significant current and future environmental regulatory requirements (e.g., air, water, waste and climate) cost effectively and at the appropriate time, while considering the variety of business impacts.

A flow chart depicting the general process of providing the environmental challenge input into Duke Energy's overall corporate planning efforts is shown in the Appendix of this document. Prior to the Appendix, Tables summarize the current environmental controls in place at each of the coal-fired stations, EPA's current regulatory schedule and the potential impact that the various regulations may ultimately have on Duke Energy's regulated generating facilities.

This is a summary level document and may reference other documents for detail as needed. Individual strategies to address specific environmental issues are generally divided between the Carolinas, Florida and the Midwest regulated operating regions for ease of analysis, understanding, and application to both compliance and resource planning, and to assist with making general business decisions.

This document was developed through input from the Environmental Regulatory Working Group. The group is identified in Section 7.0 of this document and was established to support the development of Duke Energy's environmental strategy to address the legislative and regulatory risks facing the corporation, both near term and over the next ten years. This Working Group is focused on regulated utility operations and provides guidance and direction by identifying and quantifying specific environmental issues and assumptions.

[redacted]

2.0 Air Quality Strategic Issues

Over the next several years, the major regulatory drivers related to air emissions that will most influence environmental strategy include the MATS rule, state implementation plans (SIP) related to current and potentially more stringent SO_2, Ozone and Fine Particles ($PM_{2.5}$) NAAQS, and sulfuric acid mist impacts. Requirements related to controlling or otherwise reducing GHG emissions (principally CO_2) resulting from expected future EPA regulation will be another potential challenge. A brief description of each program and how they have or could impact Duke Energy's regulated operations is presented below. Table 1 at the end of Section 2.0 summarizes likely air quality impact challenges.

2.1 North Carolina Clean Smokestack Act (NC CSA)

North Carolina passed legislation in 2002 to place a firm annual cap on NO_X and SO_2 emissions. These caps will remain separate and specific for the two operating utilities: Duke Energy Carolinas and Duke Energy Progress. The specific requirements for Duke Energy Carolinas and Duke Energy Progress units in NC are:

Duke Energy Carolinas
SO_2 – Phase II: 80,000 tons (began in 2013).
NO_X – Phase II: 31,000 tons (began in 2009).

Duke Energy Progress
SO_2 – Phase II: 50,000 tons (began in 2013).
NO_X – Phase I: 25,000 tons (began in 2007).

Duke Energy Carolinas Strategy - NC CSA establishes firm system-wide NO_X and SO_2 emissions caps.

All controls to meet the SO_2 and NO_X requirements have been completed.

Unit environmentally-affected dispatch is based on total production cost ($/MWh), which includes the market allowance value of NO_X and SO_2.

Duke Energy Carolinas Strategy Challenges

The major compliance challenges include higher customer demand than forecast and forced outages on nuclear or other lower- or non-emitting units. Based upon emissions projections, there appears to be minimal concern with being able to meet the caps.

[redacted]

SO_2 – The lower cap in 2013 should be readily met with Cliffside Unit 6 in commercial operation, combined cycle operation, plans for increased renewable generation and conservation, and continued retirement of non-scrubbed units.

NO_X –The emission cap of 31,000 tons per year is slightly more restrictive than the Duke Energy Carolinas portion of the 2013 and 2014 CAIR Phase I requirements but less restrictive than the CAIR Phase II annual NO_X allocations.

Duke Energy Progress Strategy - NC CSA establishes firm system-wide NO_X and SO_2 emissions caps.
All controls to meet the SO_2 and NO_X requirements have been completed.

Unit environmentally-affected dispatch is based on total production cost ($/MWh), which includes the market allowance value of NO_X and SO_2.

Duke Energy Progress Strategy Challenges

The major compliance challenges include higher customer demand than forecast and forced outages on nuclear or other lower- or non-emitting units. Based upon emissions projections, there appears to be minimal concern with being able to meet the caps.

SO_2 - The lower cap in 2013 should be readily met with the Wayne County Combined Cycle Units at the H.F. Lee Energy Complex entering service along with existing combined cycle operation, plans for increased renewable generation and conservation, and retirement of non-scrubbed units.

NO_X –The NC CSA NO_X emission cap of 25,000 tons per year is slightly more restrictive than the Phase 1 CAIR requirements.

2.2 Clean Air Interstate Rule (CAIR) and the Cross-State Air Pollution Rule (CSAPR)

Barring an unlikely reversal by the Supreme Court, the D.C. Circuit's vacatur and subsequent denial of EPA's request for rehearing leaves the CAIR in place until the EPA completes a CSAPR replacement rulemaking. It is unknown how long it will take EPA to complete and implement a replacement rule, but it's likely to take beyond 2015 which means that Phase II of CAIR would take effect on January 1, 2015. Until that time, CAIR Phase I is in place. Little to no risk for compliance with CAIR Phase I or Phase II exists, especially with controls added for the MATS rule.

[redacted]

2.3 Mercury and Air Toxics Standard (MATS)

EPA's final MATS rule was published in the Federal Register on February 16, 2012. The rule regulates Hazardous Air Pollutants (HAP) by establishing unit-level emission limits for mercury, acid gases, and non-mercury metals, and work practice standards for organics from coal and oil-fired electric generating units. Compliance with the rule will be required by April 16, 2015. Permitting authorities have the discretion to grant up to a one-year compliance extension, on a case-by-case basis, to sources that are unable to install emission controls before the compliance deadline. The one-year extension to meet compliance is not to be granted for units set to retire unless a retirement would cause grid reliability problems.

On November 30, 2012, EPA published a notice of reconsideration of a limited number of MATS related issues. The main issues addressed in the reconsideration proposal were the emission limits applicable to new units (addressed March 29, 2013) and the definition of startup and shutdown. EPA is expected to finalize its startup and shutdown proposal by mid- 2013.

Numerous petitions for review of the final MATS rule have been filed with the United States Court of Appeals for the District of Columbia. The court established a schedule for the litigation that has final briefs being filed on April 8, 2013. Oral arguments have not been scheduled. A court decision in the case is likely in late 2013 or early 2014. Duke Energy cannot predict the outcome of the litigation or how it might affect the MATS requirements as they apply to regulated operations.

Because of the emission limits and other requirements, the MATS rule may potentially drive the accelerated retirement of up to 1,776 MWs of coal-fired generation by April of 2015. By April 2013, Duke Energy (including Duke Energy Progress) will have retired 2,789 MWs of regulated coal-fired generation. A significant portion of this is in anticipation of new regulations.

The 1,776 MWs that are at risk for accelerated retirement in response to the MATS rule include:

- 370 MWs at Duke Energy Carolinas' Lee;
- 575 MWs at Duke Energy Progress' Sutton;
- 668 MWs at Wabash River 2 – 6; and
- 163 MWs at Miami Fort 6.

Some of the requirements that the rule will impose on the remaining, operating regulated generating fleet include:

- a filterable PM emission rate limit of 0.03#/mmBTU which may be used as a surrogate for the non-mercury metals limit;
- a 30-day rolling average emission rate limit for mercury (Hg) of 1.2 #/TBTU or a 1.0#/TBTU limit if using facility averaging; and
- an HCl emission limit of 0.002#/mmBTU or 0.2#/mmBTU SO_2

[redacted]

In addition to specific emissions standards, the rule includes work practice standards to mitigate emissions of organics, dioxins, and furans. Work practices also include performance testing for optimal combustion.

In February 2012, EPA also finalized revisions to the New Source Performance Standards (NSPS) for SO_2, NO_X and PM that would affect new units, reconstructed units, and units modified such that they emit more on an hourly basis.

Regulated Generation has continued to conduct characterization and control studies to help understand the mercury, acid gas and other co-benefits from existing SO_2 and NO_X emission control equipment. One positive is that filterable particulate emissions have decreased notably since the installation of scrubbers, which will be critical in complying with MATS. In the Carolinas, average particulate levels have decreased between 60% and 92% for the units where FGDs have been installed.

Some mercury CEMs in the Midwest have not been commissioned. This needs to be done so there is confidence in the data. Mercury CEMs need to be kept in good working order so mercury emissions along with operating data can be analyzed to anticipate compliance issues. Corrective action can then be taken prior to 2015 to ensure compliance.

Burning higher sulfur coals that generate additional SO_3 will have a negative effect on native loss of ignition (LOI or unburned carbon) to capture mercury and can lead to increased mercury emissions. Additional mercury controls may be required when burning these coals to meet emission limits established by the MATS rule.

2.4 MACT Standards - Other

On January 30, 2013, EPA published revisions to the standards for industrial boilers and process heaters at major sources of hazardous air pollutants (IB MACT). There are requirements for new, reconstructed and existing boilers based on size, fuel type and type of operation (i.e., limited use). Some of the requirements must be complete within 6 months (i.e., July 30). Gas-fired boilers require a periodic tune-up and reporting every 1 to 5 years starting by 2016. "Limited use" (<10% capacity) and small liquid-fueled boilers require tune-ups every 5 years, but have no specific emission limits. Larger liquid-fueled boilers have emission limits which must be met in 2016. Compliance is based on stack testing and/or fuel sampling. The rule also requires a one-time energy assessment for all of the affected boilers except for "limited use" boilers. Environmental Services will finalize the list of affected boilers, communicate specific requirements and develop an implementation plan.

On January 30, 2013, EPA also published revisions to the standards for reciprocating internal combustion engines (RICE MACT). The rule takes effect on May 3, 2013 for diesel engines and October 19, 2013 for spark ignition engines. Operating limits and

[redacted]

testing requirements are based on unit size, location, designation and type. Additions to the final rule include the use of ultra low sulfur diesel fuel beginning in 2015 and the 50-hour peak-shaving exemption will expire in May 2014. Demand-response is only allowed within a 100 hour limit that also accommodates NERC Alert Level 2 emergency use, testing and maintenance. Operation during a weather emergency will continue to be unregulated and engines that operate less than 15 hours per year are exempt from most requirements. Beginning in 2015, sources including Duke Energy will be required to report on customers' emergency generators.

In addition to these MACT standards, EPA is considering the development of a revised Combustion Turbine MACT to target certain HAPs emitted from those facilities. At this time a schedule for when EPA may issue these standards is not known.

2.5 National Ambient Air Quality Standards (NAAQS): 8-hour ozone standard

On May 21, 2012 EPA finalized area designations for the 2008 standard. Both the Charlotte and Cincinnati areas were classified as marginal nonattainment areas. Marginal areas have until December 31, 2015 to attain the standard. Marginal areas need only have "clean" air during the 2015 ozone season to qualify for the first of two possible one-year extensions of the attainment date. States are not required to develop SIPs for marginal nonattainment areas. If a marginal area doesn't either attain the standard by the 2015 attainment date or at least qualify for a one-year extension based on having clean air in 2015, the area would get bumped up to the moderate nonattainment classification and would have six years from that time to attain the standard.

EPA is targeting June 2013 to issue a proposed implementation rule for the 75 ppb standard that will address various implementation issues, including policies on required control measures and guidance to the states regarding Reasonably Available Control Technology (RACT). That proposal should provide important information that will help assess if implementation of the 75 ppb standard could potentially pose risk to any Duke Energy facilities in the Charlotte or Cincinnati areas.

The EPA is working on a review of the 75 ppb standard and could propose a new standard in late 2013 and finalize a revision toward the end of 2014. Attainment dates associated with a revised standard would depend on an area's nonattainment classification. For a standard finalized in 2014, 2019 would be a potential attainment year for marginal nonattainment areas and 2021 or 2022 for moderate nonattainment areas. The extent of nonattainment areas and their classifications will be highly dependent upon the level of the standard EPA finalizes (EPA is considering a range from 60 ppb to 70 ppb).

[redacted]

The Florida service area is attaining the current standard; therefore, it is not expected to have a material effect on Florida operations.

2.6 NAAQS Fine Particle ($PM_{2.5}$) Standard

On December 14, 2012 the EPA issued a revised NAAQS lowering the previous 15 ug/m^3 $PM_{2.5}$ annual standard to a level of 12 ug/m^3. EPA retained the 24-hour standard at 35 ug/$m^3$and set the secondary $PM_{2.5}$ standard equal to the primary standard. It is expected that EPA will finalize area designations in early 2015. States with nonattainment areas will be required to submit SIPs to EPA in mid-2016, with an attainment date of 2021. Based on 2009 –2011 air quality data, a handful of monitors in Duke's service territories (Southern and Central Indiana and Cincinnati area) had values higher than 12 ug/m^3. The EPA will likely use the most current air quality data to make final designations, which could show improved air quality.

To date the annual and daily $PM_{2.5}$ standards have not driven emission reductions through the state SIP process. Instead, the reductions in SO_2 and NO_X emissions to address the $PM_{2.5}$ standards are currently being addressed through CAIR, and could be addressed through a potential CSAPR replacement rule. SO_2 and/or NO_X emission reductions to address the 12 ug/m^3 $PM_{2.5}$ standards could also be required as part of the state SIP development process

Carolinas and Midwest Strategy
At this time, it is too early to determine how future $PM_{2.5}$ non-attainment designations might impact regulated operations. However, any potential impact will be mitigated by the SO_2 and NO_X controls already being installed and by additional controls installed in response to the MATS rule that reduce SO_2 and NO_X emissions. Any additional SO_2 and/or NO_X reductions that may be required in response to lower $PM_{2.5}$ standards could be required in 2020.

Carolinas and Midwest Strategy Challenges
The risk of additional controls will be greater for plants located near non-attainment areas, possibly including those near Cincinnati, Indianapolis and Louisville.

Florida Strategy
All of Florida is currently attaining the revised standard; therefore, the revision is not expected to have a material effect on Florida operations.

2.7 NAAQS SO_2 Standard

On June 22, 2010 EPA established a 75 ppb 1-hour SO_2 NAAQS and revoked the annual and 24-hour SO_2 standards. EPA plans to make final area designations for the 75 ppb

[redacted]

standard in June 2013. Based on EPA's preliminary final designations, the only area across Duke Energy's regulated service territory that will be designated nonattainment is a small area around Wabash River. Assuming Wabash River is retired or repowered in response to MATS, the nonattainment designation will have no impact on the facility. If this does not occur, Indiana is required to develop a SIP by the end of 2015 that will have to address the SO_2 emissions from Wabash River to bring the area into attainment by 2018.

On February 6, 2013 the EPA released a document that updates its strategy for addressing all areas that it will not be designating as nonattainment areas in June 2013. The document indicated that EPA will allow states to use modeling or monitoring to evaluate the impact of large SO_2 emitting sources relative to the 75 ppb standard. The document also laid out a schedule for implementing the standard. Key dates in that schedule are as follows.

- 2015: States identify sources that will deploy new air quality monitors and those that will instead be subject to modeling
- 1/2017: States have new monitors deployed and operational. States submit modeling analyses for selected sources and nonattainment area boundary recommendations as appropriate.
- 12/2017: EPA finalizes area designations for modeled areas
- 8/2019: State SIPs due for modeled areas designated nonattainment in 2017
- 5/2020: States submit designation recommendations for areas relying on monitoring
- 12/2020: EPA makes final area designations for monitored areas
- 8/2022: State SIPs due for areas designated in 12/2020 based on monitoring

The EPA plans on undertaking notice and comment rulemaking to codify the implementation requirements for the 75 ppb standard. The outcome of that rulemaking, which EPA currently intends to complete in late 2014 could be different from what EPA put forth in its February 6, 2013 document.

Carolinas and Midwest Strategy

Scrubber installations at Allen, Cliffside 5 and Cayuga, Gibson Units 1 – 3, and the implementation of the Gallagher consent decree should positively impact 2009 – 2011 data. Reductions made by neighboring utilities for CAIR and other reasons should also make contributions to lower ambient SO_2 concentrations. Data from the Indiana ambient SO_2 monitoring network have already shown positive trends near the Gibson and Gallagher stations. Potential SO_2 impacts from Wabash River and Miami Fort 6 may be identified in future nonattainment designations, but retirements for these units would avert 2018 control requirements.

Carolinas and Midwest Strategy Challenges

It is possible that regulatory agencies will increase their focus on short-term power plant emission rates including those from scrubbed units. Stations with shorter stacks, such as Marshall, may have increased modeling risks. The potential for increased use of higher sulfur coal may also pose additional risk to Carolinas generation.

[redacted]

Gibson Unit 5 operates an older design scrubber unit with a comparatively high emission rate, and as a result emits a relatively high amount of SO_2. Longer term, new and relocated ambient SO_2 monitors could pose new challenges.

In addition, maintaining efficient scrubber operations, even though not potentially required in order to comply with NC CSA and CAIR SO_2 requirements, is important to avoid triggering monitored SO_2 exceedances near the scrubbed stations.

Duke Energy has begun to perform its own dispersion modeling to see what plants might be at risk and might be helpful with decisions about future coal purchases and compliance planning strategies.

Florida Strategy

The fuel used in the Anclote plant is being converted from a mixture of residual oil and natural gas to 100 percent natural gas. Installation of scrubbers on Crystal River Units 4 and 5 was completed in 2010. Crystal River Units 1 and 2 will be potentially retired in the 2015 to 2020 time frame.

2.8 Sulfuric Acid Mist or "Blue Plume" Impacts

When coal is combusted, a portion of the SO_2 that is created will ultimately convert to sulfuric acid mist (SAM). A visible "blue plume" can be more acute with units that operate SCRs, particularly when using higher sulfur coal, and at units operating wet FGD systems because of the cold, wet stack conditions.

The main concern is that the plume opacity once it exits the stack could be in excess of applicable opacity standards. In addition, there is the possibility of "touchdown" of a plume in the area surrounding the facility. Projects of potential concern can include the installation of a new SCR, installing additional SCR catalyst layers, or projects that change the catalyst SO_2 to SO_3 conversion rate. Such projects could require increased operation of plume mitigation systems.

The selection of sorbents for new systems or the increased use of sorbents on existing units with plume mitigation should be studied to provide a clear understanding of the impacts of the FGD system wastewater discharge and the effects on the leaching of pollutants from CCR solids. Soluble sorbents such as sodium are problematic in various disposal scenarios by affecting both discharges to surface water from leachate storm water and ground water.

Carolinas and Midwest Strategy and Challenges

Any unit with a wet scrubber has some type of SO_3 mitigation system installed or has the capability to readily install some type of SO_3 mitigation system. Historical use of lower sulfur coal in the Carolinas has significantly reduced the potential for visible emissions

[redacted]

associated with sulfuric acid mist, but new fuel blending and use of higher sulfur fuels may increase the risk of sulfuric acid mist formation. Scrubbed units that may require future SCR or additional catalyst layers may also have to be evaluated for SO_3 mitigation. Use of SO_3 mitigation technology necessitates balance-of-plant evaluations to determine operational impacts.

[redacted]

Table 1 – Air Quality Issues/Challenges Summary

Carolinas	Existing Controls	CAIR Phase I Existing/(Planned Yr)		MATS (Potential Impacts)	CAIR (Potential Impacts)		NAAQS (Potential Impacts)
		NO_X	SO_2	HAPs	NO_X	SO_2	
Allen	SOFA, SNCR, FGD			$CaBr_2$ Add. and/or ACI . Add'l control risk/uncertainty if loss of CAPP fuel. Dry Sorbent injection for SO3 control if higher sulfur fuel use.			Ozone – NOx control using SCR or NOx Oxidation Technology (hydrogen peroxide injection)
Belews Creek	OFA/SCR, FGD						
Cliffside 5 & 6	SOFA/SCR 5, FGD 5 OFA/SCR 6, FGD 6			U5 - $CaBr_2$ Add. and/or ACI. Dry Sorbent injection for SO3 control if higher sulfur fuel use. Possible ESP enlargement depending on required injection levels of ACI and dry sorbent			
Lee	SOFA			Retire/gas conversion	Potential operational reductions in 2013 - 2014	Potential operational reductions in 2013 - 2014	Retire or convert to gas
Marshall	SOFA, SNCR 1, 2 & 4, SCR 3, FGD 1- 4			U1&2 - Br Add. and/or ACI; possibly ESP enlargement, depending on injection levels of ACI and sorbent; U4 – $CaBr_2$			Ozone – NO_X control using SCR or NO_X Oxidation Technology (hydrogen peroxide injection)
Asheville	SCR, FGD						Take lower SO2 permit limit
Mayo	SCR, FGD			Possible ACI or re-emission chemical.			
Roxboro	SCR, FGD						

[redacted]

Carolinas	Existing Controls	CAIR Phase 1 Existing/(Planned Yr)		MATS (Potential Impacts)	CAIR (Potential Impacts)		NAAQS/Other (Potential Impacts)
		NO_X	SO_2	HAPs	NO_X	SO_2	
Sutton	SNCR – U3			Retire coal units			Retire coal units by 12/31/13
Florida							
Crystal River	SCR, FGD – U4&5	U1&2 BART – Options either control by 2018 or retire by 2020	U1&2 BART – Options either control by 2018 or retire by 2020	U1&2 – Investigating options including coal switch and de-rate. Possible ACI or re-emission chemical.			U1&2 Ozone – Options either control by 2018 or retire by 2020. Timing should take care of SO2

[redacted]

Midwest Reg	Existing Controls	CAIR Phase I Existing/(Planned Yr)		MATS (Potential Impacts)	CSAPR (Potential Impacts)		NAAQS/Other (Potential Impacts)
		NO_X	SO_2	HAPs	NO_X	SO_2	
Cayuga	LNB/OFA, FGD			Re –emissions Additive, $CaBr_2$ Add. and/or ACI. Dry sorbent injection: SCR			
East Bend 2	OFA/SCR, FGD		FGD upgraded in 2005	$CaBr_2$ Add. and/or ACI. Dry sorbent injection; Re –emissions Additive			FGD Upgrade; Upgrades to SO_3 mitigation
Gallagher	LNB/OFA		Baghouses & Low Sulfur coal	Alkali inj. – 2 units are operational. Converting to Hydrated Lime injection		Potential load reduction beginning in 2014	Ozone – NO_X control for Units 2, 4
Gibson	FGD 1-5 OFA/SCR 1-5		FGD 1-5	Re –emissions Additive; possibly ACI. Quarterly stack testing for HCl.	New LNB with OFA, new flue gas mixing, fan upgrades and ductwork mods	FGD Upgrade 1-4. New FGD 5 or derate unit or retire unit	FGD Upgrade 1-4. New FGD5 for SO_2 or derate unit or retire unit
Miami Fort 6	LNB			Potential Retirement. Site-wide averaging provision			Likely Retire
Wabash River 2-6	LNB/OFA 2-6			Potential Retirement		Potential load reduction beginning in 2013, significant operating risk in '14	Likely Retire

[redacted]

3.0 Water Quality Strategic Issues

Over the next several years, the major drivers related to water quality that will influence environmental strategy are 316(b) Cooling Water Intake Structures (fish impingement/entrainment), 316(a) thermal discharge variance renewals, steam electric effluent limitation guidelines, groundwater monitoring requirements with more stringent groundwater standards, and water availability concerns in the Carolinas. Table 2 at the end of this Section summarizes likely station-specific water quality impact challenges.

3.1 316(b) Cooling Water Intake Structures

EPA published its proposed cooling water intake structures rule on April 20, 2011. The proposed rule establishes mortality reduction requirements due to both fish impingement and entrainment and advances one preferred approach and three alternatives. The EPA's preferred approach establishes aquatic protection requirements for existing facilities and new on-site generation that are defined as existing facilities with a design intake flow of 2 million gallons per day (MGD) or more from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters and utilizing at least 25% of the water withdrawn for cooling purposes. Based on the preferred approach, most, if not all of the coal- and nuclear-fueled regulated facilities are likely affected sources. Additional sources, including some combined-cycle combustion turbine facilities, may also be impacted, at least for impingement intake modifications, due to the 2-MGD design intake flow threshold.

To comply with impingement requirements, modified traveling intake screens with fish handling and return systems are a likely retrofit. EPA proposed a strict definition of closed-cycle cooling and closed-cycle cooling systems that if units met the definition were deemed to have met the entrainment requirements, although the proposed rule does not mandate closed-cycle cooling at all sites. Site specific evaluations to determine the best technology available to address entrainment are, however, required to be conducted and closed-cycle cooling and fine mesh screens must be evaluated. EPA published a Notice of Data Availability (NODA) in mid-2012 to solicit comments on "preapproved technologies" to address impingement and other compliance alternatives along with addressing new "benefits" information from a previous survey.

The current EPA settlement agreement calls for the EPA to finalize the 316(b) rule in June 2013. If the rule is finalized as proposed, initial submittals, station details, study plans, etc, for some facilities would be due in the March/April 2014 timeframe. If required, modifications to the intakes to comply with the impingement requirements could be required as early as mid to late 2016. Within the proposed rule, EPA did not provide a compliance deadline for meeting the entrainment requirements.

[redacted]

Strategy

Work with the Utility Water Act Group (UWAG) to effect a positive outcome with EPA on the final rule. Also review EPRI research results of various technologies as those are available. Impingement Mortality and Entrainment (IM&E) studies and reports will be completed for applicable facilities and tentative plans will be made for intake screen/fish return modifications. Once the rule is finalized, compliance and technology evaluations will be conducted. If intake screen modifications are required, preliminarily, affected stations could spend approximately $5 to $30 million on average to complete these types of retrofits. The costs are primarily dependant on the number of intake bays/screens at the facility. If required, the costs and impacts of installing cooling towers will obviously be significantly greater to impacted stations. Based on the expected compliance schedule, several of the more severely affected coal-fired stations in the Carolinas and Midwest will be retired and thus should not be impacted. However, those coal sites that may be converted to gas and will continue to use the station intakes to support new combined cycle generation are likely to be impacted to comply with intake impingement requirements and installation of 316(b) compliant screens.

The Gibson Station has an NPDES permit for stormwater. Gibson may need to consider re-routing its stormwater in order to eliminate the need for the stormwater permit. The existence of the stormwater permit for Gibson could require compliance with 316(b) requirements.

3.2 NPDES and Wastewater Treatment Discharges

Every regulated coal-fired facility in the Carolinas and Midwest has an ash basin/pond which receives some combination of bottom ash, slag, fly ash, and other plant wastewater streams for treatment. Ash basin effluents (except Gibson) are regulated by a state National Pollutant Discharge Elimination System (NPDES) permit.

The NPDES permit limits vary by station, based on different state requirements and a projected reasonable potential of exceeding toxicity thresholds or other levels of concern for metals or other constituents relating to a specific discharge. Bottom ash and slag are relatively stable and pose very little impact to ash basin water quality. Fly ash can have a much larger impact on ash basin chemistry, in part due to the comparatively large combined surface area, which leads to much more leaching of various water-soluble constituents, including metals, from the particles. Fly ash is also a collector of ammonia slip from NO_X control systems, reagents for SO_3 control such as sodium, calcium bromide and magnesium, and the potential sorbents for mercury control. Ash basin chemistry is also influenced by changes in fuel source. All of these have the potential to impact metal concentrations and levels of other constituents of concern (e.g., nutrients, ionic constituents) at the NPDES discharge.

[redacted]

Steam Electric Effluent Limitation Guidelines: In September 2009, EPA announced plans to revise the steam electric effluent limitation guidelines, which are federally established, technology-based effluent limits based on the capability of the best technology available. The primary focus of the revised regulation is coal-fired generation, thus the major areas likely to be impacted are FGD wastewater treatment systems and ash handling systems. Any focus on nuclear facilities is likely to be on chemical cleaning operations. The EPA may set limits based on the performance of certain FGD wastewater treatment technologies for the industry and may require dry ash handling systems for both fly ash and bottom ash to be installed. EPA may also set limits on landfill leachate, possibly requiring leachate to be routed to a treatment system prior to it discharging to an ash basin or through an outfall.

The current EPA settlement agreement calls for the EPA to propose the revised steam electric effluent limitation guidelines by April 2013, and finalize the guidelines by May 2014.

After the final rulemaking, effluent guideline requirements will be included in a station's NPDES permit renewals. Thus requirements to comply with NPDES permit conditions may begin as early as mid-2017 for some facilities.

Selenium Water Quality Criteria: EPA establishes recommended water quality criteria for the protection of aquatic life and human health in surface water for approximately 150 pollutants. These criteria are published pursuant to CWA Section 304(a) and provide guidance for states to use in adopting surface water quality standards. EPA could issue draft revised water quality criterion (chronic) on selenium in 2013. The new criterion will incorporate water quality action levels of approximately 2 ppb selenium for lentic (non-flowing) and a slightly higher level for lotic (flowing) waters. If the action level is exceeded, a fish tissue (ovary) criterion must be met. It is uncertain when a draft implementation guidance document will be issued. This guidance will inform state regulators on how to restrict selenium in NPDES permits. Over the next several years the new chronic criteria will require fish tissue to be measured for selenium content, particularly in waterbodies where the water concentration of selenium exceeds action levels. If the tissue criteria is also exceeded, then the water body will be considered impaired and NPDES permitted facilities will have selenium limits imposed to reduce the selenium loading to the water body. Currently, an acute selenium criterion is not envisioned.

SO_2 Scrubber Wastewater Treatment (WWT): A wastewater stream is created from the scrubber blow down and dewatering of the scrubber by-product (gypsum). Many of the semi-volatile metals and nitrates that are not captured in the Electrostatic Precipitators (ESP) are captured in the scrubbers. Based on NPDES permitting requirements, the constituents of most concern are mercury, selenium, arsenic and nitrates. Although water quality standards for boron, chloride and bromide do not currently exist, EPA and various states are contemplating their inclusion in future rulemakings.

[redacted]

The regulatory limits differ from station to station, depending upon the impact on the receiving waters. Various FGD wastewater treatment systems are now in place at Allen, Belews Creek, Cliffside 5, Cayuga, Gibson, Asheville, Roxboro, Mayo and Marshall. Various stations treat FGD wastewater system effluents in the ash basins. A change in CCR rules could affect this option and thus the treatment process used at many sites.

For Cliffside 6, an FGD with a spray dryer and baghouse combination is used. The spray dryer may, however, be supplemented with an upgrade of the wastewater treatment system via a modular reactor to manage the selenium because the spray dryer cannot manage the total wastewater output from both units. A decision regarding the type of wastewater treatment system will be deferred until there is more certainty concerning the Effluent Guidelines and the upcoming NPDES permit renewal. The FGD effluent is used in the lime slurry that is injected in the spray dryer ahead of the baghouse.

Stormwater Permitting: In 2010, NCDENR Division of Water Quality (DWQ) initiated the removal of storm water discharges associated with industrial activity coverage within the NPDES Wastewater Permit at North Carolina coal-fired stations and began requiring an application and issuance for coverage under a separate NPDES Storm Water Permit. This change to an individual permit would occur during the normal renewal process for NPDES wastewater permits. Comments were submitted to DWQ in May 2012 from both Duke Energy Carolinas and Duke Energy Progress that included the request that DWQ adopt a general permit for storm water discharges associated with industrial activity that would cover steam electric plants, similar to the general permits used in other states. There has been no response to date.

If adopted, the compliance requirements of the DWQ NPDES Storm Water Permit are onerous with a number of parameters to analyze and compare to a host of benchmark values.

For Florida, Ohio, Indiana, and Kentucky storm water discharges associated with industrial activity is currently covered within the station's NPDES Wastewater Permit (i.e., as applied for in a submitted Form 2F). For states with an adopted general permit, the requirements for storm water in the NPDES Wastewater Permit are patterned after the conditions and requirements of the general permit.

Stations in Florida have decided to apply for coverage under the state's NPDES Industrial Storm Water General Permit (Sector O) and remove the storm water requirements from the NPDES Wastewater Permit. This voluntary change will occur during station NPDES Wastewater Permit renewal. Coverage for industrial storm water at stations in South Carolina are currently covered under the South Carolina NPDES General Permit for Storm Water Discharges Associated with Industrial Activity and not a component of the wastewater permit.

[redacted]

Other NPDES Limit Initiatives: There are various state initiatives to implement water quality standards changes which could directly impact the NPDES discharge limits. The impacts to the company are difficult to assess at this time. Initiatives of note are shown below:

- Lower nitrate limits will be proposed in the Midwest within the next few years. Treatment technologies are limited to expensive biological options. A water quality trading project has been initiated in the Ohio River Basin in which Duke Energy is participating with EPRI.
- The Ohio River Valley Sanitation Commission (ORSANCO) is leading an initiative to place a limit of 12 ppt for Hg on any permitted discharge with compliance required in 2013.
- Indiana finalized an Antidegradation Rule on June 28, 2012. This rule applies to a proposed new or increased loading of a regulated pollutant to a surface water of the state that results from a deliberate activity subject to the CWA including a change in process or operation that will result in a significant lowering of water quality.
- Several states have begun to look at setting water quality-based NPDES limits on boron. Currently the technology for treatment of boron is very limited and expensive.
- Some States are considering regulating the discharge of bromide and chlorides into receiving waters. Belews Creek has detected increased levels of bromide downstream of its discharge in the Dan River. These increased bromide concentrations can create disinfectant byproduct problems for drinking water systems. The municipalities of Eden and Madison, North Carolina have experienced difficulties meeting their total trihalomethane (TTHM) drinking water limits. The Belews Creek NPDES contains language that commits Duke to provide semi-annual reports to DWQ with updates on efforts to manage bromide at the source (a potentially viable treatment technology has been identified and is being pilot tested at Belews Creek.) Cliffside and other stations using wet FGD systems with discharge to relatively low flow receiving waters have the potential to impact downstream water treatment plants as well. In addition, there is a risk that EPA and/or NC could institute a water quality standard for bromide because wastewaters with high bromide concentrations are typical with shale fracking operations for natural gas.
- Florida Mercury TMDL: In accordance with a court settlement, the Florida DEP is completing a mercury Total Maximum Daily Loading (TMDL) determination for the state's waters. Florida must complete this TMDL to avoid the EPA developing and imposing one on the state. The DEP concluded that no additional mercury reductions will be required from the state's electric utilities to achieve the TMDL. EPA proposed approval on November 30, 2012. The Florida legislature is expected to ratify the TMDL in the 2013 session, and then the EPA will take final action.
- Florida Numeric Nutrient Criteria (NNC): The Florida DEP has developed alternate criteria for total nitrogen and total phosphorus in most of the state's waters that will replace more stringent criteria developed by EPA in 2011.

[redacted]

The EPA proposed approval of Florida's criteria on November 30, 2012. Final action is expected in 2013.

Strategy

The most comprehensive solution to ash basin compliance for effluent guidelines, water quality criteria and other initiatives is to convert facilities to dry ash handling and either sell the ash or dispose of it in a lined landfill.

Additional wastewater treatment systems may be required in the coming years as the use of ash basins for wastewater treatment is phased out due to effluent guidelines and CCR regulations or as additional constituents of NPDES permitted discharges become more stringently regulated.

The United States Supreme Court's January 2013 decision in *Los Angeles Flood Control District v. Natural Resources Defense Council, Inc.*, No. 11-460 unanimously held that the flow of water from an improved portion of a navigable waterway into an unimproved portion of the same waterway does not qualify as the "discharge of a pollutant" under the Clean Water Act (CWA). The Supreme Court's decision is important to the hydroelectric industry in that it preserves the long-standing precedent that discharges from reservoirs through hydropower dams are not subject to NPDES permitting.

3.3 Groundwater Standards and Monitoring

Unlined landfills and ash basins can potentially impact groundwater. Many of these waste management units, primarily in the Midwest, are constructed over significant aquifers. Duke Energy implemented a voluntary plan to monitor groundwater, and by the end of 2010 had monitoring wells around all active landfills and ash basins. North Carolina active ash basin wells were replaced in 2010-2011 with wells at the compliance boundary. Compliance sampling data is provided to NCDENR three times per year and to SCDHEC on a semi-annual basis. If an exceedance of groundwater standards is found attributable to the CCR units, Duke Energy would consult with the state regulatory agency in N.C. to decide on a plan of action. In Indiana, impacts to groundwater have been observed at all of the stations except Wabash River Station. The ash ponds at Gibson and Cayuga are a source of contaminants and have impacted off site receptors, however, no-off site MCLs have been exceeded. These ponds are in the process of being closed, evaluated, and/or retrofitted with liners.

Regulatory Status and Monitoring Results to Date

Carolinas – Elevated levels of boron and other non-carcinogenic substances have been detected at some on-site sampling wells in excess of State groundwater standards. Naturally occurring iron and manganese are frequently detected.

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Relatively higher concentrations of boron, total dissolved solids (TDS) and chlorides in FGD wastewaters being discharged to ash basins also increase the risk of boron and chloride impacts to groundwater. If groundwater standard exceedances are reported, the agencies could require a Site Investigation and Corrective Action Plan. The extent of the additional requirements would vary depending on site conditions and regulatory requirements. NC DWQ has initiated regional ash basin groundwater assessments at the seven legacy Duke fossil facilities. For Sutton plant, Phase I and Phase II groundwater investigations were completed between 2010 and 2012 to better identify the extent of the boron plume at or beyond the compliance boundary. These investigations were completed per the Wilmington Regional Office. For the Asheville plant, on March 22, 2013 the North Carolina Attorney General's office filed a Civil Enforcement Action in the Wake County Superior Court on behalf of DWQ. That action alleges that the Asheville Plant violated the groundwater standard for thallium and has seepage from the ash ponds and other locations at the plant that is not allowed by facility's NPDES permit. The company has 30 days to answer the DWQ Action. The Southern Environmental Law Center on March 26, 2013 issued a Notice of Intent of impending legal action against Duke Energy Carolinas related to ash basin seepage and groundwater exceedances at the Riverbend Steam Station. No other Duke Energy Progress ash basin is involved in investigation mandated per a state agency (e.g., the investigations completed at Weatherspoon plant were initiated internally).

Midwest – Many of the contaminants observed in the ground water monitoring networks have not exceeded health based standards. Data from groundwater monitoring networks, however, continue to be evaluated to determine potential exceedances of health-based standards. Gibson Station has received approval from the IDEM to close its East Ash Pond System under a schedule that provides reasonable time to construct and close. The station is also currently studying the performance of the only ash pond that will remain active to manage bottom ash once all flyash systems are converted to dry handling. Cayuga Station has submitted an ash pond closure plan that is pending approval from IDEM. At Cayuga Station, all ash sluice and wastewaters will eventually be managed through lined ponds and ditches until discharge via the NPDES outfall. Duke Energy has proactively facilitated provision of municipal drinking water to residents in close proximity to the Gibson and Cayuga stations. All other stations are continuing to monitor ground water and at this time no further action is necessary.

The following water-related issues and problems are expected to present challenges to regulated generation and should be evaluated and planned for over the next several years.

1. Further studies are necessary to better understand the impacts of the surface water from the Gibson cooling pond on ground water. For example, future studies may focus on the sediments in the cooling pond and how they affect surface water

[redacted]

leaching into ground water. Duke Energy will need to continue to demonstrate to the IDEM the effectiveness regarding the closure work of the East Ash Pond and the performance of the existing landfill. The Gibson cooling pond may be identified as the source of groundwater impacts at certain downgradient wells. This may trigger regulatory or enforcement issues that will need to be addressed.

2. Evaluate means to reduce or eliminate the wastewater stream (high chlorides discharge) from the reverse osmosis (RO) water system at Gibson. Evaluate deep injection wells as possible disposal means for RO water and other non-hazardous waste streams.
3. The new CCR rules will likely not allow ash ponds to remain active as a means for waste water treatment without retrofitting with liners. Alternatives to ash ponds for wastewater treatment will be required for stations that continue to operate and currently have no other waste water treatment capability.
4. With station retirements, managing leachates and other wastewaters during and after plant closure will be a challenge.
5. Studies should continue to look at using FGD Wastewater (high chlorides, and trace elements) in the fixation process to be sure it is a viable option to manage waste water that can no longer go to ponds. Past studies have been short-term, additional studies should be conducted under variable conditions and longer periods of time.

3.4 Water Availability Concerns

Climate change has the potential to affect water availability. While highly speculative, some predict that climate change will alter weather events and patterns such that they become more extreme, featuring more severe droughts and higher floods. Strategies designed to help cope with potential climate change could include measures to prepare for the potential for more extreme weather conditions coupled with increased population demand for water.

As part of a review of water availability issues in the Carolinas which began in 2009, specific issues were identified at Oconee, McGuire and Catawba Nuclear Stations. At Oconee, system requirements limit how far Lake Keowee can be drawn down, which exacerbates water availability issues during a drought or when the downstream U.S. Army Corps of Engineers (USACE) Projects require a Lake Keowee release of water in accordance with Duke Energy's1968 Operating Agreement. Oconee is preparing a modification to allow greater lake-level flexibility. At McGuire, potential thermal issues have been identified if Lake Norman is required to be drawn down in accordance with the Low Inflow Protocol (LIP) developed as part of the Catawba-Wateree Hydro Project Comprehensive Relicensing Agreement (CRA). At Catawba, an instrumentation issue on the Nuclear Service Water system limits draw-down of Lake Wylie during drought conditions to keep Catawba operational. Catawba is preparing a modification to address this instrumentation issue.

[redacted]

Currently there is no law in NC regulating withdrawals of surface water (unless returned to a different basin, also known as inter-basin transfer). South Carolina, however, passed into law the Surface Water Withdrawal Permitting, Use and Reporting Act and it became effective January 1, 2011. The General Assembly in June 2012 passed S. 1220 which removes the surface water withdrawal permitting fees sunset date provision and establishes the surface water withdrawal permitting fees via legislation. The regulations were published in the June 2012 S.C. State Register. Environmental Services submitted surface water withdrawal permit applications for all existing Duke Energy S.C. generating facilities that require a permit (i.e. Lee Steam, Oconee, Catawba, and Robinson). SCDHEC communicated that they will begin issuing surface water withdrawal permits in 2013. Hydroelectric generation is exempt from the surface water withdrawal permit requirement.

[redacted]

Table 2 – Water Issues/Challenges Summary

	Current Systems		Water Issue Challenges			
	Ash Handling Existing	FGD WWT Type/year	NPDES Limit Potential	316(b)	Dry Ash Conversion	FGD Wastewater Treatment Limits
Carolinas						
Allen	Dry	Solid Removal/Bio Reactor (09)	Se, As, B, pH	Modified traveling screens / impingement monitoring -- CT and fine mesh screen evaluation	Convert bottom ash to dry	Se, As, B, Cl, Hg, TDS
Belews Creek	Dry	Solid Removal/Bio Reactor	Se, As, B	Installation of modified traveling screens/ impingement monitoring-- CT and fine mesh screen evaluation	Convert bottom ash to dry	Se, As, B, Cl, Hg, Br, TDS; separate discharge risk concern
Cliffside 5&6	Dry	CS5 Solid Removal /Gravity Filter (10)	Se, B, pH	Modified traveling screens	U5 - Convert bottom ash to dry	Se, As, B, Cl, Hg, Br, TDS
Lee	Sluice	N/A	As, pH	Modified traveling screens/ impingement monitoring Utilize existing towers to be defined as closed-cycle cooling.	Not likely due to retirement	N/A

[redacted]

	Current Systems		Water Quality Challenges			
	Ash Handling Existing	FGD WWT Type/year	NPDES Limit Potential	316(b)	Dry Ash Conversion	FGD Wastewater Treatment Limits
Marshall	Dry	Solid Removal /Wetland	Se, As, B. pH	Installation of modified traveling screens / impingement monitoring -- CT and fine mesh screen evaluation	Convert bottom ash to dry	Se, As, B, Cl, Hg, TDS
McGuire	N/A	N/A	N/A	Modified traveling screens / impingement monitoring-- CT and fine mesh screen evaluation	N/A	N/A
Oconee	N/A	N/A	N/A	Installation of modified traveling screens / impingement monitoring -- CT and fine mesh screen evaluation	N/A	N/A
Catawba	N/A	N/A	N/A	Modified traveling screens / impingement monitoring; CT in service	N/A	N/A
Asheville	Sluice	Solid Removal/Wetland (05)	Se, B, Cl, Hg., As, Ba, Be, Br, Cd, Co, Cr, Mn, Mo, Pb, Sb, Tl, V, Cl, F, TSS	Modified traveling screens / impingement monitoring -- CT and fine mesh screen evaluation		

[redacted]

	Current Systems		Water Quality Challenges			
	Ash Handling Existing	FGD WWT Type/year	NPDES Limit Potential	316(b)	Dry Ash Conversion	FGD Wastewater Treatment Limits
Lee / Wayne NGCC	N/A	N/A		Modified traveling screens / impingement monitoring	N/A	N/A
Mayo	Dry flyash, converting to dry bottom ash in 2013	Settling Pond/Bioreactor (09). Partial ZLD complete by end 0f 2013	As	Modified traveling screens/fine mesh screen evaluation	Convert bottom ash to dry in 2013	Se. B. Cl. Hg., Ba. Be. Cd. Co. Cr. Mn. Mo. Pb. Sb. Tl. V. Cl. F. TSS
Roxboro	Dry flyash, converting to dry bottom ash 2014	Settling Pond/Bioreactor (07)	Se, B, Cl, Hg., As. Ba. Be, Br, Cd, Co. Cr. Mn. Mo. Pb. Sb. Tl. V. Cl. F. TSS	U1-3: Modified traveling screens / impingement monitoring-- CT and fine mesh screen evaluation U4: Modified traveling screens	Convert bottom ash to dry in 2014	
Sutton NGCC	N/A	N/A		Modified traveling screens / impingement monitoring	N/A	N/A
Shearon Harris	N/A	N/A	N/A	Installation of modified traveling screens; CT in service	N/A	N/A

[redacted]

	Current Systems		Water Quality Challenges			
	Ash Handling Existing	FGD WWT Type/year	Ash Handling Existing	FGD WWT Type/year	Ash Handling Existing	FGD WWT Type/year
Brunswick	N/A	N/A	N/A	Several technologies in place, incl. fine mesh screens & diversion structure. Possibility of modified traveling screens/impinge ment monitoring/ barrier nets / CT evaluation	N/A	N/A
Robinson	N/A	N/A	N/A	Installation of modified traveling screens / impingement monitoring - CT and fine mesh screen evaluation	N/A	N/A
Florida						
Crystal River	Dry	Percolation Pond (09)		Once Thru – U1&2: Modified traveling screens / impingement monitoring / barrier net – CT and fine mesh screen evaluation Closed cycle cooling – U4&5: Fine Mesh Screen evaluation		

[redacted]

	Current Systems		Water Quality Challenges			
	Ash Handling Existing	FGD WWT Type/year	NPDES Limit Potential	316 (b)	Dry Ash Conversion	FGD Wastewater Treatment Limits
Anclote	N/A	N/A		Modified traveling screens / impingement monitoring / barrier net -- CT and fine mesh screen evaluation	N/A	N/A
Bartow	N/A	N/A		Modified traveling screens / impingement monitoring / barrier net -- CT and fine mesh screen evaluation	N/A	N/A
Suwannee	N/A	N/A		Modified traveling screens / impingement monitoring -- CT and fine mesh screen evaluation	N/A	N/A
Midwest Reg						
Cayuga	Sluice to new pond	Solids removal & dilution	Hg, pH	Modified traveling screens / impingement monitoring -- CT and fine mesh screen evaluation Helper towers in place	~ $35M to convert; Convert bottom ash to dry	TSS, O & G, As, Cd, Cr, Cu, Pb, Mn, Hg

[redacted]

	Current Systems		Water Quality Challenges			
	Ash Handling Existing	FGD WWT Type/year	Ash Handling Existing	FGD WWT Type/year	Ash Handling Existing	FGD WWT Type/year
East Bend 2	Dry	Closed cycle design. FGD wastewater recycled or incorporated into solid waste and landfilled	Cu, Hg	Modified traveling screens	Convert bottom ash to dry	Min. Risk
Edwardsport IGCC	Slag-beneficial reuse			NA, Groundwater Collection Wells		
Gallagher	Dry		Nitrates, pH, Hg	Modified traveling screens -- CT and fine mesh screen evaluation / impingement monitoring	Convert bottom ash to dry or retire	
Gibson	1-3 Sluice (converting to dry in 2012-2013) 4&5 Dry	Solids removal, then to North Ash pond	N/A	Installation of modified traveling screens / impingement monitoring	Flyash - $126M for U 1-3; Convert bottom ash to dry	Se, As, B, Cl, Hg, TDS
Miami Fort 6	Sluice		Hg, Nitrates, pH	Likely Retire	Likely Retire	
Wabash River 2-6	Sluice, U6 can also handle dry		pH, hex chrome, Hg	Likely Retire	Likely Retire	

[redacted]

4.0 Waste Management Strategic Issues

Various waste related issues may have very large implications in the coming years, depending upon the outcome of regulations that EPA is considering. New regulations targeting CCRs have been proposed by EPA. CCRs include fly ash, bottom ash, boiler slag, mill rejects, FGD byproducts and many of the fossil fuel emission control additives/byproducts (i.e. activated carbon, spent sorbents).

EPA in 2010 also took advanced comment on possible mandatory phase-out of all uses of polychlorinated biphenyls (PCB) in the next decade.

Table 3 at the end of this Section summarizes likely waste issue challenges.

4.1 PCB Phase-Out

On April 7, 2010 EPA issued an Advanced Notice of Proposed Rulemaking (ANPR) to reassess authorizations for PCB use and distribution in commerce. EPA is considering the possibility of following a 2008 Canadian regulation that would require phase-out of PCBs by 2025. Following the Canadian approach would result in phasing-out all electrical equipment containing PCBs at 50 ppm or greater, as well as eliminating the authorization to use PCBs at those concentrations in gas pipeline systems. A preliminary inventory of Duke Energy Carolina's electrical equipment has been completed. Current PCB regulations do not require testing of equipment and allow companies to assume that non-tested equipment contains 50 ppm or more PCB. Thus, there is no accurate inventory of the distribution electrical equipment in the regulated business that contains PCBs at or above 50 ppm and that would be affected by such a new phase-out rule. Electrical equipment manufactured prior to 1980 has the highest risk of containing PCBs. Costs of complying with such a final regulation would primarily impact the Power Delivery function, although the generating facilities and Gas Operations will also likely incur costs.

EPA has established a new target date of the fall of 2013 for a proposed rule. EPA will likely move forward with drafting a proposed rule focused on liquid PCBs, as well as for issuing a data information collection request (ICR) later in 2013 for certain targeted gas pipeline companies. The PCB liquids rulemaking will likely focus on transformers; it is not clear at this time whether the proposal would also apply generally to all PCB liquid-containing equipment.

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4.2 Coal Combustion Residuals

The EPA issued proposed regulations relative to CCR management on June 21, 2010 and then followed up in 2011 with a NODA to gain comments on all new data from the proposed rule comment period. Final regulations are not expected to be issued by EPA until 2014 or later. EPA's final regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs in the future. The new rule will likely require the development of applications to permit all ash basins under the solid waste regulatory structure for groundwater protection. Permit applications will likely include groundwater monitoring plans, dam/dike safety requirements with inspections, composite liners for all new units and expansions, closure/post closure plans, and a financial assurance mechanism to receive a permit. Compliance monitoring is expected to begin one year after the rule is finalized and compliance with most other portions of the rule would likely begin around 2019.

There are three major CCR sub-types generated during Duke Energy's operations.

1. Bottom ash – Disposal is generally into an ash basin and poses low environmental risk due to stability. Bottom ash is also sold for various reuses.
2. Fly ash – Disposal either to a landfill or via sluicing to an ash basin. Dry ash is also sold for reuse.
3. FGD solids – Forced oxidation scrubbers generate calcium sulfate (gypsum) and inhibited oxidation scrubbers generate calcium sulfite. The gypsum is generally reused in the wall board and agricultural use markets and the calcium sulfite is generally mixed with fly ash and fixated with lime prior to disposal. If the gypsum cannot be reused, it will be disposed in a lined landfill. In addition, the filtercake from the FGD wastewater treatment plants associated with forced oxidation scrubbers must be disposed of in a landfill. The use of gypsum in agricultural markets occurs in the Midwest and is being evaluated in the Carolinas.

Carolinas and Midwest Strategy

Escalating CCR disposal costs, increasing uncertainty and risk associated with CCR disposal, changing and inconsistent regulations and diminishing land availability for disposal require multi-faceted strategic planning for future needs. In the Midwest, there are currently adequate long-term disposal options for CCR for each station. In the Carolinas, Duke Energy is implementing an improved long-term position for the scrubbed stations. Except for Lee Steam Station in South Carolina, all Carolinas non-scrubbed stations are expected to retire by the end of 2013 and will not require landfills for remaining ash disposal. The S.C. Lee station is expected to retire its coal operations in 2015. The use of landfills at the various stations is summarized in Table 3.

Bottom Ash and Fly Ash Disposal

Landfills - New landfills will be required to install a prescriptive cap/liner system to help prevent impacts to groundwater. Siting of landfills is currently one of the greatest challenges, due to the large space requirements and the diminishing availability of land around many of our sites. NC law provides a good option for constructing double-lined

[redacted]

landfills over previous on-site ash disposal/use areas. This option allows for reuse of onsite land that would otherwise not be available, and it effectively caps the past ash disposal area. Construction of composite liners with leachate collection landfills over past ash disposal areas is also an option in Indiana, where two of its existing landfills have been permitted and built. Landfills are prohibited on portions of the Marshall site due to this site being partially located within the State's Critical Watershed Areas. For preliminary budgeting purposes, the capital cost of a prescriptive (composite lined) landfill can be $500k/acre.

Ash Basins and Surface Impoundments – Under current regulations, existing ash basins will likely be required to meet a performance-based standard for groundwater protection, which may force corrective action, with the worst case being a phase-out and closure of ponds. Phasing out of surface impoundments will result in conversion to dry fly ash and bottom ash collection. Any phase-out would result in managing CCR in landfills, closure activities of the basins and significant changes to wastewater treatment. Ash basins are used not only for ash management but also for treatment of various low volume wastewater streams.

FGD Byproducts Disposal

Currently, there are 30 coal-fired units with operating scrubbers on the regulated Duke Energy system. In the Midwest, all newer FGDs were designed to produce wallboard-grade gypsum. The Gibson Unit 5 FGD upgrade (forced oxidized) produces disposable grade gypsum that is pug-milled with ash and quicklime for fixation. The byproducts from the Gibson Unit 4 scrubber and the scrubber at East Bend are pug-milled with fly ash and quicklime but need water for stabilization. Gibson Units 1-3 are in the process of converting to dry fly ash handling and the gypsum will be used for fly ash stabilization. The FGD wastewater will be used as water for hydration eliminating one of the major sources of contaminant loading in the surface water systems.

Gallagher Station is currently the only station using a dry sorbent injection system to control SO_2. Units 2 and 4 control sulfur dioxide using hydrated lime to avoid landfill leachate issues from sodium use.

In the Carolinas, all the FGD systems produce a wallboard-grade gypsum product. Gypsum residuals from the FGD wastewater treatment system are disposed of in a landfill. With the construction and operation of lined landfills at Allen and Cliffside, the lined FGD landfill at Marshall no longer receives off-site FGD wastes. Belews Creek also has on-site landfills for these FGD fines and any gypsum that is not immediately reused. At both Mayo and Roxboro, the FGD systems produce a wallboard-grade gypsum product that is sent to a wallboard plant adjacent to Roxboro. FGD materials produced at Asheville are re-used to the extent possible but unused materials are sent to an off-site landfill for disposal.

In Florida, Crystal River Units 4 and 5 are equipped with FGDs and the gypsum produced is primarily sold. Unsold gypsum is disposed in an on-site landfill.

[redacted]

CCR Reuse

In both the Midwest and Carolinas, Duke Energy currently sells its fly ash into the concrete market and its gypsum into the wallboard market. With the addition of scrubbers and possible ash beneficiation projects, saleable volumes of both fly ash and gypsum could increase. However, future CCR sales will depend not only upon the market demand but also upon the final regulatory classification of CCRs.

In the Carolinas, the contract with National Gypsum will generally be met with the gypsum produced from Marshall, Allen and Cliffside 5, with Allen being the first supply option due to its proximity. With Cliffside Unit 6 operational, an additional 250,000 to 400,000 ton/yr will be produced. An initiative is needed to find use for the additional gypsum that will be produced at Cliffside.

Going forward and in general, ash reuse as structural fill material is not a viable option.

Proposed Regulations

New federal regulations were proposed on June 21, 2010 and will dictate how regulatory programs will address both dam safety and CCR management in the future.

Both current and past ash handling practices and disposal areas are expected to be impacted by the proposed CCR regulation and will likely require significant attention in the future. The proposed CCR regulations include options to regulate CCRs as hazardous waste (RCRA Subtitle C) or as non-hazardous (RCRA Subtitle D). Except where noted, deadlines to comply with a final regulation are generally expected to fall in the 2018 to 2022 timeframe. EPA may not issue a final CCR rule until 2014 or later.

The general requirements under the proposed options for handling CCRs are summarized below:

Subtitle D

- To remain operable, existing surface impoundments would have to meet location and liner requirements within 5 years or they must close via clean closure or more likely close in place.
- A "D-prime" option (preferred by Duke Energy) allows ponds to remain in operation for their remaining useful life if they meet certain performance criteria.
- New and existing surface impoundments must meet new dam safety requirements, would require groundwater monitoring and corrective actions as needed, must meet siting restrictions, would require weekly inspections and have requirements for closure and post-closure care.
- New landfills require composite liner and leachate control.
- Landfills would have to meet stringent groundwater monitoring requirements and be subject to corrective actions for groundwater exceedances.

[redacted]

- There are no proposed restrictions to "encapsulated" uses of CCRs.
- EPA reserves the right to establish controls on "unencapsulated uses" of CCRs. Large scale fill projects would be considered as landfills.
- The Subtitle D proposed rule discusses the possibility for beginning closure activities of any inactive ash basin, landfill or structural fill as early as seven months after promulgation of a Subtitle D rule (or 30 days following the effective date of the rule) with closure completed six months later.

Subtitle C

- Existing surface impoundments must cease operation within 5 years and close via clean closure within 2 years thereafter. These closure requirements would extend to all impoundments that have not been properly closed.
- New and existing surface impoundments must meet new dam safety requirements, would require groundwater monitoring and corrective actions as needed, must meet siting restrictions, would require weekly inspections, and have requirements for closure and post-closure care.
- New landfills require composite liner and leachate control.
- Existing landfills will have to be re-permitted. All landfills would have to meet stringent groundwater monitoring requirements and be subject to corrective actions for groundwater exceedances.
- CCR destined for reuse is proposed to be exempt from hazardous waste regulation.
- Exemption would not apply to CCR used in large scale fill projects.
- EPA reserves the right to establish controls on "unencapsulated uses".
- Questionable ability to re-use CCR if labeled "hazardous waste."
- Concerns with compliance with hazardous waste regulations – spill reporting threshold (1 lb), employee training requirements, transporter requirements, re-engineering of plant systems, land disposal restrictions, etc.

New CCR regulations or the various States' implementation of the regulations may also address environmental justice concerns relative to CCR disposal, which are a priority for the current Administration. Environmental justice issues would include the potential impacts of offsite landfills on low income and minority populations. Environmental justice issues could be a factor in siting of new CCR handling and disposal facilities and could create additional challenges as dry handling and landfilling of CCRs become required and/or as hazardous waste classification of CCRs occurs.

CCR Regulation Challenges

A new rule will very likely require much more stringent maintenance and inspection requirements of CCR impoundments. Over time, wet fly ash and bottom ash handling systems are expected to be replaced with dry handling systems. Ash ponds are expected to be closed. Ash ponds and other ash fill operations will be replaced exclusively with lined landfills. New wastewater treatment systems will be required to replace treatment offered by wet ash basin systems. Closure of various wet and dry CCR disposal areas will be required in accordance with applicable regulatory requirements. Costs and

[redacted]

challenges will vary by station depending upon the magnitude, complexity and type of CCR handling operations already in place and the outcome of the final regulation.

[redacted]

Table 3 – Waste Management Issues/Challenges Summary

Station	Ash Handling		FGD Handling	Disposal Means	Risks
Carolinas	Fly	Bottom			
Allen	Dry	Wet	Yes	Bottom Ash to Pond; Fly Ash, FGD to Lined Landfill	Future pond cleanouts will likely be landfilled. Long term landfill capacity needs for ash/gypsum – beyond 2022 – may be off-site. Convert bottom ash handling to dry system. Significant ash pond closure needs
Belews Creek	Dry	Wet	Yes	Bottom Ash to Pond; Fly Ash, FGD to Lined Landfills	Significant landfill needs. Little to no current market for gypsum. Convert bottom ash handling to dry system. Significant ash pond closure needs.
Cliffside 5&6	U5 – Wet/Dry U6 - Dry	U5- Wet U6 - Dry	Yes	Bottom/Fly Ash to Pond-U5; U5&6 Fly & U6 Bottom Ash, FGD to Lined Landfill	Convert U5 bottom ash handling to dry system. Significant ash pond closure needs.
Lee	Wet	Wet	No	Bottom/Fly Ash to Pond	Significant past and present ash pond closure needs when retired.
Marshall	Dry	Wet	Yes	Bottom Ash to Pond; Fly Ash, FGD to Lined Landfills	Convert bottom ash handling to dry system. Significant ash pond closure needs.
Asheville	Wet	Wet	Yes	Bottom Ash and Fly Ash to Pond; FGD Filter Cake to Lined Landfills; FGD Reused	Difficulty anticipated siting a landfill. Convert dry and bottom ash handling to dry systems. Significant ash pond closure needs.

[redacted]

Station	Ash Handling		FGD Handling	Disposal Means	Risks
	Fly	Bottom			
Mayo	Dry	Wet (Dry in 2013)	Yes	Bottom Ash and Fly Ash to Roxboro Landfill, Mayo Landfill Under Construction with September 2013 In-Service Date; FGD to Roxboro Storage Pad for Re-use in Adjacent Wallboard Plant	Convert bottom ash handling to dry system. Significant ash pond closure needs.
Roxboro	Dry	Wet (Dry in 2014)	Yes	Fly Ash to On-site Landfill, Bottom Ash to Pond, FGD to On-site Storage Pad for Re-use in Adjacent Wallboard Plant	Convert bottom ash handling to dry system. Contractual commitments to supply gypsum. Significant ash pond closure needs.
Sutton Coal	Wet	N/A	N/A	Bottom/Fly Ash to Pond	Significant ash pond closure needs.
Florida					
Crystal River	Dry	Dry	U4&5 - Yes	Bottom and Fly Ash, FGD to Lined Landfill, sales	
Midwest					
Cayuga	Wet	Wet	Yes	Bottom/Fly Ash to Pond; Landfill for final ash and FGD disposal	Convert all ash handling to dry systems. Significant ash pond closure needs.
East Bend 2	Dry	Wet	Yes	Bottom Ash to Pond; Fly Ash, FGD to Lined Landfill	Convert bottom ash handling to dry system. Significant ash pond closure needs.
Gallagher	Dry	Wet	No	Bottom Ash to Pond; Fly Ash to Lined Landfill	Convert bottom ash handling to dry system. Significant ash pond closure needs.

[redacted]

Station	Ash Handling		FGD Handling	Disposal Means	Risks
Gibson	Wet 1-3; convert to dry in 2012-2013 Dry (4-5)	Wet	Yes	Bottom Ash to Pond; Fly Ash, FGD to Lined Landfill; U1-3 conversion in '12 and '13.	Convert bottom ash handling to dry system. Significant ash pond closure needs.
Miami Fort 6	Wet	Wet	No	Bottom/Fly Ash to Pond; Landfill for final ash disposal	Ash pond closure considerations with other unit actions.
Wabash River 2-6	U2-5 – Wet U6 - Dry	Wet	No	Bottom/Fly Ash to Pond; Dry Ash to off-site.	Significant past and present ash pond closure needs when retired.

[redacted]

5.0 Decommissioned Sites and New Combined Cycle Generation Regulatory Issues

As a result of the EPA regulations discussed in Sections 2.0 – 4.0, a general decrease in the demand for electricity, and the reduction in natural gas prices, numerous coal-fired stations have been and will continue to retire over the next few years. Most of the retiring coal-fired generation is being replaced with natural gas-fired combined cycle units. Several new combined cycle stations have become operational within the last couple of years – Buck, Dan River and the Lee Energy Complex in North Carolina with others possible in South Carolina, Florida and the Midwest.

Combined cycle generation faces significantly fewer environmental challenges than the coal-fired units they are replacing. The combined cycle units face no challenges from SO_2 emissions and coal ash and only minimal concerns with NO_X emissions and 316(b) risks due to their use of SCR and cooling towers, respectively. Though better by about 50% than coal relative to carbon dioxide emissions, this could become their most significant emissions challenge over time.

Power plant decommissioning will be a significant effort and expense over the next decade. Expenditures and plans are now well underway as part of the Plant Retirement Comprehensive Program taking place in the Carolinas. A total of 10 coal-fired facilities (some including oil and gas-fired simple cycle combustion turbines) and 2 additional stand-alone combustion turbine sites (Buzzard Roost and Morehead City) are in various stages of decommissioning.

At some point after plant retirement, remediation of various past plant activities may need to occur. Subsurface investigation, assessment and remediation of plant areas previously used for fuel oil storage and conveyance, switchyards and substations, combustion turbine operations, coal piles and coal handling operations, ash ponds and landfills, etc will be needed. To prepare for this work, planning and discussions with regulators is underway in order to understand closure requirements, especially relative to ash handling and storage where investigation and closure requirements are still being explored.

Final closure requirements are not known but could involve installation of impermeable caps for closure in place, removal of CCRs from the plant sites and disposal in landfills, or other on-site closure measures. Decisions on the proper closing method will likely vary by state and potentially by plant site. The final regulatory classification of CCRs will also impact closure method options. Some NPDES permit renewals (e.g., in NC) are beginning to require ash basin closure plans to be submitted prior to ending use of the basin. CCR removal or capped closure will require significant dollars. If capped in-place, long-term groundwater monitoring, will require significant dollars. If capped in-place, long-term groundwater monitoring (possibly 30 years) will also be required.

Closure in place has occurred at non-Duke Energy sites, and these instances provide some cost data. Closure in-place costs (5-10 years ago) have totaled approximately $200,000 per acre (Ref. "EPRI – Decommissioning Handbook for Coal-Fired Power

[redacted]

Plants," November 2004). CCR storage and disposal areas typically consume significant site acreage. Also, the projected requirements for CCR remedial activities and closure will likely be more stringent than past CCR plant closure requirements. Thus, with costs that may be significantly greater than $200k per acre and the large CCR footprints to be addressed, planning and budgeting for these retirement costs is underway.

The following general waste-related issues are expected to present challenges to regulated generation and should be evaluated and planned for over the next several years.

- The management of soluble sorbents in landfills
- The challenge of managing fugitive dust in landfills
- With station retirements, how landfill leachate and general stormwater will be managed during and after plant closure
- If and when ash ponds are required to be closed by the CCR rule, what the means of treatment for landfill leachate after pond closures will be

The solubility of sodium particles makes it very difficult to contain pollutants when disposed of in landfills. More studies are needed to understand sodium and fixation of the trace elements it reacts with to eliminate the transfer of pollutants to leachate and other wastewaters that must be treated before discharge.

[redacted]

6.0 Climate Change Strategic Issues

In May 2010 the EPA finalized what is commonly referred to as the Tailoring Rule, which increased the emission thresholds significantly above conventional pollutants that determine when a source is potentially subject to PSD permitting for greenhouse gases. The Tailoring Rule sets the GHG significant net emissions increase threshold for modifications at 75,000 tons per year CO2e, meaning that any existing Duke Energy coal-fired or large natural gas-fired generating unit, that undertakes a modification that results in a net increase of at least 75,000 tons/year of CO_2e, is subject to PSD permitting requirements for GHGs. Being subject to PSD permitting requirements for CO_2e will require a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. BACT will be determined by the state permitting authority. EPA has issued GHG BACT guidance which focuses on unit efficiency improvements as possible BACT. Duke Energy reviews all projects in advance for potential PSD compliance considerations. Currently, there are no known plans for any Duke Energy generating unit to undertake a modification that triggers PSD permitting requirements for GHGs. Thus the potential implications of this regulatory requirement are unknown.

One potential future BACT for GHGs, carbon capture and storage (CCS) has significant potential as a carbon mitigation technology for coal and natural gas based generation. Development of the technology has, however, slowed due to low natural gas prices and regulatory uncertainty regarding the reduction of carbon dioxide emissions. Enhanced oil recovery (EOR) provides a near-term economic driver for CCS, but the sheer magnitude of the carbon dioxide (CO_2) to be captured necessitates the development of saline aquifer storage. Other storage location options, albeit of less magnitude, such as coal seams, basalt formations, enhanced coal bed methane recovery and deep ocean storage are also being tested around the world. Other aspects of CCS including capture and pipeline transportation of the CO_2 are also under investigation.

Aside from the economic and technical issues, there are important regulatory and legal challenges that must be addressed before CCS can be widely used. Many of them are being addressed at the state level while some are being addressed at the federal level. However, all these activities are moving very slowly and CCS on a commercial scale has advanced very little in recent years.

The most notable regulatory development at the federal level in the recent past is the federal requirements for CO_2 injection wells. The U.S. Environmental Protection Agency (EPA) released the requirements under the *Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells* regulation in December of 2010. This rule established requirements for geologic sequestration pursuant EPA's authority under the Safe Drinking Water Act and creates within the EPA's UIC Program a Class VI for geologic sequestration wells. The rule includes the option of primacy for states that allows states to administer the program. The UIC program regulates the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal.

[redacted]

On April 13, 2012, the EPA published its proposed rule to establish New Source Performance Standards (NSPS) for carbon dioxide (CO_2) emissions for pulverized coal, IGCC, and natural gas combined cycle electric generating units that are permitted and constructed in the future. The proposal would not apply to any of Duke Energy's regulated operations' coal (which includes IGCC) and natural gas electric generation plants that are currently under construction or in operation. Any future pulverized coal and IGCC units will have to employ carbon capture and storage (CCS) technology to meet the CO_2 emission standard the EPA has proposed. The proposed standard will not require new natural gas combined cycle facilities to install CCS technology. It is not known when EPA will finalize the proposal. It has been rumored that EPA might re-propose the rule for the purpose of setting separate emission limits for gas-fired and coal-fired units. If EPA does this it will likely push the date for a final rule into 2014.

EPA is expected to propose GHG emission guidelines for existing EGUs that do not undergo a modification at some point. It's unlikely that EPA will issue a proposal until sometime in 2014. Once EPA finalizes emission guidelines for existing sources, the states will be required to develop the regulations that will apply to covered sources, based on the emission performance standards established by EPA in its guidelines.

It is highly unlikely that legislation mandating reductions in GHG emissions or establishing a carbon tax will be passed by the 113th Congress which began on January 3, 2013. Beyond 2014 the prospects for enactment of any federal legislation mandating reductions in GHG emissions or establishing a carbon tax are highly uncertain. Given the high degree of uncertainty surrounding potential future federal GHG legislation, Duke Energy cannot predict if or when such legislation might be enacted, what the requirements of any potential legislation might be, or the potential impact it might have.

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7.0 References

Environmental Regulatory Working Group Members

Chris Hallman	Environmental Regulatory Issues coordinator (Chair)
Dave Mitchell	Environmental Services, Air and Waste (Vice-Chair)
Brandon Delis	Strategic Engineering, Water Compliance
Dan Hartmann	Strategic Engineering, Strategic Programs
Elliott Batson	Regulated Fuels
Mike Stroben	Energy and Environmental Policy
Peter Hoeflich	Central Engineering, Strategic Engineering
Michael Reid	Emerging Technology, Technology Development
J Berley	Engineering Services, Environmental Controls
Mike Kennedy	State Environmental Affairs Representative
Garry Rice	Legal Representative
Tony Mathis	By-Products Management
Thomas Lawery	Business Services, Business Planning
Greg Augspurger	Central Engineering, Continuous Improvement
Richard Baker	Environmental Services, Water/Natural Resources
John Velte	Water/Natural Resources, Water Compliance
Danny Wimberly	Plant Demolition and Retirement

Ad hoc Members

Glenn Harris	Combined Cycle, Dan River Station
Jeff Lineberger	Water Strategy and Hydro Licensing
Sam Alexander	Engineering and Construction Services
Kevin Delehanty	Strategy & Development, Load Forecasting and Fundamentals
Scott Park	Energy Supply Analytics
Toby Short	Federal Government Affairs
Erin Culbert	Generation Communications
Sandy Vlahos	Corporate Accounting

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Tables

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Table 4 – Station Environmental Controls Summary

	Cayuga 1&2	East Bend 2	Gallagher 2&4	Gibson 1-5
Issue				
NO_X	LNB/OFA	LNB/OFA/SCR (2002)	LNB/OFA	LNB/OFA/SCR
SO_2	Wet FGD (2008)	Dry FGD (1981)	Low sulfur coal/hydrated lime	Wet FGD U1-3 ('06/'07); U4 '79; U5 '82
Particulate	Cold side ESPs	Hot side ESP	Baghouses (2007-2008)	Cold side ESPs
Cooling Water	Helper Cooling Towers	Cooling Towers	No CTs	Cooling pond
Fly Ash Handling	Wet Sluiced	Dry Handled	Dry Handled	Wet sluiced (U1-3); Dry Handled(U4-5)
Bottom Ash Handling	Wet Sluiced	Wet Sluiced	Wet Sluiced	Wet Sluiced
Waste Water Treatment	Solids removal & dilution; ash basin	Closed cycle design	Ash basin	Solids removal, then to North Ash pond; ash basins
Ash Disposal	Sluiced to pond, final to LF	Bottom ash to pond, fly ash as FSS to LF	Bottom ash to basin, fly ash to lined LF	Bottom ash to basin, fly ash to pond (U1-3) to lined LF (U4-5)
FGD Disposal	CCR LF	As fixated scrubber sludge to LF	N/A	As fixated scrubber sludge to LF
Disposal Units	Ash pond (1 lined and 1 unlined & CCR landfill	Ash pond (1) and special waste LF	1 ash pond, new ash LF	2 active ash ponds and 2 CCR landfills

[redacted]

Table 4 – Station Environmental Controls Summary (cont'd)

	Miami Fort 6	Wabash River 2- 6	Allen 1-5	Belews Creek 1&2
Issue				
NO_X	LNB	LNB/OFA	LNB/SOFA/LOFIR /SNCR (U1, 3, 5); LNB/SOFA/SNCR (U2, 4)	LNB/OFA/SCR (2003-2004)
SO_2	None	None	Wet FGD (2009)	Wet FGD (2008)
Particulate	Cold side ESP	Cold side ESPs	Cold side ESPs	Cold side ESPs
Cooling Water	No CTs	No CTs	No CTs	No CTs
Fly Ash Handling	Wet Sluiced	Wet Sluiced (U2-5) Dry Handled or Wet Sluiced (U6)	Dry Handled	Dry Handled
Bottom Ash Handling	Wet Sluiced	Wet Sluiced	Wet Sluiced	Wet Sluiced
Waste Water Treatment	Ash basins	Ash ponds	Solid removal/bioreactor; ash basins	Solid removal/bioreactor/ wetlands; ash basin
Ash Disposal	To pond A	To ponds and U6 dry ash off-site for re-use	Bottom ash to basin, fly ash to lined LF	Bottom ash to basin, fly ash to lined LF
FGD Disposal	N/A	N/A	CCR landfill	FGD landfill
Disposal Units	2 ash ponds	2 ash ponds, final pond is lined.	CCR landfill and ash pond	Ash basin and 2 lined landfills

[redacted]

Table 4 – Station Environmental Controls Summary (cont'd)

	Cliffside 5 & 6	Lee 1-3	Marshall 1-4
Issue			
NO_X	LNB/SOFA/LOFIR /SCR (U5- 2002) LNB/OFA/SCR (U6 – 2012)	SOFA	LNB/SOFA/LOFIR /SNCR (U1, 2, 4); LNB/SOFA/LOFIR /SCR (U3 - 2008);
SO_2	Wet FGDs (U5- 2010, U6- 2012)	None	Wet FGD (2007)
Particulate	Cold side ESP (U5); Baghouse (U6)	Hot side ESPs	Cold side ESPs
Cooling Water	Closed cycle Cooling Towers	Helper Cooling Towers	No CTs
Fly Ash Handling	Dry Handled	Wet Sluiced	Dry Handled
Bottom Ash Handling	Wet Sluiced (U5) Dry (U6)	Wet Sluiced	Wet Sluiced
Waste Water Treatment	Solid removal/Gravity filter and ash pond	Ash basins	Solid removal/wetlands; ash basin
Ash Disposal	Bottom ash (U5) to pond; fly ash and bottom ash (U6) to lined LF	To ponds	Bottom ash to ponds; fly ash to lined LFs
FGD Disposal	CCR landfill	N/A	FGD/CCR landfills
Disposal Units	1 ash pond; 1 lined CCR LF	2 ash ponds	Ash pond and 2 lined LFs

[redacted]

Table 4 – Station Environmental Controls Summary (cont'd)

	Asheville 1-2	Mayo 1	Roxboro 1-4	Sutton 1-3	Crystal River 1-2, 4-5
Issue	**Existing Environmental Controls**				
NO_X	SCR	SCR	SCR	SNCR (U3)	LNB (U1&2); SCR (U4&5)
SO_2	FGD	FGD	FGD	None	FGD (U4&5)
Particulate	Cold side ESP (U1, U2)	Hot side ESP	Cold side ESP (U1, U2, U3); Hot side ESP (U4)	Hot side ESP (U1, U2); Cold side ESP (U3)	Cold side ESP (U1, U2, U4, U5)
Cooling Water	Once-Thru; No CTs	Cooling Lake	Once Thru (U1-3); Cooling Towers (U4)	Cooling Lake	Once Thru (U1-2); Cooling Towers (U4-5)
Fly Ash Handling	Wet sluiced	Dry	Dry	Wet Sluiced	Dry
Bottom Ash Handling	Wet sluiced	Wet sluiced, converting to dry.	Wet sluiced	Wet Sluiced	Dry
Waste Water Treatment	Solid removal/Wetlands/ Ash pond	Settling Pond /Bioreactor/Ash pond, Partial ZLD complete by end of 2013	Settling ponds/Bioreactor/ Ash pond	2 ash ponds	Percolation pond
Ash Disposal	Fly and bottom ash to pond	Bottom ash to pond; fly ash to lined LF	Bottom ash to pond; fly ash to lined LF	Fly and bottom ash to pond	Fly and bottom ash to sales, lined LF
FGD Disposal	Filter Cake Off-site Landfill; FGD Re-used, But No On-site Disposal if Market Goes Away	Roxboro Storage Pad for Re-use in Adjacent Wallboard Plant	Roxboro Storage Pad for Re-use in Adjacent Wallboard Plant	N/A	Sales; onsite lined LF
Disposal Units	2 ash ponds	1 ash pond; 1 lined CCR LF (2013)	1 ash pond; 1 lined CCR LF on site	2 ash ponds	1 lined CCR LF

[redacted]

Table 5 – Station Environmental Impact Options Summary

		Cayuga	East Bend 2	Edwards-port IGCC	Gallagher 2 & 4	Gibson
Issue	Likely Impact Date	**Potential Impact/Option**				
CAIR Ph. II or CSAPR	2015		FGD Upgrade; LNB/OFA Upgrades	Pulverized Coal - Retired	SNCR	FGD Upgrade (U1-4); New FGD (U5); LNB/OFA Upgrades
MATS	2015	Re-emissions additive, $CaBR_2$ or ACI;	Re-emissions additive, $CaBR_2$ inj./ACI		Alkali Inj. for HAPS	Re-emissions additive, FGD upgrades on U5
NAAQS Ozone Std.	2020	SCR (likely 2014/2015)			SNCR	
NAAQS SO_2 Std.	2018		FGD Upgrade			FGD Upgrade (U1-4); New FGD (U5)
316(b)	2016	Screen mods; CT evaluation	Screen mods		Screen mods; CT evaluation	Screen mods; stormwater mod.
Waste Water Treatment	2017	Enhanced treatment – NPDES & FGD				Alternative to final disposal to cooling pond
CCR Handling	2018 or later	Convert to Dry ash; Pond closures	Pond closures; Dry bottom ash conv.		Pond closures	Convert U1-3 to dry ash. Pond closures; Dry bottom ash conv.

[redacted]

Table 5 – Station Environmental Impact Options Summary (cont'd)

		Miami Fort 6	Wabash River	Allen	Belews Creek
Issue	Likely Impact Date	**Potential Impact/Option**			
CAIR Ph II or CSAPR	2015	Reduced operations	Reduced operations		
MATS	2015	Likely retire	Likely retire	CaBr2, or ACI; DSI for SO3	ACI;
NAAQS Ozone Std.	2019	Likely retire	Likely retire	SNCR upgrade/ Hydrogen Peroxide Injection/ SCR	
NAAQS SO_2 Std.	2018	Likely retire	Likely retire		
316(b)	2016	Likely retire	Likely retire	Screen mods; CT eval.	Screen mods; CT eval.
Waste Water Treatment	2017	Likely retire	Likely retire	Enhanced treatment – NPDES	Enhanced treatment – NPDES
CCR Handling	2018 or later	Pond closures; Likely retire	Pond closures; Likely retire	Pond closures; Dry bottom ash conv.	Pond closures; Dry bottom ash conv.

[redacted]

Table 5 – Station Environmental Impact Options Summary (cont'd)

		Cliffside 5 & 6	Lee	Marshall
Issue	Likely Impact Date	**Potential Impact/Option**		
CAIR Ph. II or CSAPR	2015		Reduced Operations poss.	SNCR Upgrade
MATS	2015	U5 - – $CaBr_2$ or ACI; DSI for SO3 control	Likely retire/gas conversion	U1&2 - CaBr2 Addition or ACI;U4 - $CaBr_2$
NAAQS Ozone Std.	2019		Likely retire/gas conversion	SNCR upgrade / Hydrogen Peroxide Injection / SCR (U1&2)/ SCR (U4)
NAAQS SO_2 Std.	2018		Likely retire/gas conversion	
316(b)	2016	Screen mods.	Screen mods. poss.	Screen mods; CT eval.
Waste Water Treatment	2017			Enhanced treatment – NPDES, FGD
CCR Handling	2018 or later	Pond closures; Dry bottom ash conv. – U5	Pond closures	Pond closures; Dry bottom ash conv.

[redacted]

Table 5 – Station Environmental Impact Options Summary (cont'd)

		Asheville	Mayo	Roxboro	Sutton	Crystal River
Issue	Likely Impact Date	**Potential Impact/Option**				
CAIR Ph. II or CSAPR	2015					
MATS	2015		Possible ACI or re-emission chemical		Retire	Possible ACI or re-emission chemical
NAAQS Ozone Std.	2019				N/A - To Be Retired	
NAAQS SO_2 Std.	2018	Take lower permit limit	Take lower permit limit	Take lower permit limit	N/A – To Be Retired	U1&2 likely retired; Take lower permit limit
316(b)	2016	Screen mods; CT eval.	Screen mods; flow eval.	Barrier net; Screen mods; CT eval.	N/A – To Be Retired	
Waste Water Treatment	2017	Enhanced treatment – NPDES, FGD	Partial ZLD 2013	Enhanced treatment – NPDES, FGD	N/A – To Be Retired	Enhanced treatment – NPDES, FGD
CCR Handling	2018 or later	Convert to dry fly and bottom ash; Pond closures	Convert to dry bottom ash (2013); Pond closures	Convert to dry bottom ash (2014); Pond closures	Pond closures	

[redacted]

Table 6 – Major Regulatory Issues Schedule

*Bold Dates indicated in the Table are actual dates.

Regulation/Issue	Proposed Rule Date	Final Rule Date	Compliance Date	Notes
Water				
316 (b)	**April 20, 2011**	June, 2013*	Mid-Late 2016	Compliance – 3 yrs (impinge); 6 yrs (entrain) after next NPDES permit
Effluent Guidelines	April 2013**	May, 2014**	Mid-2017	
Air				
CSAPR	**August 2, 2010**	**August 8, 2011**		CSAPR vacated August 2012; CAIR remains in place
MATS	**May 3, 2011**	**February 16, 2012**	April 16, 2015	One year ext. possible for compliance.
Industrial Boiler MACT	**June 8, 2010**	**May 20, 2011**	May 2014	Revised standards in May/June 2012; may reset the compliance period to June 2015
NAAQS - 8 hr. Ozone Std. Implementation (2008 Std – 75 ppb)		**2008**	**December 31, 2015**	NA Areas designated – May 2012
NAAQS - 8 hr. Ozone Std	Late 2013	Late 2014	Starting 2019	Compliance date depends on designation (e.g., marginal)
NAAQS $PM_{2.5}$ Std.	**June 14, 2012**	**December 14, 2012**	2020	NA Areas designated – 2015
NAAQS SO_2 Std.	**November 16, 2009**	**June 22, 2010**	2018	NA Areas designated - June 2013

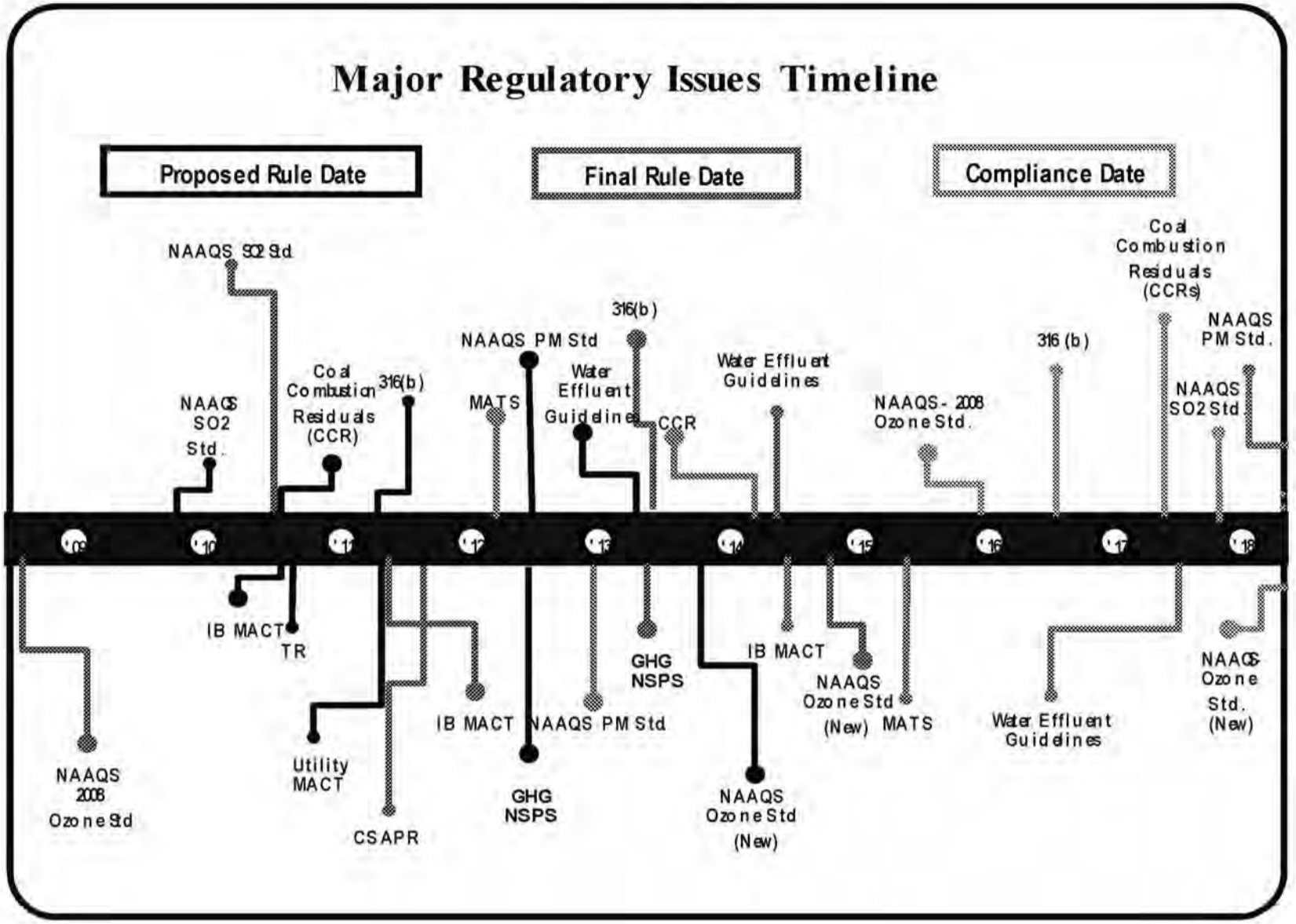
[redacted]

Table 6 – Major Regulatory Issues Schedule (cont'd)

Regulation/Issue	Proposed Rule Date	Final Rule Date	Compliance Date	Notes
Waste				
Coal Combustion Residuals (CCRs)	**June 21, 2010**	2014 or later	2018 or later	
PCB Use Authorization	2013 or later	Unknown		
Climate				
Greenhouse Gas Regulation – New Source Performance Standards for New or Modified Sources	**April 13, 2012****	2013**	Takes effect upon proposal	Applies to new/modified facilities that haven't commenced construction by proposal publication date
Greenhouse Gas Regulation – New Source Performance Standards for Existing Sources	Unknown	Unknown	Unknown	Tailoring Rule in effect **1/2/11** for PSD and Title V.

* Date specified per Settlement Agreement
** Dates specified per consent decree.

[redacted]



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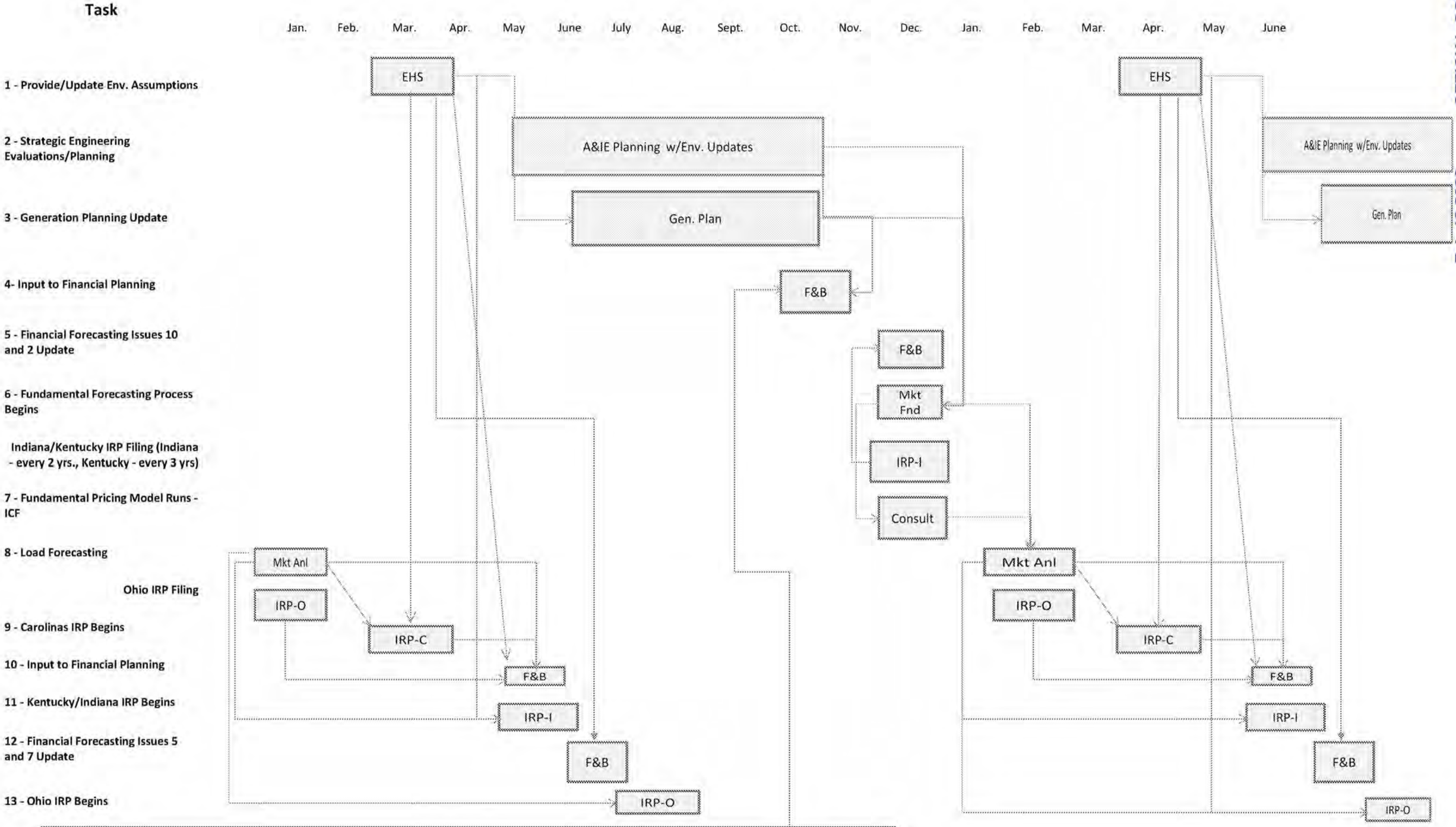
Appendix – Environmental Issues Input to Planning Process

[redacted]



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Notes:
ES - Env. Strategic Issues Working Group (Dave Mitchell); Str. Eng – Strategic Engineering (Joe Miller); F&B - Forecasting and Budgeting (Dwight Jacobs); Mkt Fnd - Market Fundamentals - Comp. Analysis (Kevin Delehanty);
Mkt Anl - Market Analysis (Dick Stevie); IRPs - Integrated Resource Planning - (Janice Hager);
Gen. Plan - Generation Planning Budget Input.

[redacted]

Ash Basin Closure Strategy

Recently the Company has retired designated fossil units in NC while their associated ash basins continue to remain active for a period. In some cases, waste streams other than ash (e.g., coal pile run-off, drains, etc.) will need to continue to be transported to the ash basins for treatment until those plant support systems can be decommissioned fully. Currently federal regulatory programs do not specifically address the decommissioning and closure of ash basins; however, state regulations provide some options for closure framework. The company is working closely with NCDENR to define a closure process that provides a framework for certainty in the absence of specific federal regulatory requirements.

It is important for the corporation to move forward with ash basin closures under the process to be submitted to NCDENR, to minimize environmental risks and costs (mostly O&M) associated with maintaining ash basins for an extended period until federal rulemakings are complete and final. Other timing considerations include:

1. Ash basin closures can take years to complete so beginning the process is important.
2. While a final federal coal combustion residuals (CCR) rule is not expected before 2014, and lack of a federal ruling introduces an element of uncertainty, state requirements exist now. There is reasonable belief with internal company experts that any federal rule would be based on Subtitle D requirements to be implemented by the states.
3. Until the ash basin is dewatered, the NPDES permit must be maintained, or possibly renewed in certain cases, thus opening the renewal process to regulatory and greater public scrutiny (including public comments supporting clean closure). O&M Costs would continue to accumulate especially while the permit is active.
4. Dewatering the ash basins in accordance with the NPDES permit will over a relatively brief time reduce and/or eliminate seepage which the company is currently addressing.
5. Shaping and capping the ash basins soon after dewatering will help address possible dusting issues. Other dusting measures during dewatering will be needed.
6. Capping the basins soon will help begin the process of natural attenuation or other means to reduce constituents in groundwater. Constituent levels monitored in groundwater wells can take many years to observe substantial reductions.
7. Ash basin closure has recently seen increased attention and scrutiny and that scrutiny can only be expected to increase while the ash basins have no approved closure plan and reasonable efforts to close them are not underway.

To address these concerns representatives from Environmental, Strategic Engineering, and Plant Demolition conducted a Value Stream Analysis in 2012 to develop a standard process for ash basin closure option evaluation and decision-making, including factors such as timing, technologies, environmental and geotechnical considerations, risks, resources, and costs. The team developed a combined company ash basin closure process, which was analyzed using the Weatherspoon site. The team then completed a Kepner-Tregoe problem solving/decision analysis to determine the best closure design options for the Weatherspoon ash basin closure using site scoping information already collected.

[redacted]

While the site conditions supported a simple soil cover in earlier analysis, the K-T analysis considered other factors including environmental protection, long-term maintenance costs, public perception and risk minimization, and concluded that an HDPE geo-synthetic cap system would be the best solution for Weatherspoon ash basin closure.

The recommended strategy is to dewater, cap the Weatherspoon ash basin, and monitor. The ash basin strategy does not address lay-of land ash disposal areas such as landfills and possibly other historic ash placements. An engineering design is currently being performed for ash basin closure at Weatherspoon based on the recommended strategy. The conceptual design was utilized to further define scope, cost, and schedule of ash basin closures. This design will be submitted to NCDENR in May 2013, expecting final approval in July 2013.

Once NCDENR approval is received, the team recommends closure of the Weatherspoon ash basin for the following reasons.

1. This closure strategy process and NCDENR approval will establish precedent with the state on the method for future ash basin closure.
2. The Weatherspoon ash basin is one of the simplest and smallest basins on the system. Cost for closure is estimated to be approximately $18 - $34 million. It will provide a useful test case for lessons learned that can be applied to future closures.
3. Defining future costs for closure is critical to estimating liabilities for corporate reporting.
4. While the federal Coal Combustion Residual (CCR) rule has not yet been finalized, EPA's current thinking, based on recent agency comments, is that regulation of CCR disposal under RCRA Subtitle D may be "adequate".
5. It is anticipated that final CCR regulations requiring ash basin closure will be finalized no earlier than 2014. Assuming a Subtitle D rule contemplated by federal legislative efforts, state rulemaking will be initiated to create the framework for state implementation of the federal program. Duke Energy's retired plants in the Carolinas have at least 20 ash basins that will need to be closed. It is important that the corporation be proactive in developing the expertise in closure methods and have the qualified contractors on board to help meet this challenge.
6. The Plant Demolition and Retirement team includes individuals who are capable of performing the work utilizing trained fuel handling operators and existing equipment for basin grading. The project will be supplemented with engineering, QA and liner/specialty contractors. Future ash basin closures will be managed similarly to Weatherspoon. However, grading services may be contracted depending on in-house resource availability.

Current activities include budget development with Strategic Engineering and Cape Fear, Dan River, Lee (NC), and Buck ash basins site characterization studies.

[redacted]

O&M Cost Reduction:

Anticipated ongoing O&M work for retired facilities include:

1. Inspections
2. Dike maintenance (Mowing slopes, brush cutting, toe ditch and interior slope maintenance)
3. Fugitive dust mitigation
4. Repairs as needed (reseeding, runoff, animal burrow)

Anticipated cost per site is $50K-$150k

Support for the Process of natural attenuation caused by capping:

Attached are selected pages from the most recent groundwater monitoring report conducted by Blackrock Engineers for the Roxboro landfill. Note highlighted discussion from a couple of sections of the report regarding the downward trend in contaminant concentrations and the fact that the lined landfill is partially intended to minimize recharge and thus allow for concentration reduction to occur which is happening. Following the text is a series of graphs that support the generally downward concentration trend.

Roxboro Landfill
Groundwater Data Tr

Capital cost bases:

The range provided for closure is based on $18 million closure estimate based on Belews Creek ash land fill closure and $34 million estimate from Strategic Engineering.

[redacted]