IOWA UTILITIES BOARD
Energy Section

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TO: The Board

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SUBJECT: Summary of Participant Comments and Recommendation to Terminate Inquiry Regarding Utility Coal Plant Planning

Note: This document contains **CONFIDENTIAL** material which is shaded in gray.

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I. Background

On September 2, 2011, the Iowa Utilities Board (Board) issued its "Order Opening Inquiry on Utility Coal Plant Planning and Soliciting Comments," which initiated Docket No. NOI-2011-0003. The purpose of the inquiry was to assess the potential impact on Iowa's electric utilities (and their ratepayers) of various pending or adopted regulations promulgated by the U.S. Environmental Protection Agency (EPA). The EPA has proposed or adopted various regulations that address such diverse subjects as discharges into water, coal fly ash, cooling water intake structures, and air regulations concerning ozone (O_3), sulfur oxides (SO_X), nitrogen oxides (NO_X), mercury (HG), carbon dioxide (CO_2), and other greenhouse gasses. The Board set out eleven specific questions that MidAmerican Energy Company (MidAm) and Interstate Power and Light Company (IPL) were required to respond to. Cooperatives and municipals that own generation in Iowa were invited to provide information similar to that required of MidAm and IPL. IPL and MidAm were also invited to provide their own description of the proposed EPA regulations and what strategies each intends to use to respond to those regulations. The responses to the questions are summarized in Appendix A - Part 1.

The Board issued its "Order Soliciting Comments on RICE Standards and From Non-Utilities Owning Coal-Fired Generation" on November 8, 2011. This order extended the inquiry to address reciprocating internal combustion engines (RICE) which are sometimes used by utilities to generate electricity on an intermittent or emergency basis. The Board stated that there were two areas not addressed in the original inquiry that could impact grid reliability in ways similar to the EPA rules applicable to utility coal plants. These areas are: 1) EPA standards for diesel powered stationary reciprocating internal combustion engines (RICE) that could significantly impact utilities, and 2) EPA standards that will likely impact some non-utility coal-fired generation in Iowa. The order included three questions related to RICE which MidAm and IPL were required to respond to and municipal and cooperative utilities were invited to respond to. The responses to these questions are summarized in Appendix A - Part 2. The November 8 order also included two questions related to non-utility coal plants and invited the owners of the nine non-utility coal plants to respond to them. The responses to these questions are summarized in Appendix A - Part 3.

Presented below is a combined list of all of the questions the Board sought comment on in this docket.

Initial Inquiry Questions
From September 2, 2011, Board Order

1. A list of the utility's existing coal plants, including the existing technology of each such plant, and its emissions. Describe individual units, if the technology varies by unit.

2. The EPA rules, and their expected implementation schedule, that could affect the utility's decisions.

3. A list of up to ten possible strategies to address the EPA rules. This list should include the following two strategies:

   a. A business as usual strategy; and
   b. Upgrade all coal units to meet the new rules.

   Examples of other possible strategies include:

   c. Replace all coal units with gas;
   d. Replace selected units with gas or other alternatives and upgrade other units with new pollution prevention technology; or
   e. Replace some or all coal units with nuclear units.

4. The costs and timing of capital investments for each strategy (e.g., x pollution control equipment in year y, gas pipeline or electric transmission upgrades in year z, etc.) should be described and quantified where possible.

5. Along with the strategies, the utility is to provide a list of possible scenarios that address possible levels of key variables such as gas price, coal price, carbon emissions prices, economic growth, construction cost changes, interest rate, speed of EPA rule implementation, economic efficiency implementation, and the use of demand response. The source of the various variable values should be described – e.g., low, medium, and high gas prices from EIA's 2011 Annual Energy Outlook.

6. The projected results in each of the ten years (2012 to 2021) for each of the scenarios for each of the strategies. The results should include electricity demand by residential, commercial and industrial classes, including use per customer and number of customers data; sales for resale by customer and/or market; supply mix by MW and MWh (with projected prices); NOX, SOX, CO2, and mercury emissions; capital cost recovery and O&M expenditures; total rate impact and impact per kW and kWh on each customer class; impact on existing company work force, new construction work force and new operation workforce; decommissioning and waste disposal and/or storage costs, as applicable, for nuclear facilities; and capital and operating expenditures to meet the various new EPA regulations. Net present values of the ten-year stream of payments projected to be paid by the utility's customers for each strategy under each of the scenarios considered are to also be calculated.

7. Generally, discuss how the alternative strategies would meet the current and future emission reduction requirements of the federal Clean Air Act and other federal environmental legislation and of the applicable Iowa environmental statutes.

8. The impact of possible coal plant retirements on transmission reliability and system operations, the transmission constraints that currently exist and that could develop on the utility's system, how the utility currently manages them, and how it proposes to manage them.

9. Details of the utility's transmission, production cost, and general cost model(s) so that the assumptions are supported and transparent, and the operation of the model to derive the various numerical outputs is easily understood.

10. In connection with any natural gas repowering or new gas generation alternatives, the utility's consideration of long-term gas supply contracts.

11. Any advanced ratemaking principles or special rate recovery mechanisms contemplated such as construction work in progress, allowance for funds utilized during construction, and accelerated depreciation, which the company proposes, or the advanced ratemaking principles described in recent proposed legislation.

Questions on RICE Standards
From November 8, 2011, Board Order

1. Do you use RICE engines on your system? If so, what engines do you have and where are they? How many kW does each supply?

2. Would the projected use of those engines be significantly reduced by the EPA NESHAP regulations as recently amended?[1] If so, describe, and quantify to the extent possible, the impact of those regulations on the use of your RICE engines in possible emergency situations that could occur in your service area.

3. What alternatives are available to you in lieu of operating your RICE engines? What is the capital and operating cost of these alternatives?

Questions on Non-Utility Coal Plants
From November 8, 2011, Board Order

1. Is the table provided in the order accurate insofar as it contains data concerning your facilities? Please provide the nameplate capacity, annual net generation, and location of any coal-fired generation not listed above.

2. Do you intend to continue to operate the individual plant(s) listed above or newly described in your answer to Question No. 1 above, in light of the new and proposed EPA regulations? If not, assuming you have a continuing need for the electric power the plant produces, how will you seek to obtain electric power for your operations?

Nineteen parties, listed below, filed comments in this docket. Attachment 1 of Appendix A indicates which sets of questions each party responded to.

Ag Processing Inc.	AGP
American Coalition for Clean Coal Electricity	ACCCE
Board of Regents, State of Iowa	Board of Regents
Cedar Falls Municipal Utilities	Cedar Falls
City of Ames	Ames
Clean Air Muscatine	CAM
Deere & Company	Deere
Interstate Power and Light Company	IPL
Iowa Association of Municipal Utilities	IAMU
Iowa Chapter of Physicians for Social Responsibility	IPSR
Iowa Department of Natural Resources	DNR
Iowa Environmental Council	IEC
Iowa Interfaith Power & Light	IIP&L
MidAmerican Energy Company	MidAm
Midwest Independent Transmission System Operator	MISO
Muscatine Power and Water	MPW
North Iowa Municipal Electric Cooperative Association	NIMECA
Office of Consumer Advocate	OCA
Sierra Club – Iowa Chapter	Sierra

[1] NESHAP is the acronym for National Emission Standards for Hazardous Air Pollutants for Source Categories.

II. Additional Comments

In addition to responding to the Board's questions, some parties had additional comments. These are summarized below.

AGP Comments

Ag Processing Inc. (AGP) agrees with the Board that the Board has no jurisdiction over AGP's facilities, but AGP wants to provide comments in this proceeding in the voluntary spirit of helping the Board with its planning function. AGP is a cooperative owned by farmers and pays patronage to its owners based on the volume of commodities either sold to or purchased from AGP. AGP owns and operates six soybean processing plants, a vegetable oil refinery, and two bio-diesel plants in Iowa. AGP has a coal-fired combined heat and power (CHP) facility in Eagle Grove along with a soybean processing plant and vegetable oil refinery. Other locations are Sheldon, Sergeant Bluff, Emmetsburg, Mason City, Algona, and Manning. AGP employs 479 people in Iowa with an annual payroll of over $18 million.

AGP does not know what the final EPA rules will be and therefore does not know the long-term fate of its CHP facility. AGP completed an internal study and determined that the cost of controls, scrubber, and other equipment will exceed $15 million in capital investment which will increase the facility operating costs. AGP operates in a global market and added costs will impact AGP's competitive position in the market.

ACCCE Comments

American Coalition for Clean Coal Electricity, Inc. (ACCCE), is a not-for profit association of major American railroads, coal suppliers, electric utilities, and a variety of other industrial firms related to coal-based electric generation.[2] It commends the Board for initiating this inquiry in advance of the EPA's issuance of final regulations that could lead to the premature closure of hundreds of coal-based generating units nationally, the loss of hundreds of thousands of industry-related jobs, widespread electric rate increases harmful to consumers, energy-intensive industries, and national economic wellbeing, and threaten the reliability of the electric grid.

In 2010 coal produced nearly 72 percent of Iowa's electricity—well above the national average of 45 percent. Coal-fired generation has kept electric prices relatively low for Iowa's consumers, businesses and industries. In August 2011, Iowa's average residential electric rate of 11.3 cents/kWh was 7 percent below the national average rate of 12.17 cents/kWh. Iowa's average industrial rate of 5.82 cents per kWh was 22 percent below the national average rate of 7.47 cents/kWh. Residential electricity rates in Iowa have declined by 20 percent in real, inflation-adjusted terms since 1990, while the price of residential natural gas has increased by 20 percent. Recent electric rate

[2] For additional information on ACCCE see www.americaspower.org.

increases have raised consumer electric bills somewhat, but the residential price of electricity in Iowa has not kept pace with inflation. Residential natural gas prices have decreased in real terms over the past several years but are above their 1990 levels in inflation-adjusted prices.

ACCCE released an analysis in September 2011 conducted by National Economic Research Associates (NERA) showing that several of EPA's regulations would lead to the net loss of 183,000 jobs per year and significant increases in the price of electricity and natural gas.[3] The study projects that 39.1 GW of coal capacity may retire by 2015 as a result of the EPA regulations—representing 12 percent of the nation's coal fleet. This is consistent with other studies such as studies by The Brattle Group.

NERA projects coal capacity retirements of 1.9 GW in the Upper Midwest region (MRO)—representing 6 percent of the region's 28.8 GW of coal capacity. This implies that the majority of coal units in MRO will be able to comply with EPA's regulations through retrofit or other compliance strategies.

Given the short compliance timeframes of EPA's rules, electric generators may consider fuel-switching to natural gas. NERA projects that the four EPA rules would produce a 19.7 percent increase in average annual natural gas-fired generation over the period 2012 to 2020, and an 11.1 percent decrease in coal-based generation over the same period. The increased demand for natural gas for electric generation is projected to increase average Henry Hub prices by 11.1 percent over this period. NERA projects that higher natural gas prices over the 2010 to 2020 period would increase costs for non-electric natural gas consumers by approximately $8 billion annually ($52 billion net present value as of January 1, 2011).

In evaluating the compliance options facing Iowa utilities, ACCCE urges the Board to ensure that appropriate sensitivity analyses are conducted on future natural gas prices and to be mindful of the economic impacts on consumers as it evaluates compliance options for Iowa's electric utilities. NERA projected that the disposable personal income of the average U.S. family would be reduced by $270 per year because of the four EPA rules.

ACCCE provided an electronic copy of another study on the impacts of energy costs on Iowa consumers.[4] The key findings of this analysis, which includes expenditures for household utilities and the cost of motor gasoline, are:

1. Compared with the rest of the U.S., Iowa has lower unemployment rates and a smaller fraction of the population living below the federal poverty line.

[3] See http://www.americaspower.org/sites/default/files/NERA_Four_Rule_Report_S percentE2 percent80 percentA6.

[4] Eugene M. Trisko, Esq., *Energy Cost Impacts on Iowa Families, 2010* (prepared for the American Coalition for Clean Coal Electricity (February 2011).

2. Energy costs are accounting for an increasing percentage of after-tax household incomes.

3. The 289,000 Iowa families with annual incomes of $10,000 to $30,000 (nearly one-quarter of the state's population) spent an estimated 24 percent of their after-tax family budgets on energy.

4. The 82,000 poorest families in Iowa are being hit hardest by increasing energy costs, and families have to choose between purchasing energy or food and paying rent.

CAM Comments

Clean Air Muscatine (CAM) is a non-profit, tax-exempt Iowa corporation established for the purpose of improving the air and water quality of its community. The over-use of coal, combined with insufficient regulatory requirements to clean emissions from coal-fired combustion plants, threatens the health and safety of its citizens; damages property; reduces the ability of its citizens to enjoy open, public spaces; and discourages economic development. CAM supports changing Iowa law in the following ways:

1. Funding to more comprehensively track and monitor adverse health events; only if the public knows the facts can it — through its elected officials — make good policy decisions.
2. Strengthening of standards for energy efficiency and their enforcement because CAM knows that money spent for energy efficiency is more cost effective than spending money to produce more energy.
3. A moratorium on new coal plants in Iowa and shutting down existing coal boilers; utility companies now produce significantly more power than Iowans use.
4. Tightening standards for particulate matter and other pollutants.
5. We support stronger efforts to clean up and contain coal ash waste at the state and federal level.
6. The reduction and ultimate elimination of coal subsidies and tax and financial incentives that make this pollution-creating form of energy more attractive and discourage the greater uses of alternative forms of renewable energy and stronger energy efficiency programs.
7. Although there are costs related to the tightening of these standards as stated in the responses of IPL and MidAm, the costs to the system and citizens are great as well.

Cedar Falls Comments

The Cedar Falls Municipal Utilities (Cedar Falls) has operated coal-fired generating facilities in Cedar Falls since 1913 at the Streeter Electric Generation Station (Streeter). Over the years units have been added and retired. Currently two units are in service with nameplate capacities of 16.6 and 35 MW. Since the 1970s Cedar Falls has worked to diversify generation assets via jointly-owned coal-fired base-load plants. Cedar Falls' current portions of three jointly owned units total 51 MW which produce two thirds of its annual requirements. Cedar Falls also owns two simple cycle combustion turbines with nameplate capacity of 40 MW, 1.5 MW of wind generation, and has a long-term purchase power agreement for 6 MW of wind. Cedar Falls also dispatches and tests the 7.5 MW cogeneration facility owned by the University of Northern Iowa.

The 3.5 MW Streeter unit is most at risk from the Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards Rule (MATS aka MACT or Utility MACT) regulations. It represents 23 percent of the Cedar Falls generating capacity and about 21 percent of peak day energy supply. Streeter Units 5 and 7 are currently permitted through the Title V Air Operating Permit to fully operate with coal or natural gas. Retention of both coal and gas fuel supply provides important flexibility. Cedar Falls will not make an irrevocable decision on the continued use of coal in Streeter Unit 7 until the regulations are finalized and court actions are settled. The continued operation of these units is not in jeopardy, only the loss of dual fuel flexibility and the associated physical fuel price protection.

IPL Comments

IPL has 14 coal-fired generating units in its generation fleet, comprised of varying ages and boiler technologies, which have served IPL's customers energy needs for decades. The emissions control equipment currently installed on these units has maintained compliance with the changing environmental regulations at a reasonable cost to IPL's customers. The upcoming changes in environmental regulations will result in significant changes to IPL's generating fleet to maintain compliance with current, emerging, and future emissions regulations in a cost effective manner. These changes are profound in the electric utility industry as one of the possible compliance options from a customer-impact perspective is to cease operating a generating unit.

The past decade has shown that there can be rapid and sweeping changes in the regulations impacting electric generating units. IPL has been planning for the emerging and future environmental regulations in its generation plan. This plan remains flexible and has been adjusted as environmental regulations continue to change. For example, IPL has grouped its electric generating units into tiers, to aid in determining which units will be able continue to serve its customers at a reasonable cost and which ones will no longer be viable generating options under new environmental regulations.

There are multiple options for compliance with current and emerging regulations. IPL's response to this NOI docket attempted to provide a range of potential scenarios and potential impacts. IPL has provided, and will continue to provide, regular information on its plans for coal-fired power plants in its Emissions Plan and Budget (EPB) filings every other year. IPL's next plan is due by April 1, 2012. **Staff Update**: IPL filed its EPB on April 2, 2012.

The scenarios described in this response should not be perceived as the complete expected scenarios for IPL's resource plan. Potential changes in environmental regulations will result in the need for some amount of additional, replacement generation capacity, and it is premature to address the specifics of IPL's resource plan in this response.

IPL recognizes that as decisions are reached and proposals for cost recovery are made, additional supporting detail will be needed. However, those scenarios and decisions will be vetted in other Board dockets, such as ratemaking principles and EPB filings. If the foregoing information has not met the underlying needs of the Board, IPL is willing to work with the Board to provide additional information.

IAMU Comments

New and proposed EPA regulations effecting operation of coal-fueled power plants and RICE engines will impose substantial costs on Iowa's municipal utilities and the communities they serve. Compliance timelines need to be extended to mitigate reliability and rate impacts. RICE NESHAP rule changes are needed to expand the definition of emergency operation, increase the non-emergency hours of operation, and allow operating utilities to recover costs of operating the generators. Without these changes, consumers will face significant rate shock.

IPSR Comments

The Iowa Chapter of Iowa Physicians for Social Responsibility (IPSR) is a state based chapter of the national organization representing over 35,000 members. IPSR is the medical and public health voice working to slow, stop, and reverse global warming and the toxic degradation of the environment. Broadly speaking, its mission is to prevent that which it cannot cure. Coal plants are front and center on the list of concerns for IPSR members. Here in Iowa it has about 650 members and close relationships with colleagues in the medical and public health fields and other state based environmental groups.

The clean air standards will address and markedly reduce mercury releases (among a number of targeted releases) from burning coal. IPSR is concerned about mercury releases because there is no known safe lower limit of exposure to this neurotoxin. Its effects have been known for many decades, but concern is increasing due to its environmental ubiquity, persistence and the developmental effects observed and measurable even at very low levels of exposure.

DNR Comments

The Iowa Department of Natural Resources (DNR) states that although the Board has indicated that it is looking at EPA regulations "as a whole," it is an important consideration that each of these EPA regulations is in a different stage of completion. Several of the relevant regulations, including the air quality regulations impacting coal-fired boilers and stationary diesel engines/generators, are under reconsideration by EPA.

At least one commenter to the Board's September 2, 2011, order stated that the requirements for reduction in levels of pollution were "unprecedented." This is not true. The requirement to perform an air toxics study at utilities, and to follow up with appropriate regulation, originates in the Clean Air Act Amendments of 1990 at section 112(n)(1) (U.S.C. §7412(n)(1)). The Clean Air Act provides that EPA must take several steps before regulating air toxics emissions (such as mercury) from power plants.

Regarding the Ames' response to the Board's September 2, 2011, order, Ames has indicated that to comply with new EPA regulations, it would need to close two surface impoundments and a landfill. The cost for the closure of these three items is estimated to be $6.9 million. The EPA currently is soliciting comments regarding three different regulatory approaches. Surface impoundment closure requirements vary in each proposal. Without the need to close a landfill and without knowing which regulatory approach EPA will take regarding surface impoundments, the basis for the $6.9 million cost is unclear.

There are nine non-utility coal plants in Iowa that produce electricity and supply it to the grid and that may be subject to EPA's proposed Industrial, Commercial, and Institutional Boiler National Emissions Standards for Hazardous Air Pollutants. Recent data from the Energy Information Administration indicate that these facilities generally consume more electricity than they generate.

The EPA granted reconsideration of the 2010 RICE NESHAP amendments in December 2010 and has not yet completed the reconsideration. See 75 Fed. Reg. 75937-75941 (December 7, 2010). The issues currently under EPA reconsideration are particularly pertinent to municipal utilities, cooperative utilities, and other entities that use engines for "demand response," "peak shaving," "grid stability," and other uses. EPA has stated that it plans to issue proposed amendments to the RICE NESHAP in early 2012.

IEC Comments

The Iowa Environmental Council (IEC) is a broad based environmental policy organization with focus areas in clean water, clean air, conservation, clean energy, and climate change with the mission of a safe, healthy environment and a sustainable future for Iowa. IEC is a membership organization consisting of over 70 diverse organizations ranging from agricultural, conservation, and public health organizations, to educational institutions, business associations, and churches, along with over 600 individual members.

IEC has ongoing concerns about the adverse impacts on public health and the environment due to the use of coal as an energy source. It is a leading source of dangerous and harmful pollutants. Nationally coal-fired power plants are responsible for

60 percent of all SO_2 emissions, 50 percent of mercury air emissions, 60 percent of arsenic air emissions, and 50 percent or more of all acid gas air emissions. A recent report identified Iowa's 2009 mercury emissions at 2,735 pounds—17^{th} in the nation. In addition to these pollutants, coal-fired power plants emit particulate matter, CO_2, additional heavy metals, and known carcinogens, and contribute to the formation of ozone and additional particulate matter. As of 2002, over two thirds of Iowa's population, including 567,140 children, was potentially at risk because of coal-sourced pollution.

Pollution from coal constitutes an environmental externality with costs attributed to premature deaths, lung and heart diseases, cancer, lost work days, increased hospitalization and associated health care costs, damage to agricultural crops, and the loss of high quality air and water resources, natural habitats, and other environmental assets. These costs are difficult to quantify but are very real and paid for by employers who face lost work days, or by individuals needing medical attention for coal-related health problems. Regulations that require better pollution control equipment do not impose new costs so much as they attempt to eliminate the externalized costs and attribute those costs to the entities that create them—electric utilities.

In 2009, the National Academy of Sciences valued the damage from 406 coal-fired power plants operating in 2005 at 3.2 cents/kWh. This analysis only examined the damage from power plants themselves and only looked at four pollutants (SO_X, NO_X, particulate matter (PM) PM 2.5 and PM 10). Many Iowa coal plants caused damage from externalities valued at 5 to 15 cents/kWh, reflecting the age of many Iowa coal plants and the lack of pollution control equipment. Utilities may report their cost of operating an existing coal-fired power plant at 3 cents/kWh, but the true cost of operating that plant is closer to 9 cents/kWh.

The Board's inquiry focuses in part on the utility cost and rate impact to comply with the new and expected EPA regulations. IEC understands that this is a core component of the Board's role as an agency but potential utility costs and rate impacts cannot be taken in isolation. IEC encourages the Board to consider that much higher costs, such as the adverse public health impacts described above, are already being incurred from coal pollution. Reducing coal pollution with improved pollution control equipment and other strategies (e.g., fuel switching, energy efficiency, and renewable energy) is cost-effective; in the long-term, the costs to comply will be far below the benefits.

Most coal-fired power plants in Iowa today do not have pollution controls for some or all of the many pollutants they emit and, therefore, emit hundreds of pounds of toxic pollutants. The adverse impacts of these pollutants are well known and have been for years, and most of the rules currently at issue have been expected or under development for many years.

By 2014, on an annual basis nationally CSAPR avoids 13,000 to 34,000 premature deaths; 15,000 nonfatal heart attacks; 19,000 hospital and emergency room visits; 1.8 million lost work days or school absences; 400,000 aggravated asthma attacks; and

420,000 cases of upper and lower respiratory illness. The EPA estimates the rule will avoid between 93 and 240 deaths in Iowa annually and will provide monetized benefits of between $79 million and up to $1.8 billion to Iowans annually, both starting in 2014. The total estimated annual cost of this rule will be approximately $800 million in 2014 compared to the health and environmental benefits EPA's estimates at $120 to $280 billion.

MATS will eliminate 91 percent of the mercury in coal that is currently released into the air, as well as heavy metals like arsenic, chromium, and nickel, hydrogen chloride and other acid gases, and particulate pollution. In 2016 the rule would avoid 6,800 to 17,000 premature deaths; 4,500 cases of chronic bronchitis; 11,000 nonfatal heart attacks; 12,200 hospital and emergency room visits; 11,000 cases of acute bronchitis; 220,000 cases of respiratory symptoms; 850,000 days of missed work; 120,000 cases of aggravated asthma; and 5.1 million days when people must restrict their activities. These public health benefits are estimated to be between $59 billion and $140 billion annually in 2016. The cost for pollution controls necessary to achieve compliance are estimated at $10.9 billion annually in 2016. When compared to the benefits, this rule would produce between $5 and $13 in benefits for every $1 spent on compliance.

IEC also summarized the EPA's regulations under Section 316(b) of the Clean Water Act including standards and compliance options. In regard to the Coal Combustion Residuals Rule (CCRs), IEC stated that managing CCRs from cradle to grave would also create incentives for CCR generators to put these wastes to beneficial uses to avoid regulatory oversight and any costs associated with Subtitle C regulation. EPA's management of CCRs will only include those that are destined for disposal, while CCRs dedicated to beneficial re-use will remain exempt from the Resource Conservation and Recovery Act (RCRA)—beneficial uses include the options of incorporating CCRs into roof shingles, wallboard, asphalt, and bricks. Fly ash is particularly valuable to the highway construction industry as it increases concrete durability in a highly cost-effective way.

Several years ago, Edison Electric Institute (EEI) distributed a timeline of EPA regulations that has been popularly referred to as a regulatory train wreck. IEC provided an updated and corrected version of the EEI timeline.[5] IEC believes that the public health and environmental benefits from these rules justifies the implementation of these rules. The rules also offer additional benefits for Iowa—the EPA concluded that CSAPR and MATS nationally would create approximately 33,000 jobs with a range of potential impacts on jobs in the power industry from a loss of 17,000 to a gain of 35,000. A study released by CERES[6] found that new jobs would be added over a five year period equaling about 300,000 nationally or approximately 20,000 in Iowa.

[5] See IEC Attachment 1.

[6] **CERES** is a national coalition of investors, environmental groups, and other public interest organizations working with companies to address sustainability challenges such as climate change and water scarcity.

IEC supports the Board's use of different strategies and scenarios to understand different approaches to comply with various EPA regulations but believes some received minimal attention both in the order initiating the docket and in the utility responses. IEC believes the utilities need to provide significantly more information on the use of energy efficiency and renewable energy to replace coal units. Most energy efficiency technologies are the most cost-effective energy resources available. By reducing demand, energy efficiency can reduce the need for coal units, potentially allowing units to be retired instead of retrofitted. Energy efficiency can also mitigate the cost of pollution control equipment upgrades if those upgrades result in an increase in rates or other energy costs. Energy efficiency and renewable energy are among the fastest strategies to meet energy needs. There is also significant potential for more utility-scale wind energy; other renewable resources like solar, biomass, biogas, and geothermal; and a range of efficiency technologies. Additional transmission lines that bring these resources to market can also result in the improved grid stability needed to allow for coal plant retirements.

IEC suggests that the Board ask the utilities (as well as other interested stakeholders) to more fully investigate scenarios for renewable energy and energy efficiency, as well as the best combinations of these technologies and scenarios that will allow for additional coal plant retirements.

IIP&L Comments

Iowa Interfaith Power & Light (IIP&L) represents communities of faith from around the State of Iowa and believes that climate disruption is among the greatest challenges that humanity has ever encountered. It is committed to the moral imperative of preserving and protecting the planet for generations to come. IIP&L feels there can be no effective strategy to address climate disruption without significant restructuring of electricity production including a rapid and just transition away from coal powered generation.

Every step of the current coal-fired process is dangerous to human health, from mining and processing to burning and storage of waste ash. It carries huge societal costs around air and water pollution and is one of the most significant drivers of climate disruption. These external costs are not captured in the price of coal power. Those most often impacted by these dangerous processes are the most vulnerable members of our communities—the poor, the elderly, and children.

Transitioning away from coal is a crucial step in mitigating climate disasters. In the U.S. there must be a halt in construction of all new coal power plants unless and until safe and affordable carbon capture and storage have been conclusively demonstrated. Existing coal plants utilizing 20th century technology should be phased out as quickly as possible during the transition to clean energy and become more energy efficient.

IIP&L opposes mountaintop removal mining and advocates for its immediate discontinuation. Iowans need to acknowledge its complicity in mining operations which destroy the environment and endanger the health of our neighbors in other parts of the country as long as coal is burned to produce electricity.

MidAm Comments

Before considering supply-side generation alternatives, MidAm considers the impacts of cost-effective energy efficiency programs. Next, MidAm assesses supply relative to demand to evaluate reasonable options that may be available to provide reliable and cost-effective electric service to its Iowa customers.

As noted in the Board's order initiating this inquiry, future environmental regulations and the timing of those regulations are uncertain. The order also identifies several other factors that will have an impact on electric supply, demand and/or pricing (including prices of gas, coal, and carbon emissions, economic growth, changes in construction costs, interest rates, economic energy efficiency implementation, and the use of demand response). Other relevant factors include federal legislation unrelated to environmental issues, trade agreements, national fiscal policy, and Iowa legislation. These uncertainties must be considered in a context where generation facilities have long useful lives ranging from approximately 20 years for wind facilities to 50 years or longer for conventional generation. This makes it important to develop a plan that maintains adequate flexibility to adapt to these changing factors.

Because of these uncertainties, quantitative analysis and results need to be carefully reviewed. For example, projections of future gas and coal fuel costs are likely to heavily influence which generation resources appear to provide the most economical solutions. However, such a quantitative approach obscures the fact that there is uncertainty as to future estimates for fuel costs. If gas prices remain low by historical standards and coal, coal transportation, or related environmental costs related to coal substantially increase as is the current trend, the gas-fired generation will look good in long-term projections, for example, compared to nuclear generation. Conversely, if gas costs escalate or become volatile, gas-fired generation looks less attractive compared to nuclear generation. Similarly, if new economical and environmentally acceptable energy storage technologies emerge along with an enhanced electric transmission grid, the economics for renewable resources will improve. Because of these uncertainties there can be no definitive best or least-cost plan. The quantitative results are a reflection of multiple assumptions. This is why Iowa developed a law (Iowa Code Section 476.53) that recognizes that generation options must be reasonable. MidAm believes a diversified generation portfolio using a variety of fuel sources is a sound strategy to address uncertainty and risk.

For the reasons discussed above, MidAm cannot respond to the NOI questions with a specific, prescriptive generation plan to follow for the next 10-year period. MidAm's responses describe options and key assumptions that are being considered and analyzed on a continual basis. Subsequent specific plans, which could vary from the strategies described in the NOI responses, will be the subject of future Board filings.

This NOI cannot replace contested case proceedings such as environmental plan and budget filings (EPB dockets) and ratemaking principles proceedings which are statutorily mandated vehicles to establish policy for certain types of environmental emissions investments and new generation. For example, MidAm will continue to pursue additional cost-effective wind power projects. MidAm is also studying the deployment of nuclear generation as a potential base-load option as directed by the 2010 legislation. Until such a nuclear feasibility study is completed, it would be premature to either include or exclude nuclear generation in the 10-year study horizon that is the focus of the NOI.

MidAm stands ready to fully participate in the direction the Board selects for this NOI. In deciding what comes next, MidAm requests that such options not replace the existing statutory processes for consideration of energy efficiency and various forms of new generation.

MISO Comments

Beginning in 2010 MISO conducted a study using Electric Generation Expansion Analysis System (EGEAS) to analyze potential impacts and implications for Midwest generation from four proposed EPA rules. MISO identified nearly 13,000 MW of generation for retirement. MISO's evaluation indicated that unit retirements will have an impact on local transmission reliability. Estimated costs for ensuring transmission voltage and thermal support are $580 million and $880 million, respectively. The estimates depend on location and study assumptions. This assumes no replacement capacity at retired units. With replacement capacity, the transmission upgrade cost could likely decrease.

Potential planning reserve margin requirements could decrease if the less reliable fleet is replaced with a more reliable fleet. Loss of Load Expectation Analysis (LOLE) showed reductions of 0.2 to 1.0 percent. If no replacement capacity is added for resource adequacy purposes, LOLE is estimated to be 0.2 to 1.028 days/year. This compares with the current target of 0.1 days/year.

There is a compliance risk with the proposed regulations. New investment in generation and transmission will maintain bulk system reliability – at a cost. Another risk to be considered is that building replacement combustion turbines could take 2 to 3 years and transmission upgrades could take up to five years. The time for final compliance may be difficult for some situations throughout the system. Perhaps one of the most significant risk factors will be taking the existing units out for maintenance to install the needed compliance equipment. Given the tight window for compliance, much of the capacity on the MISO system will need to take their maintenance outages concurrently. The need to take multiple units out of service on extended outage has significant potential to impact resource adequacy.

Reliability in the Midwest could be severely challenged throughout the implementation period. Obviously, 62,000 MW of generation cannot be removed from service concurrently without interrupting loads in the region. To meet reliability obligations, MISO may need to deny outage requests. Thus, generation owners will face conflicts between complying with Federal Energy Regulatory Commission (FERC) Tariff, North American Electric Reliability Council (NERC) standards, and EPA air quality rules.

Many coal-fired base load units will be impacted by EPA regulations. If base load units are retired or are operated under reduced conditions, peaking units will be dispatched to meet load requirements. This will present operational challenges; the larger impact will be the likelihood of increased energy prices. The fundamental dispatching will not change. The regulations may limit capacity or increase start-up time based on unit characteristic changes. MISO's operational processes will respect the new unit offers and parameters. Increases in start-up times may require decisions to be made well in advance in time before the unit is needed. This may have an impact on efficiency.

MISO is evaluating blackstart facilities. Transmission operators will modify their restoration plans to address impacts on increase in restoration times (since there will be fewer blackstart islands to build in parallel) and impacts on ability to meet nuclear plant requirements if it requires resources that are located farther away. Once restoration plans are shared with MISO, it is required to approve such plans by 2013. If a blackstart unit intends to retire, MISO requires the unit to run under an exemption until the appropriate reliability solution is implemented.

The EPA's proposed mercury rule would hit the MISO system hardest because most of the work needed to comply with this rule would occur during the 2014 to 2015 time frame. There is also concern that the sheer volume of generation impacted by the rules will result in supply chain shortages for the necessary control equipment. MISO has joined other regional operators to ask EPA for some flexibility to give the generators more time to comply to safeguard reliability. This safety valve would allow units identified through the retirement analysis as necessary to maintain reliability to run until an appropriate solution is implemented. In addition, MISO supports alternative proposals that mitigate the potential for decreased reliability, such as a proposal by the Clean Air Task Force to allow a targeted "Reliability-Only Dispatch" approach. As opposed to a multi-year delay in implementation, it is logical to allow MISO and other RTOs to plan for measured retirements allowing for construction of alternative resources or transmission upgrades.

MISO's current planning policies (Attachment FF of MISO Tariff) are sufficient to take into account planned resource retirements and changes to the dispatch of the MISO system. EPA proposals would likely require MISO to obtain additional information to properly plan potential resource retirements. MISO has already started a study to determine the near-term impacts of the final CSAPR regulation.

MISO does not have data to determine the retirement decisions made by resource owners. A key element of such a decision is the timing and capabilities of transmission facilities that transmit power. Federal and state antitrust laws and regulations can impact the ability of generation owners to discuss future decisions. In the face of such legal obstacles, regional transmission organizations (RTOs) can coordinate optimal regional decision making.

Retirement of 13,000 MW of coal-fired generation would cause MISO's current projected 2016 reserve margin to decrease from 17.4 percent to 8.3 percent. MISO and other RTOs are concerned that given the tight time frame for compliance, unit retirement may adversely affect reliability before an appropriate solution can be implemented. Potential impacts on generation highlight the need for coordinated planning between generator owners and market transmission providers. Tariff provisions generally do not address means for this coordination.

State and federal agencies, along with RTOs and individual utilities, will need to work together to address these issues in order to minimize financial, reliability, and resource adequacy problems while complying with EPA regulations.

MISO filed additional comments on January 5, 2012, which state that the implementation timeline for EPA regulations is tight and overlapping. Since it takes three to four years to retrofit or replace a power plant, it is possible that 62,000 MW of coal units could be unavailable for reliability purposes—at the same time. Even though many would not be retired, they would need to be shut down for many months to install environmental controls to comply with EPA regulations. Improved capacity deliverability can be used to manage and mitigate reliability impacts from the substantial compliance obligations—including across RTO seams. Up to 4,000 MW of additional capacity transfers between MISO and PJM should be possible. Physical capacity exists, but non-physical barriers inhibit the movement across seams.

MISO and The Brattle Group developed a preliminary proposal to resolve these barriers which includes the following design elements:

1. Joint agreement upon a total transfer capability that could be simultaneously achieved at each modeled interface between the markets.
2. Each RTO would model the other as an external market zone in their respective capacity auctions to enforce established capacity transfer limits.
3. Resources making a cross-border capacity commitment would make an energy offer into its host market to meet its must-offer obligations.
4. During declared system emergencies, each regional transmission organization would have firm rights to call on resources committed to their loads without limitations.
5. Holders of existing firm transmission reservations that use these agreements for capacity sales would be compensated for any price differences between the RTOs.
6. All cross-border generation resource obligations would be unit-specific.
7. Each RTO would develop separate market monitoring and mitigation rules to govern their respective auctions.

OCA Comments

The following is a summary of the Office of Consumer Advocate's (OCA's) December 15, 2011, comments.

Resource planning decisions arise in multiple regulatory proceedings including:

1. Ratemaking principles proceedings for new generation resources under Iowa Code § 476.53.
2. Generation siting and certification proceedings in § 476A.6;
3. Emissions planning and budget proceedings under Iowa Code § 476.6(22);
4. Energy efficiency plan proceedings under Iowa Code § 476.6(16); and
5. General rate cases under Iowa Code § 476.6.

These decisions are based on integrated resource plans and avoided cost information required under 199 IAC 15.3 and include and affect the utility's environmental compliance strategies. Planning efforts occur on a continuous basis so the Board should regularly review the integrated resource plans of regulated utilities to ensure consistent and reasonable planning assumptions and scenarios are utilized in resource planning proceedings. The Board can achieve a more cohesive treatment of these costs by periodically providing guidance on critical planning assumptions and criteria—for example, guidance on appropriate CO_2 cost assumptions which should be consistent across long-term planning processes.

Although Iowa has not adopted a specific integrated resource planning statute, the Board has indicated its interest in continuing to explore ways to improve state resource planning processes through contested case proceedings—an example being the scenario analyses required in the last Energy Efficiency Plan filings. Given their long-term nature, this guidance is appropriate because it is vital to ensure that inputs and assumptions are reasonable and modeled consistently. An analysis of environmental compliance strategies that does not recognize the role of energy efficiency and demand-side management is incomplete.

The optimal resource planning and environmental compliance strategy is greatly impacted by assumptions about long-term fuel forecasts and other assumptions, which are subject to change. IPL and MidAm indicate that the information provided in their responses is subject to change, and that no decision should be reached based on the information provided. Although the information provided is useful in getting a directional sense of the utilities' compliance strategies, it is not sufficient to guide a meaningful review of proposals to implement strategies responding to new environmental rules.

Utilities routinely provide long-term resource plans and proposals based on those plans where the costs and assumptions change after the proposal has been submitted and the planning analysis completed—this does not mean that costs and assumptions cannot be more fully addressed by regulatory agencies. A more in-depth and regular process of reviewing long-term resource planning assumptions (perhaps through biennial filings under 199 IAC 15.3 or the EPB filings) could provide more guidance on planning criteria and better accommodate the expedited procedural timelines. This approach would also benefit entities like MISO when they evaluate various policy considerations.

There are limitations and gaps in the data provided by the investor-owned utilities (IOUs) that prevent a full evaluation of potential rate impacts associated with environmental compliance strategies. The utilities' responses suggest a preference to address rate impacts in contested case proceedings. However, past proceedings in these areas can offer some insight on rate impacts associated with strategies to meet environmental regulations. The IOU EEP dockets provide an indication of the costs associated with higher levels of energy efficiency, and Iowa ratepayers are experiencing rate impacts due to expanded investments in renewable energy and emissions control equipment. The actual rate impacts have been influenced by utility-specific rate structures and cost recovery provisions for these investments—MidAm's rates have not been impacted and IPL's have.

Below is a summary of OCA's December 22, 2011, comments. These comments were prepared for OCA by Synapse Energy Economics to address the filings IPL and MidAm made in this docket.

Comments Applicable to MidAm and IPL: Neither utility examined a compliance strategy that included additional energy efficiency, demand response, rate structures, or purchased power.

Comments on MidAm Filing: MidAm's responses are missing important data including sufficient detail to determine whether the underlying assumptions are reasonable and whether the strategies lead to sufficient emissions reductions. Currently, only Walter Scott Units 2 and 4 fall below CSAPR NO_X emissions and only Walter Scott Units 3 and 4 and Louisa have SO_2 emissions below the CSAPR allocations for 2012. MidAm did not state how it plans to comply with the 2012 allowance allocations under CSAPR. With the first compliance deadline approaching, MidAm has limited options to comply—reducing generation or purchasing allowances, neither of which were evaluated in the filing.

MidAm included five scenarios of which only two might be realistic to implement—1. Business as Usual (BAU) and Scenario Number 4. Add a gas-fired combined cycle combustion turbine (CCCT). MidAm shows the gas-fired CCCT option to be more costly than the BAU, but it is unclear whether one of these or some other option would be the least-cost compliance scenario. Also, MidAm has not included water, effluent, and coal ash regulations in the strategies analyzed.

MidAm's sensitivity values do not represent the full range of possibilities that should be considered including low natural gas prices, higher construction costs for the gas-fired CCCT, and low and high emissions control technology capital costs. The high natural gas price scenario does not provide the original value making it difficult to determine whether the sensitivity value is reasonable.

OCA recommends that in connection with any proposed environmental compliance strategy the Board require MidAm to:

1. Describe CSAPR SO_2 and NO_X compliance plans;
2. Examine additional scenarios including a compliance strategy with additional energy efficiency, renewable energy and CHP, demand response, rate structures or purchased power;
3. Ensure coal ash, water and effluent compliance is analyzed and included in future scenarios;
4. Provide the base values for all sensitivity variables considerate to enable evaluation of the reasonableness of the high and low sensitivity values; and
5. Consider variability of natural-gas replacement capacity cost and emissions retrofit technology costs.

Comments on IPL Filing: IPL's output is based on past models, and this means it is potentially out of date. Therefore, the accuracy of the strategies is questionable as are the cost estimates. IPL stated it is premature to address its compliance plan; however, the first deadline for CSAPR occurs in 2012, and IPL must be prepared to meet it. It appears that of the units generating in 2010, only Burlington Unit 1 and Dubuque Unit 6 currently comply with CSAPR emissions limits for both NO_X and SO_2, Ottumwa and Kapp Unit 2 comply with NO_X, and Dubuque Units 1 and 5 comply with SO_2. Installation of approved emissions control technologies will bring Ottumwa into CSAPR and MATS compliance, and Lansing Unit 4 into compliance with SO_2 regulations. IPL failed to describe how it will bring the remainder of its generating units into compliance.

IPL's compliance strategy concentrates on emissions control investments on its larger units—Ottumwa and Lansing 4. Strategies 2 and 3 (non BAU) comply with the MATS rule and take steps to comply with ash and water rules. Strategy 2 (Tier 1 Incremental and Tier 2 Controlled) appears to provide the most flexibility allowing IPL options for compliance from Tier 2 units.

IPL's base inputs for its sensitivity variables includes an out-of-date price for natural gas—IPL should use updated prices and vary its sensitivity cases using revised price forecasts. IPL should also include a set of CO_2 prices which will enable it to evaluate high and low CO_2 price scenarios. Renewal of the Duane Arnold Energy Center PPA is integral to IPL's long-term resource plans and environmental compliance strategies and should be considered under these criteria. IPL should consider variability of natural gas replacement capacity cost and emissions retrofit technology costs.

MISO Efforts: MISO performed a three-phase modeling examining six scenarios to analyze the impact of proposed EPA regulations on the generating units in the MISO territory from a regional perspective. The results showed that 2,919 MW of coal capacity are at-risk for retirement of the impact of proposed EPA regulations to under all scenarios and 12,652 MW has been identified to be within prudence considerations and error bounds of the MISO study—MISO expects the higher value to be the more likely scenario. The estimated cost of capital cost compliance for the 20-year period analyzed ranges from $31.6 billion to $33.0 billion, energy costs will increase as plants are retired by approximately $1 to $5 per MWh translating to retail rate increases of 7 to 7.6 percent. The addition of a CO_2 price would lead to cost increases of $30/MWh. Each scenario would require transmission upgrades requiring investment of approximately $580 million to $880 million. MISO is now surveying its members regarding EPA compliance plans.

Other State Efforts: Other states are also addressing compliance with EPA regulations. Minnesota is taking a collaborative approach to planning for compliance. Colorado's Clean Air-Clean Jobs Act requires a coordinated plan for emissions reductions. Two electric utilities in Kentucky are working with Black and Veatch to develop unit by unit compliance options, and in Georgia, the public utility commission (PUC) is exploring compliance through Georgia Power's Updated Integrated Resource Plan for 2010.

OCA recommends that in connection with any proposed environmental compliance strategy the Board require IPL to:

1. Use up-to-date data;
2. Indicate how IPL is progressing toward compliance;
3. Analyze a scenario that does not include retirement of Dubuque Units 3 and 4—three years after converting them to natural gas;
4. Revise the second scenario to include an analysis comparing costs of retrofitting, retiring, and converting each Tier 2 unit under IPL's base and sensitivity assumptions;
5. Indicate whether replacement capacity would be needed under the second or third scenarios;
6. Examine additional scenarios including a compliance strategy with additional energy efficiency, renewable energy and CHP, demand response, rate structures or purchased power;
7. Include a set of CO_2 as an input and examine high and low CO_2 price scenarios;
8. Evaluate the option of PPA extension of Duane Arnold Energy Center; and
9. Consider variability of natural-gas replacement capacity cost and emissions retrofit technology costs.

Overall Recommendations. The Board's final guidelines should require a thorough inventory and description of all relevant resource options; an assessment of costs, benefits, uncertainties and risks; an objective sensitivity analysis of how the uncertainties and risks affect the various resource plans considered; and the development of a plan consisting of a portfolio of resources that delivers the lowest life cycle cost, and manages risk and uncertainty over a full range of future scenarios.

Utility commissions play an important role in shaping utility compliance plans. The Board is urged to establish a comprehensive consistent process for considering utility proposals for major investments in existing generating units that:

1. Considers all resources that may contribute to meeting the need;
2. Uses up-to-date forecasts;
3. Models compliance scenarios—all of which should be both individually feasible, jointly comprehensive, and each should achieve the required emissions reductions;
4. Includes rigorous analysis of reasonable sensitive scenarios; and
5. Uses transparent modeling.

Sierra Comments

In its December 16, 2011, comments, the Sierra Club – Iowa Chapter (Sierra) states that most reports on EPA rules suggest that there will be little, if any, impact on reliability and that impacts are easily remedied. The retirement of older inefficient plants might lead to a more reliable system. Reliability concerns have been overblown by industry groups. System reliability should not be an issue for an operator that has been planning for the impact of regulation and determining whether a least-cost compliance strategy considers new generation. IPL and MidAm recently announced plans for new generation suggesting that both utilities are already thinking about replacing old inefficient units with clean energy. A 2007 DOE report suggests that utilities can benefit from distributed generation, as well. There are distributed generation polices within the Board's authority that would result in a more reliable grid than we have today. The Board has the authority to require Rural Electric Cooperatives (RECs) and municipals to provide net metering. Another way to support distributed generation is through feed-in tariffs. There is no reason this model should not work in Iowa. Sierra believes that the Board has authority to adopt such regulations.

III. Staff Analysis and Recommendations

Staff believes that Docket No. NOI-2011-0003 has achieved its purpose. The NOI has provided the Board with a snapshot of the environmental challenges facing Iowa electric utilities and given the Board insight into the concerns and positions of various stakeholders.

Additionally, this NOI has demonstrated the uncertainty inherent in environmental regulations. During the course of this NOI, the CSAPR rules were stayed and the proposed RICE rules were amended. RICE and CSAPR were relatively far along in the regulatory process. These events illustrate the difficulty associated with projecting the timing and impact of proposed environmental rules.

Staff notes that the EPB dockets will serve as a continuing forum to explore the impacts of environmental regulations on the two largest utilities in Iowa.

Staff recommends that the Board direct General Counsel to draft an order for its consideration closing Docket No. NOI-2011-0003 and thanking the participants for the information and insights that they provided.

RECOMMENDATION APPROVED

IOWA UTILITIES BOARD

/s/ Elizabeth S. Jacobs *2-22-13*
Date

/s/ Darrell Hanson *2-21-13*
Date

/s/ Swati A. Dandekar *2-21-13*
Date

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Appendix A

Part 1 - Summary of Responses to Questions From Board Order Issued September 2, 2011

1. A list of the utility's existing coal plants, including the existing technology of each such plant, and its emissions. Describe individual units, if the technology varies by unit.

In the responses below, existing environmental controls are labeled as Existing Technology and include the technologies listed below. The descriptions of the individual technologies are a composite of the information provided by MidAm and IPL.

1.	Neural network	Used to enhance plant efficiencies.
2.	HESP	An electrostatic precipitator (ESP) is a particulate collection device that removes particulate matter (PM) from a flowing gas such as air. The **hot-side electrostatic precipitator** is installed upstream of the air preheater where the exit gas temperature is higher.
3.	CESP	The **cold-side electrostatic precipitator** is installed after the air preheater to control PM emissions.
4.	Baghouse	**Baghouses** are fabric filters used to reduce PM emissions. They are also integrated with SO_2, acid gas, and mercury emission control systems to allow facilities to comply with emission limits beyond just PM.
5.	FGC	If PM in the flue gas has high resistivity, **flue gas conditioning** agents such as sulfur trioxide (SO_3) can be injected to lower resistivity levels and improve collection of PM emissions.
6.	LNB	**Low NO_X burners** are installed in the boiler where the fuel is delivered for combustion to reduce NO_X emissions.
7.	OFA	**Over fire air** is a technology that stages combustion, resulting in lower NO_X emissions. Air staging involves removing a portion of the air from the burners to reduce oxygen availability early in the combustion process and then reintroducing it later in the process.
8.	RRI	**Rich reagent injection** is the process of adding NO_X reducing agents such as urea or ammonia into the fuel rich region of a furnace to reduce the formation of NO_X.

9.	SNCR	**Selective non-catalytic reduction** involves injecting a reagent (ammonia or urea) into the firebox of the boiler where the agent reacts with the NO_X formed in the combustion process. The resulting product of the chemical reduction reaction is elemental nitrogen (N_2), CO_2, and water.
10.	SCR	A **selective catalytic reduction** system uses a catalyst to convert NO_X into elemental nitrogen (N_2) and water. A reagent (typically anhydrous ammonia, aqueous ammonia, or urea) is added to the flue gas stream where it reacts with NO_X and passes through the catalyst where the conversion to nitrogen takes place.
11.	Dry scrubber	**Dry scrubbers** are used to reduce SO_2 emissions.
12.	ACI	**Activated carbon injection** involves injecting carbon compound (which may be halogenated) into the flue gas upstream of a particulate control device. Oxidized forms of mercury (Hg) are absorbed into the carbon and collected with the fly ash in the PM control device.
13.	LSC	The use of **low sulfur coal** is a non-physical approach to reducing SO_2 emissions.

MidAm Response: Below is a summary of the coal plants that MidAm operates in Iowa including plants with joint ownership. This information is also provided in table form in Attachment 2.

1. <u>Neal North Energy Center Unit 1</u>

Operation Date:	1964	
Capacity:	140 MW	
Ownership:	MidAm	
Dual Fuel:	Powder River Basin coal or natural gas	
Boiler design:	Cyclone	
Existing Technologies:	Neural network, OFA, HESP	
Emissions:[7]	NO_X:	2,594
	SO_2:	3,062
	CO_2:	1,104,141

[7] For MidAm this includes 2010 emissions reported to EPA in tons, for IPL this includes actual 2010 emissions.

2. Neal North Energy Center Unit 2

Operation Date:	1972	
Capacity:	294 MW	
Ownership:	MidAm	
Fuel:	Powder River Basin coal	
Boiler design:	Pulverized coal, front wall fired	
Existing Technology:	Neural network, LNB, OFA, CESP	
Emissions:	NO_X:	2,470
	SO_2:	6,689
	CO_2:	2,184,352

3. Neal North Energy Center Unit 3

Operation Date:	1975	
Capacity:	522 MW	
Ownership:	Joint[8]	
Fuel:	Powder River Basin coal	
Boiler design:	Pulverized coal, opposed wall fired	
Existing Technology:	Neural network, LNB, OFA, CESP	
Emissions:	NO_X:	4,434
	SO_2:	11,911
	CO_2:	4,006,764

4. Neal South Energy Center Unit 4

Operation Date:	1979	
Capacity:	654 MW	
Ownership:	Joint[9]	
Fuel:	Powder River Basin coal	
Boiler design:	Pulverized coal, opposed wall fired	
Existing Technology:	Neural network, LNB, OFA, CESP	
Emissions:	NO_X:	5,754
	SO_2:	16,575
	CO_2:	5,289,497

5. Walter Scott Energy Center Unit 1

Operation Date:	1954
Capacity:	38 MW

[8] MidAm 72 percent and IPL 28 percent.

[9] MidAm 40.57 percent, IPL 25.695, Corn Belt Power Cooperative 9.028 percent, Northwestern Energy 8.681 percent, Northwest Iowa Power Cooperative 4.860 percent, Algona 2.937 percent, Webster City 2.604 percent, Cedar Falls 2.5 percent, Spencer 1.215 percent, Coon Rapids 0.521 percent, Bancroft 0.347 percent, Milford 0.347 percent, and Graettinger 0.174 percent.

Ownership:	MidAm
Fuel:	Powder River Basin coal[10]
Boiler design:	Pulverized coal, front wall fired
Existing Technology:	LNB, HESP
Emissions:	NO_X: 607
	SO_2: 1,346
	CO_2: 439,142

6. <u>Walter Scott Energy Center Unit 2</u>

Operation Date:	1958
Capacity:	84 MW
Ownership:	MidAm
Fuel:	Powder River Basin coal[11]
Boiler design:	Pulverized coal, tangentially fired
Existing Technology:	LNB, OFA, HESP
Emissions:	NO_X: 476
	SO_2: 2,374
	CO_2: 698,516

7. <u>Walter Scott Energy Center Unit 3</u>

Operation Date:	1978
Capacity:	710 MW
Ownership:	Joint[12]
Fuel:	Powder River Basin coal
Boiler design:	Pulverized coal, opposed wall fired
Existing Technology:	Neural network, LNB, OFA, CESP, dry scrubber, baghouse
Emissions:	NO_X: 5,411
	SO_2: 8,723
	CO_2: 5,955,897

8. <u>Walter Scott Energy Center Unit 4</u>

Operation Date:	2007
Capacity:	811 MW
Ownership:	Joint[13]

[10] Originally designed as a dual-fuel unit with natural gas; however, the gas burners have been removed and on-site pipeline capacity would not support full-load gas operations today.

[11] Originally designed as a dual-fuel unit with natural gas; however, the gas burners have been removed and on-site pipeline capacity would not support full-load gas operations today.

[12] MidAm 79.1 percent, Central Iowa Power Cooperative 11.5 percent, Corn Belt Power Cooperative 3.8 percent, Cedar Falls 3.1 percent, and Atlantic 2.5 percent.

Fuel:	Powder River Basin coal
Boiler design:	Supercritical, pulverized coal, opposed wall fired
Existing Technology:	Neural network, LNB, OFA, SCR, dry scrubber, ACI, baghouse
Emissions:	NO_X: 1,405
	SO_2: 2,129
	CO_2: 5,649,243

9. <u>Louisa Generating Station Unit 101</u>

Operation Date:	1983
Capacity:	750 MW
Ownership:	Joint[14]
Fuel:	Powder River Basin coal
Boiler design:	Pulverized coal, opposed wall fired
Existing Technology:	Neural network, LNB, OFA, HESP, dry scrubber, baghouse
Emissions:	NO_X: 4,745
	SO_2: 7,075
	CO_2: 5,358,252

10. <u>Riverside Generating Station Unit 5</u>

Operation Date:	1961
Capacity:	133 MW
Ownership:	MidAm
Fuel:	Powder River Basin coal or natural gas
Boiler design:	Pulverized coal, tangentially fired
Existing Technology:	Neural network, LNB, OFA, CESP
Emissions:	NO_X: 900
	SO_2: 3,014
	CO_2: 917,827

IPL Response: Below is a summary of the coal plants that IPL operates in Iowa including plants with joint ownership. This information is also included in table form in Attachment 3 of this memo.

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[13] MidAm 59.66 percent, Lincoln Electric 12.658 percent, Central Iowa Power Cooperative 9.013 percent, Mean 6.67 percent, Corn Belt Power Cooperative 5.33 percent, Cedar Falls 2.022 percent, Pella 1.33 percent, Spencer 1.07 percent, Eldridge 0.53 percent, Montezuma 0.40 percent, Waverly 0.40 percent, Alta 0.13 percent, and West Bend 0.13 percent.

[14] MidAm 88 percent, Central Iowa Power Cooperative 4.6 percent, IPL 4 percent, Waverly 1.1 percent, Harlan 0.8 percent, Eldridge 0.5 percent, Tipton 0.5 percent, and Geneseo 0.5 percent.

1. Burlington Generating Station Unit 1

Operation Date:	1968	
Capacity:	212 MW	
Ownership:		
Fuel:		
Boiler design:	Tangential fired, dry bottom	
Existing Technology:	CESP, FGC, LNB, OFA, LSC	
Emissions:	NO_X:	718
	SO_2:	2,890
	CO_2:	1,003,468
	Hg:	52

2. Dubuque Generating Station Unit 1

Operation Date:		
Capacity:	37 MW	
Ownership:		
Fuel:		
Boiler design:	Wall fired, dry bottom	
Existing Technology:	CESP, LSC	
Emissions:	NO_X:	489
	SO_2:	504
	CO_2:	156,396
	Hg:	52

3. Dubuque Generating Station Unit 5

Operation Date:		
Capacity:	31.7	
Ownership:		
Fuel:		
Boiler design:	Wall fired, dry bottom	
Existing Technology:	CESP, LSC	
Emissions:	NO_X:	306
	SO_2:	268
	CO_2:	82,686
	Hg:	52

4. Dubuque Generating Station Unit 6

Operation Date:	
Capacity:	37 MW
Ownership:	
Fuel:	
Boiler design:	Wall fired, dry bottom

Existing Technology:	CESP, LSC	
Emissions:	NO_X:	24
	SO_2:	11
	CO_2:	5,278
	Hg:	0.1

5. Lansing Generating Station Unit 3

Operation Date:	1957	
Capacity:	35.8 MW	
Ownership:		
Fuel:		
Boiler design:	Wall fired, dry bottom	
Existing Technology:	CESP	
Emissions:	NO_X:	0
	SO_2:	0
	CO_2:	0
	Hg:	0

6. Lansing Generating Station Unit 4

Operation Date:	1977	
Capacity:	270 MW	
Ownership:		
Boiler design:	Turbo fired, dry bottom	
Existing Technology:	HESP, baghouse, FGC, LNB, OFA, SCR, LSC, ACI	
Emissions:	NO_X:	1,611
	SO_2:	4,729
	CO_2:	1,472,024
	Hg:	104

7. Kapp Generating Station Unit 2

Operation Date:	1967	
Capacity:	235.8 MW	
Ownership:		
Boiler design:	Tangential fired, dry bottom	
Existing Technology:	CESP, flue gas conditioning, LNB, OFA, LSC	
Emissions:	NO_X:	540
	SO_2:	3,462
	CO_2:	1,005,076
	Hg:	69

8. Ottumwa Generating Station Unit 1

Operation Date:	1981

Capacity:	727 MW		
Ownership:			
Boiler design:	Tangential fired, dry bottom		
Existing Technology:	HESP, flue gas conditioning, LNB, OFA, LSC		
Emissions:	NO_X:	3,382	
	SO_2:	13,461	
	CO_2:	4,923,997	
	Hg:	346	

9. <u>Prairie Creek Station Unit 1</u>

Operation Date:	1997	
Capacity:	16 MW	
Ownership:		
Boiler design:	Spreader stoker, dry bottom	
Existing Technology:	CESP, LSC	
Emissions:	NO_X:	381
	SO_2:	659
	CO_2:	156,206
	Hg:	4

10. <u>Prairie Creek Station Unit 2</u>

Operation Date:	1951	
Capacity:	23 MW	
Ownership:		
Boiler design:	Spreader stoker, dry bottom	
Existing Technology:	CESP, LSC	
Emissions:	NO_X:	428
	SO_2:	539
	CO_2:	175,222
	Hg:	3

11. <u>Prairie Creek Station Unit 3</u>

Operation Date:	1958	
Capacity:	50 MW	
Ownership:		
Boiler design:	Wall fired, dry bottom	
Existing Technology:	CESP, flue gas conditioning, LNB, OFA, LSC	
Emissions:	NO_X:	632
	SO_2:	1,132
	CO_2:	361,299
	Hg:	14

12. <u>Prairie Creek Station Unit 4</u>

Operation Date:	1958	
Capacity:	149 MW	
Ownership:		
Boiler design:	Wall fired, dry bottom	
Existing Technology:	CESP, flue gas conditioning, LNB, OFA, LSC	
Emissions:	NO_X:	1,503
	SO_2:	2,424
	CO_2:	776,089
	Hg:	51

13. <u>Sutherland Generating Station Unit 1</u>

Operation Date:	1955	
Capacity:	37.5 MW	
Ownership:		
Boiler design:	Wall fired, dry bottom	
Existing Technology:	CESP, LNB, LSC	
Emissions:	NO_X:	417
	SO_2:	890
	CO_2:	257,666
	Hg:	7[15]

14. <u>Sutherland Generating Station Unit 3</u>

Operation Date:	1961	
Capacity:	96 MW	
Ownership:		
Boiler design:	Cyclone furnace, wet bottom	
Existing Technology:	CESP, OFA, RRI, SNCR, LSC	
Emissions:	NO_X:	826
	SO_2:	4,285
	CO_2:	532,262
	Hg:	5

Ames Response: The City of Ames (Ames) owns and operates one coal plant consisting of two coal-fired units using coal and refuse-derived fuel (RDF) for fuel, along with #2 distillate fuel oil for startup, ignition, and flame stabilization.

Unit 7 is a 33,000 kW nameplate rated unit with a tangential pulverized coal boiler burning ultra-low sulfur sub-bituminous coal from the Powder River Basin in Wyoming and RDF. Unit 7 went into operation in 1967. The emission control device is an electrostatic precipitator. A continuous emissions monitoring system (CEMS) monitors

[15] Data for both Sutherland plants derived from stack test or published emissions factors.

SO_2, NO_X, and CO_2, and a continuous opacity monitoring system (COMS) monitors opacity.

Unit 8 is a 65,000 kW nameplate rated unit with a wall-fired pulverized coal boiler burning ultra-low sulfur sub-bituminous coal from the Powder River Basin in Wyoming and RDF Unit 8 went into operation in 1982. The emission control device is an electrostatic precipitator. CEMS monitors SO_2, NO_X, and CO_2, and COMS monitors opacity.

Cedar Falls Response: Cedar Falls provided the following table in response to Question Number 1.

SOURCE	INSTALLED	NAME-PLATE MW	TEST Net MW	FUEL(s)	Technology	Environmental Controls
STREETER UNIT 6	1963/1989	16.5	19.4	COAL-NATURAL GAS	Stoker Boiler Steam turbine	Mechanical Collector +baghouse
STREETER UNIT 7	1973	35.0	34.9	COAL-NATURAL GAS	Pulv. C Boiler Steam turbine	ESP
WS3 (3.1% share of 690MW)	1978	21.4	21.97	COAL	Pulv. C Boiler Steam turbine	Dry scrubber +baghouse
WS4 (2.14% share of 790 MW)	2007	16.97	17.36	COAL	Pulv. C Supercritical Boiler Steam turbine	Dry Scrubber, SCR, Hg control
Neal 4 (2.5% share of 630 MW)	1979/1985	15.75	16.13	COAL	Pulv. C Boiler Steam turbine	ESP +new construction dry scrubber, SNCR, Hg control
IDWGP (Algona – 2/3 share)	1998	1.5	0.0	WIND		
COMBUSTION TURBINE 1	1968	19.635	18.8	NATURAL GAS-OIL	Simple cycle	
COMBUSTION TURBINE 2	1970/2000	23.8	23.3	NATURAL GAS	Simple Cycle	
ELECTRIC UTILITY OWNED Firm GENERATION		149.055	151.888			
UNI COGNERATION ASSIGNED BY CONTRACT	1984	7.969	7.5	COAL	PC & Baghouse/ CFB & Baghouse	
TOTAL ELECTRIC FIRM CAPACITY		157.024	159.388			

MPW Response: MPW is the municipal electric, water, and telecommunications utility providing service to 25 square miles in and around Muscatine, Iowa, and serving approximately 11,248 customers. It owns three steam and four generating units (all coal-fired) with a combined nameplate capacity of 293.5 MW. MPW's native system peak load of 149.9 MW was reached in July 1999, and the 2011 peak was 140.88 MW on July 20, 2011. Between 1978 and 2010, the historical average annual native system load growth was approximately 1 percent.

Unit 7 is a spreader-stoker boiler, with a 25 MW nameplate rated condensing turbine/generator and has been in operation since 1958. Prior emission control investments on this unit include the switch to low sulfur sub-bituminous coal (1999) (reduced permitted and actual SO_2 emissions), and the addition of an electrostatic precipitator (removal of particulate from boiler flue gas). This unit is subject to the Small Boiler MACT.

Unit 8 is a cyclone-fired wet bottom boiler, with a 75 MW nameplate rated condensing turbine/generator, and has been in operation since 1969. It is a backpressure turbine with an 18 MW nameplate rated generator and is part of a system used to supply steam to an adjacent industrial customer. Prior emission control investments on these units include installation and operation of an Over-Fire Air System (2008) (NO_X emission reduction); switch to low sulfur sub-bituminous coal (1999) (reduced permitted and actual SO_2 emissions); and the addition of an electrostatic precipitator (removal of particulate from boiler flue gas). The specific rules affecting these units include the Air Toxics Rule (previously called the Utility MACT, addressing mercury and other hazardous air pollutants) and the CSAPR, limiting SO_2 and NO_X emissions.

Unit 9 is a pulverized coal-fired boiler, with a 175.5 MW nameplate rated condensing turbine/generator, which has been in operation since 1983. Prior emission control investments on this unit include addition of an Over-Fire Air System (2008) (NO_X emission reduction); switch to low sulfur sub-bituminous coal (1993) (reduced SO_2 emissions); Flue Gas Desulfurization Scrubber (1983) (currently achieving 98 percent plus SO_2 removal); and addition of an electrostatic precipitator (removal of particulate from boiler flue gas). The specific rules affecting this unit include the Air Toxics Rule and CSAPR.

Major emission control investments throughout the site include using low sulfur sub-bituminous coal for all 3 units; numerous coal handling dust control projects (PM 2.5, PM 10); and the use of baghouses to collect particulate emissions from material handling operations (coal and coal combustion residue). Additional regulations that will impact the entire site include changes to NAAQS for PM 2.5, SO_2, NO_X, Ozone, PM 10, CO, etc.; GHG Tailoring Rule; Cooling Water Intake- 316(b) Rules; Effluent Limit Guidelines for Generating Stations; and the possibility of an EPA coal combustion residue re-designation to hazardous waste.

NIMECA Response: The North Iowa Municipal Electric Cooperative Association (NIMECA) is a municipal joint action agency formed in 1965 to serve its municipal utility members which serve approximately 25,000 electric meters. NIMECA members own coal, natural gas, wind, and diesel fueled generation sources and also have long-term contracts for hydropower, wind, and coal fueled generation.

NIMECA has a life of unit purchase power agreement with Heartland Consumers Power District of Madison, South Dakota for 3 to 20 MW of coal based generation from the Whelan unit 2 near Hastings, Nebraska. The purchase began in mid-2011 with NIMECA purchasing 3 MW and will increase annually until it reaches 20 MW in 2019. The plant includes an electrostatic precipitator, a scrubber, selective catalytic reduction, a baghouse, and mercury removal controls. NIMECA members are joint owners in Neal Unit 4 and Walter Scott Unit 4.

Sierra Response: IPL and MidAm provided an incomplete listing of existing technologies at their coal units by failing to include technologies (if any) to treat wastewater effluent, the cooling water intake system type, or the current system of disposing of bottom or fly ash. They also included only partial lists of emissions and did not provide PM 10 and PM 2.5 emissions, and failed to identify the water and ash waste created by the units including the contents of wastewater effluent, which commonly contains arsenic, mercury, selenium, lead, cadmium and other dangerous metals. MidAm did not include mercury emissions. The Board should require the regulated utilities to develop a complete picture of future liabilities and costs of continued operation by submitting a more complete set of pollution data and controls.[16]

2. The EPA Rules, and their expected implementation schedule, that could affect the utility's decisions.

MidAm and IPL provided summaries of various regulations. Rather than include virtually duplicate summaries of the regulations that both MidAm and IPL commented on, staff compiled the MidAm and IPL comments into the composite summary below. IPL also filed comments on other regulations and those are summarized separately following the composite summary. Staff updates have also been included where applicable.

Composite Summary of EPA Regulations

Clean Air Interstate Rule (CAIR). In 2005 the Environmental Protection Agency (EPA) promulgated the Clean Air Interstate Rule (CAIR) applicable to electric generating facilities in 28 Eastern states and the District of Columbia with greater than 25 MW of capacity. CAIR established new SO_2 and NO_X (both annual and ozone season) emission caps beginning in 2010 and 2009, respectively, with further reductions in SO_2 and NO_X emission caps effective 2015. CAIR included a large regional cap-and-trade system where compliance could have been achieved by either adding emission controls and/or purchasing emission allowances. In 2008, the U.S. Court of Appeals for the D.C. Circuit remanded CAIR to the EPA for revision to address flaws identified in a 2008 opinion.[17] It found that allowing CAIR to remain in effect until it was replaced by a rule consistent with the court's opinion would temporarily preserve the environmental objectives sought to be achieved under the CAIR. CAIR obligations became effective for NO_X on January 1, 2009, and SO_2 on January 1, 2010, and remain in place until a final CAIR replacement rule is put into effect.

[16] See http://www.catf.us/resources/publications/files/The_Toll_from_Coal.pdf and http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm.

[17] The court held that the EPA's approach in CAIR, utilizing region-wide caps with no state-specific quantitative contribution determination or emissions requirements, was fundamentally flawed.

Cross-State Air Pollution Rule (CSAPR). In July 2011, the EPA issued the final CAIR replacement rule, referred to as the CSAPR,[18] to address interstate transport of sulfur dioxide and nitrogen oxides emissions in 27 Eastern and Midwestern states, including Iowa. The rule affects fossil-fueled electric generating units with greater than 25 MW of capacity. Phase I of CSAPR, which establishes state emission caps for SO_2 and NO_X, was scheduled to go into effect beginning January 1, 2012. These caps were to be lowered further in 2014 when Phase II became effective. Phase II also includes a penalty requirement for utilities whose emissions exceed established levels. In July 2011, the EPA also issued a supplemental notice of proposed rulemaking requiring six states, including Iowa, to make summertime NO_X reductions under the CSAPR ozone-season control program, which was expected to go into effect in 2012. The EPA also establishes enforceable state emission caps which in effect limit the amount of emissions trading allowed to meet compliance requirements. The emission allowances used for Acid Rain and CAIR program compliance cannot be used for compliance with CSAPR.[19] The final CSAPR rule was challenged by many groups. **Staff Update:** The EPA issued its final supplemental rule to the CSAPR in December 2011 setting more stringent summertime limits on NO_X emissions from Iowa and 4 other states. Also, on December 30, 2011, the D.C. Circuit Court of Appeals issued an order that stays implementation of CSAPR pending the court's resolution of the multiple petitions for review of the rule. The order also says the Court expects the EPA to continue administering the CAIR until the appeals are resolved. Therefore, utilities will continue to have to comply with CAIR, not CSAPR, for the time being. It is not know how long this will last or how the Court will rule on the appeals. On August 21, 2012, the U.S. Court of Appeals vacated CSAPR and remanded it to the EPA. On October 5, 2012, the EPA filed a Petition for Rehearing with the Court.

IPL and MidAm provided their expected CSAPR emission allocations—IPL system-wide and MidAm by unit as follows:

[18] Formerly known as the Clean Air Transport Rule (CATR).

[19] IPL commented that as part of a comprehensive strategy to prudently delay installation of SO_2 emissions control projects for the benefit of customers, it has banked acid rain allowances or entered into allowance futures contracts for compliance with the SO_2 compliance requirements of CAIR.

IPL System-Wide Expected CSAPR Emission Allocations

CSAPR Implementation Year	Ownership[20]	SO_2 Annual Tons	NO_X Annual Tons	NO_X OS Tons
2012 – Phase I	IPL 100 percent	33,648	11,400	4,963
2012 – Phase I	IPL Share	33,781	44,445	5,000
2014 – Phase II	IPL 100 percent	23,323	11,165	4,870
2014 – Phase II	IPL Share	23,412	11,209	4,906

MidAm Expected CSAPR Emission Allocations By Unit

Plant Name	Unit	SO_2 2012	SO_2 2014	NO_X Annual 2012	NO_X Annual 2012	NO_X OS[21] 2012	NO_X OS 2012
Electrifarm	1	0	0	18	18	10	10
Electrifarm	2	0	0	22	21	10	10
Electrifarm	3	0	0	33	32	18	18
Neal North	1	2,808	1,944	947	925	441	432
Neal North	2	5,277	3,653	1,781	1,738	752	736
Neal North	3	10,332	7,145	3,483	3,400	1,526	1,494
Neal South	4	12,904	8,933	4,354	4,250	1,858	1,818
GDMEC	1	1	1	21	21	9	9
GDMEC	2	1	1	24	24	8	8
Louisa	101	13,031	9,021	4,397	4,292	1,893	1,818
Ottumwa	1	12,881	8,917	4,346	4,243	1,842	1,803
Pleasant Hill	1	0	0	4	3	3	3
Pleasant Hill	2	0	0	4	3	3	3
Pleasant Hill	3	3	3	17	17	10	10
Riverside	9	2,100	1,453	708	692	305	298
Sycamore	1	2	2	16	16	9	9
Sycamore	2	2	2	18	17	11	11
Walter Scott	1	1,173	812	396	386	172	168
Walter Scott	2	1,777	1,230	599	585	246	241
Walter Scott	3	14,288	9,891	4,821	4,706	2,021	1,978
Walter Scott	4	2,132	2,132	1,625	1,625	641	641
MidAm Operated Allowances		**65,821**	**46,223**	**23,288**	**22,771**	**9,946**	**9,749**
MidAm Share Allowances		**56,550**	**39,541**	**19,794**	**19,345**	**8,464**	**8,294**

[20] "IPL 100 percent" represents 100 percent of units operated by IPL, whereas "IPL Share" represents ownership share regardless of ownership.
[21] OS = Ozone Season

Mercury and Air Toxics Standards Rule (MATS aka Utility MACT). In 2005, the EPA issued the Clean Air Mercury Rule (CAMR) limiting national mercury emissions from new and existing coal-fueled power plants and establishing a cap-and-trade program. In 2008 CAMR was vacated. In December 2009 certain utilities were issued an Information Collection Request (ICR) from the EPA to collect fuel and emissions data. This data was used to develop a proposed MACT Rule for the control of mercury and other federal hazardous air pollutants (HAPs) and to define the MACT floor. In March 2011, the EPA issued the proposed Utility MATS. The rule limits emissions of mercury and other HAPs from new and existing power plants and establishes numeric emissions limits. The EPA proposes to allow facility-wide averaging for all HAPs emission from existing units within the same fuel subcategory. Under the proposed rule, all applicable units must be in compliance with emission limits and operating limits at all times. **Staff Update:** On December 21, 2012, the EPA issued its final rules which are mostly unchanged from the proposed rules.

Cooling Water Intake Structures[22]– 316(b) Rule. The EPA issued its revised proposed rule in March of 2011, establishing requirements under section 316(b) of the Clean Water Act (CWA) for all existing power generating facilities that withdraw more than 2 million gallons of water per day from waters of the U.S. and use at least 25 percent of the withdrawn water exclusively for cooling purposes. Section 316(b) of the Clean Water Act requires the EPA to establish standards for cooling water intake structures that will minimize impingement[23] and entrainment.[24] The EPA is required to finalize this rule by July 27, 2012. All but one of IPL's coal-fired power plants will be affected in some way by the requirements on this rule. MidAm's Neal Energy Center, Walter Scott, Jr. Energy Center, and Riverside Generation Station may be impacted by the requirements of this rule. Louisa uses cooling water sourced by groundwater wells and would not be affected by this rule. All but one of IPL's coal-fired plants will be affected in some way by this regulation. **Staff Update:** On June 1, 2012, the Acting Assistant Administrator for the Office of Water approved publication of a Notice of Data Availability (NODA). The NODA addresses new data related to the results of EPA's stated preference survey to estimate total willingness to pay for improvements to fishery resources affected by in-scope 316(b) facilities. Upon completion of the analysis and independent peer review, EPA will consider how the new benefits analysis informs the final rule.

Coal Combustion Residuals (CCR). In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rains, releasing a significant amount of fly ash, bottom ash, coal combustion byproducts, and water to the surrounding area. This resulted in federal and state officials calling for

[22] Water Quality Standards.

[23] "Impingement occurs when fish and other organisms are trapped against the outside part of a facility's water intake structure."

[24] Entrainment refers to the process where fish and shellfish are incorporated with the intake water flow entering and passing through a cooling water intake structure and into a cooling water system.

greater regulation of the storage and disposal of coal combustion byproducts. On May 4, 2010, the EPA released a proposal for regulating the disposal and management of CCR from coal-fueled power plants. EPA requested comments on two primary options for regulating CCR (including fly ash, bottom ash, boiler slag, and flue gas desulfurization materials that are generated from the use of coal to generate electricity). Both options would regulate CCR under the RCRA. Under the first proposal, EPA would list these residuals as special wastes subject to regulation under subtitle C of RCRA, when destined for disposal in landfills or surface impoundments. Under the second proposal, EPA would regulate coal ash under subtitle D of RCRA, the section for non-hazardous wastes. EPA considers each proposal to have its advantages and disadvantages and includes benefits which should be considered in the public comment period. MidAm includes a side-by-side comparison of these two options on pages 14 to 16 of its response to Question 2. Each of IPL's coal-fired power plants has one or more ash surface impoundments, and IPL also has two active CCR company-owned landfills. EPA is not currently under a deadline to issue the final rules for coal combustion residual management.

IPL Response: In addition to the regulations covered in the composite summary, IPL provided comments and detailed information on other regulations which are summarized below:

As part of its comments, IPL provided a list of its existing coal-fired generating units including the unit nameplate capacity, boiler type, and currently installed emission controls. (IPL Comments, Table 1, p. 3). Additionally, IPL provides the actual 2010 operations emissions for each of its coal-fired electric generating units. (IPL Comments, Table 2, p. 10). IPL states that its facilities with a nameplate capacity greater than 25 MW will be affected by CSAPR. IPL states that there is uncertainty around best available retrofit technology rule (BART) as part of the Clean Air Visibility Rule (CAVR) and is unable to predict the impact that the CAVR might have on the operations of its existing electric generation units until the EPA final approval of state CAVR plans. IPL also states that in 2009 it filed its case-by-case MACT application to the DNR as required by the Clean Air Act (CAA) and the outcome is uncertain at this time. In response to Clean Water Act (CWA) requirements, IPL states that it is currently addressing the need for thermal discharge requirements on a case-by-case basis with DNR as each generation plant permit becomes subject to renewal. IPL states that all but one of its coal-fired power plants will be affected in some way by CWA's Section 316(b) requirements to regulate cooling water intake structure and all of its coal-fired power plants will be affected by effluent limitation guidelines (ELG) requirements. Additionally, each of IPL's coal-fired power plants has one or more ash surface impoundments, and IPL's two active CCR[25] company-owned landfills will be subject to proposed CCR rules anticipated to be final in late 2012 or in 2013. (IPL Comments, p. 30).

[25] CCR is often referred to as coal ash.

IPL notes that there is currently significant regulatory uncertainty with respect to the various environmental rules and regulations. Given the dynamic nature of environmental regulations, IPL has established an integrated planning process for environmental compliance. IPL anticipates that future expenditures for environmental compliance will be material, and will likely include significant capital investments. The following are major environmental matters that could potentially have a significant impact on IPL's financial condition and results of operations:

Clean Air Visibility Rule (CAVR). CAVR requires states to develop and implement state implementation plans (SIPs) to address visibility impairment in designated national parks and wilderness areas across the country, with a national goal of no impairment by 2064. Proposed CAVR SIPs for Iowa and Minnesota have been submitted to the EPA for review and approval. The SIPs include Best Available Retrofit Technology Rule (BART) emission controls and other additional measures needed for reducing state contributions to regional haze. The EPA has not issued responses on the Iowa or Minnesota SIPs. In August 2011, a legal challenge was filed citing the EPA's failure to issue timely approval of CAVR SIP submissions or alternatively issue CAVR federal implementation plan (FIPs). Electric generating unit emissions of primary concern for BART and regional haze regulation include $SO_{2,}$ NO_X, and PM. The EPA had allowed SO_2 and NO_X CAVR obligations to be fulfilled by CAIR. However, this is less certain due to the D.C. Circuit Court's remand of CAIR to the EPA and the fact that the final CSAPR does not address the EPA's prior decision allowing CAVR SO_2 and NO_X obligations to be met by compliance with CAIR. IPL is unable to predict the impact that CAVR might have on the operations of its existing electric generating units until the EPA's final approval of state CAVR plans, which remains pending.

Industrial Boiler and Process Heater MACT. The initial rule proposed by the EPA to go into effect beginning in 2007 was vacated in 2007. In March 2011, the EPA published the final revised rule requiring existing boilers and process heaters located at major sources to comply with the HAP emission limitations and work practice standards. A major source is a facility which emits 10 tons per year or more of a single HAP or 25 tons per year or more of all HAPs. A legal challenge resulted in the EPA publishing a stay postponing the effective date of the rule with a final reconsidered rule expected by April 2012. **Staff Update**: On September 20, 2012, the EPA finalized a specific set of adjustments to Clear Air Act standards for boilers and certain solid waste incinerators.

Ozone National Ambient Air Quality Standards (NAAQS) Rule. In 2008 the EPA announced reductions in the primary NAAQS for eight-hour ozone to a level of 0.075 parts per million (ppm). In January 2010, the EPA issued a proposal to reduce the primary standard to a level within the range of 0.06 to 0.07 ppm and establish a new seasonal secondary standard. In September 2011, President Obama requested that the EPA withdraw the agency's ozone NAAQs proposal to reconsider it in 2013. Further action by the EPA remains pending. Depending on the level and location of non-attainment areas, IPL may be subject to additional NO_X emissions reduction requirements.

Fine Particulate NAAQS Rule. In 2006, the EPA lowered the 24-hour PM 2.5 primary NAAQS (PM 2.5 NAAQS) from 65 micrograms per cubic meter to 35 micrograms per cubic meter. In 2009 the EPA announced its final designation of non-attainment areas. IPL does not have any generating facilities in the announced non-attainment areas; however, as a result of D.C. Circuit Court decision, the EPA must re-evaluate its justification for not tightening the annual standard related to adverse effects on health and visibility. If the standard becomes more stringent, it could require SO_2 and NO_X emission reductions in additional areas not currently designated as non-attainment.

Nitrogen Dioxide (NO_2) NAAQS Rule. In January 2010, the EPA issued a final rule to strengthen the primary NAAQS for NO_X as measured by NO_2. The final rule establishes a new one-hour NAAQS for NO_2 of 100 parts per billion (ppb) and associated ambient air monitoring requirements, while maintaining the current annual standard of 53 ppb. The EPA is expected to designate non-attainment areas for the new NO_2 NAAQs by January 2012. The final rule is currently being challenged by several groups in the D.C. Circuit Court. The schedule for compliance with this rule has not yet been established.

SO_2 NAAQS Rule. In June 2010, the EPA issued a final rule that establishes a new one-hour NAAQS for SO_2 at a level of 75 ppb and revoked both the existing 24-hour and annual standards. The EPA is expected to designate non-attainment areas for the SO_2 NAAQs by June 2012 with compliance expected to be required by 2017. The final rule is being challenged by several groups in the D.C. Circuit Court.

Section 316(a) Rule. Thermal wastewater discharges in the state of Iowa are subject to effluent limitations for temperature. Exceptions to these limits are allowed under the temperature variance provisions of the CWA, Section 316(a). Permittees must demonstrate that the variation for the thermal component of the discharge assures the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in the receiving water. IPL is currently addressing the need for thermal discharge requirements on a case-by-case basis with the DNR, as each electric generation plant permit becomes subject to renewal. If the DNR determines that a facility's thermal discharge needs to be controlled, IPL may need to install equipment such as cooling towers.

Effluent Limitation Guidelines. The EPA is required to revise effluent limitation guidelines (ELG) for power plant wastewater discharges by July 2012 with the final rule expected in January 2014. IPL anticipates that the revised ELG will focus on wastewaters associated with flue gas desulfurization (i.e., wet scrubber) emission control equipment, combustion ash transport water, combustion ash landfill operations including leachate and cooling towers. No compliance schedule has been established yet. All of IPL's coal-fired power plants will be affected by the ELG requirements.

Land and Solid Waste. The Resource Conservation and Recovery Act (RCRA) of 1976 set national goals for:

1. Protecting human health and the environment from the potential hazards of waste disposal;
2. Conserving energy and natural resources;
3. Reducing the amount of waste generated; and
4. Ensuring that wastes are managed in an environmental-sound manner.

The following three programs were established by the RCRA to achieve these goals:

1. <u>The solid waste program</u> encourages states to develop comprehensive plans to manage nonhazardous industrial solid waste and municipal solid waste, sets criteria for municipal solid waste landfills and other solid waste disposal facilities, and prohibits the open dumping of solid waste.

2. <u>The hazardous waste program</u> establishes a system for controlling hazardous waste from the time it is generated until its ultimate disposal.

3. <u>The underground storage tank (UST) program</u> regulated USTs containing hazardous substances and petroleum products.

The RCRA was amended and strengthened by Congress in 1984 with the passing of the Federal Hazardous and Solid Waste Amendments (HSWA). These amendments increased enforcement authority for the EPA, established more stringent hazardous waste management standards, and created a comprehensive UST program. CCR is currently exempt from the hazardous waste requirements under an amendment to the RCRA.

<u>New Source Performance Standards (NSPS) for GHG Emissions from Electric Utilities</u>. In December 2010, the EPA announced the future issuance of GHG standards for electric utilities under the CAA. The GHG emission limits are to be established as NSPS for new and existing fossil-fueled electric generating units. The EPA entered a settlement agreement that required the issuance of proposed regulations for new and existing power plants by July 26, 2011, and final regulations no later than May 26, 2012. In June 2011, the deadline for the EPA to issue a proposed rule was extended to September 30, 2011. The EPA has announced that the proposed rule will be further delayed but has not yet established a new deadline for issuing a proposed rule. For existing electric generating units, the NSPS is expected to include emission guidelines that states must use to develop plans for reducing GHG emissions. The guidelines will be based on demonstrated controls, GHG emission reductions, costs, and expected timeframes for installation and compliance. Under existing EPA regulations, states must submit their plans to the EPA within nine months after publication of the guidelines, unless the EPA sets a different schedule. States have the ability to apply more or less stringent standards and longer or shorter compliance schedules. The implications are uncertain, including the nature of required emissions controls and the compliance timeline for mandating reductions of GHGs.

Ames Response: Ames provided a table listing new and proposed EPA rules (and implementation information) that either have or will have an impact on its coal-fired electric generation. Below is a listing of the rules included in the table on pages 1 to 2 of the comments filed November 3, 2011:

1. Coal Combustion Residuals (CCR);
2. Cross State Air Pollution Rule (CSAPR);
3. Mercury and Air Toxics Standard (MATS);
4. NAAQS (Ozone); and
5. GHG (CO_2).

Cedar Falls Response: The immediate rule of concern is the CSAPR scheduled to begin January 1, 2012, unless blocked or stayed by the Federal Courts (see **staff update** on p. 36 of this memo). For planning purposes, Cedar Falls assumes that the rule will eventually become effective substantially as written. CSAPR will significantly impact Streeter Unit 7 (35 MW) by further limiting SO_X and NO_X emissions. Annual production will be limited to 800 hours while burning coal. It is an intermediate plant resulting in a low baseline heat input. During the 2008 Midwest flood, it was impacted for 9 months which falls within the 5-year baseline period.

MPW Response: Each of MPW's coal-fired units will be affected by multiple changing regulations or new regulations. For many years, the EPA entered into confidential settlement agreements to resolve CAA/CWA litigation. The confidential settlements included deadlines for revising existing regulation and also called for new rulemaking, but did not involve any input from the regulated entities. The timing of these negotiated deadlines, court imposed deadlines, and agency initiated actions are cumulatively impacting utilities because the regulatory changes all call for compliance in the next four years (2012 to 2015). For regulations with compliance deadlines a few years out, utilities must invest in advance to perform the intensive studies and analysis required to become complaint. There is also uncertainty created by numerous court challenges filed against the changing regulations.

The immediate concern for MPW is the very short time frame to comply with CSAPR—the final rule was very different from the initial proposed draft and the few months to comply have not been adequate to address control investment needs, resource planning, etc. CSAPR includes significant limitations on allowance trading and penalties for individual units should a state exceed its allowance budget and variability limit. Because there has not been adequate time to install controls to meet CSAPR, utilities whose allowance allocation does not meet operating needs must consider idling units, retiring units, or taking risks in the new allowance market.

On October 6, 2011, EPA announced further revisions to CSAPR that could impact planning for 2012, which are moving through the federal rulemaking process and are subject to change based on the public comments and further EPA analysis. MPW supports EPA's effort to delay the penalty provisions of CSAPR to allow for development of liquidity in the allowance market. Until the revisions to CSAPR are finalized in late 2011, MPW must plan to comply with CSAPR as it is written today and strategize in case the final version of the revisions to CSAPR are adopted as currently presented.

NIMECA Response: EPA regulations that will have an impact on NIMECA members include the CSAPR, HAPS MACT, NESHAP RICE, among others. MidAm handles these issues for NIMECA with the members paying their proportional share of compliance costs.

Sierra Response: Economists have studied how the cost of compliance with EPA regulations will impact electric generation and Sierra provided a recent study as Exhibit 1.[26] This report concludes that the environmental externalities of coal-fired power plants far exceeds their value added. Excluding carbon dioxide, coal-fired power plants result in gross external damage of $53 billion annually which is far greater than the value added. The report left out other externalities the EPA is poised to regulate including mercury and other air toxics, cooling water intake structures and their impact on aquatic ecosystems, coal combustion residuals and their impact on human health, rivers, and water supply, and coal plant wastewater effluent, which ends up in our waters.

Sierra provided summaries and information on several regulations.[27] These include: CAA Air Toxics Rule, CCR Rulemaking, Cooling Water Intake Standards, Effluent Limitation Guidelines, and GHG Rules, and also provided a table setting out the rules, compliance dates, and regulated pollutants which is reproduced as Attachment 8 to this memo.

3. A list of up to ten possible strategies to address the EPA rules. This list should include the following two strategies:

- **a. A business as usual strategy; and**
- **b. Upgrade all coal units to meet the new rules.**

Examples of other possible strategies include:

- **c. Replace all coal units with gas;**
- **d. Replace selected units with gas or other alternatives and upgrade other units with new pollution prevention technology; or**
- **e. Replace some or all coal units with nuclear units.**

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[26] Muller, Nicholas Z., Robert Mendelsohn, and William Nordhaus. "Environmental Accounting for Pollution in the United States Economy." *American Economic Review* 101.5 (2011): 1649-675.

[27] See Potential Impacts of Environmental Regulation on the U.S. Generating Fleet. Edison Electric Institute; prepared by ICF International, January 2011 (Sierra Exhibit 10), EPA's NPDES Permit Writer's Manual, available at: http://www.epa.gov/npdes/pubs/pwm_2010.pdf, and Sierra Exhibit 3.

MidAm Response: For this NOI, MidAm considered five potential strategies. Energy efficiency will continue and is embedded in all of the five strategies considered. No new wind generation is included in MidAm's strategy, however, MidAm states it will continue to look for cost-effective opportunities to increase wind power generation in the portfolio. The five potential strategies MidAm considered include:

1. Business-as-usual (BAU);
2. Upgrade all coal plants to meet the new rules;
3. Replace all coal units with gas;
4. Add a gas-fired CCCT; and
5. Replace some or all coal units with nuclear units.

<u>MidAm Strategy 1 - Business as Usual (BAU)</u>

The BAU strategy is MidAm's current plan of action for the next decade. MidAm believes its BAU strategy recognizes a potentially very fluid regulatory environment and "allows flexibility, enhances diversity, is environmentally sound and controls costs for customers." Key features of this plan include the addition of emission controls at Neal North Energy Center Units 1, 2, 3, and Neal South Energy Center Unit 4; switching Riverside Generating Station Unit 5 from coal to natural gas; additional wind development; ongoing energy efficiency; and peak demand growth at 1.1 percent annually.

<u>MidAm Strategy 2 - Upgrade all coal units to meet the new rules</u>

As part of the environmental plan filed with the Board, MidAm detailed the coal-fired plants that it may be practical to upgrade to meet new environmental rules. Additions of emission controls to smaller and older plants are considered impractical based on their size, remaining life, and the cost of environmental retrofits.[28] However, the Neal North Energy Center Unit 1 (135 MW, in-service 1964) is unique because it might have the ability to share some emission control equipment and costs with the adjoining Neal North Energy Center Unit 2, thus making the economics of environmental emission control retrofits potentially reasonable.

In addition to the capital costs for emission control equipment, these coal-fired units would experience higher operating costs, variable operating and maintenance costs (i.e., reagents), a higher heat rate (i.e., additional fuel use), and a reduced net electrical unit output to serve customers. A summary of generic capital costs for various emission control equipment by size for a typical coal-fired unit is shown below. The table shows that it becomes economically impractical to add emission controls to smaller older plants given the limited period to recover the costs. Also, uncertainty over a national or

[28] Walter Scott Jr. Energy Center Unit 1, 45 MW plant, in-service 1954; Walter Scott Jr. Energy Center Unit 2, 88 MW, in-service 1958; Riverside Generating Station Unit 5, 130 MW, in-service 1961; Neal North Energy Center Unit 1, 135 MW, in-service 1964 – unique in that it might have the ability to share some emission control equipment and costs with the adjoining Neal North Energy Center Unit 2.

regional GHG policy also adds further doubt to the already poor economics for older, small coal-fired units.

Capital Cost for Emission Control Additions (2008 $ per kW)

Plant Size (MW)	FGD Wet	FGD Dry With Filter Fabric	SCR	SNCR	Baghouse	ACI
100	$861	$817	$492	$30	$438	$27
200	$697	$662	$467	$25	$359	$26
300	$585	$556	$443	$20	$292	$24
400	$526	$500	$418	$15	$262	$22
500	$467	$444	$393	$10	$231	$20
600	$443	$420	$369	$10	$207	$17
700	$418	$397	$344	$10	$182	$15
800	$381	$362	$307	$10	$182	$15

FGD – Flue Gas Desulfurization
SCR – Selective Catalytic Reduction for NO_X control
SNCR – Selective Non-Catalytic Reduction for NO_X control
ACI – Activated Carbon Injection

<u>MidAm Strategy 3 - Replace all coal units with gas</u>

Replacing all coal-fired units with natural gas in the next 10-year period is impractical and ill-advised from a fuel diversity standpoint for the following reasons:

1. Natural gas infrastructure is not currently available to support this change and would likely take years to develop.
2. Once converted, the plants would be expensive to operate because of the higher fuel costs with no improvements in plant efficiency or start-up costs.
3. The impact on the demand for natural gas (especially if other utilities adopt this strategy) could result in near-term gas supply shortages and increased gas prices.
4. Reliability could be degraded as the electricity transmission system is subjected to power flows different from those which the grid was designed for due to the change in unit dispatch pricing caused by higher natural gas prices.
5. Customers could be subjected to natural gas price volatility and therefore electric price volatility.
6. The Iowa economy and employment could be adversely impacted.

MidAm Strategy 4 - Add a gas-fired CCCT

The addition of a gas-fired CCCT strategy deviates from MidAm's BAU strategy starting in 2015 with the CCCT. The CCCT would be developed in 2018 for modeling purposes but could be developed any time from 2015 to 2018 as future conditions dictate. The strategy modeled assumes that the operations cease at Walter Scott Jr. Energy Units 1 and 2 and Neal North Energy Center Unit 2 on January 1, 2015. Also, Neal North Energy Center Unit 1 and Riverside Generating Station Unit 5 which are currently able to burn natural gas without further modification would be switched to natural gas from January 1, 2015, through December 31, 2017, and then those units would cease operation. The natural gas infrastructure necessary to support this switch is in place, but natural gas supply and transportation would need to be arranged.

MidAm Strategy 5 - Replace some or all coal units with nuclear units

Nuclear generation may be able to replace some or all of the coal-fired generation as a base load resource in the long-term; however, nuclear generation will likely not be a significant replacement in the next 10 year period. MidAm is currently assessing the feasibility of deploying nuclear generation in Iowa, specifically, small modular nuclear reactors which may permit the matching of nuclear capacity additions to coal-fired generation capacity retirements and may also have similar base load and dispatchable operating characteristics to coal-fueled generation.

IPL Response: IPL performed EGEAS analyses of three strategies (listed below) in order to provide the Board with a broad range of plans. At this time, IPL does not propose any of the three strategies as a specific action plan—IPL needs additional time for further analysis and clarification of final EPA regulations. Further, IPL did not evaluate a strategy of replacing some or all of its coal-fired generating units with nuclear units, because IPL considered the time period for considering nuclear plants to be beyond the timeframe of the study period of this NOI. The three strategies IPL analyzed are:

Strategy 1. BAU
Strategy 2. Tier 1 Incremental and Tier 2 Controlled
Strategy 3. Tier 1 Incremental and Tier 2 Retired

Tier 1 units are:
Expected to operate throughout the study period;
Expected to get full controls for NO_X, SO_2, and Hg; and
Candidates for efficiency upgrades to improve heat rate and lower emissions.

Tier 1 Units include:
Neal Units 3 and 4
Louisa
Ottumwa
Lansing Unit 4

Tier 2 units are:

Smaller and less efficient than Tier 1 units;
Not likely to economically withstand full environmental controls; and
Potentially able to withstand low-cost emissions control options.

Tier 2 Units include:

Burlington
Kapp Unit 2
Sutherland Unit 3
Prairie Creek Units 3 and 4

The EGEAS analysis does not quantify and include accelerated decommissioning and site remediation costs of retired Tier 2 units or the recovery of remaining book value of units. These costs exist in any strategy due to the eventual retirement of units—the difference is the timing of recovery. The remaining book value of Tier 2 units is provided in the following table.

Remaining Book Value of Tier 2 Units

Plant	Book Cost	Accumulated Depreciation	Net Book Value
Burlington	109,614,808.18	(64,861,767.05)	44,753,041.13
Kapp 2	105,954,907.55	(62,257,236.16)	43,697,671.39
Prairie Creek 1-2-3	62,172,521.51	(15,981,137.67)	46,191,383.84
Prairie Creek 4	85,153,953.00	(68,404,290.86)	16,749,662.14
Prairie Creek 1-4	80,414,167.85	(8,793,207.59)	71,620,960.26
Sutherland 3	82,362,761.79	(32,086,801.54)	50,275,960.25
	525,673,119.88	(252,384,440.87)	273,288,679.01

Notes:
Accumulated Depreciation balances do not include RWIP.
Prairie Creek 4 excludes Prairie Creek Ash Disposal.
Prairie Creek 1-4 includes assets common to all units.

Tier 3 Units are:

Not able to withstand any additional emissions control expenditures; and
Not planned to operate throughout the study period.

Tier 3 Units include:

All other coal plants

IPL Strategy 1 - BAU

IPL's BAU strategy is intended as a "snapshot in time" tied to the 2010 Integrated Resource Plan (IRP) to provide a baseline. As such, this strategy does not meet compliance with all new regulations. Plants continue status quo operations as proposed in the 2010 IRP without regard to the "new" air emissions rules—it is also the closest tie to IPL's EPB. Under the BAU strategy, IPL would implement the following retirements and upgrades as noted:

Retirements

Immediate
- Sixth Street Station
- Prairie Creek Unit 2
- Dubuque Unit 2
- Lansing Units 2 and 3
- Kapp Unit 1
- Sutherland Unit 2
- Fox Lake Unit 1
- Fox Lake Unit 2
- Fox Lake Unit 4 (CT)
- Agency Street peaking units

January 15, 2015
- Dubuque Units 3 and 4
- Sutherland Unit 1

Uprades

2010 - Lansing Unit 4
- Capacity
- Efficiency
- SCR
- Baghouse
- Scrubber (2014)

2014 - Ottumwa
- Capacity
- Efficiency
- Scrubber
- Baghouse

Modifications to the Reference Case for the analysis in this docket include converting Dubuque Units 3 and 4 to natural gas effective January 1, 2012, before retirement in January 1, 2015, and not renewing the Duane Arnold Energy Center purchased power agreement. **(Staff Note: On August 7, 2012, in Docket No. SPU-2005-0015, IPL and NextEra Energy Duane Arnold, LLC, filed an amendment concerning a new eleven-year purchased power agreement with a start date of February 2014.)** IPL's 2010 IPR also included its minority shares of Neal Units 3 and 4 and Louisa which MidAm operates. IPL's 2010 IRP assumed the installation of scrubbers, baghouses, and SNCRs at Neal Units 3 and 4 in 2014.

IPL Strategy 2 - Tier 1 Incremental and Tier 2 Controlled

Strategy 2 provides the Board with a scenario where the Tier 2 units remain in service with upgrades. Ottumwa, Lansing Unit 4, and Tier 2 units receive upgrades above and beyond the BAU strategy. Strategy 2 also assumes that ash will not be classified as a hazardous waste, which is currently an uncertainty. IPL's Strategy 2 includes the following assumptions and upgrades:

Assumptions

Ottumwa – implementing capacity and efficiency upgrades as well as installing scrubber and baghouse in 2014.

Lansing Unit 4 – implementing capacity and efficiency upgrades, installing a SCR and baghouse in 2010, and installing a scrubber in 2014.

Tier 3 units – retirement with potential gas conversions prior to retirement.

Neal Units 3 and 4 – installation of scrubber, baghouse, and SNCR in 2014.[29]

Not renewing the Duane Arnold Energy Center Purchase purchased power agreement.

Upgrades

2020 – Install a SCR at Ottumwa to meet future NO_X emission reduction requirements. Therefore, Lansing Unit 4 and Ottumwa will eventually have SCR, scrubber, and baghouse controls.

2014 – Install ACI and upgrade ESPs at Tier 2 units to meet Utility MATS.

2020 – Install cooling towers at Burlington, Kapp Unit 2, Prairie Creek, and Lansing Unit 4 to meet Section 316(a) and (b) water rules. (Sutherland and Ottumwa already have cooling towers.)

Ottumwa, Lansing Unit 4, and Tier 2 Units – Upgrades to meet ELG water rules.

Ottumwa, Lansing Unit 4, and Tier 2 Units - Upgrades for dry ash handling to meet the CCR rule.

Ottumwa, Lansing Unit 4, and Tier 2 Units - Close ash ponds by 2018 to meet the CCR and ELG rules.

Whether the Strategy 2 upgrades will be adequate to meet all future rules is still uncertain. If rules are ultimately more stringent, IPL may consider the potential of retiring Tier 2 units or switching unit fuel to natural gas instead of installing upgrades. A good candidate for this fuel conversion would be Sutherland Unit 3.

<u>IPL Strategy 3 - Tier 1 Incremental and Tier 2 Retired</u>

Strategy 3 is the same as the "Business as Usual" Strategy 1 for Tier 1 units; however, rather than upgrading Tier 2 units, they will be retired effective January 1, 2015, to

[29] IPL is the minority owner and will take its lead from MidAm on further upgrades.

coincide with the need to begin meeting Utility MATS rule compliance requirements. Strategy 3 also assumes that ash will not be classified as a hazardous waste. The following assumptions and additional plant upgrades beyond Strategy 1 are included in Strategy 3:

Assumptions

Ottumwa - implementing capacity and efficiency upgrades as well as installing scrubber and baghouse in 2014.

Lansing Unit 4 - implementing capacity and efficiency upgrades, installing a SCR and baghouse in 2010, and installing a scrubber in 2014.

Tier 3 units - retirement with potential gas conversions prior to retirement.

Neal Units 3 and 4 - installation of scrubber, baghouse, and SNCR in 2014.[30]

Not renewing the Duane Arnold Energy Center Purchase purchased power agreement.

Upgrades

2020 - Install a SCR at Ottumwa to meet future NO_X emission reduction requirements. Therefore, Lansing Unit 4 and Ottumwa will eventually have SCR, scrubber, and baghouse controls.

2020 - Install cooling tower at Lansing Unit 4 to meet Section 316(a) and (b) water rules.

Ottumwa and Lansing Unit 4 - Upgrades to meet ELG water rules.

Ottumwa and Lansing Unit 4 - Upgrades for dry ash handling to meet the CCR rule.

Ottumwa and Lansing Unit 4 - Close ash ponds by 2018 to meet the CCR and ELG rules.

Ames Response: Ames described the seven strategies below which are followed by a table showing each option's compliance status for the various EPA rules.

1. Business as Usual - no changes to Ames Units 7 and 8.

2. Upgrade Units 7 and 8 to meet the new EPA rules.

[30] IPL is the minority owner and will take its lead from MidAm on further upgrades.

3. Retire Unit 7 and retrofit Unit 8 with control equipment necessary to meet the new EPA rules. Purchase capacity from the MISO market to offset the retirement of Unit 7. Purchase energy from the MISO market and run combustion turbine peakers to offset the loss of energy due to the retirement of Unit 7.

4. Repower Units 7 and 8 with natural gas.

5. Retire Units 7 and 8. Construct 105 MW (or larger) combined cycle natural gas power plant.

6. Retire Units 7 and 8. Buy a share of capacity and energy from an existing or new base load power plant (coal, nuclear, or combined cycle natural gas) equal to or greater in size (MW) than the combined total of 105 MW of retired Units 7 and 8.

7. Retire Units 7 and 8. Purchase capacity from the MISO market to offset the retirement of Units 7 and 8. Purchase energy from MISO market and run combustion turbine peakers to offset the loss of energy due to the retirement of Units 7 and 8.

Summary of Compliance Status by Strategy

	Proposed CCR	**Final CSAPR**	**Proposed MATS**	**Future NAAQS**	**Future GHG**
Strategy 1	No	No	No	Unlikely	Unlikely
Strategy 2	Yes	Yes	Yes	Unknown	Unknown
Strategy 3	Yes	Yes	Yes	Unknown	Unknown
Strategy 4	Yes	Yes	Likely	Unknown	Unknown
Strategy 5	Yes	Yes	Yes	Unknown	Unknown
Strategy 6	Yes	Likely	Likely	Unknown	Unknown
Strategy 7	Yes	Yes	Yes	Yes	Yes

Cedar Falls Response: Cedar Falls is a minority owner in the Neal Unit 4, Walter Scott Unit 3, and Walter Scott Unit 4. MidAm will discuss these plants.

Streeter Unit 6 (16.5 MW) will be regulated by the small and commercial boiler MACT. Compliance with the chlorine and mercury limits should be controllable by purchasing suitable stoker coal and injection of small amounts of chemicals such as Trona. Plans will be finalized when a final MACT is issued. Due to its size, this unit is not subject to CSAPR. This unit may be used more if the projected retirement of 13,000 MW of older coal-fired units occur.

The two Cedar Falls turbines burn natural gas and back-up #2 fuel oil. These units are less than 25 MW and are not subject to CSAPR. They may be used more if the projected retirement of 13,000 MW of older coal-fired units occurs.

Streeter Unit 7 appears to be Cedar Falls' unit that will be most affected by environmental regulations. It represents 35 MW of 152 MW or 23 percent of the fleet capacity. MACT requirements are not likely to be technically achievable for this unit. Strategies for 2012 through 2014 include burning coal in the winter and natural gas in the summer. If the mercury limit is enforceable by 2015, the unit will likely burn natural gas from December through March with a firm capacity rating from December through March. Through the American Public Power Association, Cedar Falls has petitioned the EPA to create a mercury subcategory for coal units less than 100 MW which would likely result in an achievable mercury limit for those plants. Cedar Falls anticipates the addition of low NO_X burners, over-fire air burner management and controls to be installed in 2012 and 2013.

Cedar Falls nominated with Northern Natural Gas (NNG) for additional firm summer pipeline capacity in order to provide firm natural gas to both the Streeter Station boilers and the combustion turbines. The application is being processed and is now ready for final signatures.

MPW Response: At this time, it is extremely difficult to project how much MPW will spend in the coming years to address EPA regulations given the changes in the regulations and the numerous court challenges. MPW recently engaged a consulting firm to provide confidential advice regarding possible responses to the pending and anticipated regulations, evaluation of potential operating changes, resource planning options, and consideration of technological investments. MPW is also evaluating different technologies to obtain further reductions in NO_X emissions and to address the mercury requirements of the Small Boiler MACT and Air Toxics Rule. Due to confidentiality and trade secret protections, MPW is unable to share this information. In order to finance any necessary investments in control technology or transmission/distribution upgrades, MPW anticipates borrowing for capital projects and price increases.

For MPW and many other municipal utilities, there is not much more trimming of operation, maintenance, and capital costs that can be done without negatively impacting reliability and customer service. Reliable, coal-fired base load generation is important to Muscatine, and many other Iowa communities.

NIMECA Response: Members' decision-making ability concerning plant upgrades is limited as it follows MidAm's lead on baseload coal resources. Due to the relatively small size of the group, NIMECA participates in jointly owned projects when they are available.

Sierra Response: Sierra noted the number of scenarios MidAm and IPL submitted and commented that for two sophisticated utilities it is hard to believe that those are the only options being considered to both comply with EPA rules and to provide reliable and affordable electricity to their customers. Both utilities failed to discuss specific energy efficiency or demand-side benchmarks and the option of replacing some coal-fired generating capacity and/or energy with wind. Additionally, neither adequately addressed the full suite of existing and emerging regulations—a compliance strategy for Resource Conservation and Recovery Act (RCRA) and CWA affluent regulation is missing.

Nuclear plants present less risk on a traditional-pollutant basis but face future risks including the high cost of building and operating the plant. The bill that was before the legislature last session would force ratepayers to pay for development before a plant is built whether it is built or not and would limit the Board's authority to establish ratemaking principles for a new plant. Nuclear plants require many years to build, are extremely expensive to build, to fuel, and to decommission at the end of their use, and they produce waste that is radioactive for thousands of years.

Energy Efficiency is the quickest, easiest, and most cost-effective alternative to coal, gas, and nuclear generation. Studies have shown the average cost to a utility for energy efficiency measures to be 2.5 cents per kWh and 6 to 15 cents per kWh for new generation sources. One study found that by 2018 new energy efficiency programs could decrease summer peak capacity by 20,000 MW of the 40,000 MW that may be needed and the U.S. could cost-effectively reduce energy consumption by 20 to 30 percent or more over the next 20 years.[31] The Board could undertake alternative regulatory measures to gain greater energy efficiency including: 1) decoupling, 2) provide funding for energy efficiency programs and treat energy efficiency as a qualified resource, and 3) provide incentives for energy efficiency—treat investments as capital investments which would reduce rate impact.[32]

An alternative energy future would include the expansion and development of renewable energy. Recent studies demonstrate that the U.S. can supply all of its needed electricity from renewable sources if those sources are developed and tied together by the electric grid.[33] Iowa has made strides in developing wind generation but given Iowa's abundant wind resources more can be done.[34]

Although they are not rate-regulated by the IUB, RECs and municipals should be included in addressing responses to the EPA regulations. There are several strategies the Board could use to encourage them to avoid the impacts of the EPA regulations and transition to energy efficiency and renewable energy.

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[31] See Sierra Exhibit 4-- Elliott, Gold, and Hayes, Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency (August 2011).

[32] See Sierra Exhibit 5-- York and Kushler, The Old Model Isn't Working: Creating the Energy Utility for the 21st Century (September 2011).

[33] See Sierra Exhibits 6, 7, and 8.

[34] See Sierra Exhibit 9.

4. **The costs and timing of capital investments for each strategy (e.g., x pollution control equipment in year y, gas pipeline or electric transmission upgrades in year z, etc.) should be described and quantified where possible.**

MidAm Response: MidAm discussed the categories of capital investments included below:

Pollution Controls – By the end of 2010, MidAm had invested over $425 million to comply with existing and future environmental regulations for Louisa Generating Station, Walter Scott Jr. Unit 3, and other "required environmental equipment such as coal combustion residue surface impoundments, and coal combustion residue monofills."

Gas Pipeline Investments – No new gas pipeline costs were included in this analysis but will be analyzed in detail if gas generation is the preferred route. The need for new pipeline is very site-specific, and no specific sites have been selected. Unsubscribed firm natural gas transportation capacity is limited in many areas of Iowa, and it may be very costly from MidAm to acquire new transportation in constrained areas. Four interstate pipelines currently serve the state of Iowa—ANR Pipeline Company, Natural Gas Pipeline Company of America (NGPL), Northern Border Pipeline Company (NBPL), and Northern Natural Gas Company (NNG).

Transmission Upgrades – see response to Question 8.

IPL Response: IPL currently estimates that the impact from the actions provided would require capital additions to existing IPL generating units of approximately $300-$350 million over the study period for Strategy 2 and $150-$175 million for Strategy 3. These are high level estimates, and they are incremental to IPL's 2010 IRP (Strategy 1 - BAU) and do not include capital additions for new generating resources.

Ames Response: The costs and timing of capital investments for each strategy are shown in the following table.

	Estimated Costs	Timing
Strategy 1	0	As is
Strategy 2	$86,400,000 to $132,200,000	2017
Strategy 3	$51,500,000 to $80,100,000	2017
Strategy 4	$56,000,000	2015
Strategy 5	$116,900,000	2015
Strategy 6	$336,900,000	Uncertain
Strategy 7	$6,900,000 plus	January 2013

Cedar Falls Response: Cedar Falls will incur capital investments at Walter Scott Units 3 and 4 and Neal Unit 4 operated by MidAm. Costs will likely be incurred for adding low NO_X burners at Streeter Unit 7, for mercury and chlorine control at Streeter Unit 6, and possibly for controls at Streeter Unit 7 if EPA actions create a less than 100 MW category for MACT regulations.

Sierra Response: The analyses for the various compliance scenarios considered by the utilities are insufficient to provide the foundation of a meaningful discussion of how compliance costs relate to alternatives and ultimately impact ratepayers. Sierra included an analysis of the forward-going costs of Iowa's coal-fired units if environmental retrofits are included in the analysis. These are based on publically available 2009 data from EPA and EIA.[35] The first table gives the Board a reference point for where the units fit in the marketplace *before* massive capital investments and reveals the units already operating on the margin.

Table 1. Operating Characteristics and Estimated Running Cost (2009)

Plant / Unit	Nameplate Capacity MW	First Year of Operation	Plant Coal Heat Rate mmbtu/ MWh	Capacity Factor 2008 to 2009	Estimated Fuel Cost $/MWh	Est. Fixed O&M Costs $/kW per Year	Est. Variable O&M Costs $/MWh	Est. Running Cost in 2009 $/MWh
Burlington 1	212	1968	10.69	64.2%	$14.87	$21.00	$4.00	$22.60
Lansing 3	38	1957	11.58	25.1%	$18.13	$30.00	$5.00	$36.80
Lansing 4	275	1977	11.58	60.0%	$18.13	$21.00	$4.00	$26.13
Kapp 2	218	1967	11.70	32.6%	$19.13	$21.00	$4.00	$30.48
Sutherland 1	38	1955	12.62	51.4%	$23.85	$30.00	$5.00	$35.51
Sutherland 2	38	1955	12.62	39.9%	$23.85	$30.00	$5.00	$37.44
Sutherland 3	82	1961	12.62	41.3%	$23.85	$30.00	$5.00	$37.15
Neal North 1	147	1964	10.37	71.8%	$11.27	$21.00	$4.00	$18.61
Neal North 2	349	1972	10.37	60.8%	$11.27	$18.00	$3.75	$18.40
Neal North 3	550	1975	10.37	71.7%	$11.27	$18.00	$3.75	$17.88
Ottumwa 1	726	1981	11.19	62.6%	$17.99	$18.00	$3.75	$25.02
Louisa 1	812	1983	10.50	67.8%	$15.05	$18.00	$3.75	$21.83
Walter Scott	49	1954	9.96	57.2%	$10.73	$30.00	$5.00	$21.72
Walter Scott	82	1958	9.96	77.3%	$10.73	$30.00	$5.00	$20.16
Walter Scott	726	1978	9.96	77.1%	$10.73	$18.00	$3.75	$17.15
Walter Scott	923	2007	9.96	72.2%	$10.73	$18.00	$3.75	$17.33
Muscatine 7	25	1958	14.23	40.4%	$22.10	$30.00	$5.00	$35.57
Muscatine 8	75	1969	14.23	13.3%	$22.10	$30.00	$5.00	$52.84
Muscatine 9	176	1983	14.23	59.1%	$22.10	$21.00	$4.00	$30.15
Earl Wisdom 1	33	1960	18.11	14.0%	$53.73	$30.00	$5.00	$83.22
Fair Station 1	25	1960	12.56	51.0%	$37.26	$30.00	$5.00	$48.98
Fair Station 2	38	1967	12.56	45.0%	$37.26	$30.00	$5.00	$49.87
Pella 5	12	1964	17.33	35.3%	$23.59	$30.00	$5.00	$38.30
Pella 6	27	1972	17.33	23.7%	$23.59	$30.00	$5.00	$43.05

[35] See Sierra December 16, 2011, filing, pages 15 to 22.

Table 2 calculates the capital costs of installing controls on Iowa's coal-fired units.

Table 2. Estimated Environmental Upgrade Capital Expenditures (Million 2009 $)

Plant / Unit	FDG Total Project Cost Million $	SCR Total Project Cost Million $	Baghouse Capital Cost Million $	ACI Capital Cost Million $	Wet Cooling Tower Capital Cost Million $	Total Capital Expenditures Million $
Burlington 1	$145	$54	$40	$3	$54	$296
Lansing 3	$44	$15	$9	$3	$18	$88
Lansing 4	$181	$71	$47	$3	$55	$358
Kapp 2	$155	$59	$44	$3	$55	$317
Sutherland 1	$45	$16	$10	$3		$74
Sutherland 2	$45	$16	$10	$3		$74
Sutherland 3	$79	$28	$19	$3		$129
Neal North 1	$110	$39	$26	$3	$49	$227
Neal North 2	$205	$79	$59	$4	$66	$412
Neal North 3	$284	$116	$75	$4	$85	$564
Ottumwa 1	$358	$157	$100	$4		$620
Louisa 1		$164		$5		$168
Walter Scott	$49	$16	$10	$3	$23	$102
Walter Scott	$71	$24	$16	$3	$33	$146
Walter Scott		$142	$103	$4	$112	$362
Walter Scott						$0
Muscatine 7	$36	$13	$8	$2	$17	$76
Muscatine 8	$79	$29	$19	$3	$30	$160
Muscatine 9		$58	$39	$3	$54	$154
Earl Wisdom 1	$48	$18	$13	$3		$82
Fair Station 1	$33	$11	$8	$2	$17	$71
Fair Station 2	$44	$15	$12	$3	$18	$92
Pella 5	$22	$9	$5			$36
Pella 6	$41	$15	$10	$3		$69

Table 3 demonstrates how the capital investments change the operating costs of each unit.

Table 3. Estimated Impact of Environmental Upgrades on Forward-Going Cost ($/MWh)

Plant / Unit	Est. Running Cost in 2008 $/MWh	Inc. Cost of FGD Upgrade $/MWh	Inc. Cost of SCR Upgrade/ $/MWh	Inc. Cost of Baghouse Upgrade $/MWh	Inc. Cost of ACI Upgrade $/MWh	Inc. Cost of Cooling Tower Upgrade $/MWh	CO_2 Price	Forward Going Cost $/MWh
Burlington 1	$22.6	$23.9	$7.8	$5.4	$0.8	$6.9	$20.0	$87.3
Lansing 3	$36.8	$107.8	$31.3	$17.9	$5.3	$33.0	$20.0	$252.0
Lansing 4	$26.1	$24.6	$8.4	$5.2	$0.8	$5.8	$20.0	$90.9
Kapp 2	$30.5	$45.8	$15.6	$11.2	$1.3	$13.5	$20.0	$137.9
Sutherland 1	$35.5	$56.1	$16.5	$9.4	$2.9	$0.0	$20.0	$140.4
Sutherland 2	$37.4	$71.3	$21.1	$12.1	$3.6	$0.0	$20.0	$165.5
Neal North 1	$18.6	$23.8	$7.4	$4.5	$0.9	$8.1	$20.0	$83.2
Neal North 2	$18.4	$21.5	$7.3	$5.0	$0.7	$5.4	$20.0	$78.3
Neal North 3	$17.9	$16.7	$5.9	$3.5	$0.5	$3.8	$20.0	$68.3
Ottumwa 1	$25.0	$18.1	$6.8	$4.1	$0.6	$0.0	$20.0	$74.5
Louisa 1	$21.8	$4.0	$5.9	$0.2	$2.6	$0.0	$20.0	$54.6
Walter Scott	$21.7	$41.5	$11.7	$6.7	$2.0	$14.4	$20.0	$118.9
Walter Scott	$20.2	$26.3	$7.7	$4.5	$1.2	$9.0	$20.0	$88.9
Walter Scott	$17.1	$3.8	$5.2	$3.4	$0.5	$3.5	$20.0	$53.4
Walter Scott	$17.3	$3.7	$0.7	$0.2	$2.4	$0.0	$20.0	$44.3
Muscatine 7	n/a	$66.9	$18.6	$9.7	$3.5	$19.3	$20.0	$173.7
Muscatine 8	$52.8	$123.0	$38.3	$23.8	$4.1	$35.3	$20.0	$297.5
Muscatine 9	$30.2	$7.1	$7.7	$4.7	$0.9	$6.1	$20.0	$76.6
Earl Wisdom 1	n/a	$184.5	$56.5	$36.6	$8.4	$0.0	$20.0	$389.3
Fair Station 1	n/a	$52.7	$14.2	$8.0	$3.0	$16.3	$20.0	$163.3
Fair Station 2	n/a	$49.7	$13.8	$9.4	$2.5	$13.2	$20.0	$158.5
Pella 5	n/a	$119.3	$33.0	$15.1	$0.0	$0.0	$20.0	$225.7
Pella 6	n/a	$116.5	$34.5	$19.2	$5.7	$0.0	$20.0	$238.9

As expected, larger units with high capacity factors enjoy the impact of economies of scale. The last few charts are the beginning of an analysis showing how a retrofitted coal plant compares to alternative generating options. Very few of Iowa's coal-fired plants can compete with world-class wind resources and less polluting natural gas. The compliance plans provided by IPL and MidAm must reconcile the cost of retrofits with the cost of alternative resources.

5. **Along with the strategies, the utility is to provide a list of possible scenarios that address possible levels of key variables such as gas price, coal price, carbon emissions prices, economic growth, construction cost changes, interest rate, speed of EPA rule implementation, economic efficiency implementation, and the use of demand response. The source of**

the various variable values should be described – e.g., low, medium, and high gas prices from EIA's 2011 Annual Energy Outlook.

MidAm Response: MidAm considered the following five sensitivity scenarios to test the robustness of its strategies:

1. High natural gas prices. This scenario was chosen to observe the impact of a general trend toward the addition of gas-fired generation, which would cause gas prices to increase significantly. The natural gas price baseline was increased by 50 percent uniformly throughout the forecast period. The percentage increase was determined by reviewing EIA's 2011 Annual Energy Outlook (AEO) and other proprietary forecasts to determine a reasonable high gas price scenario.

2. High carbon prices from GHG regulation implementation beginning in 2018. Development of a GHG policy remains one of the most significant uncertainties facing fossil-fueled generation on several levels including timing, magnitude, escalation, and implementation policy. Strategy 1 (BAU) reflects the implementation of a $16/ton carbon tax in 2021 escalated thereafter at a real rate of 3 percent annually. In the High Carbon Price scenario, the timing of the carbon tax is advanced to 2018 and the magnitude of the tax increased to $30/ton escalated at a real rate of 3 percent annually. The GHG policy is assumed to be implemented in the form of a carbon tax rather than a carbon cap-and-trade approach for simplicity. The scenario was developed based on the current political climate, assumptions used in EIA's 2011 AEO, prior carbon proposals analyses, and other third-party proprietary forecasts.

3. No load growth through the 10-year period. This scenario was evaluated to determine the impact the lack of load growth would have on the BAU and CCCT strategies along with the lower construction cost scenario below. The load forecast in the BAU and CCCT strategy base cases represent 1.1 percent equivalent annual system peak load growth over the 10-year study period.

4. Delayed implementation of Hazardous Air Pollutants Maximum Achievable Control Technology (HAPs MACT). The impact on the BAU strategy for a delay in implementation of EIA's HAPs MACT is difficult to assess. A significant issue is the response of other regional and/or national utilities and merchant generators and the impacts of their responses on market prices. MidAm's BAU strategy allows for flexibility in the event of a delay—emission controls have been installed at Louisa and Walter Scott Units 3 and 4, and Neal Units 3 and 4 are scheduled for emission control additions in the 2013 to 2014 timeframe. Decisions on the remaining units can be made once more information is available about emission regulation implementation.

5. Lower construction cost for the CCCT. A 10 percent decrease in construction costs of the CCCT strategy was evaluated to identify the sensitivity of construction costs on the strategy. The results can be used to extrapolate the impacts of alternative percentage cost reductions (e.g., a 20 percent reduction in construction costs would

yield approximately twice the incremental change associated with the 10 percent change.)

IPL Response: IPL considered the nine scenarios listed below to address possible levels of key input variables. Scenarios 2 to 9 are all separate changes to the base set of inputs used in the first scenario and described in IPL's 2010 IRP. IPL filed the base set of inputs as Confidential Attachment A.

1. A base set of inputs tied to IPL's 2010 IRP
2. +10 percent change in coal fuel prices
3. -10 percent change in coal fuel prices
4. +10 percent change in natural gas fuel prices
5. -10 percent change in natural gas fuel prices
6. -30 percent change in natural gas fuel prices
7. High load forecast
8. Low load forecast
9. Wood Mackenzie CO_2 prices with adjustments in energy prices and emission costs

Ames Response: No specific response.

Cedar Falls Response: Cedar Falls anticipates large variability in future natural gas prices, allowances, and the resulting MISO market energy prices. Cedar Falls has diverse resources and fuel mix. Further, Cedar Falls has no specific data to add to the forecasts and speculation commonly available in the industry.

Sierra Response: The Board should require MidAm to provide more information about its assumption of a delayed HAPS MACT scenario, support for the high gas price scenario, and its failure to include a high-coal cost scenario.

6. The projected results in each of the ten years (2012 to 2021) for each of the scenarios for each of the strategies. The results should include electricity demand by residential, commercial and industrial classes, including use per customer and number of customers data; sales for resale by customer and/or market; supply mix by MW and MWh (with projected prices); NO_X, SO_X, CO_2, and mercury emissions; capital cost recovery and O&M expenditures; total rate impact and impact per kW and kWh on each customer class; impact on existing company work force, new construction work force and new operation workforce; decommissioning and waste disposal and/or storage costs, as applicable, for nuclear facilities; and capital and operating expenditures to meet the various new EPA regulations. Net present values of the ten-year stream of payments projected to be paid by the utility's customers for each strategy under each of the scenarios considered are to also be calculated.

MidAm Response: MidAm provided data for the strategies as described below that was available from the analysis.

A. **Electricity demand by residential, commercial and industrial classes, including use per customer and number of customers data, sales for resale by customer and/or market.**

   MidAm's sales are projected to grow at 1.24 percent and the peak demand at 1.11 percent. Estimated energy efficiency and demand response levels are built into the forecasts.

B. **Supply mix by MW and MWh (with projected prices).**

   See Attachment 4 to this memo which reproduces Attachment 6.1 from MidAm's filing. It includes the supply mix by capacity and energy for the various scenarios. Prices are not included as they are not available from the analysis.

C. **NO_X, SO_X, CO_2, and mercury emissions.**

   See Attachment 5 to this memo which reproduces the data provided in Attachment 6.2 from MidAm's filing. It provides NO_X, SO_X, CO_2, and mercury emissions for each strategy.

D. **Capital cost recovery and O&M expenditures.**

   The table below provides a revenue requirement comparison for scenarios and sensitivities to the BAU case on a 10-year present value basis.

Case	$ Million
BAU with No Growth	$(358)
BAU with High Gas	$32
BAU with High Carbon	$894
CCCT Case	$36
CCCT with No Growth	$(322)
CCCT with High Gas	$143
CCCT with High Carbon	$890
CCCT with Lower Const. Costs	$10

E. **Total rate impact and impact per kW and kWh on each customer class.**

   No specific response.

F. Impact on existing company work force, new construction work force and new operation workforce.

MidAm has not calculated nor determined impacts for this category for any of the scenarios.

G. Decommissioning and waste disposal and/or storage costs, as applicable, for nuclear facilities.

No specific response.

H. Capital and operating expenditures to meet the various new EPA regulations.

No specific response.

I. Net present values of the ten-year stream of payments projected to be paid by the utility's customers for each strategy under each of the scenarios considered are to also be calculated.

No specific response.

IPL Response: Rather than create new models for this response, IPL used output from past (2010 IRP) models that were readily available. These modeling systems are not designed to estimate class rate impacts over a long period of time. IPL discussed this with Board staff and was instructed to make its best effort to provide what information was possible within the time allowed—which IPL did. Using its EGEAS model, IPL analyses were performed for 27 cases – three strategies (a/k/a plans) across nine scenarios (a/k/a futures).

A. Electricity demand by residential, commercial and industrial classes, including use per customer and number of customers data, sales for resale by customer and/or market.

IPL's **<u>CONFIDENTIAL</u>** Attachment B (reproduced below) shows the energy forecast, by class, the number of customers, and use by customers for the three primary classes for the period ending 2026. The attachment also shows the system peak forecast, but IPL does not make such forecasts by customer class. These forecasts are used for the purposes of this response only and are subject to change for other applications.

[redacted]

[redacted]

[redacted]

[redacted]

B. Supply mix by MW and MWh (with projected prices).

See Attachment 6 to this memo which reproduces IPL's **<u>CONFIDENTIAL</u>** Attachment C. It summarizes the energy supply mix, by resource category, for each of the strategies through 2024. IPL does not have immediate access to the related capacity percentages but could acquire that information if necessary. Additionally, the Expansion Plan Summary in the table provided in response to Item I below shows the type and number of units being added under IPL's three strategies.

C. NO_X, SO_X, CO_2, and mercury emissions.

See Attachment 7 to this memo which reproduces IPL's **CONFIDENTIAL** Attachment D. It summarizes the emissions data under each strategy, through 2024. Key findings from Confidential Attachment D include:

1. Strategy 3 SO_2 and NO_X emissions are significantly lower than Strategy 1 and Strategy 2 because after the Tier 1 units are controlled, the bulk of the remaining SO_2 and NO_X emissions come from the Tier 2 units which are retired in Strategy 3;

2. CO_2 emissions do not change significantly between Strategy 1 and Strategy 2; and

3. Strategy 3 has lower CO_2 emissions after 2014 by approximately 20 percent.

D. Capital cost recovery and O&M expenditures.

See IPL's response to Section 4 for estimates of the anticipated capital additions specifically related to environmental compliance equipment at coal-fired generating plants above and beyond the equipment already included in IPL's 2010 IRP (essentially Strategy 1 - BAU). Over the study period, IPL estimates that the total of the incremental fixed and variable O&M expenditures for Scenario 2 would be approximately $120 million and $35 million for Scenario 3. Other costs which could be significant, such as changes in purchased power contracts, new gas plants or decommissioning costs, are not reflected in these estimates.

E. Total rate impact and impact per kW and kWh on each customer class.

IPL was not able to calculate a specific total rate or per kW and kWh impact for each customer class due to limitations of its EGEAS analysis.

F. Impact on existing company work force, new construction work force and new operation workforce.

IPL has not done any analysis on new construction or on-going workforce calculations but could do so if it is deemed critical.

G. Decommissioning and waste disposal and/or storage costs, as applicable, for nuclear facilities.

This does not apply to IPL as it is not an owner of any nuclear units. There will be potential decommissioning costs for coal-fired units, but estimates of these costs are not available at this time.

H. Capital and operating expenditures to meet the various new EPA regulations.

No specific response.

I. Net present values of the ten-year stream of payments projected to be paid by the utility's customers for each strategy under each of the scenarios considered are to also be calculated.

Present value revenue requirements were calculated for each of the three strategies based on the EGEAS 2010 to 2025 study period with a 35-year extension to capture end effects.

Strategy 1 - $13 billion to $20 billion
Strategy 2 - $13 billion to $21 billion
Strategy 3 - $14 billion to $21 billion

Expansion Plan total quantities are shown in the table below. Note that nearly all cases optimally select 1 or 2 baseload coal or intermediate gas combined cycle alternatives, and there are several peaking units and several one-year peak power capacity purchases selected. IPL has not attempted to prevent the models from selecting coal, and the information in the table lists several new coal-fired generating units being selected as options. IPL understands the political and environmental regulation barriers which may preclude the installation of new coal-fired generation. However, IPL's Strategic Plan, which is focused on competitive costs, reliability, and balanced generation, does not include new coal-fired generation. Therefore, the table below should not be interpreted as indicative of the type of new generation for specific units but rather that new capacity and energy resources will be required—the specific units to be added are subject to further analysis and decision making.

The Expansion Plan in the table below is based on the assumptions in IPL's 2010 IRP including fuel prices. Any future evaluation of generation additions would include current assumptions which may result in different generating unit selections.

Expansion Plan Summary

(Number of units selected during plan period)

Scenario	Strategy	50 MW 1 Yr Peak Power Purchase	CT189	CC579	CC300J	PC300J	Wind100
Base	Business as Usual	16	2	0	0	1	5
	Tier 1 Incremental and Tier 2 Controlled	14	2	0	0	1	5
	Tier 1 Incremental and Tier 2 Retired	22	4	0	1	1	9
Coal +10%	Business as Usual	19	3	0	0	0	12
	Tier 1 Incremental and Tier 2 Controlled	17	3	0	0	0	10
	Tier 1 Incremental and Tier 2 Retired	11	3	0	2	0	14
Coal -10%	Business as Usual	16	2	0	0	1	5
	Tier 1 Incremental and Tier 2 Controlled	14	2	0	0	1	5
	Tier 1 Incremental and Tier 2 Retired	23	4	0	0	2	6
Gas +10%	Business as Usual	19	2	0	0	1	7
	Tier 1 Incremental and Tier 2 Controlled	14	2	0	0	1	7
	Tier 1 Incremental and Tier 2 Retired	14	3	0	0	2	8
Gas -10%	Business as Usual	14	2	0	1	0	3
	Tier 1 Incremental and Tier 2 Controlled	11	2	0	1	0	3
	Tier 1 Incremental and Tier 2 Retired	14	3	0	2	0	8
Gas -30%	Business as Usual	19	2	0	1	0	0
	Tier 1 Incremental and Tier 2 Controlled	11	2	0	1	0	1
	Tier 1 Incremental and Tier 2 Retired	14	4	0	2	0	0
High Load Forecast	Business as Usual	14	2	0	1	0	8
	Tier 1 Incremental and Tier 2 Controlled	19	3	0	0	1	6
	Tier 1 Incremental and Tier 2 Retired	21	4	0	1	1	10
Low Load Forecast	Business as Usual	21	3	0	0	0	8
	Tier 1 Incremental and Tier 2 Controlled	22	3	0	0	0	8
	Tier 1 Incremental and Tier 2 Retired	14	3	0	1	1	7
Wood Mackenzie CO2	Business as Usual	13	1	0	1	0	28
	Tier 1 Incremental and Tier 2 Controlled	12	1	0	1	0	28
	Tier 1 Incremental and Tier 2 Retired	19	1	1	1	0	28

Ames Response: Ames provided the information below for Option Number Two in Questions 3 and 4 above.

Demand	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
MW	126.6	127.5	128.5	129.4	130.4	131.4	132.4	133.3	133.9	133.9
Res.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Com.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Ind.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Energy	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
GWh	583.0	582.5	582.0	581.4	580.9	580.4	579.9	579.4	578.9	578.4
Res	166.6	166.4	166.3	166.1	166.0	165.8	165.7	165.5	165.4	165.2
S. Com.	51.7	51.6	51.6	51.5	51.5	51.4	51.4	51.3	51.3	51.3
L. Com.	229.9	229.7	229.5	229.3	229.1	228.9	228.7	228.5	228.3	228.1
Ind.	133.9	133.8	133.7	133.6	133.4	133.3	133.2	133.1	133.0	132.9

No of Customers

Res.	21,651
S. Com.	2,404
L. Com.	424
Ind.	4

Sales for Resale	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Mix – MW

Coal	96.3
RDF	8.2
Fuel Oil	40.5
Total	145.0

Mix – GWh

Coal	298
RDF	26
Fuel Oil	2
P. Pwr.	257

Price	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Coal $/ton	60.60	63.63	66.81	70.15	70.15	70.15	70.15	70.15	70.15	70.15
RDF $/ton	24.38	25.60	26.88	28.22	28.22	28.22	28.22	28.22	28.22	28.22
Fuel Oil $/gal	3.22	3.38	3.55	3.73	3.91	4.11	4.32	4.53	4.76	5.00
P. Power $/MWh	32.00	33.60	35.28	37.04	38.90	40.84	42.88	45.03	47.28	49.64

Emissions	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
SO_X tons/yr	802	936	1069	1069	1069	1069	1069	1069	1069	1069
NO_X tons/yr	830	484	554	554	554	554	554	554	554	554
CO_2 mmtons/yr	0.443	0.516	0.590	0.590	0.590	0.590	0.590	0.590	0.590	0.590
HG tons/yr	0.054	0.063	0.072	0.072	0.072	0.036	0.007	0.007	0.007	0.007

Cap. Cost Rec	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

O&M Costs	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
$ million	7.5	7.6	7.7	7.8	7.9	8.4	8.6	8.7	8.8	8.9

Rate Impact	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2011=Base	B+2%	B+16%	B+18%	B=21%	B+26%	B+30%	B+30%	B+30%	B+30%	B+30%

Workforce	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Total Utility	0	0	0	0	+3=3	+3=6	+1-7	7	7	7
New C.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
New Op.	0	0	0	0	+2=2	+2=4	4	4	4	4

Nuclear	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

$ Because of EPA	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Capital $ million	1	7	10	20	28	20	0	0	0	0
O & M $ million	0.1	0.2	0.2	0.4	0.4	0.9	1.1	1.1	1.1	1.1

Cedar Falls Response: Cedar Falls anticipates large variability in future natural gas prices, allowances, and the resulting MISO market energy prices. Cedar Falls has diverse resources and fuel mix. Further, Cedar Falls has no specific data to add to the forecasts and speculation commonly available in the industry.

Sierra Response: Sierra encourages IPL to select Scenario 3 and to also increase its investment in clean energy before committing to other generating resources while also working to reduce electric demand. In any future rate case, the Board should require a showing that Iowa utilities are achieving as much reduced demand as possible through energy efficiency and demand-side management programs. The Board should also take the no or low growth scenarios into consideration as part of any rate case that asks ratepayers to pay for expensive coal-plant upgrades that might lead to excess capacity.

7. Generally, discuss how the alternative strategies would meet the current and future emission reduction requirements of the federal Clean Air Act and other federal environmental legislation and of the applicable Iowa environmental statutes.

MidAm Response: MidAm focused on the two key air regulations that could have a material impact on coal-fueled generation nationally—CSAPR and the MATS rule. MidAm believes that compliance with these regulations will reduce emissions to such a level that it will not likely be significantly affected by other pending regulations.

MidAm identified Strategies 1 (BAU) and 2 (CCCT) as its primary scenarios. Based on its experience with the performance of the emission controls expected to be placed on the coal-fueled units under those scenarios and the planned modifications each unit's projected emission rates in 2015 are all below the requisite levels for MATS compliance, the SO_2 emissions levels will be below the allowance allocation level for compliance with CSAPR, and NO_X emissions are also expected to remain below allocated emission levels prior to 2017 in the BAU case.

<u>Compliance with CSAPR</u>. By 2015 MidAm's projected SO_2 emissions in all cases are expected to be approximately 10,000 tons per year or less and for nearly all scenarios NO_X emissions are expected to be below allocated emission levels. Where the NO_X emissions exceed the allowances, they fall within 6 percent which is well within the required assurance level of the rule. To address this, MidAm will investigate either additional reductions or allowances—whichever is more cost effective at the time. MidAm's share of allowances will be as follows:

	2012	**2014**
SO_2 Allowances	56,550	39,541
NO_X Allowances	19,794	19,345

<u>Compliance with MATS Rule</u>. Each unit must be controlled to meet certain emission levels or cease operation by the compliance deadline. With the controls under the two primary scenarios, MidAm expects the projected emission rates (which are set out on

page 3 of its response to Question 7) to fall below the January 2015 emission limits which are:

SO_2	0.20 lb/mmBtu
PM	0.03 lb/mmBtu
HG	1.00 lb/mmBtu

IPL Response: IPL discusses compliance expectations for each of the three strategies below.

Strategy 1. IPL would not be able to meet all existing or anticipated environmental compliance requirements discussed in response to Question 2 above. Tier 2 units would not be able to comply with unit-specific emission limits, particularly the Utility MATS requirements. However, compliance with Utility MATS is anticipated beginning as early as 2015. Additionally, the lack of investment in environmental controls and compliance may result in the failure of both Tier 1 and Tier 2 units to meet:

1. Additional air quality program requirements, such as CAVR or NAAQS, which might require unit-specific emission limits;
2. Wastewater discharge and water intake requirements; and
3. Solid waste and wastewater requirements associated with coal ash generation and management.

Compliance may only be achievable for the CSAPR if emission controls are installed at Tier 1 units to provide sufficient SO_2 and NO_X emission reductions. IPL would need to acquire SO_2 allowances in 2012, 2013, and 2014 to meet Phase 1 CSAPR requirements. The lowering of SO_2 allocations under CSAPR Phase II would also require SO_2 allowance purchases under Strategy 1 in order for Tier 2 units to continue to operate.

Strategy 2. Under Strategy 2, IPL would make investments in Tier 1 and Tier 2 units to comply with existing and anticipated environmental compliance requirements. Applicable controls would be in place to meet air pollution requirements, coal ash ponds would be closed, and ash handling equipment improvements would be in place, thereby eliminating any discharge from ash ponds and cooling water intake structure improvements would be completed to prevent impact to aquatic life. Concerning compliance with CSAPR, IPL would have sufficient NO_X allocations for compliance, and from 2015 forward, IPL would have sufficient SO_2 allowances for compliance. Prior to 2015, IPL would need to acquire the following SO_2 allowances:

Year	**Tons**
2012	2,000
2013	1,000
2014	6,500
2015 Forward	0

Strategy 3. Under Strategy 3, IPL would generally be able to comply with existing or anticipated environmental compliance requirements. Applicable controls would be in place to meet air pollution requirements, coal ash ponds would be closed; and ash handling equipment improvements would be in place, thereby eliminating any discharge from ash ponds, and cooling water intake structure improvements would be completed to prevent impact to aquatic life. The response to Question 6 shows that there are several future scenarios where IPL would need to acquire a relatively small number of NO_X allocations after retired unit allocations have been lost. For the period 2015 forward, IPL would have sufficient SO_2 allowances to comply with CSAPR but would need to acquire the following SO_2 allowances prior to that:

Year	**Tons**
2012	4,100
2013	3,200
2014	8,800
2015 Forward	0

Ames Response: See response to Question 3.

Cedar Falls Response: Cedar Falls has no specific data to supply.

Sierra Response: The strategies do not articulate the control options necessary to comply with RCRA and CWA requirements and also fail to fully identify how the one-hour SO_2 ambient standards will impact individual plants. In this docket the Board should require compliance plans for all of these rules.

8. The impact of possible coal plant retirements on transmission reliability and system operations, the transmission constraints that currently exist and that could develop on the utility's system, how the utility currently manages them, and how it proposes to manage them.

MidAm Response: Each scenario of coal plant retirements would need to be modeled and evaluated to determine transmission constraints and their impacts. Such detailed studies have not been completed. MidAm has completed preliminary review of system impacts associated with the retirement of several MidAm units which may result in the following potential transmission upgrades:

Riverside Unit	$25 to $30 million
Walter Scott Units 1 and 2	$5 to $15 million
Neal Units 1 and 2	$5 to $10 million

Any coal plant closure or conversion may adversely impact the transmission system reliability and operation. The impact size depends on plant size and location. Currently MidAm has identified the following twelve transmission constraints that are managed by MISO:

1.	Reasnor – DPS	161 kV
2.	Montezuma – Bondurant	345 kV
3.	Hills – Parnell	161 kV
4.	Sub 92 – Hills	345 kV
5.	Quad – Sub	91 kV
6.	Cordova – Sub 39	345 kV
7.	Plymouth – Sioux City	161 kV
8.	Bondurant – Sycamore	345 kV
9.	Sub 39 345	161 kV transformer
10.	Sub Bunge – Hastings	161 kV
11.	Webster 345	161 kV transformer
12.	Oak Grove to Galesburg	161 kV

These constraints are managed by MISO staff through security constrained economic dispatch and energy market and ancillary service rules. On a long-term basis, new transmission and new generation can provide solutions to transmission constraints and reliability.

IPL Response: The overall planning of the electric system effects how and why coal plant retirements will impact the transmission system. Generating and transmission plant design and locations generally complement each other and both generation and transmission were originally planned and designed together in a single package. Generation siting anticipated system reliability needs, and transmission anticipated ability to deliver generation to load. In some ways, transmission depends on existing generation.

IPL's generation fleet is generally located near its large load centers. In urban areas, nearby generation supports requisite voltage during outages on the transmission system and of other neighboring generation resources. Local generation reduces loading on large regional lines and also reduces requirements for larger scale lines with large import capability into a load center. The transmission system that serves IPL's load was not designed to import or export large amounts of power from generating resources remote to its service territory.

A summary of probable local transmission system issues by power plant is provided below. These do not provide an absolute answer. Any proposed plant retirements must go through the MISO Attachment Y process. The issues caused by multiple retirements would most likely impact the larger regional transmission system. These issues were not considered in IPL's analysis. Both local and regional impacts would ultimately be vetted through MISO Attachment Y study process. Most transmission issues that are caused by retirements are because the transmission was planned assuming that existing resources will operate indefinitely. Many issues that arise are pre-existing system limits. Issues created by generation outages can be fixed short-term by the use of transmission guides. IPL's existing generation provides operational flexibility for planning transmission outages.

Burlington Generating Station (BGS): The retirement of BGS could cause several local transmission system issues. The main issue (low voltages in southern Iowa) is expected to happen during an outage at Ottumwa Generating Station (OGS). This is a new issue, as the system was not planned or operated with both OGS and BGS off line at the same time. The long-term solution to low voltages in southern Iowa is the proposed MISO Multi Value Project (MVP) that connects OGS substation to Palmyra substation via a 345kV line. Before this project is expected to be in service in 2018, additional investment will need to be made in the transmission system if BGS is retired. BGS retirement would result in additional line overloads that will need to be resolved. Some lines may require re-building with a larger conductor size.

Kapp Unit 2 (Kapp 2): Retirement of Kapp 2 causes several line overloads in the Clinton area. Some overloads do occur with Kapp 2 in service but would be much more severe with Kapp 2's retirement. Because Kapp 2 is in close proximity to large industrial load, this avoids a portion of potential overloads. Again several overloads can be avoided by increasing or removing terminal limits while others may need line rebuilds. There would be no major voltage issues due to the retirement of Kapp 2. With Quad Cities Nuclear plant close by, the 345kV Clinton-Quad Cities line, and the new 345kV line scheduled to connect Salem to Hazelton, the voltage support for the Clinton area remains adequate.

Prairie Creek Units 3 and 4: The retirement of the Prairie Creek Units would not cause any major issues (either voltage or line overloading) with the planned Cedar Rapids transmission projects in-service dates tentatively set for the end of 2014.

Sutherland Generating Station Unit 3 (SGS 3): The retirement of SGS 3 does not cause any significant voltage or line overloading issues. Most issues can be mitigated by running the existing Sutherland combustion turbines to provide transmission system support. Reasons why retiring SGS 3 would not cause significant issues include the fact that SGS 3 is a smaller unit and does not provide as much system support as larger units and much of the 115kV system at Sutherland is in the process of being re-built and converted to 161kV which provides better system support.

AGP Response: AGP did not directly respond to the Board's Question 8 on transmission issues but provided the following comments on system reliability issues. Some experts believe that EPA actions could put reliability of the nation's electric system at risk by shutting down 5 percent of generation capacity in the U.S. and thousands of jobs may be lost. The question needs to be asked, "Does the EPA or any other federal agency have a feasible plan to replace base load capacity that will be lost?"

MPW Response: MPW operates as a local balancing authority and is a MISO member. The NERC, the FERC, and MISO are studying the impact of changing environmental regulations on reliability and regional power supplies. These studies have gaps in the analysis and results. For example, due to timing issues, the MISO study only considered a draft of the Clean Air Transport Rule (CATR) rule. This draft was significantly revised to become CSAPR which could have considerably more influence on unit retirements than what is projected in the MISO study. MPW shares MISO's concerns regarding the timing of the regulations, scheduling of outages to install control technologies, and the cost/time needed to upgrade transmission in response to unit retirements.

MPW asserts that EPA's model is not designed to consider the cumulative impact of multiple regulations or potential for reduced returns from stacked regulations. The Board is urged to consider these weaknesses when utilizing EPA studies. Anecdotal information indicates that EPA has underestimated the number and timing of unit retirements. Because utility plant retirement information is not publicly available, it is difficult to quantify the impact of pending regulations on resource availability.

Ames Response: The current infrastructure connecting the City of Ames (Ames) to two utilities in central Iowa is constrained under certain circumstances. Ames interconnects with MidAm at 69 kV and with CIPCO at 161 kV. Ames is limited in the amount of power it can import to serve its customers. When Ames' generating plants (Units 7 and 8) are on partial or full outage, the city can import 53 to 71 MW based on ambient temperature at the time of the import. With historical summer peak loads of 128 MW, Ames cannot import all of its power needs when Ames owns generating units that are not operational.

Ames can reconfigure its transmission in two ways; both options present system reliability problems and risks for Ames and for the region. One option is to disconnect with the MidAm 69 kV line and import power over the single 161 kV interconnection subject to MISO limitations. With this option, an event that takes this line out would cause Ames to go black and create reliability concerns for MidAm and other providers between Ames and Des Moines. A second option is equally problematic. This option splits the Ames system into two—one-half to be served by MidAm's 69 kV line and the other half by the 161 kV CIPCO line. Again, any single event on either of these lines can cause half of Ames to go black. Due to local generation shortfalls, Ames has reconfigured its system 20 times as described. The events described above actually happened, on August 12, 2011, when one of the MidAm 69 kV lines tripped and half of Ames lost power.

Since January 2006, Ames has sought approval from the Board to build a new 161 kV line to interconnect Ames' electric system with a MidAm substation in Ankeny, Iowa. **Staff update**: Final order and franchises issued in September 2012.

If Ames' Units 7 and 8 are shut down as a result of the proposed EPA regulations, as the transmission system exists today, it is not capable of reliably supporting Ames' electric requirements. Also, on almost a daily basis Ames would need to choose between the two problematic configurations that most view as unacceptable—each option involves switching which is not risk-free.

Cedar Falls Response: Plant retirements as well as effects of CSAPR effectively placing seasonal hourly limits on the operation of peaking turbines (>25MW) may exacerbate the ability to mitigate transmission constraints. MISO will need to perform a detailed review of the compliance plans in the region.

Sierra Response: Numerous recent reports and articles suggest there will be little if any impact on reliability, any impacts are easily remedied, and retirement of older inefficient plants might lead to a more reliable system.[36] Planning is done in a dynamic way to evaluate the impact of taking units offline.

There are many distributed generation policies within the Board's authority that would result in a much more reliable electric grid than we have today. These include supplementing a distribution system's ability to supply sufficient power during periods of peak demand, providing ancillary services, and improving power quality. Policies that utilities can undertake to promote distributed generation include net metering and feed-in tariffs.

9. Details of the utility's transmission, production cost, and general cost model(s) so that the assumptions are supported and transparent, and the operation of the model to derive the various numerical outputs is easily understood.

MidAm Response: MidAm used the four models described below.

1. Integrated Planning Model (IPM). This model is used to evaluate the impact of various environmental policies enacted by the EPA, state requirements, or potential environmental policies. IPM models generation throughout the continental U.S., Canada, and northern Mexico. IPM optimizes the addition of various emission controls, fuel switching, plant closures, and plant additions to meet the desired requirements with minimized costs. The model also produces a forecast of emission allowance prices used in downstream models. MidAm used IPM to analyze the emission allowance prices under scenarios with high natural gas prices and high carbon prices. Model set-

[36] See Sierra December 16, 2011, filing - Exhibit 11.

up time varies from a number of hours to days and running the model takes about eight hours.

2. Market Power. This model is used to develop long-term, electric energy hourly spot market prices based on the operating cost of the marginal unit required to meet the load in each defined region considering constraints. MidAm defined a broad market region covering 75 percent of the Eastern Interconnect. A 30-year forecast typically requires 15 hours of run time.

3. PROMOD IV: This model conducts a detailed evaluation of the dispatch of MidAm's generation allowing MidAm to perform a multi-year study in detail for fuel analysis, financial planning, and resource planning. The model produces individual unit generation output, fuel costs, variable operation and maintenance costs, and emissions for each generating unit by performing hourly chronological dispatch of MidAm's generation. It requires about two hours of computer run time per case.

4. Economic Model: The Economic Model is based on an in-house spreadsheet program used to calculate revenue requirements based on output from the other three models described above. Scenario development requiring the full suite of models can require from 2 to 3 days for simple sensitivities to more than a couple of weeks where complex changes are required. Limits also exist with regard to vendor supplied inputs and operation due to the use of proprietary models and vendor licensing.

Assumptions. Vendors of the first three models listed above provide proprietary databases containing the necessary parameters to make a run of their respective software. MidAm modifies the data using its own fuel price forecasts, load forecasts, environmental assumptions, renewable portfolio assumptions, plant additions and retirements, new technologies parameters, and other miscellaneous inputs which are described below.

Fuel Price Forecasts. MidAm has its own fuel price forecasts for natural gas, coal, and petroleum products. The forecasts typically reflect forward prices for the initial years followed by a third party's proprietary forecast for the longer term.

Environmental Assumptions. MidAm reflected the EPA's proposed policies outlined in response to Question 2 in the coal plant closure analysis. Also, in the BAU strategy the carbon policy was assumed to commence in 2021 at $16/short ton, escalating at 3 percent in real terms annually. In the response to Question 5, a scenario was analyzed assuming the carbon policy was advanced to 2018 and that the tax was increased to $30/ton, escalating at 3 percent in real terms annually.

Coal Unit Retirements. In response to EPA policies, a number of coal plants may close, switch fuels, or alter operations. Because insufficient data exists to determine with precision the decisions that will be made by other generation owners, MidAm applied the following approach to determine retired coal capacity for generation external to MidAm. MidAm chose to close older, smaller coal-fired units without emission controls, and coal units with lives in excess of 60 years were also retired. The resulting coal capacity retired is shown for three scenarios.

Assumed Retired Capacity in Eastern Interconnect Modeled (MW)

	2016	**2021**
Business-as-Usual	39,300	66,700
High Natural Gas Prices	21,192	30,664
High Carbon	66,473	74,693

Emission Allowance Price Forecast. Emission allowance price forecasts were developed for SO_2 Group 1 and Group 2 states, annual NO_X and seasonal NO_X for the BAU strategy, the high gas price scenario, and the carbon scenario. The BAU emission allowance forecasts were based on the EPA estimates when the CSAPR were released. The BAU emission allowance price forecasts apply to the combined-cycle combustion turbine strategy and related scenarios other than the high gas price and high carbon scenarios.

Renewable Portfolio Standard Assumptions**.** MidAm reflected state renewable portfolio standards and goals in the market model in order to estimate the amount of renewable generation required based on each state's sales forecast. A federal renewable energy requirement was assumed to commence in 2017 with 75 percent of the annual target met with renewable resources and 25 percent met with energy efficiency. The target is based on a percentage of retail sales as outlined below:

2017	6.0% (4.50% renewable)
2018 to 2019	9.5% (7.12% renewable)
2020 to 2021	13.0% (9.75% renewable)

The renewable generation added in the Eastern Interconnect to meet both the state and federal standards is shown below:

	MW
Wind	77,649
Biomass	2,559
Solar	4,127
Total	**84,335**

Load Assumptions. Load assumptions were developed for MidAm and external regions. MidAm used its most recent internal system demand and sales forecast for its system and resource analysis. For the external regions, MidAm completed a high-level sales forecast for each of the 48 states in the continental U.S. This was used to determine the amount of renewable generation necessary by state to meet the individual state renewable portfolio standards and goals and an assumed federal energy standard. The national average sales growth rate for the period 2012 through 2021 is 1.32 percent and the average peak demand growth rate over the same period was forecast at 1.25 percent. MidAm's sales are projected to grow at 1.24 percent and the peak demand at 1.11 percent. Estimated energy efficiency and demand response levels are built into the forecasts. A scenario wherein the energy and peak demand were held constant throughout the 10-year period was also modeled. In that scenario, the outside world was assumed to continue along the BAU strategy path. An energy forecast was derived from the sales forecast by including losses. The energy forecast was consolidated into respective regions used by the environmental and market forecast models.

Transmission. Transmission transfer capabilities among the market regions are required for modeling market prices. Such information is not readily available due to differences in modeled region and area definitions and limited public access to information due to compliance with FERC Standards of Conduct. Transfer capabilities among the regions were estimated through research of public transmission documents, internal analysis, and anecdotal evidence of market prices. No changes to transfer capabilities were made during the 10-year period due to the uncertainty of transmission additions, added transmission capacity, and timing of the additions.

Capital Costs for a CCCT. This was developed based on proprietary cost information from the Electric Power Research Institute (EPRI).

IPL Response: The starting point for IPL's EGEAS analysis included in response to Question 6 is IPL's 2010 IRP, the "No DAEC"[37] scenario. The assumptions used are described and supported throughout IPL's 2010 IRP. For this docket, the changes to IPL's 2010 IRP are described in the strategies and scenarios in response to Questions 3 and 5, and the results are presented in response to Question No. 6. Major IRP/EGEAS input assumptions are highlighted in IPL's filing in its Confidential Attachment A.

Ames Response: No Response.

Cedar Falls Response: Cedar Falls has no specific data to supply.

10. In connection with any natural gas repowering or new gas generation alternatives, the utility's consideration of long-term gas supply contracts.

MidAm Response: If a CCCT is planned to be added to MidAm's generation portfolio, MidAm will consider contracting for firm natural gas transportation service. Since a CCCT plant would be a base load or intermediate generation plant, MidAm would plan to enter into a long-term natural gas transportation contract with one or more interstate pipeline companies. Based on a 662 MW CCCT, MidAm would contract for a combined maximum total of 132,000 Dth per day of firm transportation capacity (a CCCT's

[37] Duane Arnold Energy Center.

maximum natural gas requirement for a twenty-four hour period), and for balancing services to manage the CCCT's daily imbalance requirements. Based on current natural gas supply availability, MidAm would likely enter into long-term supply contracts but would continue to monitor supply availability and the impact of derivative regulations. MidAm's response to Question No. 4 lists the interstate pipelines that currently serve the state of Iowa.

IPL Response: Historically, long-term supply contracts at fixed prices were not uncommon. However, in the mid-1980s, trading arrangements became shorter-term and more flexible regarding pricing, terms, and conditions. The current view is that shale gas will help assure the U.S. has adequate gas supplies for the next several decades. Utilities and gas suppliers have both given more attention to the possibility of long-term gas supply contracting based on the presumption that the U.S. supplies will be ample for decades along with more stable and predictable prices. There are a number of potential benefits for a utility to enter into a long-term gas supply contract including:

1. Ensuring reliability over time at a reasonable price;
2. Avoiding the consequences of demand and supply shock that could drive up the spot price of gas;
3. Having the flexibility to vary the daily or seasonal take of gas;
4. Lowering transaction costs due to fewer transactions;
5. Mitigating of price risks;
6. Protecting against long-term price increases or supply constraints; and
7. Supporting infrastructure investment since long-term contracts can assure revenues to receive financing for new infrastructure investment.

There are also a number of potential costs involved in long-term gas supply contracting:

1. Negotiations;
2. Monitoring;
3. Time and money associated with contract renegotiations or renewals;
4. Counterparty risk—risk of financial stability associated with non-utility counterparties; and
5. Market changes making the terms and conditions of the contract undesirable during the life of the contract.

Although long-term contracts can reduce supply and price risks over time, they may not reflect the current prevailing economic value of natural gas under changed conditions if the contract is significantly different from the market price in which case one of the parties would likely have an incentive to either renegotiate or terminate the contract. IPL believes that the bottom line for regulators is whether long-term contracts are economical and provide a benefit to the utility and its customers. Such contracts can reduce risk in the form of a price guarantee that is either fixed or moves with the market. However, long-term commitments that are inflexible and rigid can pose a risk to the utilities and its customers by being out of the market.

IPL urges the Board to evaluate long-term contracts in the context of a portfolio that accounts for the special circumstances faced by each utility. Regulators should encourage utilities to strike a balance between risks and reliable service at the lowest possible costs.

Ames Response: In response to an inquiry, NNG indicated there is not sufficient pipeline capacity to repower the Ames' Units 7 and 8. The closest points to Ames, Iowa on NNG's system with sufficient capacity to power Units 7 and 8 are at Ogden, Iowa to the west and at Story City, Iowa to the north. Ogden is approximately 23 miles west and Story City is approximately 14 miles north of Ames.

Ames would have to pay for the pipeline extension from either of these two points to the power plant plus commit to a "reservation charge" for NNG to guarantee firm service in the quantity necessary to support Units 7 and 8. Ames could pay for the pipeline extension up front, or it could amortize the cost of the pipeline extension over an extended contract period (likely 10 years or more) plus the cost of gas.

The construction of a pipeline extension 14 or 23 miles in length would be very expensive and time consuming given the planning, engineering, permitting, acquiring of easements, specifying bidding and awarding of contracts, and finally, the construction required to complete the project. Unit 7 would require significant work to upgrade the unit so it is ready to burn natural gas as a fuel (it last burned natural gas in the early 1970s), and Unit 8 would have to be completely retrofitted to burn gas.

Cedar Falls Response: Cedar Falls has requested additional summer capacity on NNG in order to ensure access to existing capacity without the risk of complications of special assessments for new pipeline construction costs that might occur if there are numerous generation plant retirements in the Midwest Region.

11. Any advanced ratemaking principles or special rate recovery mechanisms contemplated such as construction work in progress, allowance for funds utilized during construction, and accelerated depreciation, which the company proposes, or the advanced rate making principles described in recent proposed legislation.

MidAm Response: MidAm's current generation plans involve adding environmental equipment where necessary and cost effective compared to plant closure and keeping future generation options open—with the main goal being a diversified approach to energy supply. MidAm cannot be specific with this response; however, when subsequent plans are known, they will be the subject of future contested case filings before the Board. Below is a non-inclusive list of ratemaking principles MidAm may select:

1. Return-on-equity;
2. Depreciation;
3. CWIP recovery;
4. Tracker mechanisms which may include recovery of capital;
5. Cost cap;
6. Cancellation Cost Recovery;
7. Revenue Sharing; and
8. Recovery of remaining investment for early plant closures due to environmental regulations.

IPL Response: In this response IPL will address costs related to existing coal-fired power plants and not new plants and other types of generation. Potential costs related to existing coal-fired power plants fall into the following general categories:

1. Capital costs related to environmental retrofits, including fuel source conversions, fuel-related chemicals needed to reduce emissions, and any resulting byproducts that may require disposal;
2. MISO-related costs for plants (that would otherwise be retired) to provide voltage support for the transmission system;
3. Plant retirements; and
4. Emission allowances—including allowances prudently purchased that changed in value due to subsequent changing environmental rules or market conditions.

IPL's response is based on the following context:

1. Utilities should be allowed timely recovery of prudently incurred costs, since such costs are being incurred for the benefit of customers or to meet environmental regulations or other mandates;
2. Utilities will need to spend additional dollars to comply with changing environmental requirements;
3. Current ratemaking structures are based on historical situations and may not fully reflect the changing requirements, either now or in the future; and
4. Such recovery of prudently incurred costs should be done as efficiently as possible.

IPL states that Iowa's current regulatory system provides a reasonable foundation to allow review and recovery of related costs and includes the following:

1. EPB filings provide a forum for stakeholders to review and approve plans related to retrofits and other activities;
2. The energy adjustment clause rules allow for allowance cost recovery and fuel related costs; and
3. Rate cases provide for interim rate relief associated with capital investments.

IPL discussed the following examples for improvement based on its unique situation and noted that it is not intended to be a complete list of all possible ratemaking changes that may develop in the future. IPL is likely to pursue the following in the near term:

1. Update the Iowa Administrative Code (IAC) to allow for allowance recovery related to CSAPR. The current rules, 199 IAC 20.1(3) and 199 IAC 20.9(2)"b," relate to Energy Adjustment Clause (EAC) collection of CAIR allowance costs. Since CSAPR is a replacement for CAIR, the rules need to be adjusted to reflect the new regulations.

2. Update the IAC to explicitly allow the recovery of chemical costs needed to reduce emissions. Capital investment is typically required to install emissions control equipment and certain chemicals must also be used in this equipment to cause emissions to be reduced. The costs for these chemicals are directly related to the fuel burned (not unlike the costs of transporting coal) and therefore should be reflected in the EAC.

Emissions allowances and chemicals may both be used to meet emissions targets. Determining which to use will largely be an economic decision with the goal to achieve the lowest costs for customers. Since emission allowances and chemical costs are complementary options, both should be recovered through the same mechanism, otherwise incentives may be created. Lastly, these costs may rise very drastically over time making it less feasible to set representative levels in a base rate case.

Other alternatives to the existing ratemaking systems could take several forms, including legislative action, alternative regulation plans, special rate riders, and other mechanisms. The desirability of these options will be dictated as the level and timing of costs become known. To the extent that the costs are significant, and/or temporary, alternatives to the current construct may have appeal. Such mechanisms may or may not be utility-specific. While IPL has proposals planned at this time, it will continue to monitor requirements, costs, and timing to assess whether additional ratemaking changes are warranted. IPL expects to work with stakeholders on such proposals should they arise.

Ames Response: Ames electric utility rate structure is fairly basic. Rates are set to produce the necessary revenue to offset expenses plus maintain a reserve fund targeted at $10,000,000. Ames would most likely rely on the issuance of bonds to raise monies for projects requiring large short-term cash flows.

Cedar Falls Response: Cedar Falls has no additional data to supply or to comment on in addition to what has been submitted.

Sierra Response: Predetermination of ratemaking principles allows utilities some level of certainty that their investment decision is sound and that the commission will allow recovery of the capital expenses. It also allows the Board and other stakeholders to participate in a major capital investment decision before the utility commits itself to one course of action.

Overall, Sierra recommends that the Board consider the following options:

1. Requiring the utilities to submit a more complete inventory of pollution that may lead to future regulatory liability, including but not limited to all air toxics, fine particulate matter, and wastewater and coal ash constituents and quantities.
2. Requiring a more complete description of compliance strategies with EPA's proposed CCR regulation, both under Subtitles D and C, and a more complete description of compliance strategies with case-by-case effluent requirements as well as EPA's anticipated update to the industry guidelines.
3. Requiring the utilities to submit the results of a modeling analysis pursuant to EPA's guidance on the one-hour SO_2 NAAQS as well as a discussion of compliance strategies.
4. Requiring the utilities to address how a change in the Ozone NAAQS as recommended by the Clean Air Scientific Advisory Committee (CASAC) would impact future compliance.
5. In addition to the "replace with nuclear" option, requiring the utilities to submit a "replace with clean energy" planning scenario as a strategy for compliance with EPA rules.
6. Opening a docket to investigate various regulatory options for the rate treatment of energy efficiency programs.
7. Requiring the utilities to submit a full forward-going cost analysis similar to the analysis submitted by Sierra under Question 4 with supporting documentation filed for public review.

Part 2 - Summary of Responses to Questions on RICE Standards From Board Order Issued November 8, 2011

As noted in the Board's November 8, 2011, order in this proceeding, in Subpart ZZZZ of Part 63 (National Emission Standards for Hazardous Air Pollutants for Source Categories, or NESHAP) of the EPA regulations, the EPA sets forth detailed regulations that address emissions emitted by diesel powered stationary RICE engines. Such engines are sometimes used by utilities to generate electricity on an intermittent or emergency basis. The regulations have been amended a number of times.
Staff Update: On January 14, 2013, the EPA finalized amendments to the NESHAP RICE standards.

The EPA applied emissions rules to larger engines in 2004. In 2008 the rules were applied to smaller engines installed after June 12, 2006, but EPA delayed implementation of standards for engines installed prior to that date. On December 18, 2008, the D.C. Court of Appeals determined that EPA's air toxics standards must address RICE emissions during all phases of operation including periods of startup, shutdown, and malfunction. EPA was required by a consent decree to complete the implementation of these rules and apply them to all existing engines by a set date. Concerns have been raised about the impact of the proposed rules on electrical utilities, especially concerning the proposed definition for emergency engines.

In an Executive Order issued April 4, 2011, Governor Branstad stated, among other things, that the NESHAP RICE standards might make it cost prohibitive for some utilities to operate emergency engines, which could jeopardize the security of the national power grid. The Governor ordered that the Iowa administrative rules implementing the RICE standard for emergency engines be rescinded.

In the November 8, 2011, order, the Board stated that it shares the Governor's concerns regarding the impact of these EPA regulations on the reliability of the grid and the cost of alternatives to RICE engines used for grid support. The order set out three questions concerning RICE engines which MidAm and IPL were required to respond to and municipal utilities and electric cooperatives owning generation subject to RICE standards were invited to respond. Those questions are listed below and followed by summaries of the parties' comments.

1. **Do you use RICE engines on your system. If so, what engines do you have and where are they? How many kW does each supply?**

2. **Would the projected use of those engines be significantly reduced by the EPA NESHAP regulations as recently amended? If so, describe, and quantify to the extent possible, the impact of those regulations on the use of your RICE engines in possible emergency situations that could occur in your service area.**

3. **What alternatives are available to you in lieu of operating your RICE engines? What is the capital and operating cost of these alternatives?**

MidAm Response: MidAm currently has 29 Caterpillar diesel -driven 2 MW portable power module generator sets, Caterpillar model 3516B, at various locations throughout the State of Iowa. MidAm's individual RICE units are listed below.

Location	Number of Rice Units	Fuel	Total Nameplate kW
Knoxville Power Station	8	Diesel	16,000
Shenandoah Power Station	10	Diesel	20,000
Waterloo/Lundquist Power Station	9	Diesel	18,000
Anderson Erickson Dairy Company	1	Diesel	2,000
Charles City, Iowa	1	Diesel	2,000
Total	**29**		**58,000**

MidAm does not project that the applicability of the EPA NESHAP for reciprocating internal combustion engines will significantly affect the use of these 29 portable power modules. MidAm is making provisions to install oxidation catalyst emission controls on the exhaust of each unit and will be in compliance with the recently amended EPA NESHAP regulations. The preliminary estimated cost to install diesel oxidation catalyst is $4.1 million.

MidAm has reviewed options to provide replacement power in lieu of operating its 29 reciprocating internal combustion generator sets totaling 58 MW. These options include installation of combustion turbines or use of transmission lines, which could transport electricity to replace that from the RICE engines. MidAm estimates that capital costs for the combustion turbine option could exceed $50 million. Operating costs for combustion turbines are under review. Plans to accommodate system changes for the transmission lines are also under review.

IPL Response: The RICE engines installed as part of IPL's system are compression ignition RICE with the capability to supply power to an electric grid. However, in 2010, the plant use of power from these engines exceeded the gross generation, resulting in negative net generation. In addition, historical annual operation of these RICE in the last five years for each engine has not exceeded 50 hours per year. IPL's individual RICE units are listed below.

Location	**Number of Rice Units**	**Fuel**	**Total Nameplate kW**
Centerville, Iowa	3	Oil	6,000
Dubuque, Iowa	2	Oil	4,000
Lansing, Iowa	2	Oil	2,000
Hills, Minnesota	2	Oil	4,000
Total	**9**		**16,000**

The projected use of IPL's above-listed engines is not expected to be significantly reduced by the EPA NESHAP RICE regulations due to the low number of hours of operation of these units.

The RICE listed in the table above could be limited in the number of hours allowed for non-emergency operation and also in the ability to supply power for demand response under the RICE NESHAP rule. However, energy supply from these RICE is not essential to assuring electric grid reliability during prolonged circumstances of power disruption. The cost impact of this alternative is deemed immaterial relative to other IPL capital and operational costs.

Board of Regents Response: The Board of Regents provided the following information concerning its RICE engines.

University of Iowa. The University of Iowa has 2 natural gas engine generators on the Oakdale campus that are affected by, and in compliance with, the RICE standards. In addition, the four 2 MW natural gas engines currently in design for the Main Power Plant will need to comply with the RICE standards.

Iowa State University. Iowa State University has many emergency diesel generators installed across the campus. These emergency generators only operate during a power outage or for testing and serve life-safety systems in campus buildings. Iowa State University does not use these emergency diesel generators for peak shaving or other power generation uses. As long as the generators are used only for emergency purposes, there are minimum requirements under the RICE standards.

University of Northern Iowa. The University of Northern Iowa uses 25 varying size RICE engines on its campus as emergency generators. The projected use of these engines would not be significantly reduced by the EPA NESHAP regulations, as recently amended. Although these engines are subject to RICE standards, there is little to do to be in compliance with the standard. There have been no alternatives identified to operating the RICE engines.

Deere Response: Currently Deere operates internal combustion engines that will be affected by the RICE regulations. Deere is evaluating methods of complying with this standard and does not expect to reduce electrical generating capacity in response to this regulation.

IAMU Response: The Iowa Association of Municipal Utilities (IAMU) is a non-profit trade association whose member communities operate electric, gas, and broadband utilities including 136 electric utilities. In Iowa, 68 municipal utilities operate a total of 283 RICE generators with a total nameplate capacity of 549.2 MW and serve approximately 106,000 customers.

The average run time for all IAMU member RICE units from 2005 through 2010 was 28.69 hours per year. Although these units provide behind-the-meter generation, operation would be limited to only 15 hours per year under the RICE NESHAP rules which is insufficient.

The EPA estimated the cost of retrofitting engines to be about $50 per kW. If the IAMU members' 283 engines (excluding the 2011 additions) could be retrofitted with catalytic converters, the one-time cost would be $27,460,000. However, IAMU's conservative 10-year cost estimate is closer to $36 million or $34 per customer per year. Not all engines can be retrofitted; some lack sufficient space around them to accommodate the conversion equipment, and others will not be retrofitted because of the risk of regulatory uncertainty.

Engines that are not retrofitted or designated as emergency units are subject to the 15 hours of authorized operation. The generating capacity of those units will not be counted toward the region's reliability reserve, and the municipality will lose the credits currently received from its power supplier. The credits currently range from market rates of about $27/kW/year to contractual rates of $42 to $48/kW/year. The utility will lose the credit and be required to pay for replacement capacity. One option for replacement capacity includes "renting" capacity at market rates estimated to go from $27/kW/year to over $100/kW/year within 7 years of the effective date of the rule. Another option would be to add peaking capacity which would cost about $80 to $100/kW/year for combustion turbines. In short, the cost of designating a 2 MW diesel generator to run for emergencies only would be about $1,100 to over $1,800 per kW over 10 years.

IAMU believes that time lines for compliance need to be extended to mitigate the impact on reliability and rates. In 2005 through 2010, RICE engines were used by municipals significantly during weather related emergencies when transmission was unavailable. RICE engines are also used to meet obligations to buy or meet reserve capacity obligations. The credit/payment for reserve capacity from power suppliers enables communities to afford and operate the engines. The proposed rules allow the utility to run the engine in an emergency but essentially take away the ability of small communities to afford them. MISO includes RICE units in its emergency demand response (EDR) program. This program requires that a RICE unit must be capable of operating for a minimum of 20 hours during the summer season. With the NESHAP RICE rules, operation would be limited to 15 hours per year. The 15-hour allowance is insufficient to operate in the MISO EDR program and would result in significant reduction in RICE use.

While the final RICE rules allow operation of RICE engines during emergencies, they do not allow operation to maintain grid and system reliability. Under the rules. "voltage support" does not constitute an emergency, yet many utilities use these engines to keep system voltage within acceptable limits. Municipals are interconnected to transmission owned by third parties. These parties anticipate that RICE units will be run in parallel to the grid for voltage support when the transmission has issues during peak load events. RICE operation mitigates low voltage situations which can be a precursor to outages. IAMU has requested that in reconsidering the allowable operation of RICE units, the definition of "emergency" be clarified to include situations encompassed by the NERC definitions of "Emergency" and "Energy Emergency," but broadened to fit the reality of a rural transmission network.

Many Iowa municipal utilities are connected to the grid at 34.5kV to 69kV lines – below the voltage considered as transmission by an RTO. When maintenance is required on the transmission system, the utilities RICE units must be synchronized and run to maintain electric service. Often utilities have secondary ties which may not be sufficient in size to carry load. For municipals connected to a radial system, during maintenance hours local RICE generation is the only means of providing service.

There are several examples available where RICE units have operated for voltage support, reliability, and to allow the safe and efficient maintenance or replacement of upstream facilities.

1. For voltage support, Algona operated its units in December 2009; Tipton operated its units many times during 1999 to 2004 (in 2001, Tipton units operated continuously for five straight days and operated for 109 days in 2010); Vinton operated its units multiple times in 2009; and New Hampton helped Corn Belt Power Cooperative (Corn Belt) maintain service during outages in 2010.

2. Units were also operated for local reliability. Engines at Rockford have been run to provide support to the transformer. This may be called an emergency situation (but the EPA rule is not clear on this issue). Operation of these engines in 2006 and 2007 avoided the replacement of a transformer at a cost in excess of $250,000. To allow more than 15 hours of EDR operations, Rockford could retrofit units. The annual compliance cost to Rockford's ratepayers would be $17.90 per customer per month. Since these units are run fewer than 30 hours in an average year, the retrofit costs are not justified.

3. RICE units are also operated to support safe repair of upstream facilities. Grundy Center operated its units that enabled Corn Belt to conduct maintenance on its radial line that serves Grundy Center. Corning, Tipton, and Vinton units also operated to provide support during maintenance outages.

4. RICE units provide support during severe weather events. Emergency operation in response to weather-related outages is allowed under current rules. If the units do not qualify as reserve capacity, small communities may not be able to afford these units. Traer, Milford, and Vinton have operated during weather-related emergencies.

NIMECA Response: NIMECA itself does not own or operate any RICE units, but 11 of the 13 NIMECA members do own and operate RICE units totaling nearly 81,000 kW of capacity. NIMECA provides a table listing the units, their location, and kW capacity on pages 1 to 2 of its December 1, 2011, filing.

The RICE units operated by the NIMECA members serve several functions. The primary purpose of the units is to provide emergency power to each of the communities in the event of an outage caused by the loss of the transmission line serving the community. This purpose would not be impacted by the NESHAP regulations as emergency operation under this scenario is permitted without modification to the units.

Another purpose is to provide capacity that can be used to meet capacity and reserve requirements of the NIMECA members. Under the amended rules, the NIMECA member RICE units would not be able to meet the requirements necessary to be counted for capacity and reserve requirements without modification. Modification would include the installation of catalyst units on each engine. The total estimated cost for the NIMECA members for installation of the catalyst units is approximately $5 million.

A third purpose is operation to prevent outages when maintenance is necessary on the transmission system. Under this maintenance scenario the retail utility customer has no interruption of service and likely is not even aware that this process is occurring. However, as the NESHAP rule is written, this scenario would no longer be allowed unless the engines are modified, because it does not meet the definition of emergency use until an actual outage has occurred.

A fourth purpose is grid support. NIMECA and its members have an agreement with Corn Belt for the joint operation of their respective transmission facilities. Corn Belt serves as the operator of the joint system under this agreement. If Corn Belt sees a transmission issue, such as a line overloading, Corn Belt may call on one or more NIMECA members to operate their RICE unit(s) to provide relief by changing the power flow on the system. This prevents the line from failing and causing an outage and/or Corn Belt having to disconnect customers to prevent a line failure. Under the amended rules, the NIMECA members would no longer be able to operate their units to provide relief unless the units are modified at the estimated $5 million cost.

A final purpose of the units is to provide a hedge against high market prices for energy. NIMECA and its members know the cost per kWh to operate the units. If market prices for energy exceed the price of operating the units, they can be turned on to reduce purchases or even make sales into the market. This purpose would no longer be allowed under the amended rules without installation of the catalyst system.

If the NIMECA members declare their RICE units as "emergency only," they can continue to operate without modification in emergency situations. If this option is chosen, the NIMECA members will have to purchase additional capacity from outside parties to meet capacity and reserve requirements. NIMECA members currently are able to sell excess capacity to third parties and that revenue would be lost. The cost of this option is estimated to be $3 million annually for the capacity related issues alone.

In lieu of that option, the NIMECA members that do not currently have a second tie to the transmission system could build a second connection to improve reliability and reduce the chance of a transmission related outage. The estimated cost of building those second ties is estimated to be over $6 million.

The installation of small natural gas turbines is a possibility for the NIMECA members. However, the size of the turbines would make this an impractical solution for most, if not all, NIMECA member communities so this option has not been explored to the point of determining a cost.

Sierra Response: Sierra believes it is important to know the types of horsepower of each RICE unit. Based on the size of the units, the EPA regulations may have little or no impact. The information as to the hours and purposes of use filed by the municipal utilities is inconsistent, and the Board cannot make an informed decision in this inquiry without accurate consistent information. The RICE rules have been in existence since 2008 so the utilities have had three years to plan for implementation of the rule and make the necessary changes to comply. Besides emergency backup, the purpose served by RICE engines by the municipals should be accomplished by a better transmission grid, supporting energy efficiency, and transitioning to renewable energy.

Sierra supports regulations requiring pollution controls on all RICE units used for non-emergency purposes and recommends the following:

1. The Board should wait until the EPA finalizes the rule and conduct a further inquiry at that time.
2. The costs of running RICE units without pollution controls should be balanced with the costs of the health affects to the people of Iowa.
3. If there is a need for reserve capacity, grid support, and voltage regulation, they should be met by improvements in the generation, transmission, and distribution systems.
4. Based on the comments of the municipal utilities highlighting the vulnerability of the electric grid with respect to the present generation and transmission facilities, the Board should open a separate inquiry to review the vulnerability of the grid as it is now configured.
5. The municipal utilities indicate that some of the RICE units cannot be retrofitted because they are too old or lack space to install pollution control equipment. This is an example of the utilities refusing to upgrade and being content to pollute the air.
6. The Board should encourage aggressive energy efficiency programs to reduce peak demand thus reducing reliance on RICE units.
7. Based on the inconsistent information provided by the municipal utilities, the Board should pursue a thorough and independent review of the nature and extent of the use of RICE engines by the municipal utilities.

Part 3 - Summary of Responses to Questions on Non-Utility Coal Plants From Board Order Issued November 8, 2011

As noted in the Board's November 8, 2011, order in this proceeding, data available to the Board indicates that there are nine non-utility coal plants in Iowa that will be subject to EPA's proposed Industrial, Commercial, and Institutional Boiler National Emissions Standards for Hazardous Air Pollutants. These plants may need to incur substantial costs to continue operating their coal facilities. If any of these facilities close, it could impact Iowa's utilities, because they might be required to furnish substantial amounts of power to commercial, industrial, and institutional facilities that previously supplied some of their own power. Also, as is true with the RICE rule, new regulations on these facilities could impact grid reliability, if any of those facilities have to be closed or their output reduced. The nine facilities along with the data provided in the order are:

Plant Name	DOE/EIA ORIS Plant Or Facility Code	Plant Nameplate Capacity MW	Plant Annual Net Generation MWh
Ag Processing, Inc.	10223.0	8.5	45,605.5
Archers Daniels Midland Cedar Rapids	10223.0	256.1	970,706.8
Archers Daniels Midland Clinton	10860.0	211.4	151,327.9
Archers Daniels Midland Des Moines	10861.0	7.9	26,173.0
Cargill Corn Milling Division	10855.0	40.0	77,540.4
Iowa State University	54201.0	46.0	156,571.0
John Deere Dubuque Works	54414.0	23.0	31,496.0
University of Iowa Main Power Plant	54775.0	22.7	53,130.1
University of Northern Iowa	50088.0	7.5	28,232.8

The November 8, 2011, order included two questions addressed to the nine entities inviting their response. The two questions are listed below and followed by summaries of the parties' comments.

1. **Is the table provided in the order accurate insofar as it contains data concerning your facilities? Please provide the nameplate capacity, annual net generation, and location of any coal-fired generation not listed above.**

2. **Do you intend to continue to operate the individual plant(s) listed above or newly described in your answer to Question No. 1 above, in light of the new and proposed EPA regulations? If not, assuming you have a continuing need for the electric power the plant produces, how will you seek to obtain electric power for your operations?**

Board of Regents Response: The Board of Regents provided the following data about the power plants it operates:

Plant Name	Plant or Facility Code	Nameplate MW	FY 2011 Net Generation MWh
University of Iowa Main Power Plant	54775.0	21.0	75,420
Iowa State University	54201.0	46.0	30,596
University of Northern Iowa	50088.0	7.5	22,871

The Regent universities hired Burns & McDonnell to complete a visioning process to establish an environmental strategy for the power plants located at each of the campuses. The report identified solutions and a range of costs required to ensure compliance with the proposed EPA emissions regulations. On December 2, 2011, the EPA issued revised rules. The following comments were provided prior to the issuance of the revised rules—the universities are assessing the implications of the revisions.

> University of Iowa: The University of Iowa intends to operate its coal-fired plants as required to meet its campus steam loads and will continue to cogenerate electric power, while complying with the proposed EPA regulations. In addition, the University of Iowa is implementing strategies to reduce its dependency on coal and increase the utilization of biomass to assist in the reduction of emissions from the power plant.
>
> Iowa State University: Iowa State University power plant has five boilers that are impacted by the proposed EPA rules. Iowa State University has not yet made a determination on a final compliance strategy for these rules. The most likely strategy would be to replace three of the boilers with natural gas boilers, while continuing to burn coal in the remaining two boilers. Iowa State University expects to increase the amount of purchased electricity, depending on production costs versus wholesale electricity costs. Iowa State University will continue to operate the plant and has no plans to reduce nameplate electrical generating capacity.
>
> University of Northern Iowa: The University of Northern Iowa intends to continue to operate its power plant. It is likely the University of Northern Iowa will retrofit its existing boilers with pollution control equipment to meet the MACT standards as required, at significant expense.

AGP Response: AGP confirmed the accuracy of the data related to its Eagle Grove facility. AGP stated that CHP facilities, such as the one owned by AGP in Eagle Grove, have many benefits. The Eagle Grove facility supplied electric power to the City of Eagle Grove during a winter ice storm several years ago. If such CHP facilities are shut down, utilities may have to seek replacement power from outside the area putting strain on the remaining resources. AGP supports building of additional CHP facilities, not necessarily coal-fired, to diversify generation to reduce the need to install additional expensive transmission lines. AGP is concerned about RTO and ISO rules that fail to recognize the operational differences between CHPs and merchant generators. If AGP facility's ability to burn coal becomes uneconomical, then the only option for AGP is to buy power from MidAm.

Deere Response: Dubuque's current nameplate capacity installed is approximately 9 MW of diesel-powered generation, and Deere has correspondingly modified its firm kW under IPL Rider INTSERV effective May 1, 2011. Energy (MWh) produced at John Deere Dubuque Works will likely be limited to interruptible or other limited use of the diesel generators. Deere boilers located at Dubuque, Iowa, and at East Moline, Illinois, may be affected by the industrial boiler MACT standards. These boilers operate both for facility and process steam needs as well as electric generation. The Dubuque plant has ceased use of coal-fired generation for several reasons including implications of the proposed MACT standards. Deere stated that it cannot be more specific about other impacts or plans for these facilities at this time and thus did not specifically comment on reliability issues. In its limited comments to EPA on the MACT rule, Deere proposed a staged implementation of industrial boilers to avoid direct competition with utilities on the same timeline for similar pollution control equipment.

Attachment 1

Filings in this Proceeding

Submitter	9-2-11 Board Order Questions	RICE Response	Industrial Boiler Response	Other Comments
Ag Processing Inc.			✓	
American Coalition for Clean Coal Electricity				✓
Board of Regents, State of Iowa		✓	✓	
Cedar Falls Municipal Utilities	✓			
City of Ames	✓			
Clean Air Muscatine				✓
Deere and Company			✓	
Interstate Power and Light Company	✓	✓		
Iowa Association of Municipal Utilities		✓		
Iowa Chapter of Physicians for Social Responsibility				✓
Iowa Department of Natural Resources				✓
Iowa Environmental Council				✓
Iowa Interfaith Power & Light				✓
MidAmerican Energy Company	✓	✓		
MISO				✓(2)
Muscatine Power and Water	✓			
North Iowa Municipal Electric Cooperative Association		✓		✓
Office of Consumer Advocate				✓(2)
Sierra Club Iowa Chapter				✓(3)

Note: Parenthetical numbers represent multiple filings.

Attachment 2

MidAm Coal-Fired Generating Units, Emission Control Technologies, and Emission Allocations under CSAPR.
Source: OCA December 22, 2011, **CONFIDENTIAL** filing, page 2.

Unit Name	Operation Date	Capacity (MW)	Existing Environmental Controls	Approved Environmental Controls	NO_X 2010 Emissions	NO_X 2012 CSAPR Allocation	NO_X 2014 CSAPR Allocation	SO_2 2010 Emissions	SO_2 2012 CSAPR Allocation	SO_2 2014 CSAPR Allocation
Neal North Unit 1	1964	140	Neural network, OFA, HESP		2,594	947	925	3,062	2,808	1,944
Neal North Unit 2	1972	294	Neural network, LNB, OFA, CESP		2,470	1,781	1,738	6,689	5,277	3,653
Neal North Unit 3	1975	522	Neural network, LNB, OFA, CESP	[redacted]	4,434	3,483	3,400	11,911	10,322	7,145
Neal South Unit 4	1979	645	Neural network, LNB, OFA, CESP	[redacted]	5,754	4,354	4,250	16,575	12,904	8,933
Walter Scott Unit 1	1954	38	LNB, HESP		607	396	386	1,346	1,173	812
Walter Scott Unit 2	1958	84	LNB, OFA, HESP		476	599	585	2,374	1,777	1,230
Walter Scott Unit 3	1978	710	Neural network, LNB, OFA, CESP, dry scrubber, baghouse		5,411	4,821	4,706	8,723	14,288	9,891
Walter Scott Unit 4	2007	811	Neural network, LNB, OFA, dry scrubber, baghouse, SCR, ACI		1,405	1,625	1,625	2,129	2,132	2,132
Louisa Unit 101	1983	750	Neural network, LNB, OFA, HESP, dry scrubber, baghouse		4,745	4,397	4,292	7,075	13,031	9,021
Riverside Unit 5	1961	133	Neural network, LNB, OFA, CESP		900	708	692	3,014	2,100	1,453

Attachment 3

IPL Coal-Fired Generating Units, Emission Control Technologies, and Emission Allocations under CSAPR.
Source: OCA December 22, 2011, filing, page 5.

Unit Name	Operation Date	Capacity (MW)	Existing Environmental Controls	Approved Environmental Controls	NO_X 2010 Emissions	NO_X 2012 CSAPR Allocation	NO_X 2014 CSAPR Allocation	SO_2 2010 Emissions	SO_2 2012 CSAPR Allocation	SO_2 2014 CSAPR Allocation
Burlington Unit 1	1968	212	CESP, flue gas conditioning, LNB,OFA, low sulfur coal		718	1,244	1,244	2,890	3,883	2,688
Dubuque Unit 6		13.8	CESP, low sulfur coal		24	36	25	11	12	12
Dubuque Unit 5		31.7	CESP, low sulfur coal		306	160	157	268	475	329
Dubuque Unit 1		37	CESP, low sulfur coal		489	203	199	504	603	417
Lansing Unit 3	1957	35.8	CESP		0	177	173	0	525	3,644
Lansing Unit 4	1977	270	HESP, flue gas conditioning, LNB, SCR, low sulfur coal, baghouse, ACI	Scrubber	1,611	1,561	1,524	4,729	4,627	3,203
Kapp Unit 2	1967	235.8	CESP, flue gas conditioning, LNB,OFA, low sulfur coal		540	997	973	3,462	2,955	2,045
Ottumwa Unit 1	1981	727	HESP, flue gas conditioning, LNB,OFA, low sulfur coal	Scrubber, baghouse, ACI	3,382	4,346	4,243	13,461	12,881	8,917
Prairie Creek Unit 1	1997	16	CESP, low sulfur coal		381			659		
Prairie Creek Unit 2	1951	23	CESP, low sulfur coal		428			539		
Prairie Creek Unit 3	1958	50	CESP, flue gas conditioning, OFA, low sulfur coal		631	321	313	1,132	950	658
Prairie Creek Unit 4	1967	149	CESP, flue gas conditioning, LNB, OFA, low sulfur coal		1,503	728	711	2,424	2,158	1,494
Sutherland Unit 1	1955	37.5	CESP, LNB, low sulfur coal		417	281	274	890	832	575
Sutherland Unit 3	1961	96	CESP,OFA, RRI/SNCR, low sulfur coal		826	558	545	4,285	1,655	1,146

Attachment 4

Page 1 of 3
Source: MidAm's Attachment 6.1.
Supply Mix by Capacity and Energy.

Base Case: Capacity

	2012		2016		2021	
Capacity Type	**MW**	**Percent**	**MW**	**Percent**	**MW**	**Percent**
Coal	3,420	48%	3,156	44%	3,156	44%
Nuclear	446	6%	446	6%	446	6%
Gas and Oil	1,348	19%	1,348	19%	1,348	19%
Wind	1,880	26 %	2,285	32%	2,285	32%
Total	**7,097**	**100 %**	**7,238**	**100%**	**7,238**	**100%**

Combined Cycle Build Case: Capacity

	2012		2016		2021	
Capacity Type	**MW**	**Percent**	**MW**	**Percent**	**MW**	**Percent**
Coal	3,420	48%	2,718	38%	2,718	37%
Nuclear	446	6%	446	6%	446	6%
Gas and Oil	1,348	19%	1,613	23%	1,891	26%
Wind	1,880	26%	2,285	32%	2,285	31%
Total	**7,097**	**100%**	**7,065**	**100%**	**7,346**	**100%**

Base Case: Generation

	2012		2016		2021	
Generation Type	**MWh**	**Percent**	**MWh**	**Percent**	**MWh**	**Percent**
Coal	20,498,853	67%	20,592,799	64%	21,433,643	61%
Nuclear	3,856,271	13%	3,899,125	12%	3,888,994	11%
Gas and Oil	428,935	1%	426,081	1%	2,445,456	7%
Wind	6,007,828	20%	7,289,628	23%	7,266,202	21%
Total	**30,791,888**	**100%**	**32,207,634**	**100%**	**35,034,296**	**100%**

Attachment 4, Page 2 of 3
Source: MidAm's Attachment 6.1.
Supply Mix by Capacity and Energy.

Base Case Zero Growth Scenario: Generation

	2012		2016		2021	
Generation Type	**MWh**	**Percent**	**MWh**	**Percent**	**MWh**	**Percent**
Coal	20,498,853	67%	20,592,799	64%	21,433,643	61%
Nuclear	3,856,271	13%	3,899,125	12%	3,888,994	11%
Gas and Oil	428,935	1%	426,081	1%	2,445,456	7%
Wind	6,007,828	20%	7,289,628	23%	7,266,202	21%
Total	**30,791,888**	**100%**	**32,207,634**	**100%**	**35,034,296**	**100%**

Base Case High Carbon Scenario: Generation

	2012		2016		2021	
Generation Type	**MWh**	**Percent**	**MWh**	**Percent**	**MWh**	**Percent**
Coal	20,524,824	67%	19,863,909	63%	21,998,643	62%
Nuclear	3,856,271	13%	3,902,575	12%	3,890,494	11%
Gas and Oil	402,964	1%	361,213	1%	2,088,092	6%
Wind	6,007,828	20%	7,289,628	23%	7,266,202	21%
Total	**30,791,888**	**100%**	**31,417,325**	**100%**	**35,243,431**	**100%**

Base Case High Gas Scenario: Generation

	2012		2016		2021	
Generation Type	**MWh**	**Percent**	**MWh**	**Percent**	**MWh**	**Percent**
Coal	20,524,824	67%	18,842,190	62%	21,250,957	65%
Nuclear	3,856,271	13%	3,902,575	13%	3,890,494	12%
Gas and Oil	402,964	1%	167,733	1%	352,571	1%
Wind	6,007,828	20%	7,289,628	24%	7,266,202	22%
Total	**30,791,888**	**100%**	**30,202,127**	**100%**	**32,760,225**	**100%**

Combined Cycle Build Case: Generation

	2012		2016		2021	
Generation Type	**MWh**	**Percent**	**MWh**	**Percent**	**MWh**	**Percent**
Coal	20,524,824	67%	17,732,938	60%	18,469,820	54%
Nuclear	3,856,271	13%	3,899,125	13%	3,888,994	11%
Gas and Oil	402,964	1%	399,995	1%	4,847,102	14%
Wind	6,007,828	20%	7,289,628	25%	7,266,202	21%
Total	**30,791,888**	**100%**	**29,321,687**	**100%**	**34,472,118**	**100%**

Attachment 4, Page 3 of 3
Source: MidAm's Attachment 6.1.
Supply Mix by Capacity and Energy.

Combined Cycle Build Case Zero Growth Scenario: Generation

	2012		2016		2021	
Generation Type	**MWh**	**Percent**	**MWh**	**Percent**	**MWh**	**Percent**
Coal	20,524,824	67%	17,732,938	60%	18,469,820	54%
Nuclear	3,856,271	13%	3,899,125	13%	3,888,994	11%
Gas and Oil	402,964	1%	399,995	1%	4,847,102	14%
Wind	6,007,828	20%	7,289,628	25%	7,266,202	21%
Total	**30,791,888**	**100%**	**29,321,687**	**100%**	**34,472,118**	**100%**

Combined Cycle Build Case High Carbon Scenario: Generation

	2012		2016		2021	
Generation Type	**MWh**	**Percent**	**MWh**	**Percent**	**MWh**	**Percent**
Coal	20,524,824	67%	17,032,684	60%	18,912,031	55%
Nuclear	3,856,271	13%	3,902,575	14%	3,890,494	11%
Gas and Oil	402,964	1%	361,213	1%	4,587,089	13%
Wind	6,007,828	20%	7,289,628	26%	7,266,202	21%
Total	**30,791,888**	**100%**	**28,586,101**	**100%**	**34,655,817**	**100%**

Combined Cycle Build Case High Carbon Scenario: Generation

	2012		2016		2021	
Generation Type	**MWh**	**Percent**	**MWh**	**Percent**	**MWh**	**Percent**
Coal	20,524,824	67%	16,126,706	59%	18,247,876	60%
Nuclear	3,856,271	13%	3,902,575	14%	3,890,494	13%
Gas and Oil	402,964	1%	167,733	1%	763,157	3%
Wind	6,007,828	20%	7,289,628	27%	7,266,202	24%
Total	**30,791,888**	**100%**	**27,486,643**	**100%**	**30,167,730**	**100%**

Attachment 5

Source: MidAm's Attachment 6.2.

	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
SO2 Allowances (MEC Share)	Tons	56,550	56,550	39,541	39,541	39,541	39,541	39,541	39,541	39,541	39,541
SO2 Emissions (Base Case)	Tons	37,933	36,625	24,321	9,454	9,829	10,264	10,437	10,452	10,686	10,238
SO2 Emissions (Base Case, High Carbon)	Tons	37,933	36,625	24,321	9,128	9,486	10,007	9,856	9,772	9,966	10,350
SO2 Emissions (Base Case, High Gas)	Tons	37,933	36,625	24,321	8,772	8,994	9,176	9,293	9,274	9,422	10,012
SO2 Emissions (Case 4)	Tons	37,933	36,625	25,260	7,999	8,340	8,737	8,900	9,082	9,101	8,704
SO2 Emissions (Case 4, High Carbon)	Tons	37,933	36,625	25,260	7,691	8,022	8,500	8,370	8,450	8,445	8,779
SO2 Emissions (Case 4, High Gas)	Tons	37,933	36,625	25,260	7,378	7,590	7,772	7,878	8,011	7,975	8,472
NOx Annual Allowances (MEC Share)	Tons	19,794	19,794	19,345	19,345	19,345	19,345	19,345	19,345	19,345	19,345
NOx Emissions (Base Case)	Tons	18,670	17,707	18,412	17,758	18,418	19,407	19,823	19,989	20,452	19,535
NOx Emissions (Base Case, High Carbon)	Tons	18,670	17,707	18,412	17,012	17,642	18,795	18,439	18,375	18,701	19,717
NOx Emissions (Base Case, High Gas)	Tons	18,670	17,707	18,412	16,163	16,488	16,813	17,102	17,151	17,411	18,789
NOx Emissions (Case 4)	Tons	18,670	17,707	18,325	13,594	14,142	14,999	15,398	16,049	15,887	15,156
NOx Emissions (Case 4, High Carbon)	Tons	18,670	17,707	18,325	12,904	13,441	14,445	14,174	14,584	14,337	15,187
NOx Emissions (Case 4, High Gas)	Tons	18,670	17,707	18,325	12,208	12,496	12,820	13,074	13,543	13,280	14,367
Hg Emissions (Base Case)	Pounds				201	211	220	223	222	228	219
Hg Emissions (Base Case, High Carbon)	Pounds				194	203	214	212	209	214	222
Hg Emissions (Base Case, High Gas)	Pounds				187	193	197	200	198	202	216
Hg Emissions (Case 4)	Pounds				172	181	189	192	195	196	188
Hg Emissions (Case 4, High Carbon)	Pounds				166	174	184	182	183	183	191
Hg Emissions (Case 4, High Gas)	Pounds				159	165	169	171	173	173	185
CO2 Emissions (Base Case)	Tons	21,853,417	20,981,239	21,989,682	20,736,744	21,749,420	22,789,487	23,258,300	23,418,494	23,978,198	23,433,958
CO2 Emissions (Base Case, High Carbon)	Tons	21,853,417	20,981,239	21,989,682	20,031,188	20,989,119	22,191,639	22,341,735	22,142,210	22,584,810	23,611,906
CO2 Emissions (Base Case, High Gas)	Tons	21,853,417	20,981,239	21,989,682	19,239,678	19,868,085	20,298,649	20,539,852	20,420,474	20,804,880	22,233,334
CO2 Emissions (Case 4)	Tons	21,853,417	20,981,239	21,953,548	17,747,513	18,691,152	19,652,939	20,463,060	21,162,158	21,290,271	21,248,656
CO2 Emissions (Case 4, High Carbon)	Tons	21,853,417	20,981,239	21,953,548	17,079,240	17,982,671	19,094,817	19,939,053	20,196,928	20,223,406	21,363,130
CO2 Emissions (Case 4, High Gas)	Tons	21,853,417	20,981,239	21,953,548	16,377,220	16,984,411	17,412,985	17,731,130	17,952,881	17,968,721	19,241,118

Attachment 6

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Source: IPL's **CONFIDENTIAL** Attachment C.

Energy Supply Mix, by Resource Category for each Strategy Through 2024

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Attachment 6, Page 2 of 2
Source: IPL's **CONFIDENTIAL** Attachment C.

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Attachment 7

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Source: IPL's **<u>CONFIDENTIAL</u>** Attachment D.

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Source: IPL's **CONFIDENTIAL** Attachment D.

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Source: IPL's **CONFIDENTIAL** Attachment D.

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Attachment 8

Source: Sierra Table.[38]

Law	Regulation	Applicability to generating units	Time period	Regulated Pollutants & potential controls
Clean Air Act	Regional Haze	BART-eligible EGUs in Iowa	Final. Up to 5 years from SIP determination	SO_2 and NO_x. Controls include scrubbers and SCR.
	Cross-State Air Pollution Rule.	Electric generating units in Iowa.	Final rule 2011. Implementation 2012 and 2014.	SO_2 and NO_x. Controls include scrubbers, SCR, sorbent injection, SNCR, low-nox burners.
	Air Toxics	Units that (i.e. >10 t/yr of one pollutant or >25 t/yr of combined pollutants)	Proposed 03-2011 Final December 2011 Implementation 3 years after final rule, and no later than 2015	Includes acid gases, mercury, non-mercury metals. Potential controls include wet scrubbers, sorbent injection, bag houses, activated carbon injection.
	National Ambient Air Quality Standards revision	Potentially affected include plants in attainment areas that increase emissions in that area, and plants in non-attainment areas.		SO_2, NO_x, fine particulates. Potential controls include wet scrubbers, sorbent injection, SCR, baghouses.
Clean Water Act	Cooling Water regulations for existing plants	All existing power plants	Proposed 2011 Final July 2012 Implementation 5-8 years.	Plants using once through cooling may need to retrofit to closed-cycle cooling to reduce impingement and entrainment.
	Effluent limitation guidelines - update	All plants requiring CWA discharge permit	Proposed mid 2012 Final 2014 In the interim, case by case determination for permit renewal	Includes dissolved and undissolved metals. Control technologies include physical and/or chemical treatment, zero liquid discharge, biological treatment and reverse osmosis
Resource Conservation and Recovery Act	Coal Combustion Waste	All coal-fired power plants	Proposed 2010 Final 2012	Heavy metals and toxins. Controls include phasing out surface impoundments and requiring composite liners for new/expanded landfills
Clean Air Act – Greenhouse Gases	New Source Review	Units undergoing major modification	Rule is final and applicable.	Six greenhouse gases Case-by-case determination, may include cleaner fuel, controlling fugitive emissions, carbon sequestration, boiler efficiency
	NSPS for EGUs	Existing plants with modifications	Final 2012 Implementation 3-4 years after final rules (i.e. 2016?)	To be determined

[38] From Sierra comments filed December 16, 2011, page 9.