FILED WITH
Executive Secretary
December 16, 2011
IOWA UTILITIES BOARD
NOI-2011-0003

STATE OF IOWA
DEPARTMENT OF COMMERCE
BEFORE THE IOWA UTILITIES BOARD

IN RE:	)	
	)	
UTILITY COAL PLANT PLANNING	)	**DOCKET NO. NOI-2011-0003**

COMMENTS OF THE IOWA CHAPTER OF THE SIERRA CLUB

The following comments and policy suggestions are submitted on behalf of the Sierra Club, the nation's largest grassroots environmental organization. The Sierra Club is a national grassroots environmental organization with more than 600,000 members nationwide, and more than 5000 members in the state of Iowa. Sierra Club and its Iowa Chapter support the wise allocation of energy resources, focusing specifically on ending the nation's reliance on polluting energy sources such as coal. Long overdue life-saving environmental regulations are changing the landscape for electricity producers, and the utilities providing electricity to Iowa consumers stand at a crossroads between investing billions of dollars in aging infrastructure and choosing a mix of cleaner and renewable energy. Sierra Club looks forward to participating in this timely and crucially important docket.

Sierra Club applauds the IUB for opening a docket of this nature to allow for an early conversation about how Iowa utilities will bring their aging coal-fleet into compliance with regulations designed to protect public health and the environment. The legal framework for these regulations has been on the books for decades. EPA is now poised to implement the Clean Air Act, Clean Water Act, and the Resource Conservation and Recovery Act's legislative directives. The timing of these rules and their implementation over the next several years arguably provides utilities and regulators with a unique opportunity to look holistically at each coal-fired unit, at what it might take to bring that unit into compliance with all current and anticipated regulations, and then, most importantly, evaluate whether a fully compliant coal-fired unit is the least-cost option for compliance. For some units in Iowa, as described below, the cost of meeting public health and environmental regulations is much more expensive than turning to alternative generating resources options in the region.

In Iowa, rate recovery is allowed only for least cost and prudent investment. The IUB should take note of the units identified in our comments where environmental retrofits are an expensive and risky choice. To the extent utilities make non-economic decisions to retrofit, the IUB should deny rate recovery to protect consumers.

<u>IUB Request 1.</u> 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.

The utilities are in the best position to describe the individual coal-fired units in their respective fleets and identify controls and emissions. However, the submissions are incomplete in the following ways:

(1) Both IP&L and MidAmerican provide an incomplete list 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 for disposing of bottom and fly ash. Both utilities should fully describe the technologies (or explain that no technologies are used) for effluent, cooling water intake, and ash handling.

(2) Both IP&L and MidAmerican include only partial lists of emissions. The submissions fail to list both PM10 and PM2.5 emissions. The latter is a particularly deadly pollutant that contributes to more than 13,000 deaths annually. *See* http://www.catf.us/resources/publications/files/The_Toll_from_Coal.pdf. Furthermore, the utility submissions do not include carbon monoxide, or toxic air pollutants like acid gases and non-mercury metals that are commonly emitted from coal-fired power plants. MidAmerican fails to include mercury emissions. The submissions also fail to identify the water and ash waste created by the units. This would include the contents of wastewater effluent, which commonly contains arsenic, mercury, selenium, lead, cadmium and other dangerous metals. *See* EPA's 2009 report at http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm. The submissions also fail to include a description of the amount of coal ash created by each station annually.

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. It is similarly important to note where no controls currently exist.

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

IP&L and MidAmerican give a relatively thorough description of EPA's final, proposed, and anticipated rules. Sierra Club includes a chart of the rules and compliance dates below. First, a few comments and clarifications are warranted.

As EPA's much-needed and in most cases, long-overdue rules are finalized, a growing number of economists have studied how the cost of compliance will impact electric generation. In essence, this evaluation studies the impacts of internalizing the true cost of coal-fired generation. In "*Environmental Accounting for Pollution in the United States Economy*," authored by Nicholas Z. Muller, Robert Mendelsohn, and William Nordhause and appearing in the August 2011 American Economic Review, the environmental externalities of coal-fired power plants far exceeds their value added. Not counting carbon dioxide, coal-fired power plants result in gross external damage of $53 billion annually, which is far greater than the value added. *See* Exhibit 1 attached.

The report provides an important backdrop to the Board's investigation in this docket to identify the cost of complying with EPA rules that will begin to internalize the true costs of coal-fired generation. The study even left out several types of externalities that EPA is poised to regulate. Among them are mercury and other air toxics, cooling water intake structures and their impact on aquatic ecosystems, coal combustion residuals and their impact on human health and our rivers and water supply, and coal plant wastewater effluent, which ends up in our waters. A few regulations are described just briefly below as most of the rules have been covered by earlier submissions.

Clean Air Act Air Toxics Rule

"*Environmental Accounting for Pollution*" evaluated six air pollutants, but none of them were toxic air pollutants, which are the subject of EPA's Clean Air Act Section 112 "maximum available control technology" rule for electric generating units. The air toxics rule will regulate several categories of toxic air emissions, but mercury in particular has received a lot of attention due to its harm to human health. EPA states in the executive summary of the proposed rule:

> Hazardous air pollutants from [electric utilities] contribute to adverse health and environmental effects. [Electric utilities] are by far the largest U.S. anthropogenic sources of mercury (Hg) emissions into the air and emit a number of other HAP. Both the finding in 2000 and our conclusion that it remains appropriate and necessary to regulate HAP from [electric utilities] are supported by the CAA and scientific and technical analyses.
>
> Mercury is a highly toxic pollutant that occurs naturally in the environment and is released into the atmosphere in significant quantities as the result of the burning of fossil fuels. Mercury in the environment is transformed into a more toxic form, methylmercury (MeHg), and because it is also a persistent pollutant, it accumulates in the food chain, especially the tissue of fish. When people consume these fish they consume MeHg, the consumption of which may cause neurotoxic effects.
>
> **********
>
> In addition to Hg, [electric utilities] are significant emitters of HAP metals such as arsenic (As), nickel (Ni), cadmium (Cd), and chromium (Cr), which can cause cancer; HAP metals with potentially serious noncancer health effects such as lead (Pb) and selenium (Se); and other toxic air pollutants such as the acid gases hydrogen chloride (HCl) and hydrogen fluoride (HF).

This rule will become final on December 16, 2011, and may warrant further analysis within the scope of this docket once its requirements are better defined.

Resource Conservation and Recovery Act Coal Combustion Residuals

The "*Environmental Accounting for Pollution in the United States Economy*" study explains that it "excludes other externalities such as those involving water, soil, and radiation." One such externality is the cost to human health and the environment from coal combustion residuals (CCR) that are disposed of in wet ponds and landfills around the country, often discharging directly into surface water or groundwater with no treatments, monitoring, or controls. We saw the devastating impacts of the status quo for storage of CCR when a CCR impoundment burst in Kingston Tennessee, sending millions of gallons of arsenic, lead, selenium, mercury, and cadmium-laced sludge into a nearby river. EPA has conducted extensive data gathering and risk analysis, concluding that CCR presents a significant threat to human health and the environment. 75 Fed. Reg. 35127 (June 21, 2010).

If EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system will apply to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. The coal combustion rulemaking is required as a result of a combination of missed statutory deadlines and court orders covering some 30 years. The 1980 Bevill amendment, part of the Solid Waste Disposal Act amendments to RCRA, exempted coal combustion residues from regulation for two years while EPA gathered additional information about such wastes. The EPA missed that deadline and several subsequent deadlines, which prompted litigation that eventually resulted in this rulemaking. In the 30 years since that Amendment was passed, EPA's studies and research have produced a growing body of evidence that overwhelmingly support a subtitle C regulation of CCR to protect human health and the environment. At the very least, the regulation will require approximately $43 million in capital for dry ash handling per unit, and $80 million in wastewater treatment per plant not including annual O&M costs. *See Potential Impacts of Environmental Regulation on the U.S. Generating Fleet*. Edison Electric Institute; prepared by ICF International, January 2011 (Exhibit 10 attached).

Clean Water Act Cooling Water Intake Standards

Section 316(b) of the Clean Water Act requires power plants and other industrial users to minimize the environmental impact of cooling water intake structures using best technology available. The best technology available is closed-cycle cooling, which protects fish and other aquatic species from being impinged and entrained on these systems by reducing water usage by 95-98%. The harm to our rivers, lakes, estuaries and oceans from unfettered water use and resulting aquatic impacts was not taken into account in the "*Environmental Accounting*" study, which still found that coal-fired power plants cost us more than they are worth. The cost of compliance with this rule, which is now nearly 40 years overdue, has been discussed in the utility submissions and is important for the board's consideration in a state with two of our country's mightiest rivers on its borders.

Clean Water Act Effluent Limitation Guidelines

EPA is working on a much-needed update to its 1982 effluent regulations for the steam industry. The final rule is expected in mid-2014. However, the submissions in this docket do not acknowledge that even now, before the rule is final, effluent limits are set on a case-by-case basis relying on the permit writer's "best professional judgment." These technology-based effluent limits must be consistent with best technology available. This case-by-case analysis applies to new wastewater streams such as FGD waste, but also to pollutants not covered by the industry guidelines such as selenium, arsenic, boron, lead, cadmium, and mercury, all of which are common constituents of coal plant effluent and none of which are currently covered by the guidelines. *See* EPA's NPDES Permit Writer's Manual, available at: http://www.epa.gov/npdes/pubs/pwm_2010.pdf

In Iowa several plants have a Clean Water Act NPDES permit that is either expired or due for renewal before EPA's expected 2014 regulation and is thus subject to case-by-case review. It must be noted that in many cases, utility operators have filed timely applications for renewal and delays result from the Department of Natural Resources' decision not to process timely renewals. On rivers such as the Missouri and the Mississippi that are so vital to local economies, there is no excuse for permits that are almost a decade overdue. The Board should require the utilities to submit a more thorough analysis

of their compliance plans for new effluent guidelines, but also its plan to meet "best technology available" on a case-by-case basis.

Name	***NPDES Expiration Date***	***WaterSource***
Lansing	10/1/2003	Mississippi River
Milton L Kapp	7/15/2004	Mississippi River
Sixth Street	12/9/2003	River/Lake
Sutherland	11/12/2011	Wells
Burlington	9/4/2011	River
Ottumwa	3/4/2008	River
Iowa State University	12/28/2010	Wells
Walter Scott Jr Energy Center (Council Bluffs)	2/26/2008	Missouri River, Wells
George Neal North	3/31/2003	Missouri River
Louisa	5/21/2003	Wells
George Neal South	3/30/2014	Missouri River
Muscatine Plant #1	5/22/2008	Mississippi River
Pella	12/19/2009	Municipality
University of Iowa Main Power Plant	6/11/2013	Iowa River
University of Northern Iowa	6/16/2012	Wells
Riverside	5/19/2003	Mississippi River

Clean Air Act Greenhouse Gas Rules

Utility submissions discuss potential scenarios regarding greenhouse gas regulation, and both IP&L and MidAmerican consider how the cost of carbon dioxide will impact their future planning scenarios. However, it is worth noting that while new legislation may take shape in a variety of different ways on different timelines, EPA already has the authority to regulate carbon dioxide, and is in fact already regulating it. Thus, so-called speculation as to future regulation, while perhaps true from a legislative perspective, is misleading from a regulatory approach.

Since 2007, when the United States Supreme Court held that EPA had the authority to regulate greenhouse gases under the Clean Air Act, EPA has made a finding that greenhouse gases endanger public health and welfare and has adopted a tailoring rule that adjusts the threshold limits for regulation of greenhouse gases. The need for the rule was described by the Supreme Court in the 2007 case, Massachsetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007):

> A well-documented rise in global temperatures has coincided with a significant increase in the concentration of carbon dioxide in the atmosphere. Respected scientists believe the two trends

are related. For when carbon dioxide is released into the atmosphere, it acts like the ceiling of a greenhouse, trapping solar energy and retarding the escape of reflected heat.

****

When Congress enacted [the Clean Air Act in 1970], the study of climate change was in its infancy. In 1959, shortly after the U.S. Weather Bureau began monitoring atmospheric carbon dioxide levels, an observatory in Mauna Loa, Hawaii, recorded a mean level of 316 parts per million. This was well above the highest carbon dioxide concentration – no more than 300 parts per million – revealed in the 420,000-year-old ice-core record. By the time Congress drafted [the Clean Air Act] in 1970, carbon dioxide levels had reached 325 parts per million.

In the late 1970's, the Federal Government began devoting serious attention to the possibility that carbon dioxide emissions associated with human activity could provoke climate change. In 1978, Congress enacted the National Climate Program Act, . . ., which required the President to establish a program to "assist the Nation and the world to understand and respond to natural and man-induced climate processes and their implications," . . . . President Carter, in turn, asked the National Research Council, the working arm of the National Academy of Sciences, to investigate the subject. The Council's response was unequivocal: "If carbon dioxide continues to increase, the study group finds no reason to doubt that climate changes will result and no reason to believe that these changes will be negligible. . . . A wait-and-see policy may mean waiting until it is too late."

Congress next addressed the issue in 1987, when it enacted the Global Climate Protection Act, ... Finding that "manmade pollution – the release of carbon dioxide, chloroflourocarbons, methane, and other trace gases into the atmosphere – may be producing a long-term and substantial increase in the average temperature on Earth," . . ., Congress directed EPA to propose to Congress a "coordinated national policy on global climate change," . . ., and ordered the Secretary of State to work "through the channels of multilateral diplomacy" and coordinate diplomatic efforts to combat global warming, ... Congress emphasized that "ongoing pollution and deforestation may be contributing now to an irreversible process" and that "[n]ecessary actions must be identified and implemented in time to protect the climate."

Meanwhile, the scientific understanding of climate change progressed. In 1990, the Intergovernmental Panel on Climate Change (IPCC), a multinational scientific body organized under the auspices of the United Nations, published its first comprehensive report on the topic. Drawing on expert opinions from across the globe, the IPCC concluded that "emissions resulting from human activities are substantially increasing the atmospheric concentrations of . . . greenhouse gases [which] will enhance the greenhouse effect, resulting on average in an additional warming of the Earth's surface.

Responding to the IPCC report, the United Nations convened the "Earth Summit" in 1992 in Rio de Janeiro. The first President Bush attended and signed the United Nations Framework Convention on Climate Change (UNFCCC), a nonbinding agreement among 154 nations to reduce

atmospheric concentrations of carbon dioxide and other greenhouse gases for the purpose of "prevent[ing] dangerous anthropogenic [i.e., human-induced] interference with the [Earth's] climate system." . . . The Senate unanimously ratified the treaty.

Some five years later – after the IPCC issued a second comprehensive report in 1995 concluding that "[t]he balance of evidence suggests there is a discernible human influence on global climate" – the UNFCCC signatories met in Kyoto, Japan, and adopted a protocol that assigned mandatory targets for industrialized nations to reduce greenhouse gas emissions. Because those targets did not apply to developing and heavily polluting nations such as China and India, the Senate unanimously passed a resolution expressing its sense that the United States should not enter into the Kyoto Protocol. President Clinton did not submit the protocol to the Senate for ratification.

In its most recent report in 2007, the Intergovernmental Panel on Climate Change (IPCC) made the following conclusions:

- Global greenhouse gas (GHG) emissions have grown since pre-industrial times, with an increase of 70% between 1970 and 2004;
- The largest growth in global GHG emissions between 1970 and 2004 has come from the energy supply sector (an increase of 145%);
- With current global climate change mitigation policies and related sustainable development practices, global GHG emissions will continue to grow;
- There is substantial economic potential for the mitigation of global GHG emissions over the coming decades, that could offset the projected growth of global emissions or reduce emissions below current levels;
- There are mitigation opportunities with net negative costs, in other words, for which the benefits such as reduced energy costs and reduced emissions of pollutants equal or exceed their costs to society, excluding the benefits of avoided climate change;
- Fuel switching from coal to gas, renewable heat and power (hydropower, solar, wind, geothermal and bioenergy), and early applications of carbon capture and storage (e.g., storage of removed carbon dioxide from natural gas) are key mitigation technologies and practices currently commercially available;
- Near-term health co-benefits from reduced air pollution as a result of actions to reduce GHG emissions can be substantial and may offset a substantial fraction of mitigation costs;
- It is often more cost-effective to invest in end-use energy efficiency improvement than in increasing energy supply to satisfy demand for energy services. Efficiency improvement has a positive effect on energy security, local and regional air pollution abatement and employment;
- Renewable energy generally has a positive effect on energy security, employment and on air quality; and
- In order to stabilize the concentrations of GHGs in the atmosphere, emissions would need to peak and decline thereafter.

Based on the foregoing, it is imperative that the Board conduct this inquiry on the basis that the EPA regulations are appropriate and necessary to address the air quality issues described above.

SO2 NAAQS

EPA's June 2010 1-hr SO2 standard will rely on monitored data as well as air dispersion modeling to determine which areas are not attaining the ambient standard and which sources must reduce emissions to bring an area into attainment by 2017.

The modeling will follow EPA protocols using AERMOD, a model that should be well known to the utilities in Iowa. Coal-plant operators in Iowa can and should model their plants immediately to determine whether emissions will cause or contribute to a violation of the 1-hour ambient standard. Any argument from Iowa plant operators that the SO2 rule presents regulatory uncertainty is untrue as the uncertainty at this point is self-imposed. Early plant modeling will allow the most complete picture for the Board regarding how EPA regulation will impact each plant. The Board should require each utility to submit an analysis of how it will comply with the 1-hour SO2 NAAQS, including the results of the utility's AERMOD modeling runs.

Ozone NAAQS

The science on ozone is clear: the current standard of 75 ppb is inadequate to protect public health. The Clean Air Scientific Advisory Committee (CASAC) provides peer review of EPA's technical documents related to National Ambient Air Quality Standards, including extensive review on the Ozone NAAQS. In letters dating back to 2006, CASAC has been advising EPA that an ozone standard between 60 and 70 ppb is required to protect public health. See Exhibit 3 attached.

In Iowa, several counties are in danger of violating new ozone standards based on monitored data from 2006-2008.

Bremer	0.066
Clinton	0.067
Harrison	0.068
Linn	0.068
Montgomery	0.066
Scott	0.065
Story	0.064
Van Buren	0.066
Warren	0.06

IP&L and MidAmerican's coal-fired plants that are located in these counties or are causing or contributing to ozone levels in these counties may require additional controls within the next 5 years. MidAmerican lists the NAAQS adjustments as rules that it is not concerned with given CSAPR and the Air Toxics rule. However, the air toxics rule does not directly address NOx, and if MidAmerican is planning to comply with its CSAPR NOx allocations by purchasing credits, it will need to carefully examine how a new ozone rule in particular could impact its fleet. MidAmerican should provide more information to the IUB supporting its claim that it can comply with a new ozone rule given the range EPA is considering.

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

<u>IUB Request 3</u>. 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.

First, it should be noted that in addition to the two scenarios that the IUB required (business as usual and all retrofit) IP&L submitted just one additional scenario and MidAmerican submitted three, though only one was seriously considered and strayed from the examples given by the IUB. For two sophisticated utilities, it is hard to believe that these are the only options being considered to both comply with EPA rules and to provide reliable and affordable electricity to their customers. In addition, both utilities fail to discuss specific energy efficiency or demand-side benchmarks and fail to discuss replacing some coal-fired generating capacity and/or energy with wind, which in Iowa is easily in the $30/mwh range for a long term power purchase agreement.

Neither of the regulated utilities adequately addresses the full suite of existing and emerging regulations. For example, a compliance strategy for RCRA and Clean Water Act effluent regulation is missing from the submissions to the Board. Not one of the scenarios discussed identifies specific strategies to comply with both RCRA and new Clean Water Act effluent guidelines. IP&L does identify dry ash handling and pond closures, which is a huge step toward compliance. However, IP&L does not provide estimates for what that might cost, which are presumably represented in the modeling scenarios, but are not available for public input and comment. It is crucial that the board require the regulated utilities in Iowa to fully address possible compliance strategies with not just one or two of the rules, but with all of them.

<u>The Nuclear "Compliance" Option</u>

Sierra Club understands the Board's interest in nuclear power as it relates to this docket. In many ways, nuclear plants present less risk on a traditional-pollutant basis, though they certainly face compliance costs to upgrade to closed-cycle cooling. However, nuclear plants come with their own set of future risks, not the least of which is the enormous and often prohibitive cost of building and operating nuclear power plants.

First of all, nuclear power is expensive and financially risky. This would have an impact on ratepayers. In fact, a bill is currently pending in the Iowa Legislature that would force ratepayers to pay for the development of a new nuclear plant before it is even built and would not refund the payments to ratepayers if the plant is ultimately not built. Furthermore, the bill would limit the Board's authority in establishing ratemaking principles for a new plant. The purpose of the bill is to shift the financial risk of building a new nuclear plant to the ratepayers, instead of the utility's shareholders and investors.

Nuclear plants are extremely expensive to build, to fuel, and to decommission at the end of their use. The plants require many years to build and historically are subject to cost overruns and delays. All of these costs are borne by the ratepayers. It is revealing that during discussion last spring of the aforementioned bill in the Iowa Legislature that MidAmerican was asked about putting a cap of 10% on rate increases resulting from building a new nuclear plant and MidAmerican said it could not do that and that such a cap would prevent construction of a new plant.

There are also numerous federal subsidies and preferences for nuclear power because it is so risky, both financially and in terms of safety. In fact, nuclear power, as we have seen from Three Mile Island to Chernobyl to Fukushima, is so unsafe that the Price-Anderson Act limits the plant owner's liability for a nuclear accident.

The utilities are now touting a new nuclear plant design called small modular reactors. But this design is untested and has not been approved by the Nuclear Regulatory Commission and won't be for another few years, if at all. Renewable energy, on the other hand, is available now, is constantly being improved, and is declining in cost.

Aside from the huge costs associated with nuclear power, perhaps the most troubling aspect of nuclear generation is the high-level radioactive waste that remains radioactive for thousands, perhaps millions, of years. At present, this waste is being stored on the sites of the individual nuclear plants. The problem of disposal of nuclear waste is so difficult that it has thus far been impossible to find a solution to the problem. A Blue Ribbon Commission on America's Nuclear Future was appointed by the Secretary of Energy to address the issue of nuclear waste. The meetings held by the Commission this year have made it clear that no one wants the nuclear waste in their "back yard." A proposed disposal site at Yucca Mountain in Nevada, which was designated without input from the people of Nevada, was withdrawn after Nevadans made it clear they did not want a disposal site in their state, and after it was determined that seismic and water issues rendered the site unsuitable. Furthermore, the Commission concluded that one disposal site may not be enough, especially if nuclear power expands in the future. It seems obvious that the quickest and easiest way to mitigate the problem of nuclear waste is to not make any more. To use a medical analogy, first stop the bleeding.

Compliance with long-overdue regulations to protect public health and the environment from harmful pollution from coal plants should not include trading coal for nuclear. The massive up-front construction costs, followed by the untold and immeasurable long-term costs of nuclear generation do not provide for a rational tradeoff.

Energy Efficiency and Demand-Side Management as a Compliance Strategy

Energy efficiency is the quickest, easiest and most cost-effective alternative to coal, gas and nuclear. It does not require significant capital investment or time consuming construction, and it is less expensive than new generation. Studies have shown that the average cost to a utility for energy efficiency measures is 2.5 cents per kWh and 6 to 15 cents per kWh for new generation sources. Elliott, Gold, and Hayes, Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency (August 2011). *See* Exhibit 4 hereto attached. Elliott et al. also 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 that the United States could cost-effectively reduce energy consumption by 20%-30% or more over the next 20 years.

MidAmerican and IP&L have energy efficiency plans approved by the Board. Under those plans MidAmerican's target savings goal by 2012 is 1.5% of sales and IP&L's goal is 1.2% of sales by 2012. Iowa's municipal utilities and RECs have no approved plans and their plans and goals are inconsistent and generally less aggressive than those for the investor-owned utilities. At this point, IP&L appears to be on track to meet or exceed its savings goal, but MidAmerican is falling short of its goal, at the same time it is trying to convince the public that a new nuclear plant is required. The IUB should take steps to make efforts toward energy efficiency even more vigorous by, for example, reducing the time frame for energy efficiency plans from five years to three years and finding new strategies for ensuring that the efficiency plans produce even more savings. Increased energy efficiency would avoid any effect from the EPA regulations and would reduce energy usage and thus reduce ratepayers' electric bills.

Beyond just strengthening the current energy efficiency plans, the Board can undertake alternative regulatory measures to gain even greater energy efficiency. Alternative utility regulation, sometimes called decoupling, refers to a range of regulatory practices designed to better align utility investment incentives with strategic goals of increasing energy efficiency and ensuring reliable and affordable energy with the smallest possible environmental impact.

Traditional ratemaking principles link a utility's health to the volume of electricity or gas it sells. Alternative regulation allows utilities to consider energy efficiency options by reducing the dependence of utility revenues (and shareholder profits) on unit sales. By fixing revenues to other criteria, such as the number of customers, utilities receive fixed revenues and can increase profits by operating more efficiently and/or reducing their costs.

Three classes of regulatory practices could be considered:

1. <u>Reduce the Throughput Incentive</u>

This option would link revenue to customers rather than sales. During each rate case, the Board would establish a revenue cap per customer, with a mechanism to adjust for the addition or departure of customers. Under this paradigm, the utility's revenues do not fluctuate with sales, and the fixed revenue cap allows utilities to increase profits by operating more efficiently and reducing costs.

2. <u>Provide Funding for Energy Efficiency Programs</u>

This would treat energy efficiency as a qualified resource, with energy efficiency to be procured like any supply-side option, and prudent costs would be recovered in the rate base. In this regard, the Board could determine a percentage of utility revenues to invest in energy efficiency programs.

3. <u>Provide Incentives for Energy Efficiency</u>

This would capitalize energy efficiency expenses. Treating energy efficiency investments as capital investments allows costs to be recovered over longer periods of time. This may slightly increase the overall costs of the measures, but it significantly reduces the rate impact. This process could also increase the number of energy efficiency measures that pass cost effectiveness tests used by regulatory bodies to analyze resource acquisition options. For example, the Board could authorize a slightly higher return on investment for energy efficiency investments when compared with other capital investments. An alternative is to share the value of the energy savings with the utility. Both of these incentives would be linked to actual performance of the programs.

For a more detailed discussion of alternative utility regulation regarding energy efficiency programs, see Exhibit 5 hereto attached, York and Kushler, The Old Model Isn't Working: Creating the Energy Utility for the 21st Century (September 2011).

Renewable Energy as a Compliance Option

In addition to energy efficiency, an alternative energy future would also include the expansion and development of renewable energy. Recent studies demonstrate that the United States can supply all of its needed electricity from renewable sources if those sources are developed and tied together by the electric grid. Archer and Jacobson, Supplying Baseload Power and Reducing Transmission Requirements by Interconnecting Wind Farms, Journal of Applied Meteorology and Climatology (v. 46, Nov. 2007); Jacobson and Delucchi, Providing All Global Energy with Wind, Water, and Solar Power, Part I: Technologies, Energy Resources, Quantities and Areas of Infrastructure, and Materials, Energy Policy (v. 39, p. 1154-1169); Jacobson and Delucchi, Providing All Global Energy with Wind, Water, and Solar Power, Part II: Reliability, System and Transmission Costs, and Policies, Energy Policy (v. 39, p. 1170-1190. See Exhibits 6, 7 and 8 hereto attached.

The Board has undertaken an inquiry into transmission planning in Docket No. NOI-2022-0002. In the context of utility coal plant planning and the transition to renewable energy and a transmission system to support it, we direct the Board to our comments in that inquiry. The significant points made in those comments that relate to coal plant planning and the transition to renewable energy are that transmission line projects must support and prioritize renewable energy and that transmission projects must be integrated into a comprehensive transmission grid.

In order to avoid the impacts of the EPA rules by turning to renewable energy, the utilities must invest in renewable energy. In Iowa that essentially means building more wind farms, given Iowa's abundant wind resources. Iowa has already made strides in developing wind generation, as shown by Exhibit 9 hereto attached, but more can be done. And investing in wind energy is cost-effective. According to the Department of Energy 2010 Wind Technologies Market Report, issued June 2011, 2010 was a year of higher wind prices, but indications suggest that lower wind power prices will accompany projects built in the near future. This forecast is partially based on declining prices for wind turbines. The DOE Report also states that the Midwest had the second lowest cost for wind from 2007-2010. And, of course, if the price of coal increases and natural gas prices are volatile or increase, the cost of wind becomes even more advantageous.

In sum, while Sierra Club understands why the Board asked the utilities about increased reliance on nuclear power, the Board, and the utility submissions, have failed to consider two compliance options that are far less expensive than nuclear (and coal) and are currently available as a compliance option in Iowa. Energy efficiency and renewable electricity must be thoroughly evaluated by the utilities and the Board as options for compliance with EPA regulation.

RECs and MUNIs Should Participate In This Docket

At this point, it is worth noting that some of the smallest and most inefficient units in the state are owned and operated by Rural Electric Cooperatives and Municipal Utilities, which have largely decided not to participate in this docket.

Although they are not rate-regulated by the Board, RECs and municipals should be included in addressing responses to the EPA regulations. In its Appearance in this inquiry, the Iowa Association of Electric Cooperatives stated that it does not own any coal plants. But two of its members own coal plants. Central Iowa Power Cooperative (CIPCO) owns the Fair Station in Montpelior, Iowa, and Corn Belt Power Cooperative (Corn Belt) owns the Earl F. Wisdom Station in Spencer, Iowa. In addition, CIPCO owns a share of three other coal plants: Walter Scott Units 3 and 4 in Council Bluffs, Iowa, and the Louisa Generating Station in Muscatine, Iowa, and Corn Belt owns a share of three additional coal plants: George Neal Unit 4 in Sioux City, Iowa, and Walter Scott Units 3 and 4 in Council Bluffs, Iowa. Municipal utilities are in essentially the same situation as RECs. They either own their own coal plants or share or purchase power from other coal plants.

Based on the foregoing, there is no question that the proposed EPA regulations will have an effect on the RECs and municipals. The question then is how can the RECs and municipals be encouraged to increase their efforts toward energy efficiency and renewable energy.

Even though the Board cannot regulate the rates of RECs and municipals, 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. Iowa Code §§ 476.1A and 476.1B state that RECs and municipals are subject to all regulation and enforcement activities of the Board except rate regulation.

In 2008 the Iowa Legislature enacted SF 2386, which amended Iowa Code § 476.6 to require RECs and municipals to establish energy efficiency goals and cost-effective programs to meet prescribed energy savings targets. That legislation also established a commission to evaluate utility efficiency plans and make recommendations for improvement. The commission issued a report to the Governor and the legislature on January 1, 2011. All utilities, but especially RECs and municipals since they are not rate-regulated, can and should take these recommendations to heart in order to reduce the need for fossil fuel generation.

The Board also issued two reports on January 1, 2011, evaluating the energy efficiency goals and programs of the RECs and municipals. These reports concluded that the programs proposed and commenced by the utilities was a good beginning, had made progress toward their cost-saving goals, and

should be continued. We suggest that these programs could even be more aggressive and that other steps could be taken by the RECs and municipals to achieve greater energy efficiency. As explained above in relation to the regulated utilities, the goals could systematically become more ambitious and the utilities could take steps to decouple their rates from the amount of power produced to some other basis. These steps would mitigate the impact of the EPA regulations.

The RECs and municipals could also do more to obtain power from renewable energy sources and reduce their dependence on fossil fuels. For example, they could make efforts to obtain power from currently operating wind farms and from wind farms being proposed for development. This would either be in the nature of owning a share in the wind farm or by purchase power agreements with the owners of the wind farms.

The utilities could also do more to accommodate distributed generation. This would include offering net metering and feed in tariffs.

<u>IUB Question 4</u>: 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.

The cost analyses for the various compliance scenarios considered by the utilities are insufficient to provide the foundation of a meaningful discussion about the cost of compliance as it relates to alternatives, and ultimately, how it will impact ratepayers. These analyses do not break out the costs for each control option, for each plant, or each unit. It is impossible to comment on the reasonableness of the NPVRR estimates without seeing any meaningful analysis. The IUB should request additional information that is far more precise than what has been provided to date.

Sierra Club is including an analysis of the forward-going costs of Iowa's coal-fired units if environmental retrofits are included in the analysis. These numbers are based on publicly available data, primarily from EPA and EIA, and much of it is based on 2009 information so it may be slightly out of date. For example, Sierra Club understands that IP&L has already completed a partial retrofit of Lansing 4. The analysis assumes a wet FGD for SO2 and acid gases, an SCR for NOx, a baghouse for particulate matter and metals, activated carbon injection for mercury, and closed-cycle cooling to comply with the Clean Water Act. Importantly, as described below, this does not include the cost of compliance with CCR and wastewater regulation, the cost of which is described more fully below. Utilities are generally in a better position to provide this level of detail about their own generating fleets to the IUB and so Sierra Club submits these numbers based only on publicly available information. However, Sierra Club feels strongly that the submissions to the Board by the utilities are far from the detailed analysis requested, and lack the level of detail regarding capital costs and the forward-going analysis of costs that will be placed on ratepayers. More importantly, there is absolutely no attempt to try to take these kinds of figures, and conduct a meaningful comparison of alternatives to coal retrofits in Iowa.

These first three charts represent Sierra Club's best estimate of the operating characteristics and estimated running costs (in 2009) for the coal-fired plants in Iowa. These figures give the Board a reference point for where these units fit in the marketplace *before* massive capital investments, but also

reveal the units that are already operating on the margin. Plants like Earl F Wisdom, Fair Station, Pella, and Muscatine are already candidates for retirement due to their high operating costs relative to many of the larger, newer plants in Iowa.

Ex 1 **Operating Characteristics and Estimated Running Cost (2009)**

Plant / Unit	State	Nameplate Capacity (MW)	First Year of Operation	Plant Coal Heat Rate (mmbtu/MWh)	Capacity Factor (2008-2009)	Estimated Fuel Cost ($/MWh)	Estimated Fixed O&M Costs ($/kw-yr)	Estimated Variable O&M Costs ($/MWh)	Estimated Running Cost in 2009 ($/MWh)
Burlington 1	IA	212	1968	10.69	64.2%	$14.87	$21.00	$4.00	$22.60
Lansing 3	IA	38	1957	11.58	25.1%	$18.13	$30.00	$5.00	$36.80
Lansing 4	IA	275	1977	11.58	60.0%	$18.13	$21.00	$4.00	$26.13
Milton L Kapp 2	IA	218	1967	11.70	32.6%	$19.13	$21.00	$4.00	$30.48
Sutherland 1	IA	38	1955	12.62	51.4%	$23.85	$30.00	$5.00	$35.51
Sutherland 2	IA	38	1955	12.62	39.9%	$23.85	$30.00	$5.00	$37.44
Sutherland 3	IA	82	1961	12.62	41.3%	$23.85	$30.00	$5.00	$37.15

Plant / Unit	State	Nameplate Capacity (MW)	First Year of Operation	Plant Coal Heat Rate (mmbtu/MWh)	Capacity Factor (2008-2009)	Estimated Fuel Cost ($/MWh)	Estimated Fixed O&M Costs ($/kw-yr)	Estimated Variable O&M Costs ($/MWh)	Estimated Running Cost in 2009 ($/MWh)
George Neal North 1	IA	147	1964	10.37	71.8%	$11.27	$21.00	$4.00	$18.61
George Neal North 2	IA	349	1972	10.37	60.8%	$11.27	$18.00	$3.75	$18.40
George Neal North 3	IA	550	1975	10.37	71.7%	$11.27	$18.00	$3.75	$17.88
Ottumwa 1	IA	726	1981	11.19	62.6%	$17.99	$18.00	$3.75	$25.02
Louisa 1	IA	812	1983	10.50	67.8%	$15.05	$18.00	$3.75	$21.83
Walter Scott Jr Energy Cer	IA	49	1954	9.96	57.2%	$10.73	$30.00	$5.00	$21.72
Walter Scott Jr Energy Cer	IA	82	1958	9.96	77.3%	$10.73	$30.00	$5.00	$20.16
Walter Scott Jr Energy Cer	IA	726	1978	9.96	77.1%	$10.73	$18.00	$3.75	$17.15
Walter Scott Jr Energy Cer	IA	923	2007	9.96	72.2%	$10.73	$18.00	$3.75	$17.33

Plant / Unit	State	Nameplate Capacity (MW)	First Year of Operation	Plant Coal Heat Rate (mmbtu/MWh)	Capacity Factor (2008-2009)	Estimated Fuel Cost ($/MWh)	Estimated Fixed O&M Costs ($/kw-yr)	Estimated Variable O&M Costs ($/MWh)	Estimated Running Cost in 2009 ($/MWh)
Muscatine Plant #1 7	IA	25	1958	14.23	40.4%	$22.10	$30.00	$5.00	$35.57
Muscatine Plant #1 8	IA	75	1969	14.23	13.3%	$22.10	$30.00	$5.00	$52.84
Muscatine Plant #1 9	IA	176	1983	14.23	59.1%	$22.10	$21.00	$4.00	$30.15
Earl F Wisdom 1	IA	33	1960	18.11	14.0%	$53.73	$30.00	$5.00	$83.22
Fair Station 1	IA	25	1960	12.56	51.0%	$37.26	$30.00	$5.00	$48.98
Fair Station 2	IA	38	1967	12.56	45.0%	$37.26	$30.00	$5.00	$49.87
Pella 5	IA	12	1964	17.33	35.3%	$23.59	$30.00	$5.00	$38.30
Pella 6	IA	27	1972	17.33	23.7%	$23.59	$30.00	$5.00	$43.05

The next three charts calculate the capital costs of installing controls on Iowa's coal-fired units. As described below, these figures do not include the cost of compliance with the RCRA CCR rule or with new Clean Water Act effluent guidelines. The estimates come from EPA's IPM model and (Sergeant and Lundy) and the cooling tower estimates come from NERC. Sierra Club's assumptions are based on the self-reported control technology information submitted to EPA by the utilities. Since 2009, this information may have changed.

Ex 3 **Estimated Environmental Upgrade Capital Expendatures (Million 2009$)**

Plant Name	FGD 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**
Milton L 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**

Plant Name	FGD 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 $)
George Neal North 1	$110	$39	$26	$3	$49	**$227**
George Neal North 2	$205	$79	$59	$4	$66	**$412**
George Neal North 3	$284	$116	$75	$4	$85	**$564**
Ottumwa 1	$358	$157	$100	$4		**$620**
Louisa 1		$164		$5		**$168**
Walter Scott Jr Energ	$49	$16	$10	$3	$23	**$102**
Walter Scott Jr Energ	$71	$24	$16	$3	$33	**$146**
Walter Scott Jr Energ		$142	$103	$4	$112	**$362**
Walter Scott Jr Energ						**$0**

Plant Name	FGD 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 $)
Muscatine Plant #1 7	$36	$13	$8	$2	$17	**$76**
Muscatine Plant #1 8	$79	$29	$19	$3	$30	**$160**
Muscatine Plant #1 9		$58	$39	$3	$54	**$154**
Earl F 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**

The next series of charts is perhaps the most telling. These charts demonstrate how the capital investments change the operating costs of each unit, increasing the $/mwh cost of operation, and thus the cost at which the plant owners need to sell power to recover costs. Sierra Club assumes a carbon price of $20/ton (roughly $20/mwh) in its analysis. As expected, larger units with high capacity factors enjoy the impact of economies of scale as demonstrated through lower forward-going costs.

Ex 4 **Estimated Impact of Environmental Upgrades on Forward-Going Cost ($/MWh)**

Plant Name	State	Estimated Running Cost in 2008 ($/MWh)	Incremental Cost of FGD Upgrade ($/MWh)*	Incremental Cost of SCR Upgrade ($/MWh)*	Incremental Cost of Baghouse Upgrade ($/MWh)*	Incremental Cost of ACI Upgrade ($/MWh)*	Incremental Cost of Cooling Tower Upgrade ($/MWh)*	CO_2 Price**	Forward-Going Cost ($/MWh)
Burlington 1	IA	**$22.6**	$23.9	$7.8	$5.4	$0.8	$6.9	$20.0	**$87.3**
Lansing 3	IA	**$36.8**	$107.8	$31.3	$17.9	$5.3	$33.0	$20.0	**$252.0**
Lansing 4	IA	**$26.1**	$24.6	$8.4	$5.2	$0.8	$5.8	$20.0	**$90.9**
Milton L Kapp 2	IA	**$30.5**	$45.8	$15.6	$11.2	$1.3	$13.5	$20.0	**$137.9**
Sutherland 1	IA	**$35.5**	$56.1	$16.5	$9.4	$2.9	$0.0	$20.0	**$140.4**
Sutherland 2	IA	**$37.4**	$71.3	$21.1	$12.1	$3.6	$0.0	$20.0	**$165.5**

Plant Name	State	Estimated Running Cost in 2008 ($/MWh)	Incremental Cost of FGD Upgrade ($/MWh)*	Incremental Cost of SCR Upgrade ($/MWh)*	Incremental Cost of Baghouse Upgrade ($/MWh)*	Incremental Cost of ACI Upgrade ($/MWh)*	Incremental Cost of Cooling Tower Upgrade ($/MWh)*	CO_2 Price**	Forward-Going Cost ($/MWh)
George Neal North 1	IA	**$18.6**	$23.8	$7.4	$4.5	$0.9	$8.1	$20.0	**$83.2**
George Neal North 2	IA	**$18.4**	$21.5	$7.3	$5.0	$0.7	$5.4	$20.0	**$78.3**
George Neal North 3	IA	**$17.9**	$16.7	$5.9	$3.5	$0.5	$3.8	$20.0	**$68.3**
Ottumwa 1	IA	**$25.0**	$18.1	$6.8	$4.1	$0.6	$0.0	$20.0	**$74.5**
Louisa 1	IA	**$21.8**	$4.0	$5.9	$0.2	$2.6	$0.0	$20.0	**$54.6**
Walter Scott Jr Energy Cer	IA	**$21.7**	$41.5	$11.7	$6.7	$2.0	$14.4	$20.0	**$118.1**
Walter Scott Jr Energy Cer	IA	**$20.2**	$26.3	$7.7	$4.5	$1.2	$9.0	$20.0	**$88.9**
Walter Scott Jr Energy Cer	IA	**$17.1**	$3.8	$5.2	$3.4	$0.5	$3.5	$20.0	**$53.4**
Walter Scott Jr Energy Cer	IA	**$17.3**	$3.7	$0.7	$0.2	$2.4	$0.0	$20.0	**$44.3**

Plant Name	State	Estimated Running Cost in 2008 ($/MWh)	Incremental Cost of FGD Upgrade ($/MWh)*	Incremental Cost of SCR Upgrade ($/MWh)*	Incremental Cost of Baghouse Upgrade ($/MWh)*	Incremental Cost of ACI Upgrade ($/MWh)*	Incremental Cost of Cooling Tower Upgrade ($/MWh)*	CO_2 Price**	Forward-Going Cost ($/MWh)
Muscatine Plant #1 7	IA	**NA**	$66.9	$18.6	$9.7	$3.5	$19.3	$20.0	**$173.7**
Muscatine Plant #1 8	IA	**$52.8**	$123.0	$38.3	$23.8	$4.1	$35.3	$20.0	**$297.5**
Muscatine Plant #1 9	IA	**$30.2**	$7.1	$7.7	$4.7	$0.9	$6.1	$20.0	**$76.6**
Earl F Wisdom 1	IA	**NA**	$184.5	$56.5	$36.6	$8.4	$0.0	$20.0	**$389.3**
Fair Station 1	IA	**NA**	$52.7	$14.2	$8.0	$3.0	$16.3	$20.0	**$163.3**
Fair Station 2	IA	**NA**	$49.7	$13.8	$9.4	$2.5	$13.2	$20.0	**$158.5**
Pella 5	IA	**NA**	$119.3	$33.0	$15.1	$0.0	$0.0	$20.0	**$225.7**
Pella 6	IA	**NA**	$116.5	$34.5	$19.2	$5.7	$0.0	$20.0	**$238.9**

Finally, the last few charts are just the beginning of an analysis of how a retrofitted coal plant compares to alternative generating options. The numbers in the charts are based on EPA's IPM model as well as EIA's AEO 2010 report. Furthermore, our research shows that wind costs are consistently low in the heartland, and are easily in the $30-$40/mwh range for a long-term power purchase contract. *See* DOE Wind Technologies Market Report, available at: http://www1.eere.energy.gov/wind/pdfs/51783.pdf. IP&L Attachment A page 4 estimates that wind capital costs are $62.50/mwh for new construction. As compared to fully retrofitted units, wind is cheaper, by the utility's own estimates, than retrofitting any of its coal-fired units and is less-expensive than many of the retrofits proposed for MidAmerican's fleet.

Only the utilities and plant operators are in a position to do a meaningful RFP for alternative generating resources, or talk to contractors about specific costs for new generation. The point is, the utilities should have, or can easily obtain, this key data that is crucial to the Board's consideration in this docket, as well as the Board's future consideration of any rate increase for a coal plant retrofit.

Certain plants remain competitive in the short term, but as is demonstrated below, very few of Iowa's coal-fired plants can compete with world-class wind resources, and less polluting natural gas. More importantly, retrofits where energy efficiency and demand-side management programs are available may be prohibitively expensive as those programs may eliminate the need for at least some of these units all together.

The compliance plans put forth by IP&L and MidAmerican must reconcile the cost of retrofits with the cost of alternative resources. Where some may make economic sense, like Walter Scott 3 and 4, others do not, like Walter Scott 1 and 2. In light of this information, IP&L cannot justify retrofitting any of its Tier 2 plants (putting those co-owned by MidAmerican aside) other than possibly Lansing 4, which is still very close to the cost of wind in the region and well over the cost of some natural gas options. Sierra Club reiterates its support for IP&L's Scenario 3, which would retire many of the units that would not be economic to retrofit.

Plant Name	State	Capacity Factor, Average 2008-2009	Forward-Going Cost for Existing Coal Units* ($/MWh)	Estimated All-in Cost of a New Natural Gas CC** ($/MWh)	Estimated Cost of Existing Gas CC** ($/MWh)	Estimated Cost of Converting Station to Natural Gas** ($/MWh)
Burlington 1	IA	64.2%	**$87.3**	$83.3	$64.2	$73.4
Lansing 3	IA	25.1%	**$252.0**	$121.6	$67.7	$141.7
Lansing 4	IA	60.0%	**$90.9**	$85.1	$64.4	$72.8
Milton L Kapp 2	IA	32.6%	**$137.9**	$107.1	$66.4	$76.2
Sutherland 1	IA	51.4%	**$140.4**	$89.4	$64.8	$81.2
Sutherland 2	IA	39.9%	**$165.5**	$98.3	$65.6	$87.0
Sutherland 3	IA	41.3%	**$137.7**	$97.0	$65.5	$84.9

Plant Name	State	Capacity Factor, Average 2008-2009	Forward-Going Cost for Existing Coal Units* ($/MWh)	Estimated All-in Cost of a New Natural Gas CC** ($/MWh)	Estimated Cost of Existing Gas CC** ($/MWh)	Estimated Cost of Converting Station to Natural Gas** ($/MWh)
George Neal North 1	IA	71.8%	**$83.2**	$80.7	$64.0	$69.6
George Neal North 2	IA	60.8%	**$78.3**	$84.7	$64.3	$70.7
George Neal North 3	IA	71.7%	**$68.3**	$80.8	$64.0	$68.9
Ottumwa 1	IA	62.6%	**$74.5**	$83.9	$64.3	$68.5
Louisa 1	IA	67.8%	**$54.6**	$82.0	$64.1	$66.6
Walter Scott Jr Energy Ce	IA	57.2%	**$118.1**	$86.3	$64.5	$76.1
Walter Scott Jr Energy Ce	IA	77.3%	**$88.9**	$79.2	$63.8	$71.0
Walter Scott Jr Energy Ce	IA	77.1%	**$53.4**	$79.2	$63.8	$64.8
Walter Scott Jr Energy Ce	IA	72.2%	**$44.3**	$80.6	$64.0	$66.5

Plant Name	State	Capacity Factor, Average 2008-2009	Forward-Going Cost for Existing Coal Units* ($/MWh)	Estimated All-in Cost of a New Natural Gas CC** ($/MWh)	Estimated Cost of Existing Gas CC** ($/MWh)	Estimated Cost of Converting Station to Natural Gas** ($/MWh)
Muscatine Plant #1 7	IA	40.4%	**$173.7**	$82.0	$65.5	NA
Muscatine Plant #1 8	IA	13.3%	**$297.5**	$129.2	$72.9	$118.0
Muscatine Plant #1 9	IA	59.1%	**$76.6**	$74.6	$64.4	$67.6
Earl F Wisdom 1	IA	14.0%	**$389.3**	$132.0	$72.3	NA
Fair Station 1	IA	51.0%	**$163.3**	$78.9	$64.8	NA
Fair Station 2	IA	45.0%	**$158.5**	$81.6	$65.2	NA
Pella 5	IA	35.3%	**$225.7**	$85.3	$66.1	NA
Pella 6	IA	23.7%	**$238.9**	$98.3	$68.1	NA

One significant capital investment that is not included in the above analysis (or the utility analyses) is the cost of compliance with EPA's proposed regulation of coal combustion residuals under RCRA. One of the reasons it is not included above is that the cost of remediating existing ponds exists even when a plant closes. The Edison Electric Institute's study of the impact of EPA rules has a relatively comprehensive breakdown of the capital costs, and fixed and variable O&M costs associated with both a Subtitle D and Subtitle C regulation of coal combustion residuals. *See* EXHIBIT 10 at Appendix A; Pg. 37. EEI's cost analysis for Subtitle D does not breakout the costs of pond closure and is the more lenient of the two regulatory approaches. Sierra Club calculated the following figures to be even more conservative by assuming no wet FGD discharges at any of the plants, even though we expect wet FGDs to add significantly to the cost of treatment. Using EEI's estimates as a guide, the rule would add the following capital costs to the capital investments shown above:

Plant	*RCRA Subtitle D Capital Cost*
Walter Scott Energy Center	$252 million
Muscatine	$209 million
Ottumwa	$123 million
George Neal Energy Center	$252 million
Lansing	$252 million
Louisa	$123 million
Milton Kapp	$123 million
Burlington	$123 million
Sutherland	$209 million
Pella	$166 million
Fair	$166 million
Earl Wisdom	$123 million

<u>IUB Question 5</u>: 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.

In MidAmerican's identification of key scenarios, it makes a few assumptions that the Board should request a more detailed analysis in support. First, MidAmerican only assumes that gas prices in the future will be high. Even in its discussion of current low prices, MidAmerican turns a trend in low gas prices into a high gas scenario without additional support, simply suggesting that low prices will drive up demand, and thus, drive up prices. Thus, MidAmerican does not entertain how low or moderate gas prices would impact the prudency of its compliance options, which, with the exception of closing a few very small units, bet on the continued operation of several large coal-fired power plants. Low and mid gas prices could help the Board identify the point at which continued reliance on coal is no longer economic.

The Board should also require more information from MidAmerican about its assumptions of a "Delayed HAPs MACT" scenario and its failure to include a high-coal cost scenario. MidAmerican provides no legal support for a delayed MACT strategy. Currently, EPA is legally required to finalize the rule pursuant to an enforceable consent decree. In fact, the rule is scheduled to become final during the pendency of this docket. Sierra Club urges the board to disregard a delayed MACT scenario as there is no legal support for one. The ultimate compliance date is flexible to a degree based on the language of the Clean Air Act to allow additional time for plants that are actively working toward compliance. However, delayed implementation of the rule overall is not a reasonable planning scenario. Furthermore, where high or low natural gas prices will inform future planning, changes in delivered coal prices could similarly impact utility resource planning.

<u>IUB Question 6</u>: The projected results in each of the ten years (2012-2021) 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.

IP&L's response to the IUB's question lends support to the conclusion that Scenario 3 has the same NPVRR as the business-as-usual and Scenario 2 options, but presents less future risk to IP&L's ratepayers because it would result in significant reductions in SO2 and NOx as well as significant reductions in carbon dioxide. As IP&L moves forward with an expansion strategy, it should re-run EGEAS to limit new coal-fired units to gain a more accurate picture of what it will need in the future. Sierra Club appreciates IP&L's comments that it does not currently intend to build new coal-fired generation. New coal-fired power plants are now well into the $3000 - $4000/kw range with some projects massively over budget in the $5000/kw range. Removing the coal-fired units from any possible future scenarios will allow IP&L to adequately plan for new generating resources in the future.

Even with these issues in mind, IP&L's Table 7 shows that Scenario 3 almost always allows for the greatest investment in wind energy. Scenario 3 is preferred to the Business-As-Usual strategy and Strategy 2 because it allows for the greatest pollution reductions and allows investments that would otherwise be spent on aging coal units to be spent on new clean energy resources in Iowa. Sierra Club encourages IP&L to select Scenario 3, but also to increase its investment in clean energy before it commits to other generating resources while also working to reduce electric demand.

MidAmerican includes a table titled "10-year Present Value Revenue Requirement Difference From Business-As-Usual Case" in response to the Board's Question 6. MidAmerican claims that the table might not adequately impact the costs to ratepayers in a "no growth" future scenario. However, the no growth scenario unquestionably shows lower net present value requirements, suggesting ratepayers are best served by energy efficiency and demand-side management programs to address the small percentage increase in demand that MidAmerican predicts. In any future rate case, the Board should require a showing that Iowa Utilities are achieving as much reduced demand as possible through the implementation of efficiency and demand-side management programs.

Additionally, MidAmerican's note that the no growth scenario "would result in higher per unit costs to customers due to fixed costs that must then be recovered over lower energy sales" is only true if the utility overbuilds now without giving itself the flexibility to add generation as needed. The board should take the no growth, or even low growth, scenarios into consideration as part of any rate case that asks ratepayers to pay for billions of dollars in coal-plant upgrades that might lead to excess capacity, and thus, resources that are not used and useful to MidAmerican's customers.

<u>IUB Question 7</u>: 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.

As noted above, the strategies do not articulate the control options necessary to comply with RCRA and CWA requirements. The strategies also fail to fully identify how the 1-hour SO2 ambient standards will impact individual plants. The Board should require compliance plans for all of these rules as part of this docket.

<u>IUB Question 8</u>: 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.

The last year has seen numerous reports and articles on how EPA rules might impact transmission. The most recent reports suggest that there will be little if any impact on reliability that any impacts are easily remedied, and in fact, the retirement of older inefficient plants might lead to a more reliable system. The attached letter was sent to the Office of Management and Budget on behalf of Sierra Club. In this letter, Sierra Club clearly articulates why reliability concerns have been overblown by industry trade groups. *See* Exhibit 11 attached.

All utility planning is done in a dynamic way to evaluate the impact of taking units offline. System reliability should not be an issue for a forward-looking operator that has been planning for the impact of regulation and determining whether a least-cost compliance strategy contemplates new generating resources. Just recently, IP&L and MidAmerican announced major new investments in generation, suggesting that both utilities are already thinking about the impact of taking old inefficient units online and replacing them with clean energy. "Utilities increase use of wind energy" Exhibit 2 attached.

In addition, there are many distributed generation policies within the board's authority that would result in a much more reliable electrical grid than we have today.

<u>Distributed Generation</u>

The U.S. Department of Energy, pursuant to the Energy Policy Act of 2005, issued a study of distributed generation. Department of Energy, <u>The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Its Expansion</u> (2007). That report provides the following definition of distributed generation:

> Electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side of the meter, or on the customer side.

Ordinarily, distributed generation refers to utility customers having their own generation source, such as solar panels or a small wind turbine. But the DOE report suggests that utilities can benefit from distributed generation, as well. These benefits would include supplementing a distribution system's

ability to supply sufficient power during periods of peak demand, providing ancillary services such as reactive power and voltage support, and improving power quality. These benefits would especially apply to RECs and municipals, which rely more heavily on the distribution system.

But, as noted above, distributed generation applies more generally to the customer side of the meter. Customer-owned generation is significant, however, in addressing the possible impacts of the EPA rules. This is because power generated by the customer is power that the utility does not need to generate and thus, the need for power from fossil fuels is reduced. Also, wind and solar energy is clean and does not generate pollution while it is generating electricity. There are several policies that utilities can undertake to promote distributed generation by the customers.

One such policy is net metering. Pursuant to the Board's rule at 199 I.A.C. §15.11(5), the rate-regulated utilities are now required to offer net metering to their customers. Although all electric utilities are required to provide net metering upon request of a customer according to the Energy Policy Act of 2005, this has not resulted in any uniform policy for net metering by RECs and municipals. But some RECs and municipals do offer net metering. Obviously, those who do, find it cost effective. And as explained previously with regard to energy efficiency, if the cost of fossil fuel sources rises, that will make net metering even more cost effective.

The Sierra Club believes that the Board has the authority pursuant to Iowa Code §§ 476.1A and 476.1B to require RECs and municipals to provide net metering. Requiring net metering does not involve setting the rates. It is essentially an interconnection issue and rather than setting rates, such a requirement would only specify how the customer is billed. The utility would still set the rates.

Another way to support distributed generation is through feed-in tariffs, sometimes called renewable energy payments. A feed-in tariff is a special fixed rate paid by utilities for renewable energy put onto the grid, under a contract set over a period of perhaps 15-25 years. That fixed rate is set at a higher price than the standard retail rate and is paid for by a slightly higher standard rate.

Feed-in tariffs have been employed successfully in Europe for several years. Denmark, for example, due to feed-in tariffs plans to generate 50% of its power from renewable sources by 2020. More recently, China and Japan have initiated feed-in tariff policies. The rapid growth of the solar and wind industries in these countries due to feed-in tariffs has driven down their costs to the point where grid parity has already been reached in sunny and windy regions, and has put them on course to reach parity worldwide by 2018. There is no reason this model should not work in the United States, and specifically in Iowa.

The utilities could certainly establish feed-in tariffs voluntarily to avoid the impacts of the EPA rules. And even though there is some lack of clarity in whether feed-in tariffs can be imposed by regulation, we believe the Board does have the authority to adopt such regulations. The problem arises from the requirement in the Public Utility Regulatory Policies Act (PURPA) that utilities must purchase power from renewable energy sources at the utility's avoided cost. Since a feed-in tariff would require payment by the utility above avoided cost, such a requirement might violate PURPA.

One strategy would be for the Board to establish a policy that would provide additional incentives. FERC precedent allows states to supplement avoided cost payments in one of three ways: (1) assigning renewable energy credits, (2) making cash grants or paying production-based incentives funded by the general budget or by ratepayers, or (3) establishing a purchase price that exceeds avoided cost but granting the purchasing utility a tax credit equal to the excess. Scott Hempling, Carolyn Elefant, Karlynn Cory, and Kevin Potter, Renewable Energy Prices in State-Level Feed-In Tariffs: Federal Law Constraints and Possible Solutions, NREL (January 2010).

For smaller renewable energy generators FERC has granted an exemption from seeking FERC approval for wholesale sales of electricity. Thus, for generators with capacity of 20 MW or less, if the generator is a qualifying facility and if FERC clarifies existing precedent, a feed-in tariff could be required. Hempling, et al., supra. With regard to FERC precedent, the Board could on its own, or by leading the National Association of Regulatory Utility Commissions, request clarification from FERC on this issue.

IUB Question 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.**

In the nearby states of Kansas, Minnesota, and Wisconsin, ratemaking for power plant retrofits may be decided through a type of "predetermination" of ratemaking principles. *See* KSA 66-1329; MCA 216B.1695; WI PSC Chapter 111. While each state's specific mechanism is different, they all allow the determination of ratemaking prudence before capital expenditures are made as opposed to traditional ratemaking, which does not address the prudency of an investment decision until after it is made.

Predetermination allows utilities some level of certainty that their investment decision is sound and that the commission will allow recovery for the capital expenses. Predetermination also allows the Board, and other stakeholders like the Sierra Club, the consumer advocate, industrial users, and others to participate in a major capital investment decision before the utility commits itself to one course of action. This process allows a holistic evaluation of all the alternatives available to the utility at the time of its decision to invest in an aging coal plant or to evaluate new cleaner alternatives.

The IUB should consider whether a predetermination process may work in Iowa and whether existing legislative authority would allow for it. If the IUB is faced with traditional ratemaking, it should require a utility that has decided to retrofit a coal plant to provide the following information:

-A thorough evaluation of all alternative generating resources available and their cost
-An evaluation of all EPA rules that are final and expected.
-An evaluation of the cost of compliance with EPA rules through the life of the units and how those costs would impact operating costs, and ultimately rates.
-An evaluation of demand-side management and energy efficiency programs both existing and planned. In addition, the utility should provide an explanation for its failure to fully utilize these options to reduce demand, and thus reduce the need for at least part of its proposed expenditure.

Consistent with our statements above, the Board should consider:

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 Subtitle 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 1-hour SO2 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 CASAC would impact future compliance.
5. In addition to the "replace with nuclear" option, require 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 Club under question 4 with supporting documentation filed for public review.

Sierra Club looks forward to working with the Board and the utilities in the state of Iowa to allow for a clean energy future that benefits all Iowans.

Respectfully submitted,

/s/ *Wallace L. Taylor*
WALLACE L. TAYLOR
118 3rd Ave. S.E. Suite 326
Cedar Rapids, Iowa 52401
319-366-2428
e-mail: wtaylorlaw@aol.com
Attorney for Sierra Club, Iowa Chapter

/s/ *Holly Bressett*
HOLLY BRESSETT
122 W. Washington Ave., Suite 830
Madison, Wisconsin 53703
608-257-4994
e-mail: holly.bressett@sierraclub.org
Attorney for Sierra Club, Iowa Chpater