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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-11-12**
MOUNTAIN POWER FOR	)	
APPROVAL OF CHANGES TO ITS	)	**Direct Testimony of Cathy S. Woollums**
ELECTRIC SERVICE SCHEDULES	)	
AND A PRICE INCREASE OF $32.7	)	
MILLION, OR APPROXIMATELY	)	
15.0 PERCENT	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-11-12

May 2011

Introduction

Q. Please state your name and business address and position.

A. My name is Cathy S. Woollums. My business address is 106 East Second Street, Davenport, Iowa. My position is senior vice president of environmental services and chief environmental counsel for MidAmerican Energy Holdings Company (MEHC). PacifiCorp is a subsidiary of MEHC.

Qualifications

Q. Please describe your education and business experience.

A. I received a Bachelor of Arts Degree in Political Science from Winona State University and a Juris Doctorate from Drake University Law School. I was admitted by examination to practice law in Iowa and Illinois and maintain my licensure in both states. Following law school, I served a one-year appointment as a law clerk in the 7th Judicial District in Iowa and then entered the private practice of law where I was engaged in general and litigation for approximately three years. I joined Iowa-Illinois Gas and Electric Company, a predecessor of MidAmerican Energy Company and MEHC, in 1991 where I served in the capacity of an attorney within the general counsel's office and handled environmental matters, among others. I became the manager of environmental services in 1995 and have held increasing positions of responsibility for environmental issues within MEHC. In my current role as the senior vice president of environmental services, I have responsibility for the development and implementation of MEHC's worldwide corporate environmental policy, strategy and programs, including the development of comments on proposed state and federal laws and regulations, integrating environmental assessments of existing and anticipated environmental regulations into planning and operating decisions of business units, and advising management of the impact of proposed regulations and developing potential compliance strategies. In addition, I oversee the organization's environmental compliance assurance management program, environmental permitting and reporting, and environmental litigation.

I have served on the Iowa State Bar Association's Environmental and Natural Resources Section Council, the Edison Electric Institute's Environment Executive Advisory Committee, the Iowa Climate Change Advisory Council, the Midwestern Governors' Association Power Sector Working Group, the Midwestern Governors' Renewable Electricity Advanced Coal with Carbon Capture Advisory Group, and The Climate Registry Advisory Committee. I was appointed to serve two terms as the Iowa governor's appointee to the Clean Air Act Compliance Advisory Panel, chaired the Iowa Association of Business and Industry's Environmental Committee for four years, and was recently invited to serve on the GHG Reporting and Mitigation Advisory Committee, a partnership of The Climate Registry and the Greenhouse Gas Management Institute.

Q. **Have you previously provided testimony before regulatory bodies?**

A. Yes. While I have not had the opportunity to testify before the Idaho Public Utilities Commission, I am a Company witness on environmental matters pending before the Wyoming Public Service Commission and I have testified in hearings before the Environmental Protection Agency ("EPA") and various state environmental proceedings. I have also provided testimony before various legislative bodies.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission and parties with information supporting the prudence of the Company's pollution control expenditures for coal-fired power generation plants and the Company's processes to identify environmental policy and compliance drivers that influenced the installation of the emissions controls that are subject to review in this case.

Q. Does your testimony discuss the complexity in balancing stakeholder interests that the Company faces in making prudent pollution control capital investment decisions?

A. Yes. There are many different viewpoints regarding whether the Company should make investments in its coal-fueled facilities. Some stakeholders take the position that it is imprudent to make those investments prior to the time they are absolutely required; some believe that the environmental regulations are too uncertain to make such investments. Others believe no controls should be installed because the units should be shut down. Compliance with current environmental requirements is necessary to ensure the availability of a reliable source of electricity at a reasonable cost, now and into the future.

Justification of Pollution Control Investment

Q. Why has the Company invested in pollution control equipment?

A. Because it is legally required to do so. Through the 1977 amendments to the Clean Air Act, Congress set a national goal for visibility to remedy impairment from manmade emissions in designated national parks and wilderness areas; this goal resulted in development of the Regional Haze Rules, adopted in 2005 by the EPA. The first phase of these rules trigger Best Available Retrofit Technology ("BART") reviews for all coal-fired generation facilities built between 1962 and 1977 that emit at least 250 tons of visibility-impairing pollution per year. Visibility-impairing pollutants include sulfur dioxide SO_2, nitrogen oxides NO_x and particulate matter ("PM"). The Company has 14 units that meet the construction and emissions threshold criteria and are, therefore, "BART-eligible units." Pursuant to federal regulations at 40 CFR 51.308(e)(1)(ii), each state is required to determine which BART-eligible sources are also "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to impairment of visibility in any designated national park or wilderness area. The investments in pollution control equipment are at the Company's BART-eligible units that have been determined by the state environmental regulators to be necessary after considering available technology; costs of compliance; energy and non-air quality environmental impacts; existing control equipment and the remaining useful life of the facility; and the degree of improvement in visibility reasonably anticipated to result from the use of such technology.

Q. Have the state environmental agencies in Wyoming and Utah completed their BART determinations?

Yes. After considering these five factors, the respective state departments of environmental quality for the units made their BART determinations and incorporated the results of the above mentioned BART analyses into the operating permits, construction permits and Approval Orders (defined below) for the pollution control equipment included in this case.

With respect to the Naughton Unit 2 low NO_X burners and Wyodak low NO_X burners and bag house projects, the Wyoming Department of Environmental Quality ("WY DEQ") issued BART permits for those units on December 31, 2009, incorporating the equipment and installation schedules recommended via the BART reviews. The conditions of the BART permits have been incorporated into the Wyoming State Implementation Plan ("SIP") for Regional Haze in support of its goals to reduce visibility impairing emissions. The Wyoming SIP is subject to EPA review and approval. The WY DEQ has also issued construction permits for the Naughton, Wyodak, and Jim Bridger pollution control projects included in this case.

With respect to the Hunter Unit 2 and Huntington Unit 1 projects, the Utah Department of Environmental Quality ("UT DEQ") has incorporated the results of BART reviews completed for those facilities into the Utah SIP. The Utah SIP is also subject to EPA review and approval. The State of Utah has also issued Approval Orders (*i.e.*, permits to construct) for each of the Hunter and Huntington pollution control projects included in this case.

Q. Are the Regional Haze regulations final?

A. Yes. The Regional Haze regulations were initially adopted in 1999 but were appealed and revised, with amended regulations being issued in 2005. Both Utah and Wyoming submitted their initial Regional Haze state implementation plans in

2003, in 2008, and again in 2011, focusing on meeting emission reduction goals to improve visibility. The attached Exhibit No. 18 demonstrates the EPA's timeline for states to implement the Regional Haze rule; however, the timeline does not include the time for EPA to take final action on the proposed regional haze state implementation plans. The 2011 state implementation plan submittals are final insofar as state action is considered; these submittals have not yet been approved by the EPA but, nonetheless, do result in substantive requirements being imposed on the Company's facilities. These requirements are confirmed in the WY DEQ's Decision Document on the Company's BART permit applications dated December 31, 2009, noting:

> The entire submittal is currently undergoing EPA review and the State has no control over how long the EPA takes to review the SIP. The State, however, does not wait for EPA to complete its review before implementing a SIP. . .The SO_2 levels have shown compliance with the milestones and continue to demonstrate declining SO_2 emissions levels.

Q. **Do the pollution control investments included in this case also support compliance with other environmental regulations?**

A. Yes. In addition to the BART requirements under the Regional Haze Rules, increasingly more stringent National Ambient Air Quality Standards have been and are being adopted for criteria pollutants, including SO_2, NO_2, ozone, and PM. Implementation of the pollution control projects described herein assists in meeting these more stringent standards, avoiding the negative consequences of an area being declared to be a nonattainment area. Further, while the Clean Air Mercury Rule, which would have required a reduction of mercury emissions of approximately 70 percent by 2018, was overturned by the United States Court of

Appeals for the District of Columbia Circuit in February 2008, the EPA has proposed a new rule that will require coal-fired generating facilities to reduce mercury, and other emissions of hazardous air pollutants, through a Maximum Achievable Control Technology (MACT) standard. Under a consent decree, the EPA issued a proposed rule to regulate hazardous air pollutant emissions in March 2011 and must issue a final rule no later than November 2011. Compliance with the final standards is expected to be required by November 2014. The bag house and scrubber projects described herein will assist in meeting the forthcoming MACT requirements.

Utah also has specific state regulations (State Rule 307-424-4) that require electric generating units to meet specific mercury emission rates or control efficiencies, notwithstanding any federal rules. The bag house and scrubber projects at the Hunter and Huntington facilities will assist in meeting the requirements of that regulation as well.

In short, the pollution control investments contemplated in this case are required to maintain compliance with the environmental requirements described above.

Q. **Please clarify the definition of a "presumptive BART emission limit" as it pertains to established federal pollution control standards.**

A. The use of the term "presumptive BART emission limit" in the instance cited does not mean that BART emission limits are uncertain future requirements. Instead, the use of the term refers to emission rates identified in the Regional Haze Rule, Code of Federal Regulations (CFR), Title 40, Sections 51.300 through

51.309, and Appendix Y. Electronic copies of the referenced CFRs can be found at the following link:

http://www.access.gpo.gov/nara/cfr/waisidx_09/40cfr51_09.html

Presumptive BART emission limits come from Appendix Y cited above, and are rates defined by the EPA. States use the rates defined by the EPA to assist in determining whether a BART-eligible facility is presumed to meet the requirement to install best available retrofit technology. For example, if the installation of low-NOx burners on a BART-eligible facility with cell-burners firing sub-bituminous coal achieves an emission rate of 0.28 lb/MMBtu, which is below the EPA presumptive BART rate of 0.45 lb/mmBtu (the presumptive rate for a cell-burner unit burning sub-bituminous coal), it can be presumed that the installation of low-NO_x burners on this unit meets federal BART requirements with respect to NO_x control, and no additional controls would be likely to be required. With respect to SO_2 control, the states of Utah and Wyoming, along with New Mexico, are participating in a market-trading program identified in the Regional Haze Rule, CFR, Title 40, Section 51.309. Under this program the states have set SO_2 emission reduction milestones that must be achieved. These milestones have been developed assuming that each coal-fired generating unit meets the lower of its historic emission rate or the presumptive SO_2 rate. The EPA has defined the presumptive SO_2 emissions rate as 0.15 lb/mmBtu or 90 percent removal. Here again, if the installation of pollution control equipment on a BART-eligible facility achieves an emission rate less than that presumptive limit and overall emission reduction goals are being met, it can be presumed that the installation meets federal BART requirements and no additional controls will be required.

Q. Please describe the process the Company engages in to determine whether to make investments in environmental controls.

A. First and foremost in the decision to invest in environmental controls are the Company's compliance obligations. If a permit or regulation requires the Company's plants to reduce emissions or achieve emission limits that cannot be met with existing equipment, compliance options are examined to ascertain what equipment can be installed to achieve the emission requirements. The Company also monitors state and federal rulemaking activities and legislative proposals that would have an impact on the facilities' operations. Monitoring these future requirements allows the Company to ensure it is taking a longer term view of the potential investments that may be required to lawfully continue operation of the facilities.

Q. How does the Company plan for existing and future environmental requirements?

A. Existing environmental permit and regulatory requirements, such as operating within a permitted emission limit or complying with the regulatory requirements of waste management activities, are implemented through operating practices, procedures, and plans on a daily basis within the Company's operating facilities. New compliance obligations may be imposed when operating permits are renewed or applied for to reflect changes in regulatory requirements. To assess the potential impacts of new environmental regulatory initiatives, the Company employs environmental professionals in the business units who coordinate with dedicated staff in the environmental policy and strategy group; we review proposed and final regulatory requirements and are actively engaged in the regulatory processes at both the state and at the federal level. We seek feedback from our environmental regulators to assess their concerns, read and analyze legislation and regulations proposed at the state and federal levels, provide feedback on legislation, and review and comment on proposed regulations. The Company submits written comments in regulatory proceedings and participates in public hearings on the proposals, ensuring that the Company's concerns or support, as appropriate, are considered in these public forums. We are both well informed and engaged on these issues.

In addition, when significant environmental rulemaking or legislative proposals are released, we assess those proposals and advise Company management of the potential impacts of the proposals. If the preliminary or final form of a proposal would alter the Company's business plan, those plans may be amended to reflect the likely impact on the Company to achieve compliance with the requirements within the relevant compliance period after considering our compliance options.

Q. **When you consider the Company's compliance options, what factors are considered?**

A. There are a multitude of factors, depending on the specific regulation. If a regulation prescribes a specific emissions limit, the Company reviews what types of controls may be available to achieve the requisite emissions limit, given the specific characteristics of each unit. System impacts, reliability, capital costs, operating and maintenance costs, the life of the controls, the life of the unit itself, cost of replacement generation, and other factors are all considered. If an emissions trading mechanism is available to achieve compliance, the costs of obtaining the emissions allowances is compared to the costs to install and operate controls, considering the factors noted above.

Timing of Investments

Q. How are future environmental requirements factored into the Company's analysis of its environmental compliance options?

A. The Company develops a base set of environmental assumptions that reflects the most likely scenarios to comply with air, water and waste regulations for inclusion in the development of its annual business planning process. These environmental assumptions reflect both existing and expected requirements under the most likely scenario and are utilized as the basis for the Company's integrated resource planning as well as for the Company's 10-year business plan. We also examine the actual and potential compliance timeframes and how those timeframes may be coordinated with planned plant outage schedules. Coordinating major environmental control projects with existing outage schedules allows the Company to avoid additional outage time, reducing the need for replacement power, minimizes costs, and maintains system reliability.

Q. Why is PacifiCorp installing pollution control equipment at this time?

A. The Company is installing pollution control equipment at this time to comply with the Regional Haze Rules, as well as in response to more stringent National

Ambient Air Quality Standards, the impending mercury requirements, and a number of existing and emerging emission reduction requirements. Final installation activities and tie-in of the pollution control equipment described above can only be accomplished when the units are off-line. Meeting the timing requirements of construction permits and Approval Orders and reducing plant outage time necessitated completion of final installation activities and tie-in of the pollution control equipment during the scheduled overhauls within this test period. Installation of the pollution control equipment and associated systems included in this case represent a significant step for PacifiCorp's coal-fueled power plant fleet toward meeting the SO_2 and NO_X reductions required by the Regional Haze Rules and established by the respective states' emissions reduction milestones.

Q. Has the Company installed the pollution control investments presented in this case prematurely?

A. No. The Company has been engaged in Regional Haze Rule compliance planning with the respective state departments of environmental control since the initial development of the western states' regional program. During the initial 2003 to 2008 planning period, the Company was required by the Wyoming Division of Air Quality ("WDAQ") to conduct detailed BART reviews. It was the initial expectation of the western states' regional haze program that individual states would establish BART emission limits for BART eligible units and would require installation of appropriate controls by 2013. PacifiCorp originally submitted these evaluations of its BART eligible facilities in Wyoming in January 2007, with revisions submitted in October 2007. Addendums to individual facility BART reviews were developed in March 2008. WDAQ completed its final reviews of the BART evaluations and the Company's associated permit applications and issued Air Quality Permits (construction permits) for the projects presented in this case in May 2009. WDAQ followed up by issuing BART permits for the pollution control projects presented in this case in December 2009. The pollution control projects presented in this case meet the Company's obligations in this regard.

Q. Did the Company follow a similar process for its Utah coal fueled plants?

A. Yes. For the Hunter and Huntington scrubber projects the Company completed detailed scrubber technology screening studies in 2007 and submitted its Notice of Intent (construction permit) applications to the Utah Division of Air Quality ("UDAQ") for the Hunter project in November 2007, with supplements submitted in December 2007, and its Notice of Intent application for the Huntington project in April 2008, with a supplement submitted in January 2009. UDAQ completed its final reviews of the Company's permit applications for the pollution control projects and issued Approval Orders (construction permits) in March 2008 for the Hunter projects and January 2010 for the Huntington projects. UDAQ also included these projects in its regional haze SIP in 2008. The pollution control projects presented in this case meet the Company's obligations in this regard.

Q. Do the timelines discussed above provide a reasonable progression of evaluation, agency coordination, and decision-making for the respective pollution control projects?

A. Yes. The pollution control projects presented in this case are extremely complex and require a significant amount of evaluation and planning to bring to fruition. The permitting processes described above are required to define the technical requirements the Company needs to move forward with establishing competitive pricing for the work and ultimately executing the projects. The timeline for securing contracts for this type of work through project completion often has a multi-year duration.

Q. Did other regional emissions control regulations impact planning of the Company's scrubber projects?

A. Yes. The states of Utah and Wyoming also participate in a Regional SO_2 Milestones and Backstop Trading Program. These pollution control investments support the milestones established in these states as part of this program.

Q. Did the Company consider future environmental requirements when undertaking the emission reduction projects proposed for cost recovery in this case?

A. Yes. While the projects proposed in this case were implemented as a result of current environmental requirements, the Company also considered the need for the emission reductions and the type of controls that could be required in the future when it planned for these projects. There are a multitude of environmental requirements the electric industry faces over the next several years. Exhibit No. 19, referenced colloquially as the so-called "EPA train wreck" slide, identifies some of the requirements that are currently underway or in development. There is a great deal of uncertainly associated with future environmental requirements; however, the Company must comply with the requirements that exist today and prepare for the regulations that will be adopted in the future.

Q. Is there emission reduction equipment that is being installed to comply with the requirements that exist today that would not be required in the future?

A. No. The controls are required to comply with existing requirements. Further, the addition of scrubbers, low-NO_x burners and baghouses will position the Company well to meet impending environmental requirements, including the Utility Hazardous Air Pollutant Maximum Achievable Control Technology standards that were proposed on March 16, 2011, and will be final in November 2011.

Q. Did the Company need to make the investments included in this case if it expects to continue operating the plants?

A. Yes. In order to comply with the requirements that are set forth in the facilities' air quality permits, it is necessary to install and operate the controls in question. The Company has an obligation to operate its facilities in compliance with its permit requirements and the applicable laws and regulations. There have been many electric utilities around the country that have made announcements that they plan to retire plants rather than make investments in emissions control equipment. These planned retirements are not limited to coal-fueled plants, as evidenced by Exelon's December 8, 2010, announcement that it would shut its Oyster Creek nuclear plant ten years early to avoid having to comply with a requirement to install cooling towers, because doing so would cost more than the value of the plant.[1] The Company does not have plans to shut down the facilities in which the proposed investments have been made.

[1] See: http://www.nytimes.com/2010/12/09/nyregion/09nuke.html?_r=1&partner=rss&emc=rss

Q. Shouldn't the uncertainty associated with future environmental regulations weigh in favor of waiting until the regulations are final to install any controls?

A. No. The full and final scope of environmental regulations is not easily determined, particularly when rulemakings are often lengthy in their own right and just as often followed by extensive and lengthy litigation before the rule is finalized. Perfect foresight is not possible; the EPA has recently begun to acknowledge that its approach to regulation makes it difficult for companies with compliance obligations to make long-term decisions on compliance. In EPA Administrator Lisa Jackson's remarks prepared on the release of the Utility Hazardous Air Pollutants Maximum Achievable Control Technology standards (HAPs MACT) on March 16, 2011, she stated:

> The proposal and implementation of these standards will also have benefits for American utilities. For the first time in twenty years, they will have certainty about the standards they must meet. And setting national standards for mercury and air toxics will level the competitive playing field and close loopholes for big polluters. Utilities that have already put pollution control technology in place will no longer have to compete with those who have delayed those investments – a group that includes almost half of the nation's coal-fired plants, which lack advanced pollution control equipment. In fact, facilities that have already taken responsible steps to reduce the release of toxins into our air will be at a competitive advantage over their heavy-polluting counterparts. And to ensure cost-effectiveness, we have proposed flexibility in meeting the standards. The technologies being required already exist in abundance, and under the proposal, power providers have four years to comply.[2]

The lack of certainty in environmental regulation is well recognized, but

[2] Remarks available at: http://yosemite.epa.gov/opa/admpress.nsf/12a744ff56dbff8585257590004750b6/b7e570d651cadc03852578550057011c!OpenDocument

does not obviate existing compliance obligations. The uncertainty of future environmental regulations is also acknowledged by state utility regulators. On February 16, 2011, the National Association of Regulatory Utility Commissioners Board of Directors adopted a resolution, included as Exhibit No. 20, urging the EPA to ensure, as the agency develops public health and environmental programs, that reliability, cost, compounded economic impacts of multiple environmental rulemakings, and flexibility of timeframes for compliance be considered.

Q. **Does the Company believe that any of the emissions control equipment subject to review in this proceeding will not be necessary as a result of future environmental requirements?**

A. No. The Company does not anticipate that environmental regulations will become less stringent and history demonstrates that regulations become more stringent over time. The controls subject to review in this proceeding are necessary to allow the Company to continue operating these facilities given that increasing stringency. Further, the Company's analysis suggests that these controls place the facilities in a position to continue to generate reasonably priced electricity under contemplated environmental regulations, even if greenhouse gas legislation is adopted. The Company's analysis suggests that the cost of carbon under a regulatory regime for greenhouse gas emissions would have to approach $40 per ton with gas prices sustained below the $7 - $9/mmBtu range to begin to make replacement of coal-fueled resources cost effective prior to 2030. Utilizing greenhouse gas reduction requirements as a basis for current investment decisions is highly speculative given that the current Congressional activity is focused on delay or repeal of the EPA's authority to regulate greenhouse gases, and not on a comprehensive legislative effort to reduce greenhouse gas emissions.

Additionally, in the course of applying environmental requirements to the Company's facilities, the respective state Department of Environmental Quality or the EPA consider what constitutes cost-effective emission reductions, taking the position that all cost-effective reductions are required. As discussed earlier in my testimony, in the context of the Regional Haze program's Best Available Retrofit Technology determinations, the reviewing environmental agency must consider:

(a) the costs of compliance;

(b) the energy and non-air quality environmental impacts of compliance;

(c) any existing pollution control technology in use at the source;

(d) the remaining useful life of the source; and,

(e) the degree of visibility improvement which may reasonably be anticipated from the use of BART.

Within the foregoing mandatory BART factors are considerations such as greenhouse gas regulation and other environmental regulatory drivers that may have an impact on the remaining useful life of the source are considered.

Q. Should the Company wait until all the regulations are considered, finalized, and quantified to install controls?

A. No. Doing so would put the facilities at substantial risk of noncompliance and does not reflect the reality of the multistate operations and planning process for a utility the size of PacifiCorp. Moreover, it would be imprudent for a utility the size of PacifiCorp to assume it can install all required controls under a "just-in-time" plan. This approach to compliance poses a significant risk to the Company and its stakeholders; as a practical matter, it cannot be economically achieved on a system the size of the Company's. Emission reduction projects are complex, multi-year projects. Trying to install multiple controls within the same short time frames poses a significant risk of noncompliance with penalties that can be substantial. Even if a regulatory agency did not impose penalties for failing to achieve emission reduction deadlines, third parties have not hesitated to bring lawsuits against the operators of those facilities that miss deadlines or are otherwise not in compliance with permit and emission limits. Indeed, the federal clean air act specifically allows for private citizen enforcement of air quality requirements.

Considering future environmental regulatory requirements such as the HAPs MACT when planning compliance projects for existing regulations avoids the concern many companies are expressing about the short three-year compliance period. Because the HAPs MACT had its genesis in the Clean Air Mercury Rule, which was issued by the EPA in 2005 but vacated by the court in 2008, the Company was able to, and did, consider the potential impacts of a mercury rule on its equipment decisions.

If a company waits for a rule to become final to begin to develop its compliance strategy, it may find itself in a situation similar to facilities in Oklahoma where the EPA recently rejected the state's implementation plan for Regional Haze and has required that companies install scrubbers on three plants or switch to natural gas within three years at a cost of approximately $1 billion.

The permitting, procurement and installation of such equipment in such a short time frame is challenging, if not impossible, and creates significant inefficiencies and cost increases.

Q. **Do you believe that the Company may need to change the controls that are subject to review in this case if the EPA does not approve the State Implementation Plans?**

A. No. The controls at issue, including scrubbers, low NO_x burners, and baghouses are important controls to meet both existing and future environmental regulations. Emission reduction projects completed under the Regional Haze regulations for SO_2, NO_x, and particulate matter will also serve to reduce mercury and other non-mercury hazardous air pollutants, consistent with the Utility HAPs MACT that will be finalized later this year. Likewise, these controls will assist in achieving attainment with the National Ambient Air Quality Standards, including the fine particulate standard, and the one-hour SO_2 standard as well as the impending revised ozone standard. Even if additional controls for NO_x, such as selective catalytic reduction (SCR) are required, the installation of combustion controls such as low-NO_x burners is an important step in achieving lower-cost NO_x reductions so that post-combustion controls are more efficient and operating costs are lower.

Q. **Why doesn't the Company wait until it knows the outcome of all air quality, waste and water rules to implement its environmental projects?**

A. The structure of the EPA and the nature of its rulemaking process are not conducive to the agency producing coordinated air quality, waste and water rules for the electricity sector; these media-based rules address different issues through varying methods with different compliance timeframes. Nonetheless, the Company undertakes efforts to ensure that the potential compliance requirements for all these rulemaking activities are understood and reflected in its plans, making decisions based on the best available information at the time the decisions are made and updating that information as additional details on requirements become available.

Environmental regulations and the cost of implementation are only one factor that influences whether or not to make investments in environmental projects; the Company also must consider the cost of alternative generation. Future natural gas prices, construction costs for renewable generation, and associated transmission availability and costs are also among the factors that are contemplated in a determination of whether it is economic to install controls at coal-fueled plants.

Q. Would the Company's decision to make these incremental investments in environmental controls at these units change if additional limitations were placed on carbon dioxide emissions?

A. No. The Company is engaged in assessing its existing generation resources, its planned supply and demand-side resources and its 10-year capital budget with respect to the impact of potential carbon dioxide emissions restrictions. While other planned investments may change, the Company's plans regarding the emission control investments included in this case would not change as a result of carbon-emission restrictions. The current controls are required under existing regulations and the units have depreciation lives for ratemaking purposes that provide sufficient remaining time to depreciate the investments in the environmental controls. While carbon restrictions may ultimately affect the cost of generating electricity at these units, they are still anticipated to be utilized as part of the Company's overall generating fleet that will be necessary to provide base load electricity at a reasonable cost to customers.

Q. **What efforts are being taken by the Company to understand and evaluate impacts of potential future environmental regulations on the Company's business?**

A. PacifiCorp and its parent, MidAmerican Energy Holdings Company, are active in the current state and federal legislative and agency activities regarding environmental controls affecting virtually all emissions from coal and natural gas generating units, and other environmental issues. The Company is cognizant that some potential restrictions on greenhouse gas emissions ("GHGs") could require coal (and potentially natural gas) units to adjust the depreciation lives for ratemaking purposes. The Company considers this possibility when determining whether to precede with pollution control investments.

Q. **Is the Company undertaking reasonable efforts to ensure that environmental regulators consider the uncertainty created by requiring investments in certain emissions controls prior to knowing the nature and extent of controls on other emissions?**

A. Yes. The Company filed an appeal of certain BART permits in Wyoming for this exact reason. Wyoming was the first state to make the determination that BART required the installation of SCR controls for nitrogen oxides at Naughton Unit 3, and also to impose long-term strategy requirements for SCR in a BART permit for all four units at the Jim Bridger plant. The Company disagreed with the determination that SCR was BART and asserted that Appendix Y of 40 CFR Part 51 did not contemplate the installation of post-combustion controls. The Company further disagreed that a long-term strategy requirement could be included in a BART permit. Additionally, the Company was concerned that other environmental laws and/or regulations could impact the Company's facilities affected by Wyoming's BART determinations in a way that impacted the economic analysis associated with the installation of the contemplated controls. These requirements not only include greenhouse gas reduction requirements, but also a host of regulatory initiatives underway by the EPA, including the outcome of pending coal combustion waste disposal regulations and MACT standards for mercury and non-mercury HAPs. Due to the uncertainty associated with the potential impact of these rules on the Company's facilities, the Company appealed the BART permits to ensure that these and other issues were considered in the agency's decision and, to the extent these issues had an impact on long-term viability of the facilities, the economic analysis of adding emission reduction equipment was properly reflected.

Q. Has this appeal been resolved?

A. Yes. In November 2010, PacifiCorp settled the Wyoming BART appeal to resolve the matter in a way that did not require more controls and impose additional costs earlier than originally proposed in the Department of Environmental Quality's

BART permits. To provide maximum flexibility in the event that other environmental requirements or uncertainties arose, PacifiCorp and the WY DEQ included terms in the settlement agreement to address a modification if future changes in either federal or state requirements or technology would materially alter the emissions controls and rates that would otherwise be required.

Q. Has the Company undertaken additional efforts to eliminate some of the uncertainty associated with future environmental regulations?

A. Yes. Given the so-called "EPA train wreck" facing the electric industry, the Company worked on a comprehensive approach to addressing the ever-changing and looming environmental requirements. Called REPLACES (The Retirement Plan Act for Coal-Fueled Electricity Sources), the Company undertook an effort to develop a comprehensive plan intended to harmonize environmental requirements with the nation's desire to shift to cleaner energy sources in a way that allows for a smoother transition and minimizes costs and risks by clearly identifying the requirements and timeframes that must be met, rather than being faced with constantly changing environmental requirements that make long-term investment decisions difficult.

Q. Would the proposed MidAmerican Energy Holdings Company REPLACES program result in the Company requesting accelerated depreciation treatment of pollution control investments contemplated in this case?

A. No. The goal of REPLACES (attached as Exhibit No. 21) is to address the current patchwork of existing and projected emission reduction requirements and define a clear long-term regulatory path to allow owners of coal-fueled power plants to economically plan for the viability of electrical generating units by phasing in unit retirements beginning with older, smaller units to allow for a smoother transition while replacement generation is brought online and newer technologies are developed. The REPLACES proposal reflects the Company's view that it does not make economic sense to install significant emission control on units that are likely to retire because of the creation of stranded cost for limited environmental benefit. Under REPLACES, all existing coal-fueled electric generating units would be retired, controlled or retrofitted over a period of time and near-term environmental regulatory relief would be granted for facilities that retire by 2020. Similar proposals have been advanced by other organizations seeking near-term regulatory relief but to date none have been adopted.

Q. Please summarize your testimony.

A. As previously discussed, the Company has undertaken significant efforts with permitting agencies to ensure that its environmental control investments are timely to ensure compliance with existing environmental requirements, that they proceed in a reasoned fashion, and that they are coordinated with existing outage schedules to avoid additional outage time associated with equipment tie-in. These coordinated efforts reduce costs associated with replacement power and maintain system reliability.

Due to the number of PacifiCorp's generating units impacted by environmental regulation, deferring installation of compliance-related projects is often not feasible or cost-effective and places the Company and its customers at risk of not having access to necessary capital, material, and labor while attempting to perform major equipment installations in a compressed timeframe concurrent with other utilities. For example, in the eastern United States, utilities are required to install controls under the Clean Air Transport Rule during the same 2012-2014 time frame within which compliance with the Utility HAPs MACT is required.

We have already seen a rise in project costs in anticipation of the increased demand for labor and equipment. PacifiCorp's sister company, MidAmerican Energy Company, has just negotiated a contract for the installation of scrubbers and baghouses at two of its facilities in 2013 and 2014 and the costs are approximately 20 percent higher than anticipated. The timing of the investments is also important for ensuring that the Company is in compliance and is not subject to penalties for noncompliance or third party lawsuits.

Q. Does this conclude your testimony?

A. Yes.

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Case No. PAC-E-11-12
Exhibit No. 18
Witness: Cathy S. Woollums

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Cathy S. Woollums

Regional Haze Timeline

May 2011

Regional Haze

Timeline for States to Implement EPA's Rule

Year	Event
1999	EPA issues final Regional Haze Rule
2001	PM 2.5 Monitors in place
2003-5	EPA designates PM 2.5 areas as "nonattainment", "attainment", or "unclassifiable"
2004-6	Areas designated "Attainment" & "Unclassifiable" - States submit haze plans (establish progress goals and control strategies) 1 year from PM 2.5 designation date
2004-6	Option- Regional Planning States commit to regional planning and submit haze plans one year after EPA designates first area within State
2006-8	Areas designated "Nonattainment" - States submit haze plans (establish progress goals and control strategies) 3 years from PM 2.5 designation date
2008	Option- Regional Planning States submit complete haze control strategy plans (establish progress goals and control strategies)
2011-13	Option- States complete source-specific Best Available Retro-fit Technology (BART) controls
2013	States submit progress reports on "reasonable progress" goals and strategies (every 5 years thereafter)
2016-18	Option- States complete emissions trading or alternative control measures
2018	States complete revised haze plans (every 10 years thereafter)

Option for Grand Canyon Visibility Transport Commission (GCVTC) Areas

Year	Event
2000	States submit annex to original GCVTC report (establish SO_2 milestones)
2003	States submit haze control strategy plans for 16 original areas
2008	Latest date for States to submit haze control strategy plans for other Class I areas
2018	States complete revised haze plans (every 10 years thereafter)

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Witness: Cathy S. Woollums

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

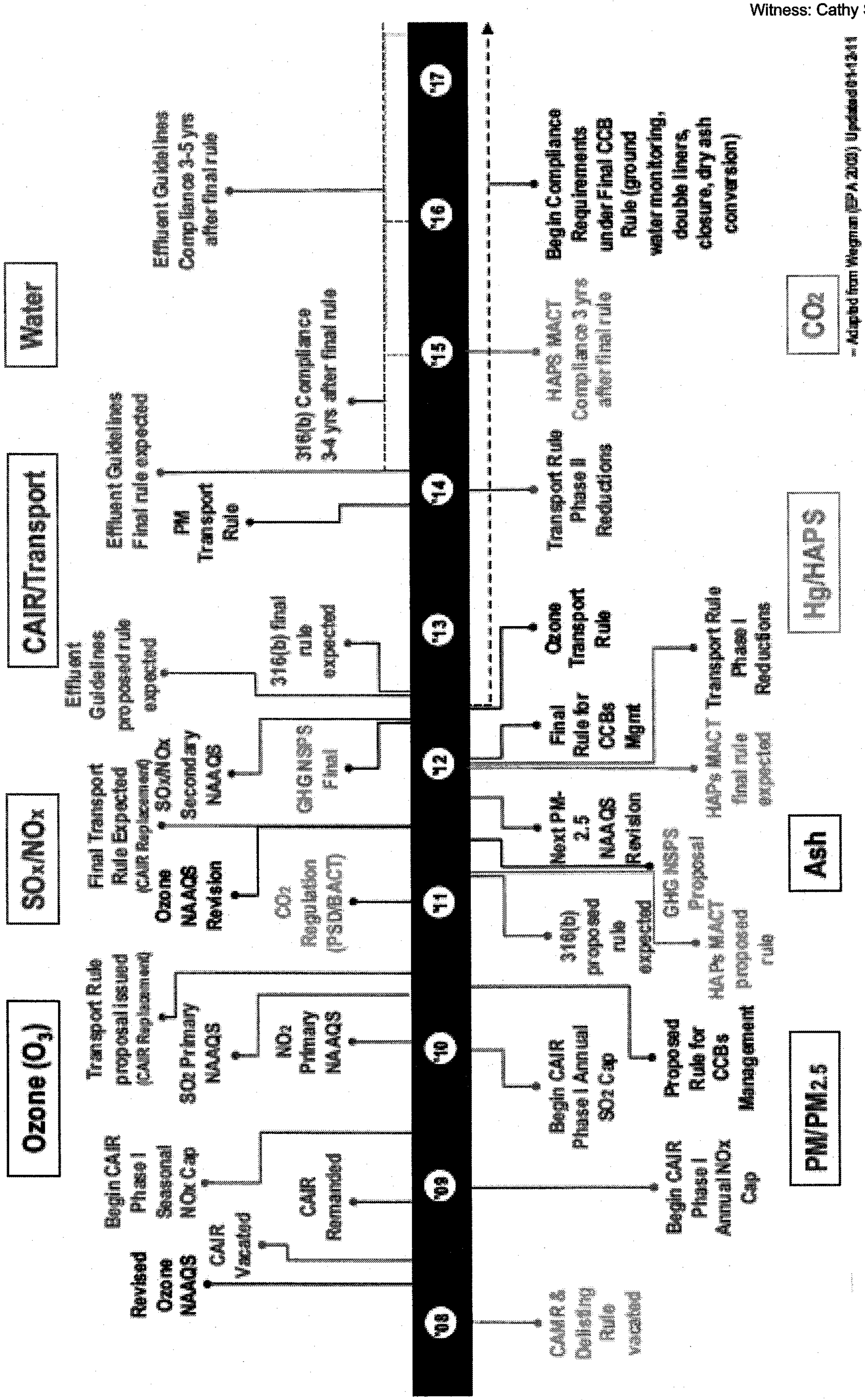
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Cathy S. Woollums

EPA "Train Wreck"

May 2011

Rocky Mountain Power
Exhibit No. 19 Page 1 of 1
Case No. PAC-E-11-12
Witness: Cathy S. Woollums



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Case No. PAC-E-11-12
Exhibit No. 20
Witness: Cathy S. Woollums

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Cathy S. Woollums

NARUC Resolution

May 2011

Resolution on the Role of State Regulatory Policies in the Development of Federal Environmental Regulations[1]

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC) recognizes that the U.S. Environmental Protection Agency (EPA) is engaged in the development of public health and environmental regulations that will directly affect the electric power sector; *and*

WHEREAS, EPA is expected to promulgate regulations to be implemented by State environmental regulators concerning the interstate transport of sulfur dioxide and nitrogen oxides, cooling water intake, emissions of hazardous air pollutants and greenhouse gases, release of toxic and thermal pollution into waterways, and management of coal combustion solid waste; *and*

WHEREAS, NARUC at this time takes no position regarding the merits of these EPA rulemakings; *and*

WHEREAS, Such regulations under consideration by EPA could pose significant challenges for the electric power sector, with respect to the economic burden, the feasibility of implementation by the contemplated deadlines and the maintenance of system reliability; *and*

WHEREAS, EPA is expected to provide opportunities for public comment and input with respect to forthcoming regulations; *and*

WHEREAS, Compliance with forthcoming environmental regulations will affect consumers differently depending upon each State's electricity market and the nature of the decisions made by State regulators; *and*

WHEREAS, Addressing compliance with multiple regulatory requirements at the same time may help to reduce overall compliance costs and minimize risk assuming reasonable flexibility with respect to deadlines; *and*

WHEREAS, State utility regulators are well positioned to evaluate risks and benefits of various resource options through policies that appropriately account for and mitigate the risks arising from compliance with pending regulations; *and*

WHEREAS, Cooperation between utility commissions and environmental regulators can promote greater policy coordination and integration and improve the quality and effectiveness of electricity sector regulation; *and*

WHEREAS, State utility regulators, by working with the power sector and State and federal environmental regulators, can help to facilitate least-cost compliance with public health and environmental goals; *and*

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[1] Based upon Resolution on *Implications of Climate Policy for Ratepayers and Public Utilities*, adopted by NARUC Board of Directors on July 18, 2007.

WHEREAS, State utility regulators can help to minimize environmental risk as well as uncertainty regarding reliability and customer rate impacts by requesting regulated utilities with fossil generation to develop plans that evaluate all relevant environmental rulemakings at U.S. EPA; *now, therefore, be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2011 Winter Committee Meetings in Washington D.C., urges the EPA to ensure that, as it develops public health and environmental programs, it will:

- Avoid compromising energy system reliability;
- Seek ways to minimize cost impacts to consumers;
- Ensure that its actions do not impair the availability of adequate electricity and natural gas resources;
- Consider cumulative economic and reliability impacts in the process of developing multiple environmental rulemakings that impact the electricity sector;
- Recognize the needs of States and regions to deploy a diverse portfolio of cost-effective supply-side and demand-side resources based on the unique circumstances of each State and region;
- Encourage the development of innovative, multi-pollutant solutions to emissions challenges as well as collaborative research and development efforts in conjunction with the U.S. Department of Energy;
- Employ rigorous cost-benefit analyses consistent with federal law, in order to ensure sound public policy outcomes;
- Provide an appropriate degree of flexibility and timeframes for compliance that recognizes the highly localized and regional nature of the provision of electricity services in the U.S;
- Engage in timely and meaningful dialog with State energy regulators in pursuit of these objectives; *and*
- Recognize and account for, where possible, State or regional efforts already undertaken to address environmental challenges; *and be it further*

RESOLVED, That NARUC urges State utility regulators to actively engage with State and federal environmental regulators and to take other appropriate actions in furtherance of the goals of this resolution.

Sponsored by the Committees on Electricity and Energy Resources and the Environment
Adopted by the NARUC Board of Directors February 16, 2011

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Case No. PAC-E-11-12
Exhibit No. 21
Witness: Cathy S. Woollums

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Cathy S. Woollums

REPLACES Document

May 2011

MIDAMERICAN
ENERGY HOLDINGS COMPANY

REPLACES: The Retirement Plan Act for Coal-Fueled Electricity Sources

Version 2.0

Overview of a Multimedia Compliance Program for Coal-Fueled Electricity Sources

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The REPLACES program promotes the reduction of traditional pollutants and greenhouse gas emissions by requiring the retirement, control, or retrofit of all existing coal-fueled electric generating units[1], as well as the adoption of a new coal unit performance standard that applies on or after January 1, 2015. It will provide certainty regarding regulatory requirements for existing coal-fueled electric generating units, incentivize earlier retirements and retrofits of existing coal-fueled electric generating units, allow for continued development and ultimate implementation of new clean coal technologies and nuclear power, and continue tax credits to support additional renewable energy development.

The REPLACES program requires the retirement, control, or retrofit of all existing coal-fueled electric generating units over a phased-in period, concluding in 2055. It also seeks near-term regulatory relief for coal-fueled units that cease operation permanently prior by December 31, 2020, as well as harmonization of the U.S. Environmental Protection Agency's regulatory authority for various rules including, but not limited to, new source performance standards, national emissions standards for hazardous air pollutants, national ambient air quality standards, and new source review programs for coal-fueled units that will continue to operate after December 31, 2020.

Applicability

For purposes of the REPLACES program;

i. A "covered electric utility" is defined as an electric utility that is an investor-owned utility, municipal utility, electric cooperative or public utility district; is subject to federal greenhouse gas and traditional emissions restrictions and prohibitions; and is subject to oversight by a state regulatory authority, governing board, or supervising state or political subdivision. The REPLACES program would be implemented by the utility under the supervision of the utility's state regulatory authority, governing board, or supervising state or political subdivision in concert with the U.S. Environmental Protection Agency.

ii. A "merchant coal unit" is defined as a coal-fueled electric generating unit that 1) is not owned by a Federal, State, or regional agency or power authority; and 2) generates

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[1] A "coal-fueled" electric generating unit is defined as a unit that derives at least 85% of its heat input from coal, petroleum coke, fuel oil, or any combination of those three fuels.

electricity solely for sale to others, provided that all or a portion of such sales are made by a separate legal entity that has full or partial ownership or leasehold interest in the unit; and is not subject to retail rate regulation or setting of retail rates by a State regulatory authority (or a State or political subdivision thereof), an electric cooperative, or an Indian tribe pursuant to tribal law. The REPLACES program would be implemented by the merchant coal unit owner/operator under the supervision of the U.S. Environmental Protection Agency.

Certification

A covered electric utility must certify that the state regulatory authority, governing board, or supervising state or political subdivision that oversees the utility has the authority to: (1) consider the interests of retail electric consumers served by the utility, and (2) require the utility to meet the program's retirement/retrofit schedule. The owner/operator of a merchant coal unit must certify that it is subject to the oversight of an appropriate Regional Transmission Organization or Independent System Operator with the responsibility to ensure the reliability of electric service in its territory and to protect the interests of electric markets served by such merchant coal unit.

- Filing of a Compliance Plan. Each certifying covered electric utility and merchant coal unit owner/operator shall file with the EPA a compliance plan within 24 months of the effective date of the legislation. Each certifying covered electric utility shall, at the same time, file a copy of the plan with its state regulatory authority, governing board, or supervising state or political subdivision. The plan must identify each coal-fueled electric generating unit that is subject to these restrictions and prohibitions; the state in which the unit is located; the date upon which the unit was placed in service; the greenhouse gas emissions from the unit in the most recent 12-month period for which data is available; the date for retirement or retrofit for the unit under the REPLACES schedule; if a unit is to be retrofitted or controlled, the nature of the retrofit and control equipment and the expected amount of reduction in emissions; and, for covered utilities, the states in which any portion of the investment in the unit is included in retail electric rates, and the plan for providing electric service after the retirement, control, or retrofit.

- Compliance Plan Updates. Compliance plans must be updated at least every four years. States and the U.S. Environmental Protection Agency will develop other procedures as necessary to ensure compliance with REPLACES.

Specifics

1. Greenhouse Gas Emissions. Section 111 of the Clean Air Act would be amended to use the following REPLACES retirement/retrofit schedule as the basis for greenhouse gas new performance standards for existing coal-fueled electric generating units. To achieve the greenhouse gas (GHG) emission reductions on a timely basis, any covered electric utility or merchant coal unit owner/operator subject to REPLACES must make a legally binding commitment in writing to EPA (and, if a covered electric utility, also to its state regulatory authority, governing board, or supervising state or political subdivision) to retire or retrofit all of its existing coal-fueled electric generating units based on the following schedule:

i. A coal-fueled electric generating unit that began commercial operation on or prior to December 31, 1959, must be retrofitted or retired by December 31, 2020.

ii. A coal-fueled electric generating unit that began commercial operation after December 31, 1959, but on or prior to December 31, 1974, must be retrofitted or retired by December 31, 2035.

iii. A coal-fueled electric generating unit that began commercial operation after December 31, 1974, but on or prior to December 31, 1999, must be retrofitted or retired by December 31, 2045.

iv. A coal-fueled electric generating unit that began commercial operation after December 31, 1999, or was initially permitted prior to January 1, 2015, without at least 50% carbon (CO_2) capture as measured on an annual basis, must be retrofitted or retired by December 31, 2055.

The dates listed above would be binding with the following exception.

a. For a coal-fueled electric generating unit scheduled for retirement or retrofit in schedule periods i., ii. or iii. above, a covered electric utility or merchant coal unit owner/operator may choose to substitute the retirement or retrofit of a coal-fueled electric generating unit in a later schedule period, as long as the resultant amount of greenhouse gas reductions is equal to or greater than the amount of greenhouse gas reductions that would have been achieved by retirement or retrofit of the scheduled unit.

The following items would qualify to meet the definition of "retrofit" under this provision:

a. Conversion of an existing boiler to eliminate the use of coal with the substitution of natural gas as the primary fuel source.

b. Repowering an existing unit with a combined cycle combustion turbine natural gas-fueled unit.

c. Replacing a percentage of the coal fuel supply with renewable biomass to meet a minimum generation performance standard of 1,100 pounds of carbon dioxide (CO_2) per gross megawatt-hour, when measured on an annualized basis[2]. For clarity, the CO_2 emissions associated with the combustion of renewable biomass would be excluded for purposes of demonstrating compliance with this generation performance standard.

   i. Renewable biomass is defined as legally harvested trees, wood, brush, thinnings, chips, and slash; renewable plant material such as feed grains, other

[2] The performance standard of 1,100 pounds of CO_2 per gross megawatt-hour is equivalent to approximately a 50% reduction from the CO_2 emissions from an average performing coal-fueled unit. This figure is also consistent with California's greenhouse gas emission performance standard under Assembly Bill 32.

agricultural commodities, plants, and algae; waste material including crop residue, vegetative waste material, animal waste and byproducts, construction waste, food and yard waste, and non-biogenic municipal solid waste and construction, demolition, and disaster debris; and residues and byproducts from wood, pulp, or paper products facilities.

d. Installing carbon capture and storage technology to mitigate a minimum of 50% of the baseline CO_2 emissions emitted by the existing unit, when measured on an annualized basis.

e. Integrating other non-emitting generation technologies (e.g., solar, nuclear, etc.) into the existing coal unit steam cycle to meet a minimum generation performance standard of 1,100 pounds of CO_2 per gross megawatt-hour, when measured on an annualized basis.

2. Preemption of GHG Regulation. For regulation of GHGs at covered coal units, preemption of:

i. The Clean Air Act. Specifically EPA would be preempted from establishing standards of performance for GHGs for existing coal units for other than climate change, such as ocean acidification; GHGs as a trigger for New Source Review for major sources; GHGs as an independent basis for requiring a Title V permit if the GHG in question is only regulated due to its impact on climate change; and incorporating GHGs into Title V permits for impacts other than climate change, including ocean acidification.

ii. Preemption of Other Federal Laws. Specifically EPA would be preempted from establishing regulations under other federal environmental laws, such as the Clean Water Act, the National Environmental Policy Act and the Endangered Species Act.

iii. State Preemption. At a minimum, where inconsistencies exist among state, regional and federal GHG programs, federal law should prevail. States should be free to pursue the policies they wish, but those policies should not regulate sources already subject to REPLACES. States would be preempted from taking any additional actions requiring GHG reductions from covered coal-fueled units, including, but not limited to, cap-and-trade requirements, taxes, fees, or limits imposed on these existing coal-fueled units for greenhouse gas emissions.

iv. State and federal common law torts.

3. Effect on Other EPA and State Regulations. The following provisions would apply to covered electric utilities and merchant coal unit owners/operators that participate in the REPLACES program:

i. Pre-2021 (Near-Term) Regulatory Relief. Each coal-fueled electric generating unit must continue to meet all the conditions of its federal, state and locally enforceable permits in existence at the time the utility enters into the REPLACES program. Notwithstanding any provision of the_Clean Air Act, any coal-fueled electric generating unit subject to REPLACES that commits to ceasing operation permanently on or before December 31, 2020, shall be exempt from the following:

a. New source review requirements under the Clean Air Act (42 U.S.C. § 7475) or state emission reduction requirements under a state implementation plan addressing new source review requirements.

b. Regulation of hazardous air pollutants under section 112 of the Clean Air Act (42 U.S.C. § 7412), including standards promulgated pursuant to subparagraph (a)(11) (D).

c. The final rule entitled ''Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations'' (70 *Fed. Reg*. 39104 (July 6, 2005)).

d. New source performance standards for greenhouse gas emissions under section 111 of the Clean Air Act (42 U.S.C. § 7411).

e. Regulation of coal combustion waste water discharges from thermal generating units under title III of the Federal Water Pollution Control Act (17 U.S.C. § 1311 *et seq*.).

f. Regulation of cooling water intake structures under section 316(b) of the Federal Water Pollution Control Act (33 U.S.C. §1326(b)), and

g. Effluent guidelines and thermal discharge requirements promulgated under the Clean Water Act.

ii. Regulatory Coordination for Coal Units Operating Post-2020. Coal-fueled units which continue to operate post-2020 shall be required to meet the criteria as outlined below.

a. Clean Air Transport Rule. Emission controls, fuel switching, or other mechanisms shall be employed by January 1, 2021 to meet the following requirements:

1) Program shall be expanded to affect all 48 continental U.S. states and the District of Columbia; versus 31 states and the District of Columbia currently affected.

2) Program shall not seek additional SO_2 reductions, since the Utility HAPs MACT requirements are more restrictive.

3) Utilities shall achieve annual and ozone season NOx emission rates of 0.17 lb/mmBtu, when measured over the year or ozone season.

i. A December 31, 2015 compliance date shall be enforced for the 31 currently affected eastern states, plus the District of Columbia.
ii. A December 31, 2020 compliance date shall be enforced for the remaining 17 western continental U.S. states.
iii. Reductions shall be completed under a cap-and-trade program.
iv. Allowances shall be fully allocated based on an average heat input from 2008-2010.
v. Each state's actual emissions must be within 110% of its annual emission allocation.
vi. An additional allowance reserve of 3% shall be set aside for new units.

4) There shall be no additional Regional Haze / Best Available Retrofit Technology (BART) reductions required for existing coal-fueled units.

5) The combination of emission controls from the Clean Air Transport Rule and Utility HAPs MACT rule shall be considered better than BART and also satisfy all reasonable progress goals established under the visibility rule.

b. <u>Utility HAPs MACT Rule.</u> Emission controls, fuel switching, or other mechanisms shall be employed by January 1, 2021 to meet the following requirements.

1) 90% reduction in SO_2 emissions, but not less than 0.15 lb/mmBtu.
   i. No specific reductions for acid gases due to strong correlation with SO_2 emissions.

2) 80% reduction in mercury emissions, but not less than 1.7 lb/TBtu.
   i. No specific reductions for non-mercury metallic HAP emissions due to strong correlation with mercury emissions.

c. <u>Coal Ash Management</u>.

1) All coal ash shall continue to be managed as solid waste (subtitle D), and not hazardous waste (subtitle C).

2) Existing beneficial uses for coal ash shall continue to be eligible.

3) No coal ash shall be deposited into unlined mines, quarries, and sand/gravel pits.

4) New coal ash landfills or landfill expansions shall install liners and leachate collection systems and be Subtitle D compliant.

5) Wet surface impoundments may continue to operate in their current form until January 1, 2025.

6) No later than January 1, 2025, surface impoundments shall be phased out (traditional cap and close without excavation) and all coal ash shall be managed dry and disposed in ash monofills.

7) Individual coal ash damage cases and impoundment structural integrity issues shall be addressed on a case-by-case basis.

8) New coal-fueled units shall be designed to manage coal ash dry.

d. Water.

1) No existing coal-fueled units with once-through cooling shall be required to install closed-loop cooling systems.

2) Each once-through cooled unit which continues to operate post 2020 shall conduct a fish impingement/entrainment evaluation and implement reasonable measures to reduce mortality of aquatic life.

   i. The evaluations shall be completed by December 31, 2015, and the most beneficial measures, as determined by the appropriate state regulatory authority, shall be implemented by December 31, 2020.
   ii. In no event shall an individual unit be required to expend more than $1 million per 100 MW of accredited capacity.

3) No existing coal-fueled unit shall be subject to more restrictive thermal discharge or effluent limits than exist in current permits.

iii. Preemption of State Regulation of HAPs. Current and future state regulations of hazardous air pollutants, including emissions of mercury, are preempted by the EPA's Utility HAPs MACT rule.

iv. Clarification of New Source Review Applicability. Efficiency and operational improvements undertaken at a coal-fueled electric generating unit by a covered electric utility or merchant coal unit owner/operator, regardless of their date, would not be subject to New Source Review regulations specified within the federal Clean Air Act.

v. "Safe Harbor" Provision. Each coal-fueled electric generating unit must continue to meet all the conditions of its existing federal, state and locally enforceable permits in existence at the time the units enters into the REPLACES program. However, except as explicitly outlined above, the existing coal units would not be subject to any future rules or changes to regulations under the existing Clean Air Act, National Ambient Air Quality Standards, Clean Water Act, Safe Drinking Water Act, Resource Conservation and Recovery Act, Comprehensive Environmental Response, Compensation and Liability Act, and any new state or local air, water, or other environmental regulations that are more stringent than currently existing federal, state and local requirements. Compliance with any additional requirements will ultimately be achieved by retiring, controlling, or retrofitting these coal-fueled electric generating units on a legally binding schedule.

vi. Cost Recovery. A covered electric utility shall be authorized to recover in rates (a) the prudently incurred costs of replacing any coal-fueled electric generating unit retired pursuant to the REPLACES compliance plan; and (b) all other reasonable costs, including but not limited to retrofit costs and accelerated depreciation expense, associated with the compliance plan.

vii. Joint Ownership. For a coal-fueled electric generating unit that is owned by more than one entity, the election to subject the unit to the REPLACES program shall be made by the operator unless otherwise provided by contract.

viii. Non-Compliance.

a. Retrofits: A covered electric utility or merchant coal unit owner/operator which fails to meet its commitment to retrofit one or more of its existing coal-fueled electric generating units based on the REPLACES schedule and its approved compliance plan will be subject to an excess emission fee. Such excess emission fee will be based on the actual monthly CO_2 emission tons from the subject unit(s) multiplied by $50 per ton (in 2010$ escalated with inflation). Any such excess emission fees shall be paid to the U.S. Environmental Protection Agency on a monthly basis, no later than 30 days following the month in which the excess emissions occurred.

b. Retirements: A covered electric utility or merchant coal unit owner/operator which fails to meet its legally binding commitment to retire one or more of its existing coal-fueled electric generating units based on the REPLACES schedule and its approved compliance plan will be subject to the same enforcement actions as a unit which operates without a valid operating permit, or is otherwise in violation of such permit, in accordance with the provisions of the Clean Air Act. This shall include, but not be limited to, Section 113 civil and criminal actions, Section 303 emergency powers, and Section 304 citizen suits.

4. New Coal-Fueled Electric Generating Units. The Clean Air Act (42 U.S.C. 7401 et seq.) would be amended to establish performance standards for new coal-fueled power plants. A "covered coal unit" is defined as a unit required to have a Title V permit under CAA section 503(a) and is authorized under Federal or State law to derive at least 30 percent of the annual heat input of the unit from (i) coal; (ii) petroleum coke; or (iii) any combination of those fuels. The standard applies on or after January 1, 2015 when the owner or operator of a covered coal unit has received a preconstruction approval or permit as a new (but not modified) source. A covered coal unit must achieve the following emissions limits:

i. 0.07 lb/mmBtu annual and ozone season NOx emission rate, when measured on a 30-day rolling average.
ii. 0.10 lb/mmBtu SO_2 emissions rate, when measured on a 30-day rolling average.

iii. 1.5 lb/TBtu mercury emissions rate, when measured on a 30-day rolling average.
iv. 1,100 pounds of CO_2 per gross megawatt-hour emissions rate, when measured on an annualized basis.

5. Income Tax Incentives. The following tax-related provisions would apply to covered electric utilities and merchant coal unit owners/operators that are participating in the REPLACES program:

   i. Accelerated Retirement or Retrofit Credit (ARRC). Under new Internal Revenue Code Section 45R, if a coal-fueled electric generating unit subject to REPLACES is retired or retrofitted at an earlier date than required under the REPLACES schedule (i.e., prior to the respective dates prescribed in Item 2), the covered electric utility or merchant coal unit owner/operator shall be eligible to receive ARRC at a rate equal to one-half of the renewable electricity production tax credit rate set forth in Internal Revenue Code Section 45(a). For a covered electric utility, the amount of credits so generated shall be utilized to benefit retail customers by reducing the cost of the energy and/or capacity of the supply or demand resource that replaces the retired or retrofitted coal-fueled electric generating unit, in the manner determined by the state regulatory authority, governing board, or supervising state or political subdivision. The ARRC shall be calculated by multiplying the average monthly megawatt-hours generated by the unit being retired or retrofitted during the 12 calendar months immediately preceding the retirement/retrofit date by the number of full calendar months the date of retirement or retrofit precedes the respective scheduled dates prescribed in Item 2. The ARRC may be claimed regardless of whether or not the taxpayer elects tax incentives under paragraphs 4.iii. and 4.iv., below.

   ii. Renewable Electricity Production Tax Credit. The existing renewable electricity production tax credit program will be extended in its current form through 2055.

   iii. Election to Expense. Under new Internal Revenue Code Section 179F, a participant in the REPLACES program, like other taxpayers, may elect to expense 100% of the cost of any qualified emission reduction project to meet these requirements and reduced CO_2 property. A qualified reduced CO_2 property means any property installed as a retrofit of an existing coal-fueled electric generating unit or constructed as a new electric generating unit, which meets a minimum generation performance standard of 1,100 pounds of CO_2 per gross megawatt-hour placed into service after enactment of Section 179F. The election to deduct costs under this section shall also apply to qualified progress expenditures incurred during the construction of the qualified equipment/property, in a manner similar to the rules of Subsection 48(b).

   iv. Dual Alternatives to the Election to Expense. In lieu of enacting a Section 179F election to expense, mutually exclusive alternatives to elect either a 30% tax credit or a 30% U.S. Treasury grant would be available to participants in the REPLACES program. The grant side of this dual approach would permit utilities without current federal income tax appetites to timely receive a cash grant equal in amount to a corresponding energy investment tax credit. These provisions are patterned after similar provisions enacted as part of the American Recovery and Reinvestment Act of 2009.

a. Investment Tax Credit. Under the REPLACES program, a new Internal Revenue Code Section 48D would be added to permit a taxpayer to claim a tax credit equal to 30% of the cost of any qualified emission reduction project to meet these requirements and reduced CO_2 property. A qualified reduced CO_2 property means any property installed as a retrofit of an existing coal-fueled electric generating unit or constructed as a new electric generating unit that meets a minimum generation performance standard of 1,100 pounds of CO_2 per gross megawatt-hour placed into service after enactment of Internal Revenue Code Section 48D. The credit under this section shall also apply to qualified progress expenditures incurred during the construction of the qualified emission reduction project and reduced CO_2 property, in a manner similar to the rules of Subsection 48(b). This credit would be claimed in lieu of a grant available under new Internal Revenue Code Section 48E, described below. The depreciable basis of the property shall be reduced by the amount of the credit.

b. Investment Grant. Under new Internal Revenue Code Section 48E, a taxpayer may apply to the U.S. Treasury for a cash grant equal to 30% of the cost of any qualified emission reduction project to meet these requirements and reduced CO_2 property. A qualified reduced CO_2 property means any property installed as a retrofit of an existing coal-fueled electric generating unit or constructed as a new electric generating unit that meets a minimum generation performance standard of 1,100 pounds of CO_2 per gross megawatt-hour placed into service after enactment of Internal Revenue Code Section 48E. The grant under this section shall be made available to qualified progress expenditures incurred during the construction of the qualified emission reduction project to meet these requirements and reduced CO_2 property, in a manner similar to the rules of Subsection 48(b). This grant would be claimed in lieu of a tax credit available under new Internal Revenue Code Section 48D, described previously, and is payable to the utility within 60 days after the later of the expenditure or the date of application. The depreciable basis of the property shall be reduced by the amount of the grant.

6. Nuclear Power Development Support. An $8 billion loan guarantee program will be provided to states for distribution to covered electric utilities participating in the REPLACES program to develop, own and operate new nuclear power plants. In addition, covered electric utilities that develop, own and operate new nuclear power plants will be eligible for the tax programs specified above in 4.iii and 4.iv.

7. Emission Reduction Benefits. Retiring, retrofitting, and controlling all of the existing coal-fueled electric generating units on the predetermined schedule outlined above will result in significant emission reduction direct benefits and co-benefits and is estimated to

result in reductions of sulfur dioxide (SO_2), nitrogen oxides (NO_X) and mercury (Hg) emissions, in addition to CO_2, as compared to baseline emissions in 2008[3].

i. Retiring all the existing U.S. coal-fueled electric generating units on the predetermined schedule outlined above and replacing them with non-carbon emitting generating units, and controlling the post-2020 coal-fueled fleet to meet the emission standards outlined above, is estimated to result in the following emission reductions

	Cumulative Reductions from Controls and Retirements							
	CO_2		SO_2		NO_X		Hg[4]	
	M Tons	%	M Tons	%	M Tons	%	Tons	%
2020	223.3	10.7	6.08	82.1	1.34	47.3	30.08	66.8
2035	958.7	46.1	6.62	89.3	1.94	68.6	36.11	80.3
2045	2,049.3	98.6	7.39	99.8	2.82	99.5	44.89	99.8
2055	2,078.0	100.0	7.41	100.0	2.84	100.0	45.00	100.0

ii. Retrofitting all the existing U.S. coal-fueled electric generating units on the predetermined schedule outlined above to meet the 1,100 pound of CO_2 per gross megawatt-hour standard, and controlling the post-2020 operated coal-fueled fleet to meet the emission standards outlined above, is estimated to result in the following emission reductions[5].

	Cumulative Reductions from Controls and Retrofits							
	CO_2		SO_2		NO_X		Hg	
	M Tons	%	M Tons	%	M Tons	%	Tons	%
2020	100.5	4.8	5.93	80.1	1.17	41.4	28.39	63.1
2035	431.4	20.8	5.93	80.1	1.17	41.4	28.39	63.1
2045	922.2	44.4	5.93	80.1	1.17	41.4	28.39	63.1
2055	935.1	45.0	5.93	80.1	1.17	41.4	28.39	63.1

[3] The total tonnage reductions would be even greater as compared to baseline emissions in 2005. Between 2005 and 2008, emissions from Acid Rain Program units have declined as follows: SO_2 down by 2.6 million tons, NO_x down by 0.6 million tons, Hg down by 2 tons, and CO_2 down by 22.7 million tons.

[4] Mercury emission data were not available on a unit-by-unit basis. Therefore, baseline mercury emissions were estimated to correlate closely with SO_2 emissions, since scrubber equipment generally has a mercury co-benefit.

[5] Since the 1,100 pound CO_2 per gross megawatt-hour emission standard (from a baseline of 2,000 pounds) could be achieved via a number of alternatives, including CCS, the addition of biomass, or integration of other non-emitting generation technologies into the steam cycle, it was assumed that CCS would be employed and not affect emissions of SO_2, NOx, and Hg above and beyond the direct emission control benefits.

iii. Converting all the existing U.S. coal-fueled electric generating units to 100% natural gas on the predetermined schedule outlined above is estimated to result in the following emission reductions[6].

	Cumulative Reductions from Controls and Natural Gas Conversions							
	CO_2		SO_2		NOx		Hg	
	M Tons	%	M Tons	%	M Tons	%	Tons	%
2020	103.5	5.0	6.08	82.1	1.22	43.1	30.08	66.8
2035	444.3	21.4	6.62	89.3	1.40	49.4	36.11	80.3
2045	949.7	45.7	7.39	99.8	1.66	58.5	44.89	99.8
2055	963.0	46.3	7.41	100.0	1.66	58.5	45.00	100.0

[6] The complete conversion to natural gas of the coal-fueled electric generating units could occur either as a fuel switch or a combined cycle repowering. The table conservatively assumes all units undergo fuel switching, and NOx is reduced from the controlled average of 0.17 lb/mmBtu to 0.12 lb/mmBtu. If some of the units were repowered, additional CO_2 and NOx reductions would be expected due to the heat rate improvement.