Power Switch

An Effective, Affordable Approach to Reducing Carbon Pollution from Existing Fossil-Fueled Power Plants

FEBRUARY 2014

The Clean Air Task Force works to help safeguard against the worst impacts of climate change by catalyzing the rapid global development and deployment of low carbon energy and other climate-protecting technologies through research and analysis, public advocacy leadership, and partnership with the private sector.

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Executive Summary

U.S. power plants emitted over 2100 million metric tons of carbon pollution in 2011, constituting nearly forty percent of domestic anthropogenic carbon dioxide emissions. Electricity production from coal-fired power plants alone was responsible for twenty-six percent of total domestic green house gas (GHG) emissions. Despite some progress in regulating power plant carbon pollution at the state level, there are no final federal standards yet in place to reduce carbon pollution from new power plants and existing coal-fired power plants remain the nation's largest source of anthropogenic carbon dioxide.

> *So today, for the sake of our children, and the health and safety of all Americans, I'm directing the Environmental Protection Agency to put an end to the limitless dumping of carbon pollution from our power plants, and complete new pollution standards for both new and existing power plants.*
>
> *—President Obama, June 25, 2013, on the announcement of the Climate Action Plan.*

Recognizing this, on June 25, 2013 President Obama directed the U.S. Environmental Protection Agency (EPA) to finalize power plant new source carbon dioxide standards and develop carbon dioxide performance standards for existing power plants, as part of his Climate Action Plan. In doing so, the President acknowledged EPA's obligation to set performance standards for GHG emissions from the largest emitting industries. The President also reaffirmed the U.S. commitment to reduce its economy-wide GHG emissions by 17 percent from 2005 levels by the year 2020, en route to an 80 percent reduction by 2050.

In this report, the Clean Air Task Force (CATF) proposes a common sense, highly cost-effective approach under Clean Air Act Section 111(d) for reducing carbon pollution from existing power plants. Simply by displacing electricity generated by high emission rate coal-fired power plants with generation from existing currently underutilized, efficient natural-gas power plants, the U.S. can realize significant, near term reductions in carbon pollution at a minimal cost. CATF believes that a regulatory mechanism that unlocks this cost-effective, near-term abatement option should serve as the first step in addressing carbon pollution from the power sector under Section 111(d). Our approach reflects the inherent structure of electricity markets, in which the imposition of a control cost for carbon emissions will result in increased use of underutilized lower-emitting facilities and reduced use of higher emitting facilities that incur costs to reduce their emissions.

Ultimately, in order to achieve the economy-wide goal of an 80 percent reduction from 2005 levels by 2050, the U.S. electricity generating sector will need to undergo a profound transformation such that any fossil-fueled units operating in 2050 capture and store their carbon emissions. Our recommended approach provides a framework for implementing these longer-term, deeper reductions over time as EPA periodically revisits and revises the new and existing power plant performance standards.

Key Recommendations:

In order to issue existing source guidelines that will yield increased reliance on generation from existing, currently underutilized natural gas combined cycle units and displace generation from the highest emitting coal units, EPA should:

- Set separate emission rate standards for subpart Da fossil fuel-fired utility boilers (1,450 lbs/MWh) and subpart KKKK natural gas combustion turbines, including combined cycle natural gas units (1,100 lbs/MWh) based on a Best System of Emission Reduction (BSER) analysis;
- Provide fossil fuel-fired utility boiler budgets for states that desire to comply with these performance standards on a mass basis, and that:
  - Provide an opportunity to reward "early action," and
  - Are structurally compatible with existing carbon markets and needed future federal policies;
- Facilitate least-cost state implementation by issuing a model interstate trading rule for emission credits with the opportunity to use free allocation of allowances to protect electric retail ratepayers of all classes;
- Treat rate-regulated and restructured electricity markets similarly and equitably by allowing states to use allowance allocations to mitigate the financial impact of the regulations on merchant coal generators;
- Provide an overall framework that allows states the flexibility to comply with the EPA performance standards in a variety of ways that suit the unique circumstances of each state; and
- Protect system reliability, grid stability, and fuel diversity by relying on proven, existing fossil electric units that are already in operation and available today.

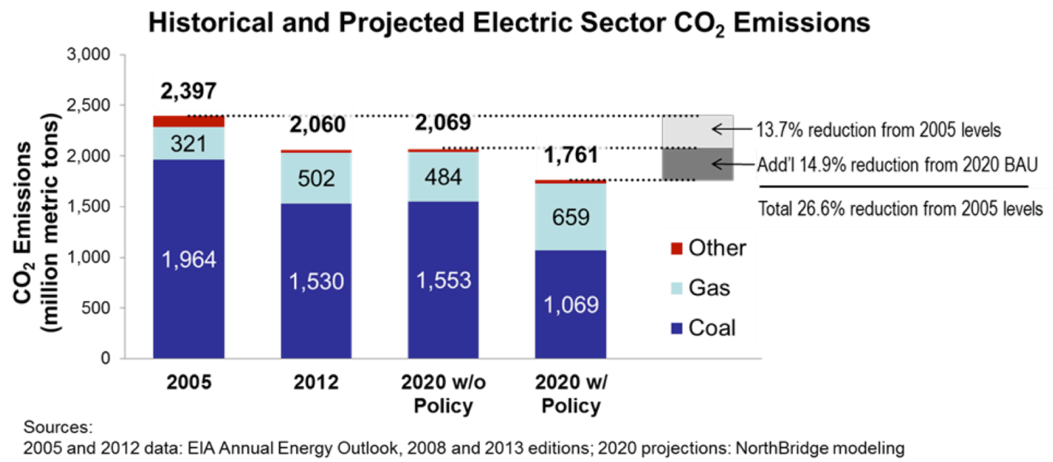
Deep Emission Reductions with Reasonable Costs and Rate Impacts

An analysis of CATF's approach by The NorthBridge Group found:

- A 636 million metric ton total carbon dioxide reduction from 2005 levels by 2020.
- A 27 percent reduction in electric sector carbon dioxide emissions from 2005 levels.
- Reductions in annual power plant sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions of over 400,000 tons each in 2020.
- A marginal cost of carbon abatement of $34/metric ton, which is less than the Social Cost of Carbon value currently used in regulatory impact analysis by the U.S. government.
- An increase in average nationwide retail electric rates of only 2 percent in 2020.

CATF's analysis shows further that the emission reductions will result in:

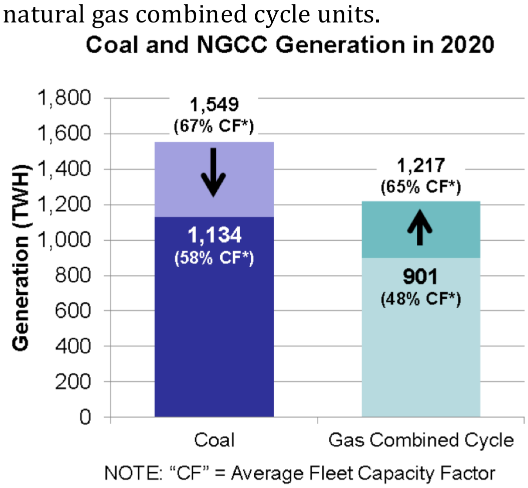
- Over 2,000 avoided premature deaths, 1,000 avoided emergency room visits, and 15,000 avoided asthma attacks per year because of the associated reductions in the pollutants that cause deadly fine particulate matter.
- Monetized health and climate benefits of $34B, which is over three times the total cost of compliance.



CATF proposes that EPA offer a "model" interstate emission credit trading rule that can be easily adopted and implemented by states, facilitating rapid compliance consistent with the President's schedule for the submission of state plans. The model emission credit trading rule would also serve to mitigate retail electric rate impacts and protect all classes of electric ratepayers (industrial, commercial and residential) in all power markets by allowing for compensation to ratepayers. Moreover, to treat coal generators similarly across rate-regulated and restructured power markets, the model emission credit trading rule would allow states to use a portion of the allowance allocations to compensate merchant coal generators for losses in asset value that may occur due to the program. The model emission credit trading rule could be structured to allow its imposition as a federal implementation plan (FIP) for states that fail to submit an approvable plan.

Least-Cost Carbon Pollution Reductions:

Displacing the generation from the highest-emitting coal facilities with generation from natural gas combined cycle units.



The NorthBridge Group analysis finds that this approach would result in the fossil-fueled electric system as a whole shifting towards increased reliance on existing, currently underutilized natural gas units and lessen reliance on inefficient, older coal units. The analysis finds that this approach will result in significant carbon pollution reductions at minimal cost.

EPA's existing source emission rate proposal must be based on the BSER for fossil utility boilers and for gas combustion turbines. Our analysis finds that there are many "source-based" and "system" options that owners and operators can use to reduce CO_2 emissions from existing fossil-fueled units including:

- Switching to a higher rank coal;
- Turbine and boiler overhauls and other equipment and system

upgrades and/or modifications to improve unit heat rate;

- Using waste heat to remove moisture from coal;
- Using renewable energy to provide support for steam heating;
- Implementing combined heat and power systems at plants near industrial facilities;
- Co-firing with low carbon-fuels such as natural gas;
- Optimizing their dispatch (e.g., working with transmission system operators to rely more heavily on underutilized natural gas combined cycle units and less on high heat rate coal units); and
- Implementing partial capture of CO_2 through retrofits.

In combination, this "suite of options" could achieve coal-fired generating unit CO_2 reductions on the order of 30 percent from uncontrolled coal-fired boilers. Consistent with these findings, CATF recommends that EPA set a net performance standard for subpart Da fossil fuel-fired utility boilers of 1,450 lbs/MWh. In addition, CATF proposes a net performance standard for subpart KKKK natural gas combustion turbines of 1,100 lbs/MWh for natural gas combustion turbines, including combined cycle natural gas units, consistent with the rates achieved by most existing gas turbines. When implemented in conjunction with a mass-based interstate trading program for fossil fuel-fired utility boilers, these performance standards will provide highly cost-effective reductions of power sector carbon pollution.

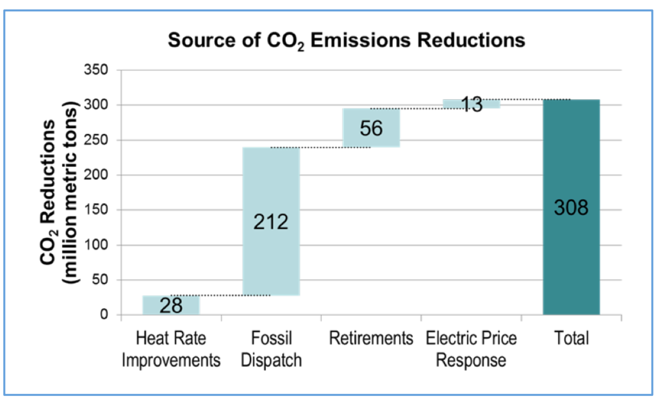
States would be able to achieve compliance with these federal emission standards in a variety of ways including any of the above-listed suite of on-site generation and emission control technology options. In addition, changes in existing dispatch, and actions beyond the boundaries of existing utility units, but that reduce on-site emissions (such as state energy efficiency and renewable energy programs) can be used for compliance under our approach.

Summary of Results by 2020	
Reduction in fossil CO2 (%) from 2005 levels	-27%
Reduction in CO2 (million metric tons) from 2005 levels	636
Reduction in CO2 (million metric tons) from forecast 2020 levels	308
CO2 price ($ 2013/metric ton)	$20
Reduction in coal TWh (%)	-27%
Coal retirements (GW)	42
Increase in gas consumption (TCF)	3.0
Increase in Henry Hub gas price ($/MMBtu)	11.4%
Increase in US wholesale electric price (%)	6.9%
Increase in US retail electric price – without allowance offset (%)	6.2%
Increase in US retail electric price – with allowance offset (%)	2.3%
Marginal cost ($ 2013/metric ton)	34
Average cost ($ 2013/metric ton)	32
Total program costs ($ 2013 billion)	9.4
Total program benefits ($ 2013 billion)	34

Finally, states can comply by taking advantage of the flexibility and low-cost compliance afforded through interstate trading by adopting the model trading rule, or an existing equivalent program.

We assume that states with existing power sector carbon pollution programs such as the Regional Greenhouse Gas Initiative (RGGI) states and California will want to demonstrate compliance with the 111(d) guidelines through their existing programs. CATF's recommended model emission credit trading rule is designed as an attractive alternative for those states that are not part of the RGGI or California programs but wish to take advantage of the flexibility and low-cost compliance afforded through interstate trading.

The NorthBridge Group analysis estimates that by 2020, almost 70 percent of the emission reductions achieved under our approach will be achieved through changes in current fossil dispatch. See chart below (million metric tons reduced from 2020 forecast levels).



Carbon Pollution from Coal-fired Power Plants

Existing U.S. power plants emitted approximately 2160 million metric tons of carbon pollution in 2011, constituting nearly 40 percent of the domestic anthropogenic carbon dioxide emissions.[1] During the same period, electricity production from coal-fired power plants emitted on the order of twenty-six percent of total domestic GHG emissions.[2]

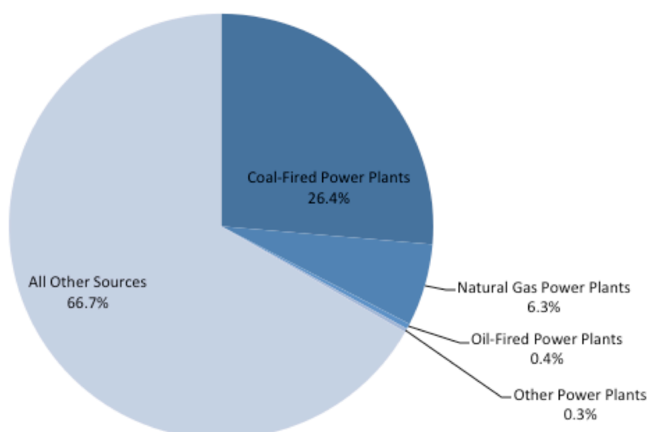
Once emitted from a smokestack, a large portion of the CO_2 persists in the atmosphere for over a century, causing enduring climate damage, so the need for near-term curtailment of these emissions is urgent. Without quick and meaningful reductions from the power sector, the U.S. simply cannot meet its 17 percent economy-wide reduction commitment by 2020.[3] And, despite some progress on regulating carbon pollution at the state level,[4] there are no federal standards in place to reduce carbon pollution from existing power plants. As a result, coal-fired power plants remain the nation's largest source of anthropogenic carbon dioxide.

While many natural factors affect global climate, scientists understand, based on direct observations, historical estimates, and computer modeling, that human activity is producing unprecedented levels of GHG emissions and that the buildup of these gases in the atmosphere over the past century is responsible for the unprecedented warming we face today. EPA relied on this massive body of science in making its determination in the Endangerment Finding.

EPA found that the climate is warming today, as evidenced by increases in global air and ocean temperatures, widespread melting of snow and ice, and rising global sea levels. As the climate continues to warm, the best science shows that the continued warming will lead to melting ice in the arctic regions, melting glaciers around the world, increasing ocean temperatures, rising sea levels, acidification of the oceans due to excess carbon dioxide, changing precipitation

patterns, and changing patterns of ecosystem and wildlife functions.[5]
In addition, EPA found that carbon pollution and other GHG emissions could lead to more intense heat waves, increases in regional ground level ozone, which has been linked to respiratory health problems ranging from decreased lung function and aggravated asthma to increased emergency room visits, hospital admissions, and even premature death, expansion of the range of certain diseases, more severe storm impacts and flooding, and increased wildfires, insect vector geographic expansion and associated increased disease outbreaks, and drought stresses to water resources, especially in mid-Western and Western states.[6]

Figure 1: US Greenhouse Gas Emissions-2011



The U.S. Supreme Court, in 2007, ruled that GHGs, including carbon dioxide, meet the broad statutory definition of "air pollutant" found in the Clean Air Act.[7] Under Clean Air Act Section 111, EPA must list and regulate categories of stationary sources if their emissions cause, or contribute significantly to air pollution, which may reasonably be anticipated to endanger public health or welfare.[8] A subsequent Supreme Court decision, declining to hear state claims in tort for climate damages due to electric utility carbon dioxide emissions, recognized that EPA may use – and indeed planned to use – this authority to regulate new and existing power plant carbon dioxide emissions.[9] EPA has now exercised its regulatory authority, and its prerogative to address the largest sources of climate emissions first, in proposing standards of performance for greenhouse gas emissions from new fossil-fueled utility boilers and natural gas combustion turbines.[10]

Clean Air Act Section 111(d) Existing Source Standards

In June 2013, building on the Agency's earlier actions on new sources under the Clean Air Act, President Obama directed the EPA also to develop existing fossil-fueled power plant carbon pollution standards.[11] EPA has now announced and commenced its plan to conduct a series of stakeholder listening and public comment sessions, and to propose existing power plant performance standards and guidelines for their implementation by June 2014, with the goal of finalizing the standards and guidelines by June 2015.[12]

Once EPA has issued "standards of performance" for *new* sources within a listed industrial category, Section 111(d) of the statute mandates that the Agency also must prescribe regulations directing the setting and implementation of performance standards for *existing* sources in the listed category.[13] The term "standards of performance" is defined in the statute, and means the emissions limitation that can be achieved through the application of the best system of emission reduction that the EPA Administrator determines has been adequately demonstrated.[14] EPA must consider the cost of emission reductions, energy requirements, and any non-air quality health and environmental impacts in determining whether a system has been adequately demonstrated.[15] Section 111(d) further requires EPA to establish a procedure similar to that provided by Section 110 of the CAA (governing state implementation plan requirements) under which each state shall submit a plan establishing the existing source standards of performance. EPA issued general regulations governing the setting of Section 111(d) existing source performance standards in 1975.[16] Those regulations provide that once EPA has proposed a standard of performance for new sources in a listed category under Section 111(b), for a pollutant (a "designated pollutant" under EPA's rules) other than an NAAQS or hazardous air pollutant, EPA must at the same time, or subsequently, publish a guideline document providing information for the development of state plans to control such pollutant from existing sources in that category.[17] The guideline document must include, among other things, the best system of emission reduction that the EPA Administrator determines has been adequately demonstrated and the "time within which compliance with emission standards of equivalent stringency can be achieved."[18]

The President's memorandum to EPA on Power Sector Carbon Pollution Standards, issued the same day as the Climate Action Plan (CAP), requests the Agency to give States twelve months to submit their plans implementing EPA's final carbon guidelines for existing power plants.[19]

State plans must be approved by EPA and, in cases where EPA has determined that the designated pollutant contributes to the endangerment of public health (as is the case with power plant carbon pollution), must include emission standards and compliance times that "shall be no less stringent than the corresponding emission guidelines…."[20] EPA shall impose a federal implementation plan if a state's plan is inadequate.[21]

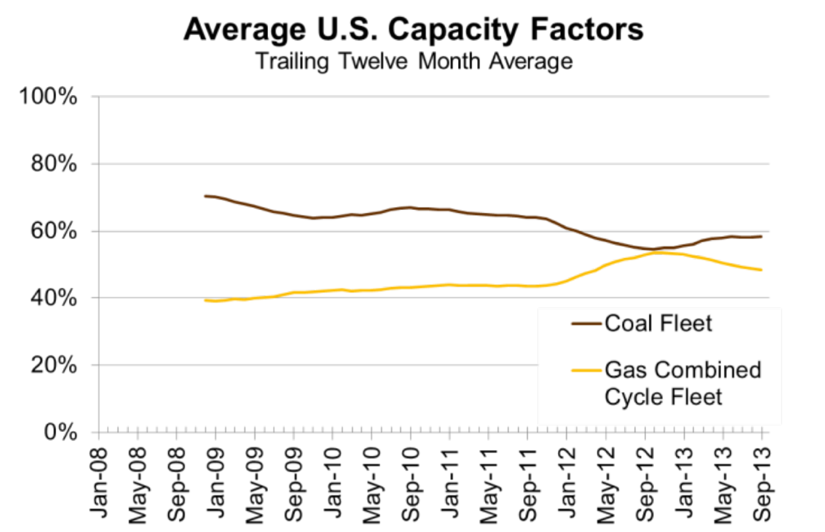
Although the states prepare plans establishing the "standards of performance" for existing sources under Section 111(d),[22] the statutory language requires that those standards must reflect the best systems of emission reduction (for existing sources) in the category, as determined by EPA.[23] EPA's 111(d) regulations also provide that emission standards included in state plans "shall either be based on an allowance system or prescribe allowable rates of emissions except where it is clearly impracticable. Such cases will be identified in [applicable] guideline documents…." [24] For convenience, in this report, EPA's BSER-based emission standard will be referred to as the "federal emission standard." State plans then may offer sources particular control option strategies that produce equivalent emission reductions to the federal emission standard.[25]

The reference to an "allowance system" in EPA's Section 111(d) implementing regulations offers states the opportunity to promulgate either rate-based or mass-based trading mechanisms as the best "system by which the standards can be met, in their 111(d) plans.[26] EPA has in the past proposed emission trading (a form of mass-based "allowance system") as an acceptable compliance mechanism in two rulemakings under Sections 111(d) and 129.[27] In the Clean Air Mercury Rule (CAMR), EPA interpreted the term "standard of performance," as applied to existing sources, to include a cap-and-trade program.[28]

An Opportunity: Underutilized Natural Gas Capacity

Prior to 2008, electricity produced by coal-fired power plants supplied nearly half of the electricity produced in the U.S. while natural gas-fired generation supplied only 21 percent.[29] Since 2008, however, primarily because of the availability of cheaper natural gas, the percentage of electricity produced by coal has declined while natural gas generation has risen. As a result, since 2008, CO_2 pollution from the power sector has fallen by 15 percent.[30] Notwithstanding this beneficial trend, natural gas combined cycle units still run on average only about 50 percent of the time as shown in Figure 2 below.[31]

Figure 2

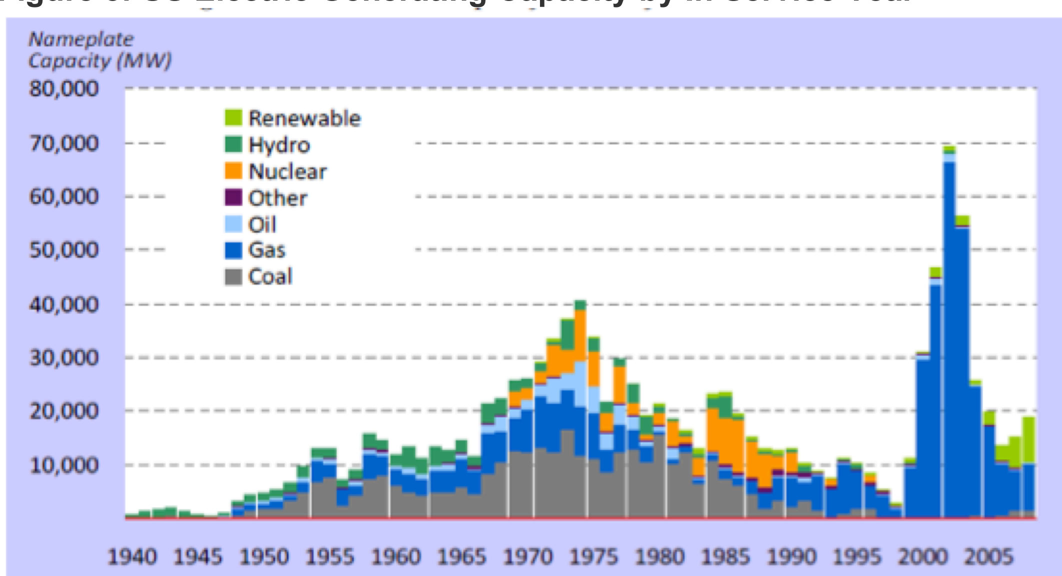


*Data from CEMS and Ventyx Velocity Suite

As Figure 3 below shows, these combined cycle units were mostly built in the last 10-15 years and were generally designed to run in baseload mode, i.e., at all times throughout the year. These highly efficient gas units have CO_2 pollution emission rates of less than half that of the average coal unit and significantly less than half of the oldest, most inefficient coal units.[32]

This situation presents an immediate opportunity to reduce carbon pollution levels while reliably meeting electricity demand and preserving grid stability and fuel diversity by relying on proven, existing fossil electric units that are already in

Figure 3: US Electric Generating Capacity by In Service Year



Source: Ceres, et al., Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States, June 2010.

operation and available today. Creating a system to unleash these potential reductions through increased operation of currently underutilized efficient natural gas units, while discouraging utilization of the highest-emitting coal units would result in significant net carbon pollution reductions according to studies by MIT and the Congressional Research Service (see figure 4 below).

Figure 4: Displacing Coal with Gas

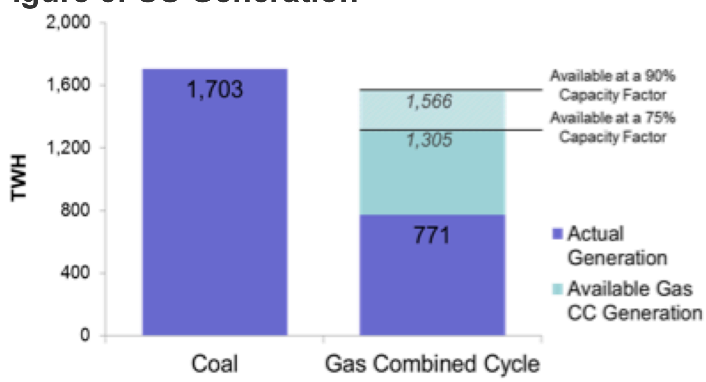
Study	NGCC Capacity Factor After Displacement	Coal Generation Displaced	CO2 Emission Reductions (MMT)
Congressional Research Service	85%	640 TWh	382
MIT	87%	700 TWh	420

CRS, Displacing Coal with Generation from Existing Natural Gas-Fired Power Plants (2010), data is from 2007, "Maximum" case MIT, The Future of Natural Gas (2011), data is 2012 forecast; "20% Reduction" Case

The NorthBridge Group independently confirmed, that there is a significant opportunity to increase the utilization of combined cycle natural gas units to displace the generation from higher-emitting coal units (see Figure 5 at right)[i].

In designing a feasible approach to regulating existing power plants under Section 111(d), CATF and The NorthBridge Group sought a policy mechanism to unlock this potential for low-cost carbon pollution reductions through optimizing the dispatch of the system. In doing so, we recognized that our nation's power grid is organized to dispatch power in a reliable and low-cost manner. This involves first ensuring that an adequate amount of generating capacity is available to produce electricity in any hour, given expected electric demand and transmission limitations, and then calling on those generating units with the lowest variable operating costs first. This typically results in renewable, nuclear and hydroelectric plants being dispatched, followed by coal plants, natural gas combined cycle plants, and finally more costly sources of gas and oil-fired generation. In recent years, as the spread between delivered coal and natural gas prices has narrowed, some gas combined cycle plants have been dispatched before coal plants, but most coal units still typically dispatch before gas combined cycle units.[33]

Figure 5: US Generation



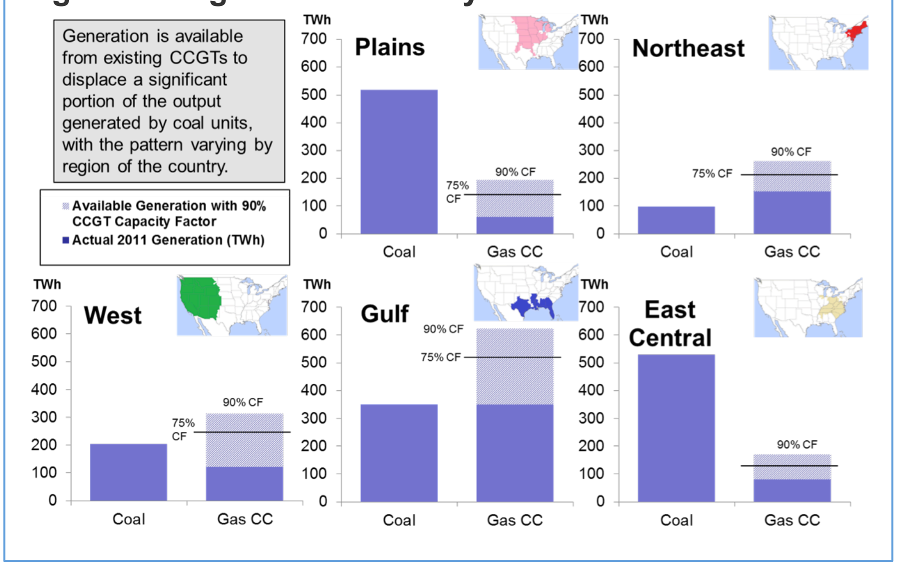
*Data from CEMS and Ventyx Velocity Suite

[i] This figure shows theoretical maximum increases in natural gas generation assuming all units are utilized at 75 -90% capacity factor. It is based on NorthBridge analysis and data from the Energy Velocity Suite and EPA's Continuous Monitoring System (CEMS). While transmission constraints, gas infrastructure constraints, duty cycle requirements, capacity and reliability demands, and air permit limitations might not allow this high a utilization of natural gas units to be realized, the analysis shows that under the CATF proposal, natural gas generation would increase only from 48 percent to 65 percent, well within these constraints, especially given an interstate emissions trading program.

Rebalancing of this system will occur whenever new emission reduction measures are imposed on existing electricity generation facilities. For example, if a state, following EPA guidelines, imposes a rate-based emission limit that a coal unit may meet by installing emissions controls or taking other emission reduction measures requiring even modest costs for each ton of emissions reduced, that coal unit would likely reflect that cost in its bid into wholesale electricity markets. This cost increase could change the order of dispatch, so that the coal unit would run less frequently and other generation would be called upon before it. For some plants, even a small reduction in capacity factor might cause that facility to retire, so that it would be replaced entirely by other capacity. Such replacement capacity may consist of increased capacity at nuclear units, renewable generation programs, natural gas units, or demand response in the form of energy conservation or efficiency. Many of the reductions in GHG emissions that have occurred recently in the electricity generation sector have been the result of this redispatch in response to lower natural gas prices coupled with new pollution control requirements for criteria pollutant emissions from existing power plants. This systemic reaction is an important fact that cannot be ignored in structuring an emissions reduction program for the electric utility industry and has been considered by EPA in all recent rulemakings for the electricity generation sector.

System dispatch is managed by regional electric system operators, such as independent system operators (ISOs) and regional transmission organizations (RTOs), so NorthBridge also explored the availability of underutilized natural gas generation on a regional basis. Importantly, underutilized natural gas capacity sufficient to displace a significant portion of the electric output generated by coal units is available in all regions of the country, although it is not uniformly distributed geographically (see figure 6).

Figure 6: Regional Availability of Gas Generation



An interstate emission credit trading system, however, could allow all geographic regions of the country to take advantage of the low-cost carbon pollution reduction potential from dispatch optimization, and provide a financially equitable solution for existing source owners and operators.

CATF's Proposal: Meaningful Reductions at Minimal Cost

Design Criteria

CATF sought to design a policy that could achieve meaningful emission reductions in a legally sustainable manner while minimizing costs and other economic impacts. Specifically, our proposal:

- Achieves significant emission reductions consistent with the U.S commitment to reduce GHG emissions by 17 percent from 2005 levels by 2020.
- Minimizes retail electric rate impacts to all classes of ratepayers and overall system costs while preventing disproportionate regional cost impacts.
- Keeps the cost per metric ton of carbon abatement within a range compatible with the Social Cost of Carbon.
- Provides states with flexibility in preparing their plans, in response to the performance standards and EPA's guidelines, through multiple technically proven compliance options as well as an emissions trading option.
- Provides resource planners and investors time to comply without compromising compliance with other EPA rules.
- Comports with the efficient operation and expansion of the Nation's competitive power markets.
- Mitigates economic impacts on merchant coal generators through the allowance allocation system.
- Limits coal unit retirements and provides for a smooth transition for any turnover of the coal fleet through an allowance allocation system.
- Recognizes actions and commitments made by states and companies in recent years to reduce carbon emissions.
- Comports with existing state and regional GHG emissions reduction and trading programs.
- Creates a framework that is structurally compatible with other federal carbon policies that will be needed in future years.

CATF's proposed policy meets each of these design criteria.

Potential for Emission Reductions

CATF assumes for the purposes of this proposal that EPA will establish separate standards of performance for existing fossil fuel-fired utility boilers under subpart Da and gas-fired combustion turbines under subpart KKKK consistent with the categories used in the proposed new unit rule under Section 111(b).[ii] Under our proposal, EPA will determine a performance standard for each subcategory, based on an assessment of the best system of emission reduction for existing sources.

Our analysis finds that a large number of options are potentially available to states in preparing their responsive plans for carbon emission reductions from existing sources in the electric sector. These include but are not limited to:

<u>Source-based Coal-fired Generation and Emission Control Technologies</u>: Heat rate improvements, coal drying, switching between different coals with varying carbon emission factors, gas co-

[ii] This report uses "fossil fuel-fired utility boilers" to refer to facilities that would be regulated under subpart Da, if they were new sources in EPA's proposed new source greenhouse gas performance standards, and "natural gas combustion turbines" to refer to combined cycle natural gas units that would be regulated under subpart KKKK in that proposed rule, if they were new sources. In its 111(b) proposal, EPA proposes to define the two subcategories as "fossil fuel-fired electric utility steam generating units and integrated gasification combined cycle units that burn coal, petroleum coke and other fossil fuels" and "natural gas-fired stationary combustion turbines". EPA shortens these to "fossil fuel-fired utility boilers" and "natural gas combustion turbines," the convention we adopt in this report. The fossil fuel-fired utility boiler subcategory includes natural gas-fired boilers as they are currently covered under Subpart Da. Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units 79 Fed. Reg. 1430 (Jan. 8, 2014) (re-proposing Section 111(b) standards of performance for EGUs).

firing,[34] and in some circumstances partial carbon capture utilization and storage;

Changes in Dispatch Mix of Covered Generation: Shifting the dispatch mix of generation from carbon intensive generation to lower or zero carbon emitting generation, in particular generation from existing natural gas-fired combined cycle units; and

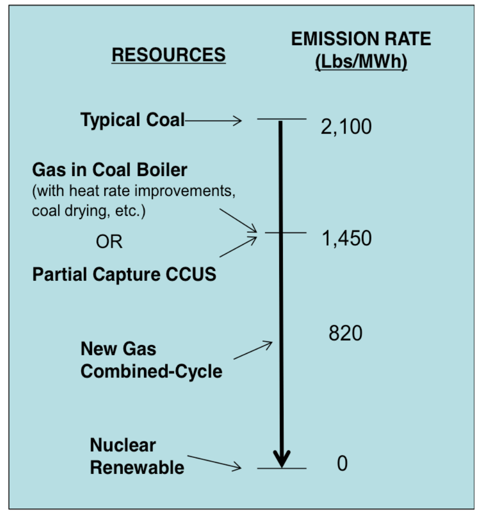
Systems-Based Supply and Demand Side Actions: State energy efficiency programs and state renewable energy programs that will reduce on-site emissions.

The technical and economic opportunity to reduce carbon emissions through these compliance options will differ from region to region and from state to state.

EPA has organized these approaches into categories, including "source-based" reductions that can be taken directly at the affected sources and "systems-based" reductions that include a broader portfolio of measures including those that can be taken beyond the affected sources but still result in reductions at those sources. Within these categories, EPA identifies "supply side options" consisting of measures that could be taken at the regulated sources themselves, and "demand side options" that instead, take place where the electricity is used, transmitted, or distributed. EPA's examples of supply side options include measures that increase energy efficiency at the sources (e.g., heat rate improvements), or increase the use of low- and non-emitting electric generation (e.g., fuel switching and co-firing), redispatch based on carbon emissions, or renewable energy portfolio requirements.[35] EPA's examples of demand side options include end-use efficiency and demand side management programs.[36]

Stakeholders have proposed a variety of approaches to setting BSER for existing coal-fired power plants considering the strategies addressed above.[37] The NorthBridge Group analysis of the CATF proposal provides an additional "supply side" approach to setting BSER by demonstrating that through dispatch optimization covered fossil units can emit significantly less carbon pollution while minimizing cost and electric rate impacts. CATF recommends that EPA use a combination of these strategies in its guidelines to evaluate and establish BSER and the resultant federal emission standard for coal units, recognizing that there are multiple control options that together support stringent performance standards for fossil fuel-fired utility boilers and natural gas combustion turbines. In combination, these options could achieve reductions in carbon pollution on the order of 30 percent from existing coal units with no carbon pollution controls.[38]

Figure 7: Achievable Emission Rate Reduction from Coal Units



Such a "suite of options" approach shows that various combinations of these strategies can achieve a net average emission rate of 1,450 lbs/MWh for fossil fuel-fired utility boilers.[iii] The vast majority of existing natural gas combustion turbines can achieve a net emission rate of 1,100 lbs/MWh. When fully implemented, after a phase-in period and through an interstate emission credit trading program, these performance standards would provide highly cost-effective reductions in power sector carbon pollution. Therefore, CATF believes that these emission rates represent BSER for these sources and recommends that EPA set them as the appropriate standards of performance for fossil fuel-fired utility boilers and natural gas combustion turbines respectively. Accordingly, the NorthBridge Group has assumed them as the target emission rates in its analysis of the CATF proposal.

[iii] The emission rate reductions outlined in this "suite of options" approach are consistent with the experience of a number of states that have developed and begun to implement programs to reduce power sector carbon emissions including the RGGI states, Colorado, and Minnesota. The rates derived are also consistent with more than one approach to establishing BSER for the fossil fuel-fired boiler sub-category. The NorthBridge Group analysis demonstrates the opportunity to achieve substantial carbon emission reductions by displacing coal generation with additional generation from existing NGCC capacity. This analysis shows the potential to reduce carbon emissions from coal plants to approximately 1,100 million metric tons and carbon emissions from all fossil plants to approximately 1,750 million metric tons. More precisely, using the 1,630 TWh of coal generation produced annually during the 2011 to 2012 period as a historic baseline, the 1,069 million metric tons of carbon emissions from coal estimated in this analysis is consistent with a 1,446 lbs/MWh equivalent emission rate. This represents roughly a 30 percent reduction relative to recent and current levels. Alternately, there are a number of source-based (or "inside the fence") technologies that might be used to reduce the carbon emission rates of coal plants and establish BSER. These include heat rate improvements, coal drying, coal rank switching, co-firing with natural gas and perhaps in some circumstances partial carbon capture, utilization and sequestration (CCUS). From a technical perspective, using natural gas as a fuel in coal boilers or partial CCUS, particularly in combination with one or more of the other technologies listed earlier, could also be used to achieve a net 1,450 lbs/MWh emission rate. CATF recommends a 1,450 lbs/MWh net output-based performance standard, that is, one that calculates the pollutant emitted per unit of electricity actually sold to the grid.

The Need for a "Model" Interstate Emission Credit Trading Rule

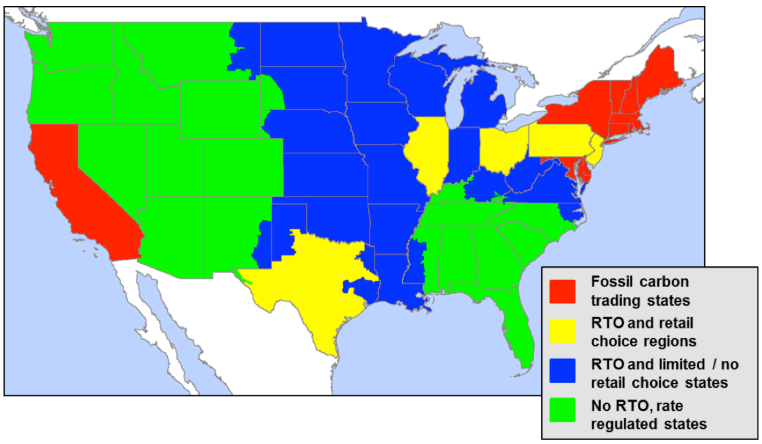
The President's memorandum, calling for submission of state plans by June 2016, provides a one-year implementation schedule. EPA can facilitate timely state implementation of the guidelines by issuing a model emission credit trading rule, state adoption of which (or demonstration of equivalence with, for existing programs) will presumptively satisfy the EPA 111(d) guidelines. In fact, in their December 16, 2013 letter to EPA Administrator McCarthy, officials from fifteen states requested that EPA offer a model rule to help facilitate state implementation of the federal guidelines.[39]

In addition, including an interstate system of emissions allowance trading in the model emission credit trading rule would facilitate least-cost compliance by states and covered electricity generators.[40] Moreover, the broadest possible geographic adoption of interstate emission credit trading would increase economic efficiency and reduce the compliance costs of the program. While states would retain the option to band together in regional trading blocs, under CATF's proposal, a model interstate emission credit trading rule would promote wider adoption of a uniform trading program more quickly, offering benefits for all states that join.

Furthermore, there is currently much diversity among the states regarding the regulatory status of the electric industry and state carbon programs. This is illustrated in the map below that clusters the states in four general groups: those with fossil carbon trading programs (currently CA and states in RGGI), states in Regional Transmission Organization

(RTO) markets with retail choice, states in RTO markets with limited or no retail choice, and states with rate regulated electric industries and no RTO markets. This variation in regulatory structure and the range of available compliance options it implies (e.g., "cap and trade" for the RGGI states or Integrated Resource Planning for the rate-regulated states with no RTO) highlights the need for compliance flexibility under the federal guideline.

Figure 8: State Regulatory Status and Carbon Programs



CATF's proposed approach would provide the needed compliance flexibility and could be utilized by all states regardless of their regulatory structure. EPA's federal emission standard would be converted into a state budget by multiplying the federal emission standard by a generation baseline, likely based on an average of several past years' generation. CATF's proposed market-based compliance mechanism would allow states that do not already have carbon markets to comply with emission standards in a flexible and cost effective manner. These states would benefit from an emission credit trading program that would expand the range of compliance options and allow for cost effective abatement through dispatch optimization of electric generation. States in RTO markets already benefit from transparent market-based energy prices. A market-based emission credit pricing mechanism tied to electric generating output would complement the market prices for energy and provide covered generators with a market price signal regarding the value of changes in generation dispatch, unit commitment, unit retirement and alternative compliance options.

CATF's State Budget-Based Alternative

The State of Kentucky recently expressed its desire for compliance flexibility through a state budget-based program in an October 2013 memorandum.[41] And, in a December 16, 2013 letter to EPA Administrator McCarthy, twenty-four officials from fifteen states requested EPA include a "mass-based performance level" compliance option in its Section 111(d) regulations.[42] By establishing such a budget-based option, EPA would help give the states a real choice in complying with the federal emission standards described above as an emission rate or through this state-specific budget.[43] Under CATF's approach, state emission budgets would be derived from each state's federal emission rates and a historic generation baseline, assumed in this analysis to be the years 2011 through 2012.[44]

In its guidance to the states, EPA must articulate not only its proposed standard and trading system, but also how it will assess whether the plans proposed by states satisfy the EPA guidelines, including the criteria it will use to determine equivalency between federal emission standards and state standards of performance.[45] EPA may choose to rely on multiple criteria to review the proposed state plans, including the cost of emission reductions, energy requirements, and any non-air quality health and environmental impacts. These guidelines should specify how RGGI and California could demonstrate compliance through their existing carbon programs. To do so will require EPA to provide those states with an emission allowance "budget" (denominated in metric tons of CO_2) for the carbon pollution emitted by the covered fossil-fuel generating units in those states. The budget will be based on the federal emission standard multiplied by a generation baseline, likely based in turn on an average of several past years' generation.

CATF therefore recommends that EPA issue a "model" interstate emission credit trading rule whereby states electing the budget-based alternative could choose to participate in a trading program with allocated emission credits. This would allow covered electric generators, if they choose, to comply with the budget in whole or in part through emission credit trading on an intra- or interstate basis.

In sum, under CATF's proposed policy design, states would have the flexibility to comply with EPA's existing source emission guidelines in a number of different ways:

1. Meeting the state budget for all fossil-fueled utility boilers through the model emission credit trading rule;
2. Meeting mass-based state budgets for fossil fuel-fired utility boilers through a state resource planning process including increased reliance of renewables and energy efficiency;[46]
3. Meeting the state budget(s) through the redispatch of existing electric resources by an Independent System Operator (ISO);[47]
4. Participating in an existing carbon trading program (such as RGGI or California) that is equivalent to the standards; or
5. Meeting the federal emission rate-based standards at each existing power plant on a plant-by-plant or statewide-average basis.

Finally, CATF recommends that EPA's guidance require compliance beginning January 2018, with the standards becoming incrementally more stringent over the following years until they reach the final target levels in 2020. The multi-year phase-in period would allow time for industry to engage in prudent resource planning and implementation and any necessary natural gas infrastructure development. It would also prevent or mitigate any undue impacts on the electric or natural gas markets.

CATF's Fossil Fuel-Fired Utility Boiler Emission Trading System

Under CATF's approach, EPA's model emission credit trading rule would set state budgets for fossil fuel-fired boiler units and permit emission credit trading only among those sources. The gas combustion turbine emission rate standard would remain in effect on a unit-specific basis, so both sub-categories would be regulated under the rule.

This is for several reasons:

First, the major immediate low-cost opportunity is to structure the standards to facilitate optimized dispatch of the existing fossil electric system to reduce carbon pollution through greater reliance on more efficient natural gas generation. Our approach takes advantage of the ability of natural gas units to run harder and more frequently, increasing gas units' total emissions (but not their emission rates) relative to current and forecasted levels, while lowering overall emissions rates and levels in the fossil-fueled electricity system as a whole. This also allows natural gas generation to serve new electric load. "Capping" gas unit emissions through an emissions budget, however, would conflict with this approach and identifying the appropriate target emissions levels would be difficult to estimate prior to program implementation.

Second, a fossil fuel-fired utility boiler-only trading program may result in lower impacts on electric rates than allowing trading between fossil utility boilers and gas combustion turbines while achieving equivalent emission reductions. At an equivalent level of emission stringency (that is, at an equivalent reduction in CO_2 tons emitted) such a program would result in higher emission credit prices, wholesale prices, and retail rate impacts than a fossil fuel-fired boiler-only budget alternative.[48]

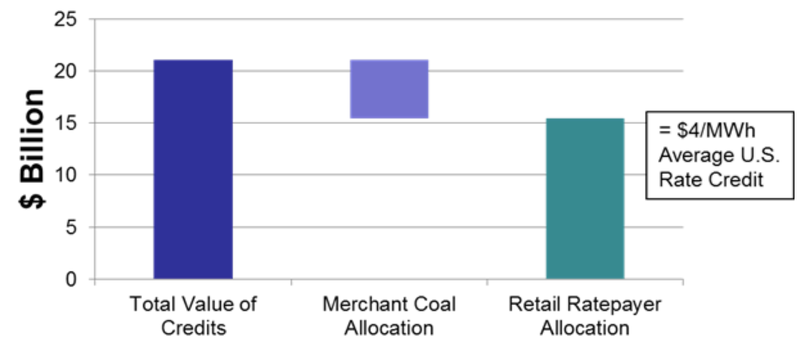
Third, the economic impact of this approach on owners of fossil fuel-fired utility boilers would be the same or no greater than under an approach setting a budget that also includes gas combustion turbines. So, they should be indifferent between the two approaches as the fossil fuel-fired boiler-only approach does not single them out in any material way.

In contrast to an emission rate-based system, providing a model interstate emission credit trading rule limited to fossil fuel-fired boilers should benefit owners of this type of generation because it enables them to efficiently comply at lowest cost, achieving meaningful emission reduction while maximizing the value of their assets. It would also allow boiler owners whose sources exceed the emission standards to continue to generate electricity while complying with the standards by purchasing credits. It will also provide these boiler owners with a market price signal regarding the relative value of other compliance options (for example, heat rate improvements, natural gas co-firing, or carbon capture), which can encourage efficient compliance.

Allowance Allocation Principles: Ratepayer Protection

To promote acceptance of the program, CATF believes that it is important to minimize the effect of the policy on ratepayers of all classes (industrial, commercial, and residential), dampen adverse economic impacts of the policy, and protect jobs throughout the economy. For states with rate-regulated retail service, the shift in generation mix from coal to gas, cost of purchased emission credits, upward pressure on natural gas prices resulting from coal displacement, and the cost of other compliance measures likely will slightly increase the generation component of retail rates. For states that have restructured their electric industry and allow for retail choice, any increase in wholesale electric prices would flow through to retail customers, raising their electric rates, while coal-fired generating capacity will diminish in value.

Figure 9: Ratepayer Protection



To mitigate such economic impact and protect jobs throughout the economy, under CATF's proposal, ratepayers of all classes could be compensated for virtually all retail rate impacts of the 111(d) policy through a state's direct allocation of allowances to load-serving entities (electric utilities in rate-regulated states and local distribution companies in restructured states). In rate-regulated states impacts of the compliance cost of the program on owners of coal generating assets could be mitigated through state rate recovery processes.

To treat coal generation asset owners similarly between restructured and rate-regulated states, CATF's approach also would allow measures to compensate merchant coal generators in restructured markets for the lost value of their generating assets and from retirements. This will have the additional benefit of easing their transition to the deployment of cleaner energy resources in the future.

The NorthBridge Group calculates that under the CATF proposal such allowance allocations would mitigate nearly all of the estimated resulting retail rate impacts and compensate merchant coal generators for their lost asset value. In NorthBridge's analysis, the projected national average increase in retail rates (without the moderating effect of emission credit allocation) would be 6.2 percent.[49] But, emission credit allocations would substantially reduce even this modest projected rate increase. Assuming a set-aside sufficient to compensate merchant coal generators for the lower market value of their assets, the annual value of the emission credits allocated for retail rate mitigation purposes would be approximately $16 billion. This translates into national average retail rate credits of $4/MWh and net retail rate impacts of about 2 percent in 2020.[50]

EPA's general implementing regulations for Section 111(d) existing source performance standards refer to the establishment of an "allowance system" as a compliance mechanism.[51] A model emission credit trading rule therefore could provide mechanisms to use free allowance allocations to compensate merchant generators. Such a federal allowance system would create strong incentives for states to adopt compliant state plans that employ rate reduction and compensation mechanisms. In the event that EPA must impose a federal implementation plan for a non-complying state, the model rule could provide a ready-made compliance option.

Compatibility with Existing State Trading Programs and Future Federal Action

Because CATF's state budget alternative and model emission credit trading rule is "mass-based," our system provides a framework that comports with existing state trading systems such as RGGI and California. In addition, by providing a familiar approach that is administratively simpler to implement, our system would facilitate state participation affording the added economic efficiency of broader interstate trading.

In contrast, under rate-based approaches, some covered sources would have emissions rates above the standard and some below the standard. Those with rates above the standard would have to undertake actions to achieve compliance while sources with rates below the standard would receive credits and have an incentive to increase production. Such a rate-based approach could exacerbate the current "seams" problem by distorting the market signals sent to similarly situated units in neighboring states with a budget-based program like RGGI.[52] A rate-based approach would also incent operators in states without an emissions budget to make heat rate improvements that increase rather than decrease their operations and net emissions by making those units more competitive and/or extending their useful lives.[53]

Other things equal, our budget-based approach would also promote deployment of renewable and energy efficiency resources by creating incrementally higher wholesale electric prices, which would make these resources more competitive and state renewable programs less expensive. This would also occur due to the relative administrative ease of taking emissions reductions from the resources into account in demonstrating compliance with the budget.

Over the longer term, deeper emission reductions than can be expected from this regulatory action will be needed from existing sources in the electric sector to achieve the U.S. commitment to an 80 percent reduction in economy wide GHG emissions by 2050.[54] CATF's proposed approach to the 111(d) system can facilitate tightening carbon pollution performance standards in future revisions of the standards as carbon capture and sequestration (CCS) for existing coal and gas plants becomes increasingly relied upon.[55] For further reductions to be achieved in an optimally efficient manner, a mandatory all-fossil budget and trading approach would be preferable and eventually necessary. This is because, in the long term, a budget and trading program covering all fossil units would cap emissions from natural gas plants and provide stronger price signals to develop zero-carbon electric generation, demand response, and energy efficiency programs, while driving further emission reductions in regions where uncontrolled coal generation no longer represents a large portion of electric supply. CATF's policy framework could facilitate a smooth transition to such a future climate mitigation regime whether it arises through future EPA regulatory actions or future federal Congressional enactments establishing a cap and trade program, a carbon tax, or clean energy standard.

The NorthBridge Group: Qualifications and Methodology

Qualifications

The NorthBridge Group is an economic and strategic consulting firm serving the electric and natural gas industries, including both regulated utilities and companies active in the competitive wholesale and retail markets.

The NorthBridge Group's practice is national in scope, and they have long-standing consulting relationships with a number of electric utility clients across the country. NorthBridge applies market insights, rigorous quantitative skills and regulatory expertise to solving complex business and policy challenges. The NorthBridge Group has provided strategic advice and analysis to CATF since its founding.

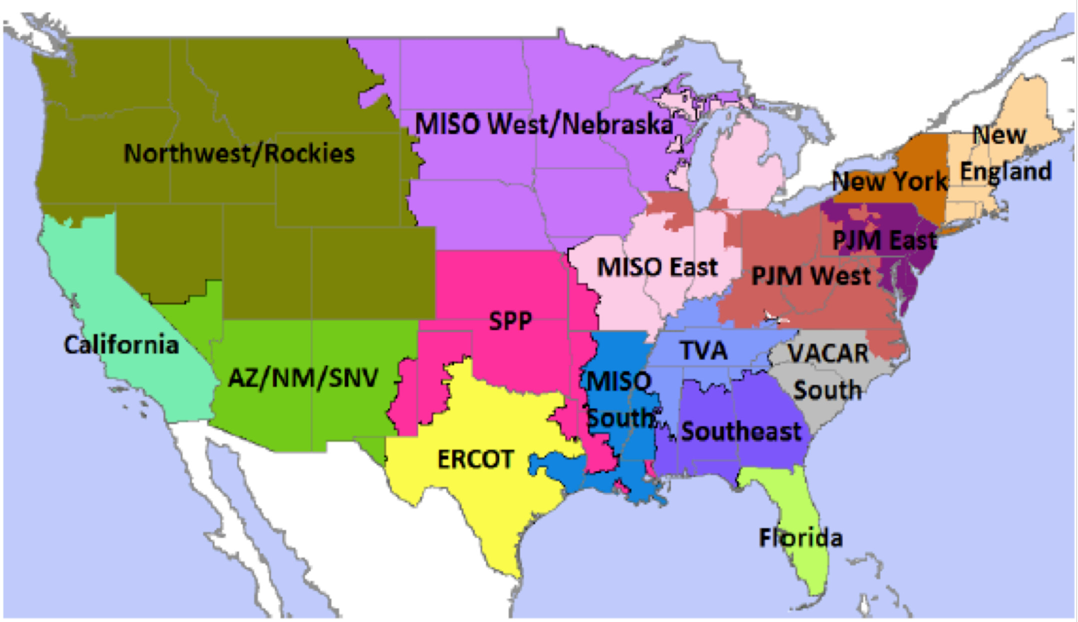
Methodology

The NorthBridge Group's utility clients rely on the firm in making business decisions including asset valuation for the purchase or sale of units, regulatory compliance decisions and planning, etc. The NorthBridge modeling approach provides unit-specific results (unlike, for example, ICF Consulting's Integrated Planning Model/IPM model, which analyzes only "model" units and then "parses" the run results to specific real-world units).

The 111(d) market model used in this analysis is a chronological hourly dispatch model developed specifically to analyze alternative 111(d) policy designs in a transparent manner. It reflects unit-specific data for the fossil generating units in 16 market regions across the country, generally corresponding to NERC sub-regions and EIA's Electric Market Module regions (see figure 10).

The base case dispatch for 2020 has been developed from hourly unit commitment and other operating data from 2011 and known changes in market conditions including planned unit retirements, new capacity additions, load growth and changes in fuel prices. The policy case reflects the impact of a nationally uniform carbon price applied to the carbon emissions from major coal generating units. Most assumptions are consistent with EIA's AEO 2013 "No Sunset" case. The model simulates unit commitment and dispatch decisions, and estimates energy and capacity prices, emissions, unit retirements, capacity additions, generation mix, electric production costs and natural gas demand and prices, and market asset values among other outputs. The model operates on an actual unit-specific rather than "model unit" basis, allowing for an understanding of the impacts of assumed policies on a highly disaggregated basis. The results have been benchmarked to several public and private forecasts.[56]

Figure 10: Modeling Regions



Results of Analysis

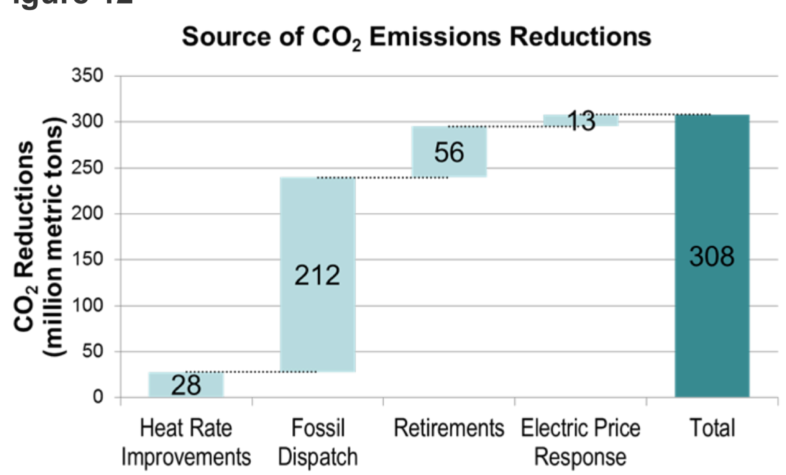
Figure 11: Summary of Results by 2020

Reduction in fossil CO2 (%) from 2005 levels	-27%
Reduction in CO2 (million metric tons) from 2005 levels	636
Reduction in CO2 (million metric tons) from forecast 2020 levels	308
CO2 price ($ 2013/metric ton)	$20
Reduction in coal TWh (%)	-27%
Coal retirements (GW)	42
Increase in gas consumption (TCF)	3.0
Increase in Henry Hub gas price ($/MMBtu)	11.4%
Increase in US wholesale electric price (%)	6.9%
Increase in US retail electric price – without allowance offset (%)	6.2%
Increase in US retail electric price – with allowance offset (%)	2.3%
Marginal cost ($ 2013/metric ton)	34
Average cost ($ 2013/metric ton)	32
Total program costs ($ 2013 billion)	9.4
Total program benefits ($ 2013 billion)	34

Figure 12 below summarizes the source of the CO_2 emission reductions under the CATF policy, nearly 70 percent of which are from optimization of fossil dispatch (i.e., displacing generation from high heat rate coal units with generation from underutilized combined cycled natural gas plants).

This dynamic is illustrated in the graph on the following page showing the resulting increase in the average capacity factor for combined cycle natural gas units from 48 percent to 65 percent capacity factor and reductions in the average coal unit capacity factor from 67 percent to 58 percent. This results in a reduction in coal terawatt hours from 1,549 to 1,134 while increasing combined cycle natural gas (CCNG) generation from 901 terawatt hours to 1,217 terawatt hours. See Figure 13 on the following page.

Figure 12



The compliance costs associated with the policy are illustrated in figure 14, the majority of which is the relatively higher cost of the additional natural gas used in ramping up the electricity produced from combined cycle natural gas plants.

Figure 13: Modeled Generation, Capacity and Capacity Factors

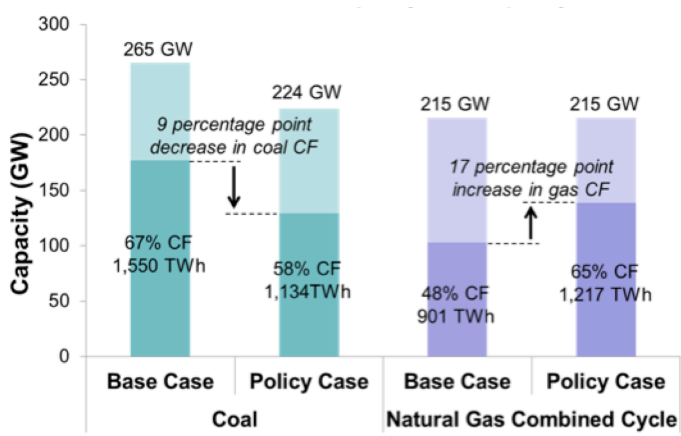
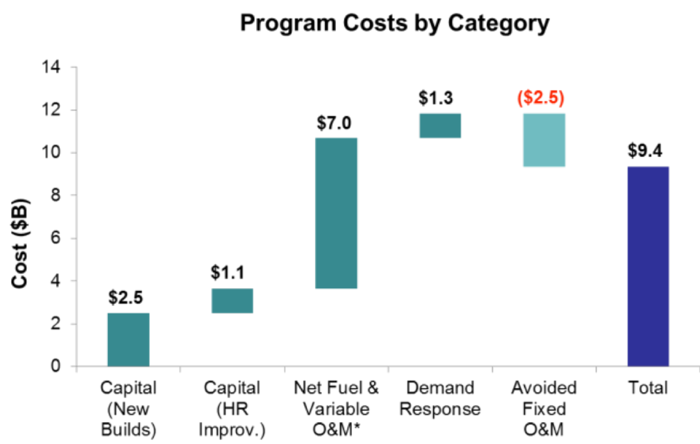


Figure 14



Sensitivities

These results, like those from other studies rely on long-term projections of natural gas prices, and are subject to forecast uncertainty. In this analysis, the results for the policy cases depend in part on the extent to which natural gas prices rise in response to the higher demand for natural gas caused by gas generation displacing coal generation. Assuming the gas price response is 50 percent higher or lower than in the core policy case and the mix of compliance actions is unchanged, the total cost of compliance would be $12.5 billion or $6.2 billion, a change of $3.2 billion or 34% relative to the core policy case result of $9.4 billion. Under the same range of assumptions, emission credit prices for the mass-based coal case would be $22.5 per metric ton or $17.8 per metric ton (compared to the core policy case of $20 per metric ton) and retail electric rates would rise by 3.5 percent or 1.1 percent (compared to the core policy case of 2.3%). Note that two factors would tend to limit the impacts of a higher gas price response. One, reflected in these estimates, is that the higher emission credit price would raise the value of the emission credit allocation, which would dampen the net impact on retail rates. The other, which is not reflected in these sensitivity estimates, is that the higher cost of coal-gas displacement would make other compliance options more cost effective on a relative basis. This would shift the mix of compliance options away from coal-gas displacement towards those lower cost options. Since this second factor is not reflected in these sensitivity estimates, they are likely to be somewhat conservative.

The results of the NorthBridge Group analysis reported above do not take into account upstream CO_2 emissions from the production, processing, and transmission of gas nor from the production and transport of coal. In addition, they do not take into account the upstream methane emissions associated with producing and delivering the gas and coal. To take these impacts into account as part of a full life-cycle GHG analysis of our proposed policy, CATF analyzed how our policy might affect overall GHG emissions. The results are summarized in Figure 15 below.[57] In sum, accounting for full life-cycle GHG emissions using EPA assumptions reduces the carbon dioxide equivalent benefits of our proposal by 3 percent (2005 vs. 2020).

Figure 15

Additional 2020 upstream emissions (MMT CO_2e) from coal to gas switch		
	Base Case (EPA Figures for CH_4 from O&G)	**High Case** (non-fracking gas production emissions 2x higher than EPA inventory)
Upstream CO_2	9.6	9.6
Upstream Methane (GWP=25)	0.3	7.3
TOTAL	**9.9**	**16.9**

Analysis of Health Benefits

In addition to carbon pollution, coal-fired power plants emit a host of other dangerous pollutants including two precursors to deadly fine particles: sulfur dioxide (SO_2) and nitrogen oxides (NO_x). The problems associated with SO_2 include not only deadly fine particles, but also damage from acid rain, and the haze that obscures scenic vistas in national parks and our urban areas. Coal-fired power plants emit about two-thirds of the SO_2 emitted in the U.S. each year.[58] The problems associated with NO_x include the massive health and ecosystem damage due to ozone smog and nitrogen deposition. Coal and gas-fired power plants are responsible for about one-quarter of the NO_x emitted in the U.S. each year.[59]

The direct link between power plant emissions and human health has been documented in an extensive body of scientific research drawing on multiple lines of evidence, including several rigorous, large-scale epidemiological studies. Over the last several years, the EPA has reviewed and summarized much of this literature in formal rulemakings and regulatory analyses.[60] CATF and other organizations advocating on behalf of more stringent regulation of power sector emissions have also cited and relied upon this work.[61]

Power plant emissions of SO_2 and NO_x are chemically transformed in the atmosphere into very small airborne particles that cause or contribute to a host of respiratory and cardiopulmonary ailments and increase the risk of premature death. Fine particles are especially dangerous because they can bypass the body's defensive mechanisms and become lodged deep in the human lung. Indeed, research also indicates that short-term exposures to fine particle pollution is linked to adverse cardiac effects, including increased risk of heart attack.[62]

Meanwhile, long-term exposure to fine particle pollution has been shown to increase the risk of death from cardiac and respiratory diseases and lung cancer, resulting in shorter life-expectancy for people living in the most polluted cities compared to people who live in cleaner cities.[63] On a population wide basis, research suggests, fine particles reduce the average life span by a few years – but for any given individual the potential is for a life shortened by as many as 14 years, depending on exposure.[64] Because most fine particle-related deaths are thought to occur within a year or two of exposure, reducing power plant pollution will have almost immediate benefits.[65]

The expected decreased reliance on coal-fired generation under CATF's approach will result in incremental additional reductions in coal-fired power plant SO_2 and NO_x emissions beyond those that result from the Mercury and Air Toxics Standards (MATS) and interstate air pollution regulations. The NorthBridge Group's analysis estimates additional annual SO_2 reductions of approximately 450,000 tons per year and NO_x reductions of 400,000 tons per year in 2020 under CATF's approach.

To estimate the health (and monetized) benefits of our proposal, CATF relied on analysis by Abt Associates using methods developed for and employed by the EPA, extensively reviewed by EPA's Science Advisory Board, approved in a review by the National Academy of Sciences, and accepted by the U.S. Office of Management and Budget in a variety of regulatory impact and assessment contexts.[66] Using this EPA-standard methodology,[67] CATF estimates that our 111(d) policy approach will result in over 2,000 avoided deaths, 1,000 avoided emergency room visits, and 15,000 asthma attacks in 2020. This translates into a monetized value of $19 billion in 2020 (expressed in 2013 dollars).

Analysis of Climate Benefits

The NorthBridge Group estimates that CATF's proposal will reduce carbon pollution emissions by approximately 636 million metric tons from 2005 levels by 2020.

The U.S. government has developed a Social Cost of Carbon (SCC) to estimate the climate benefits of environmental regulations. The SCC is an estimate of the economic damages associated with a small increase in CO_2 emissions, conventionally one metric ton, in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a ton of CO_2 reduction).

The SCC is meant to be a comprehensive estimate of climate change damages and includes, but is not limited to, changes in net agricultural productivity, human health, and property damages from increased flood risk. However, given current modeling and data limitations, it does not include all important damages. As noted by the IPCC Fourth Assessment Report, it is "very likely that [SCC] underestimates" the damages. The models used to develop SCC ranges, known as integrated assessment models, do not currently include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature because of a lack of precise information on the nature of damages and because the science incorporated into these models naturally lags behind the most recent research. Nonetheless, the SCC is a useful measure to assess the benefits of CO_2 reductions. The Agency's 2010 SCC ranges have been used in estimating the carbon pollution-related benefits of the MATS and the Cross-State Air Pollution Rule (CSAPR).[68]

Based on the recently revised (2013) Social Cost of Carbon,[69] the economic value of the carbon dioxide reductions expected under the CATF proposed approach to 111(d) existing source standards is estimated to be $15 billion per year in 2020 (expressed in 2013 dollars).[70] In this analysis, the NorthBridge Group estimated the carbon pollution reduction benefits of our proposal using EPA's 2013 mid-range Social Cost of Carbon value in 2020 derived from a three percent discount rate.[71]

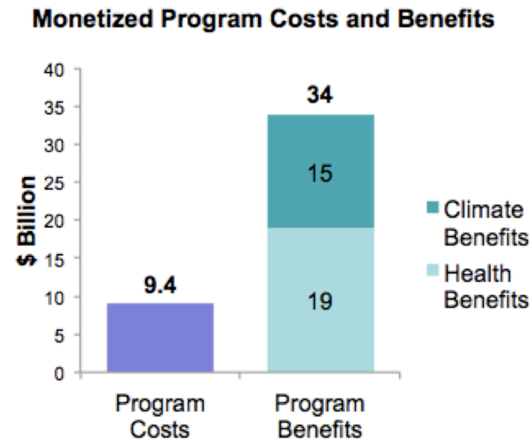
Total Benefits vs. Costs

Together, the monetized health and climate benefits of CATF's policy total $34 billion in 2020, which is over three times the cost of compliance ($9.4 billion). See Figure 16 on next page.

Conclusion

The Clean Air Task Force believes that there is a significant opportunity for carbon dioxide reductions from the existing power sector, presented by the large amount of presently underutilized combined cycle natural gas generation. In order to provide incentives to unlock that potential, CATF recommends that EPA set a net emission rate of 1,450 lbs/MWh for fossil fuel-fired utility boilers and 1,100 lbs/MWh for gas combustion turbines including combined cycle natural gas units with a model interstate emission credit trading rule including state budgets to facilitate credit trading among fossil fuel-fired utility boilers. In addition, CATF recommends that the model emission credit trading rule set allowance allocations to protect electric ratepayers of all classes and allow states with restructured electric markets to compensate merchant coal generators for lost asset value due to the policy. The analysis by the NorthBridge Group demonstrates that such a policy would result in electric sector carbon pollution 27 percent below 2005 levels by 2020 while minimizing costs and rate impacts. This policy would generate societal benefits of over $34 billion dollars with costs of only slightly over $9 billion in 2020.

Figure 16



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[1] U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011, Executive Summary "Recent Trends in U.S. Greenhouse Gas Emissions and Sinks" p. ES-5, Table ES-2 (Apr. 2013) *available at*: www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-ES.pdf.
[2] U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011 at ES-5, Table ES-2 & ES-7 (Apr. 2013) *available at:* http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf.
[3] World Resources Institute, "Can the US Get There From Here?" (Feb. 2013) *available at*: http://www.wri.org/sites/default/files/pdf/can_us_get_there_from_here_full_report.pdf.
[4] *See* U.S. EPA, State and Local Climate and Energy Program, Power Sector, http://www.epa.gov/statelocalclimate/state/tracking/power.html.
[5] U.S. EPA, Endangerment Finding, Climate Change Facts, *available at*: http://www.epa.gov/climatechange/Downloads/endangerment/EndangermentFinding_ClimateChangeFacts.pdf.
[6] U.S. EPA, Endangerment Finding, Health Effects, *available at*: http://www.epa.gov/climatechange/Downloads/endangerment/EndangermentFinding_Health.pdf; U.S. EPA, Endangerment Finding, Environmental and Welfare Effects, *available at*: http://www.epa.gov/climatechange/Downloads/endangerment/EndangermentFinding_EnvironmentalEffects.pdf.
[7] *Massachusetts v. EPA*, 549 U.S. 497, 528-29 (2007); *see also* 42 U.S.C. § 7602(g) (defining "air pollutant"). EPA, in response to the Supreme Court's Massachusetts decision, found that greenhouse gases (a pollutant comprising carbon dioxide and five other air pollutants) endanger public health and welfare within the meaning of the Act. Endangerment and Cause and Contribute Finding for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496 (Dec. 15, 2009) [hereinafter *Endangerment Finding*].
[8] 42 U.S.C. § 7411(b)(1)(A), (B).
[9] *Am. Elec. Power Co. v. Conn.*, 131 S.Ct. 2527 (2011).
[10] *See, e.g.,* Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units 79 Fed. Reg. 1430, (Jan. 8, 2014) (re-proposing Section 111(b) standards of performance for EGUs).

[11] The White House, "Presidential Memorandum - Power Sector Carbon Pollution Standards" (June 25, 2013) *available at*: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards; The President's Climate Action Plan (June 2013) *available at*: http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.
[12] *Id.*; *See also* U.S. EPA, "Carbon Pollution Standards – What Is EPA Doing?" http://www2.epa.gov/carbon-pollution-standards/what-epa-doing.
[13] *See* 42 U.S.C. § 7411(d)(1).
[14] 42 U.S.C. § 7411(a)(1).
[15] *Id.*
[16] State Plans for the Control of Certain Pollutants from Existing Facilities, 40 Fed. Reg. 53,340 (Nov. 17, 1975) (codified at 40 C.F.R. Subpart B "Adoption and Submittal of State Plans for Existing Facilities.").
[17] 40 C.F.R. § 60.22(a). EPA has proposed standards of performance under §111(b) for carbon pollution from new power plants, Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430 (Jan. 8, 2014), and the Agency is therefore required to propose §111(d) guidelines for carbon pollution from existing EGUs.
[18] 40 C.F.R. § 60.22.
[19] The White House, "Presidential Memorandum - Power Sector Carbon Pollution Standards" (June 25, 2013) *available at*: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.
[20] 40 C.F.R. § 60.24(c)
[21] 42 U.S.C. §§ 7411(d)(2), 7410(c)(1).
[22] *Id.* § 7411(d)(1).
[23] *Id.* § 7411(a)(1).
[24] 40 C.F.R. § 60.24(b)(1).
[25] *Id.* at § 60.22(b)(5).
[26] *Id.* at. §§ 60.21(f), 60.24(b)(1).
[27] *See Id.* at §§ 60.33b(d)(1)-(2); Standards of Performance for New Stationary Source and Emission Guidelines for Existing Sources: Municipal Waste Combustors 60 Fed. Reg. 65,387 (Dec. 19, 1995). EPA also established a trading system in its now-vacated 2005 Section 111(d) rulemaking for electric generating unit mercury emissions (known as the "CAMR"). That rule was struck down by the D.C. Circuit on other grounds, *i.e.,* that the coal-fired EGU industry remained listed under Section 112, and therefore that electric generating unit mercury emissions were properly regulated under that section of the Clean Air Act, not under Section 111. *N.J. v. EPA*, 517 F.3d 574 (D.C. Cir. 2008), *cert. dismissed*, 555 U.S. 1162 and *cert. denied*, 555 U.S. 1169 (2009).
[28] Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 70 Fed. Reg. 28,606, 28,616 (May 18, 2005).
[29] US Energy Information Administration, *Short Term Energy Outlook*. http://www.eia.gov/forecasts/steo/report/electricity.cfm.
[30] US Energy Information Administration, *Monthly Energy Review* (Nov. 2013) http://www.eia.gov/totalenergy/data/monthly/#environment.
[31] NorthBridge analysis based on data from the Energy Velocity Suite, a commercial database from Ventyx including data from EPA's Continuous Emissions Monitoring System (CEMS).
[32] J.A. de Gouw et al., *Reduced Emissions of CO_2, NOx and SO_2 from U.S. Power Plants Due to the Switch from Coal to Natural Gas with Combined Cycle Technology*, AGU "Earth's Future" (Jan. 8, 2014) *available at*: http://onlinelibrary.wiley.com/store/10.1002/2014EF000196/asset/eft218.pdf?v=1&t=hqnxz684&s=bbb3bb724eff263ce19a247b5e99607046123 1a9.
[33] NorthBridge analysis based on data from the Energy Velocity Suite, a commercial database from Ventyx.
[34] Brian Reinhart et al., *A Case Study on Coal to Natural Gas Fuel Switch*, Black & Veatch (2012), *available at*: http://bv.com/Home/news/thought-leadership/energy-issues/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.
[35] U.S. EPA, "Overview presentation of Clean Air Act Section 111" *available at*: http://www2.epa.gov/carbon-pollution-standards/what-epa-doing#overview.
[36] *Id.*
[37] Ceronsky, M and Carbonell, T., "Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants", Environmental Defense Fund (Oct. 2013); Lashof et al., "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," Natural Resources Defense Council (Mar. 2013); Van Atten, C., "Structuring Power Plant Emissions Standards Under Section 111(d) of the Clean Air Act," M.J. Bradley & Associates, LLC (Nov. 2013); Burtraw, D. and Woerman, M., "Technology Flexibility and Stringency for Greenhouse Gas Regulations," Resources for the Future Discussion Paper (July 2013).
[38] *Id.*

[39] Letter from Mary D. Nichols, Chair, Cal. Air Res. Bd. et al. to Gina McCarthy, Administrator, U.S. Envtl. Prot. Agency (Dec. 16, 2013) *available at*: http://www.georgetownclimate.org/sites/default/files/EPA_Submission_from_States-FinalCompl.pdf
[40] The President's memorandum requests EPA to "develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities."
[41] Commonwealth of Kentucky Energy and Environment Cabinet, "Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act" (Oct. 22, 2013) *available at*: http://eec.ky.gov/Documents/GHG%20Policy%20Report%20with%20Gina%20McCarthy%20letter.pdf.; *See also* Midwest Power Sector Collaborative, "Initial Recommendations to the U.S. Environmental Protection Agency on Regulation of Existing Power Plant Sources under Section 111(d) of the Clean Air Act" (Nov. 2013) *available at*: http://www.betterenergy.org/sites/www.betterenergy.org/files/MPSC_EPA_Recommendations_Nov2013.pdf.
[42] Letter from Mary D. Nichols et al. *supra* note 39.
[43] Van Atten, C., *supra* note 37.
[44] In this analysis, the budgets cover emissions from both existing and new fossil generating units.
[45] 40 C.F.R. § 60.22(b) (describing the requirement for EPA to lay out not only its basis for the guideline emission rates, but also the assessment rubric it will use for state plan submissions).
[46] Note that the second approach is not mutually exclusive with the first, as states may choose to comply through a mix of state resource planning decisions and emission credit trading.
[47] Great River Energy, a rural electric cooperative doing business in Minnesota, has developed an ISO-based implementation strategy based on dispatch of the electric system in response to a carbon price. *See* The Brattle Group, "An ISO-based Implementation of EPA's GHG Emissions Regulation: A Concept Presentation" (Nov. 13, 2013); http://www.brattle.com/system/news/pdfs/000/000/616/original/A_Market-based_Regional_Approach_to_Implementing_EPA's_GHG_Emissions_Regulation.pdf?1391603705.
[48] The NorthBridge Group, "Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions" (Feb. 2014). Available at: http://www.catf.us/resources/publications/view/196
[49] These estimates reflect the increase in wholesale electric prices that would be expected to be larger than the increase in rate regulated states.
[50] The NorthBridge Group *supra* at note 48.
[51] 40 C.F.R. § 60.24(b)(1).
[52] Under a rate-based approach, the financial value of emission credits received by a generating unit with emission rates below the standard would partially offset the unit's variable fuel and operations and maintenance costs, and reduce its marginal cost of dispatch. When a rate-based approach is adopted by a state that borders another state with a budget-based program, the lower cost of dispatch gives units in the rate-based state a competitive advantage over otherwise similar units in the budget-based state, simply because of the conflicting forms of emissions regulation. This is a "seams" problem.
[53] The NorthBridge Group *supra* at note 48.
[54] The President's Climate Action Plan *supra* at note 11.
[55] Clean Air Act Section 111(b)(1)(B) requires the Administrator to review, and if appropriate, revise issued new source standards. The statute also obligates the Administrator to consider any emissions limitations and percent reductions beyond the standards, but achieved in practice, when revising standards promulgated under section 111 generally. 42 U.S.C. § 7411(b)(1)(B).
[56] The NorthBridge Group *supra* at note 48.
[57] "Upstream Implications of Coal to Gas Switch Under CATF's 111d Proposal", available at: http://www.catf.us/resources/whitepapers/view/195
[58] U.S. EPA, "The Plain English Guide to the Clean Air Act – Reducing Acid Rain," *available at*: http://www.epa.gov/airquality/peg_caa/acidrain.html.
[59] *Id.*
[60] *E.g.,* U.S. EPA, "Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards," (Dec. 2011); Industrial Economics, "Expanded Expert Judgment Assessment of the Concentration- Response Between PM2.5 Exposure and Mortality" (Sept. 21, 2006).
[61] Clean Air Task Force, "Toll from Coal: An Updated Assessment of Death and Disease from America's Dirtiest Energy Source," (Sept. 2010); Natural Resources Defense Council "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters" (Mar. 2013).
[62] *See e.g.*, Robert D. Brook, et al., *Air Pollution and Cardiovascular Disease: A Statement for Healthcare Professionals From the Expert Panel on Population and Prevention Science of the American Heart Association*, 109 Circulation 2655 – 2671 (June 2004); Sun, Q, et al., *Long-term air pollution exposure and acceleration of atherosclerosis in an animal model*, 294 JAMA. 3003-3010 (2005); Miller, K., Siscovik, et al., *Long-term exposure to air pollution and incidence of cardiovascular events in women*, 356 New Eng. J. Med.447-458, (Feb. 1, 2007); Peters, Annette, and Pope, C.A., *Cardiopulmonary Mortality and Air Pollution,* 360 The Lancet 1184 (Oct. 19, 2002).

[63] *See, e.g*., Laden, F., et al., *Reduction in Fine Particulate Air Pollution and Mortality*, 173 Am. J. of Respiratory and Critical Care Med. 667-672; Pope, C. A., 3rd,et al., *Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution*. 287 JAMA 1132-41; Pope, C.A.,et al. *Fine particulate air pollution and life expectancy in the United States,* 360 New Eng.J. Med. 376 (Jan. 23, 2009); Brunekreef, B., *Air Pollution and Life Expectancy: Is There a Relation?* 54 Occup. Environ. Med. 781–84 (1997); U.S. EPA, OAR, "Final Report to Congress on Benefits and Costs of the Clean Air Act, 1970 to 1990", EPA 410-R-97-002 at I-23 (Oct. 1997).

[64] Lippmann, M. and Schlesinger, R. B., *Toxicological bases for the setting of health-related air pollution standards*, 21 Ann. Rev.Pub. Health 309-333 (2000).

[65] *Id.*

[66] National Research Council, "Estimating the Public Health Benefits of Proposed Air Pollution Regulations Committee on Estimating the Health-Risk-Reduction Benefits of Proposed Air Pollution Regulations" (2002).

[67] Abt Associates, Inc., "Technical Support Document for the Powerplant Impact Estimator Tool" *available at:* http://www.catf.us/resources/publications/files/Abt-Technical_Support_Document_for_the_Powerplant_Impact_Estimator_Software_Tool.pdf. SO_2 and NO_x tonnage reductions were outputs from the NorthBridge Group modeling analysis of the CATF proposal. These reductions were input into the Abt Associates Powerplant Impact Estimator (PIE) tool. The mortality estimate reported is based on the application of the Laden et al. dose-response relationships. The health impacts were monetized using the BenMAP model.

[68] *See e.g.,* U.S. EPA, "Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards" (Dec. 2011) *available at:* http://www.epa.gov/ttnecas1/regdata/RIAs/matsriafinal.pdf

[69] Interagency Working Group on Social Cost of Carbon, United States Government, "Technical Support Document: - Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866" (Nov. 2013) *available at*: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

[70] U.S. EPA, "Climate Change – The Social Cost of Carbon" http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.

[71] *Id.*