What is Best Available Control Technology for a Coal-Fueled Electric Generating Unit?

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Executive Summary

What is Best Available Control Technology for GHGs for a Coal-Fueled Electric Generating Unit?

Introduction

As the U.S. Environmental Protection Agency (EPA) begins to regulate greenhouse gas (GHG) emissions under the Clean Air Act (CAA), attention is focusing on how EPA and the states will define Best Available Control Technology (BACT) requirements for GHGs. New and modified stationary sources that emit above a certain threshold of GHG emissions, including much of the nation's industrial and manufacturing base, will be required under EPA regulation to undertake BACT to control those emissions.

BACT requirements for new and modified coal-fueled electric generating units (EGUs) have received particular attention. Under EPA's newly announced "tailoring rule" and its related action reconsidering the so-called "Johnson Memorandum," coal-fueled EGUs will be subject to GHG BACT requirements as of January 2, 2011. Indeed, these rules provide that state regulators may begin applying GHG requirements under state law prior to that date, and the rules encourage state regulators to immediately begin looking for ways to reduce GHG emissions for any project undergoing regulatory review.

BACT requirements become applicable when new and modified major sources of air pollutants apply for preconstruction air quality permits, termed Prevention of Significant Deterioration (PSD) permits. Although most PSD permits are issued by states, and states, therefore, determine BACT in most cases, EPA exerts a great deal of influence in defining the contours of BACT requirements as a part of its statutory role of reviewing and approving state PSD programs. EPA has announced that it intends to issue guidelines for states to follow in determining GHG BACT requirements.

As set forth in the CAA, BACT is determined on a case-by-case basis and does not result in the selection of the maximum control technology regardless of cost, commercial availability or technical feasibility. Instead, BACT requires a balancing of energy, environmental and economic impacts, along with technical feasibility.

What is GHG BACT for a Coal-Fueled EGU?

Meaningful GHG emission reductions can be obtained from coal-fueled generation through efficiency improvements. Coal generation can be made more efficient in the same way that other industries become more efficient over time—through the replacement in the normal course of older, less efficient facilities with newer, more efficient ones.

New supercritical and ultra-supercritical pulverized coal facilities produce significantly more electricity per unit of heat input than do existing units and, therefore, emit lower volumes of CO_2. An ultra-supercritical plant can achieve a thermal efficiency of 44 percent, as compared with the average thermal efficiency of 32 percent for the existing fleet – resulting in 35 percent greater efficiency than the average existing unit and a 35 percent reduction in CO_2 emissions. Supercritical and ultra-supercritical facilities also can be designed so that future technologies to capture CO_2 emissions can be added when those technologies become commercially viable.

Integrated gasification combined cycle (IGCC) also is a promising technology that, in theory, can achieve efficiencies approaching those of an ultra-supercritical plant. IGCC, however, is not BACT for a conventional coal plant, given differences in design. Moreover, IGCC still faces technical and cost challenges.

In addition, in some cases, existing coal plants can be made more efficient by restoring efficiency that was lost over time through wear and tear. Efficiency can also be improved beyond the original design with technologies developed since the plant was built, including steam turbine improvements and combustion controls. In individual cases, these types of efficiency improvements can reduce CO_2 emissions by up to 16 percent. An overall fleet improvement of 5 percent appears to be practical.

There is an important caveat, however, to achieving GHG reductions from the existing fleet under the PSD program. Historically, the PSD program and its sister nonattainment new source review program have been administered in a fashion that impedes efficiency improvements. Under these programs, an existing facility becomes subject to permit requirements if it undertakes a modification that results in a "significant" increase in emissions of any regulated pollutant. EPA has taken the position that a "significant" emissions increase must be determined by measuring the total annual amount of emissions increase that results from a modification over the course of the year rather than by measuring whether the rate of emissions per unit of output has increased.

This is an extremely important distinction in the context of using the PSD program to make the existing coal fleet more efficient. If the owner of a coal-fueled EGU makes the unit more efficient, its rate of emissions will decline. But if the efficiency upgrade results in the unit operating more hours of the year, as it should, the total annual amount of emissions may increase, even as the rate per unit of output declines. This will be true for the facility's GHG emissions as well as for its other emissions.

Measuring an emissions increase in this fashion discourages facilities from undertaking efficiency projects, because facilities want to make efficiency upgrades without triggering BACT requirements for the different types of emissions they produce. Moreover, there is no basis to be concerned that efficiency projects will, in fact, increase emissions over time, because the whole reason for a facility to improve its efficiency and run more is so that other less efficient, more costly facilities can run less. This is how the economy becomes more efficient over time, as more efficient facilities replace less efficient facilities. Under EPA's interpretation, however, facilities are incented either not to make economically justified efficiency upgrades or to make the upgrades but to limit the amount of time the facility operates, which makes no economic sense. In sum, the PSD program can result in efficiency upgrades, but only if EPA administers the program with that purpose in mind.

What is Not BACT for a Coal-Fueled EGU?

Some have advanced two ideas for what BACT should be for coal-fueled EGUs that, in reality, are thinly veiled attempts to prohibit coal use and preclude America from continuing to secure the economic advantages of our most abundant and affordable energy source. They include: (1) BACT should be capturing CO_2 from the stack, compressing it, shipping it by pipeline to a storage site, and permanently storing the CO_2 underground, a process known as carbon capture and storage, or CCS; and (2) fuel switching to natural gas.

Although CCS is the long-term solution for achieving dramatic reductions in CO_2 emissions from fossil fuels both in the United States and internationally, CCS is not commercially available at this time and, therefore, does not represent BACT. Best estimates are that with the necessary financial support, CCS can be ready for widespread deployment in the decade of the 2020s. Moreover, CCS cannot be deployed until the necessary legal and regulatory structures are in place for the long-term storage of CO_2. Indeed, EPA has discounted the notion that CCS is BACT at this time, with EPA Assistant Secretary for Air and Radiation Gina McCarthy saying recently that, "[c]learly the rules under the Clean Air Act that we are going to be implementing look at moving forward already demonstrated technologies, not innovative technologies that have yet to be properly demonstrated."

Fuel-switching to natural gas is a legally faulty alternative because it "redefines the source"—that is, it requires the developer to build a different type of facility than the one it has proposed—in violation of applicable legal requirements. It is also bad public policy.

The interest in replacing coal with natural gas for electric generation appears to be based on the view that shale gas is a paradigm shift that promises almost unlimited domestic supplies of natural gas at low prices. However, such optimism is misplaced in view of past forecasts that have overshot actual production. Moreover, according to the Energy Information Administration, shale gas production may not even offset the decline in domestic conventional sources of natural gas and decreasing Canadian imports.

In the end, pinning national energy policy on shale gas development represents a highly risky bet, with the American consumer being the ultimate loser. Conventional domestic gas supply is in decline; if we fuel-switch coal plants to natural gas and shale gas does not live up to its promoters' hopes, we will become dependent on imports of Liquid Natural Gas (LNG) from countries such as Russia, Iran and Venezuela, which control 45 percent of international LNG supplies. Such an outcome is hardly consistent with national energy independence goals.

American-produced coal has been a long-term friend to the American consumer, providing a low-cost, stable source of energy for electric generation. From 2000-2009, coal prices never exceeded $2.28 per MMBtu. During that same time period, highly volatile natural gas prices ranged from $3.56 to $12.04 per MMBtu. Attempting to fuel-switch coal plants to natural gas will worsen this price differential.

Conclusion

If done right, the BACT process can reduce CO_2 emissions from coal-fueled EGUs. If done wrong—by insisting on CCS or fuel-switching as BACT or by insisting on more efficiency than is realistically possible—the BACT process will expose the American consumer to dramatic electricity price increases. The key is to allow the construction of new, modern-technology coal plants—plants that will be much more efficient than the ones they will ultimately replace.

What is Best Available Control Technology for GHGs for a Coal-Fueled Electric Generating Unit?

I. Background

With the issuance of its regulations requiring new motor vehicles to reduce their greenhouse gas (GHG) emissions, the U.S. Environmental Protection Agency (EPA) has commenced its program of regulating GHGs under the Clean Air Act (CAA). The effect of EPA's motor vehicle GHG regulation will not be limited to just motor vehicles, but also will extend to stationary sources. This is because EPA's regulation of GHG emissions from motor vehicles makes GHGs "regulated air pollutants" under the CAA's pre-construction permit program known as the Prevention of Significant Deterioration (PSD) program. Under the PSD program, new or modified stationary sources that emit "regulated air pollutants," now including GHGs, above a certain threshold must obtain permits before commencing construction. The permit will require that the permittee undertake Best Available Control Technology (BACT) for its GHG emissions from the facility.

EPA has announced that this permit requirement will be phased in over the next six years, with the largest emitters required to obtain permits before the smallest emitters. For all new coal-fueled electric generating units (EGUs) and for most modified coal-fueled EGUs, the GHG permit requirement will become effective the beginning of 2011.

Most PSD permits are issued by state permitting agencies, which operate permit programs that are reviewed and approved by EPA. Although states have a great deal of discretion in determining BACT requirements, EPA may, within limits, disapprove a state BACT determination. EPA has indicated that it may issue a guidance document defining what it believes are appropriate standards for determining GHG BACT for the many categories of stationary facilities, including coal-fueled EGUs, that will become subject to GHG permit requirements.

Since this is the first time that GHGs will be regulated in the United States, great uncertainty exists as to what GHG BACT requirements will be. In the context of other air pollutants that have been regulated under the PSD permit program, BACT is usually, although not exclusively, set based on the emission-control capabilities of equipment that can be added on to the stack, pipe or vent to capture emissions. It is generally recognized, however, that no such equipment is commercially available at this time to control carbon dioxide (CO_2) emissions. Hence, EPA regulation of GHGs has engendered considerable debate as to how EPA and the states intend to proceed in determining GHG BACT and what the cost consequences will be both to affected facilities and the public at large.

II. How is BACT Determined?

The CAA defines BACT as follows:

> The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under

> this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.[1]

Under this definition, there are several key factors in determining BACT:

- BACT is determined on a case-by-case basis and results in the selection of an emission limitation representing application of control technology or methods appropriate for the particular facility.

- BACT does not result in the selection of the maximum control technology regardless of cost, commercial availability or technical feasibility. Instead, BACT requires a balancing of energy, environmental and economic impacts, along with technical feasibility.

- Although BACT requires consideration of "clean fuels" and "innovative fuel combustion techniques," BACT does not require the applicant to "redefine the source." For instance, a permit applicant proposing to build a coal-fueled EGU cannot be required to build a nuclear facility. Although there may not be a bright line between where a "control technology" ends and a "redesign of the facility" begins, constraints exist on how far the permitting agency can go in requiring a source to adopt design changes to its proposed facility in order to reduce emissions.[2]

In sum, a GHG BACT requirement must be set based on commercially available emissions control technology, although the technology does not have to be in widespread use. BACT does not represent the most aggressive commercially available emissions control no matter the cost; instead, BACT may represent a lower level of emissions control based on a balancing of cost-benefit factors. Finally, BACT cannot be based on emissions control technology that would result in a redefinition of the facility that the permit applicant proposes to build.

III. BACT for Coal-Fueled EGUs Should Be Commercially Available: Efficiency

Over time, the key technology for reducing GHG emissions from coal-fueled EGUs is most likely to be Carbon Capture and Sequestration (CCS). As discussed in Section V below, as this technology matures, coal-fueled EGUs will be able to operate with relatively minimal CO_2 emissions. In the nearer term, however, as also discussed in Section V, CCS is not commercially available and, therefore, cannot be determined to be BACT.

[1] 42 U.S.C. § 7479(3).
[2] *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

Nevertheless, constructing new coal-fueled EGUs and continuing to operate existing ones is consistent with the goal of steadily reducing CO_2 emissions, and CO_2 BACT requirements can be used to promote this goal. This is because new, efficient combustion technologies are available that will achieve significantly reduced CO_2 emissions as compared with the existing fleet of coal-fueled electric generation. As the existing fleet ages and is retired, it can be replaced with considerably more efficient generating units that significantly reduce CO_2 emissions per unit of electricity generated. Additionally, to the extent existing coal-fueled EGUs undertake modifications that require PSD permits and trigger BACT requirements, these plants can make efficiency upgrades that will lead to reduced CO_2 emissions. Thus, defining BACT for new and modified coal-fueled EGUs as the achievement of commercially available and economically justified levels of efficiency will create steadily reduced levels of CO_2 emissions from coal-fueled electricity.

A. BACT as Efficiency for New Coal-Fueled EGUs

Because BACT is a case-by-case requirement that cannot result in the redefinition of a specific facility, determination of BACT for any particular proposed coal-fueled EGU will depend on the specific design proposed. In general, however, it can be said that there are two main options for new high-efficiency coal generation: 1) supercritical, ultra-supercritical and advance supercritical pulverized coal plants; and 2) Integrated Gasification Combined Cycle (IGCC) plants.[3]

1. Supercritical and Ultra-Supercritical Coal Plants

Pulverized coal steam technologies can be made more thermally efficient by increasing the temperature and pressure of steam entering the turbines. As steam pressure and superheat temperatures are increased above 221 bar (3208 psi) and 374.5°C (706°F), the steam becomes supercritical (it does not produce a two-phase mixture of water and steam as in subcritical steam, but instead undergoes a gradual transition from water to vapor with corresponding changes in physical properties). Although there is no set dividing line between supercritical steam and ultra-supercritical steam, the latter generally refers to supercritical steam at more than 1100°F. The Electric Power Research Institute (EPRI) refers to plants with steam at 1300°F and 1400°F as Advanced Ultra-Supercritical plants.

The average annual thermal efficiency of the existing fleet of coal-fueled EGUs in the United States is approximately 32 percent. In contrast, ultra-supercritical plants with steam pressure at 1112°F result in thermal efficiencies of 44 percent—making them 35 percent more efficient than today's coal-fueled fleet and ,correspondingly, emitting 35 percent less CO_2.

Further improvements in thermal efficiency depend on the availability of new nickel alloys for boiler and steam turbines. The Thermie Project of the European Commission and a U.S. program managed by EPRI for the National Energy

[3] Information for the discussion of ultra-supercritical coal and IGCC is taken from Janos M. Beer, Massachusetts Institute of Technology, *Higher Efficiency Power Generation Reduces Emissions*, National Coal Council Issues Paper 2009, available at http://web.mit.edu/mitei/docs/reports/beer-emissions.pdf.

Technology Laboratory and the Ohio Coal Development Office are attempting to achieve superheat temperatures in the range of 1300-1400°F. Plant efficiency increases by about one percentage point for every 20°C in temperature. An advanced 700°C (1293°F) plant is likely to be constructed during the next seven to ten years, achieving a thermal efficiency of 46 percent. The following figure and chart show the reduced CO_2 emissions that correspond with the increased thermal efficiencies of supercritical and ultra-supercritical pulverized coal plants:

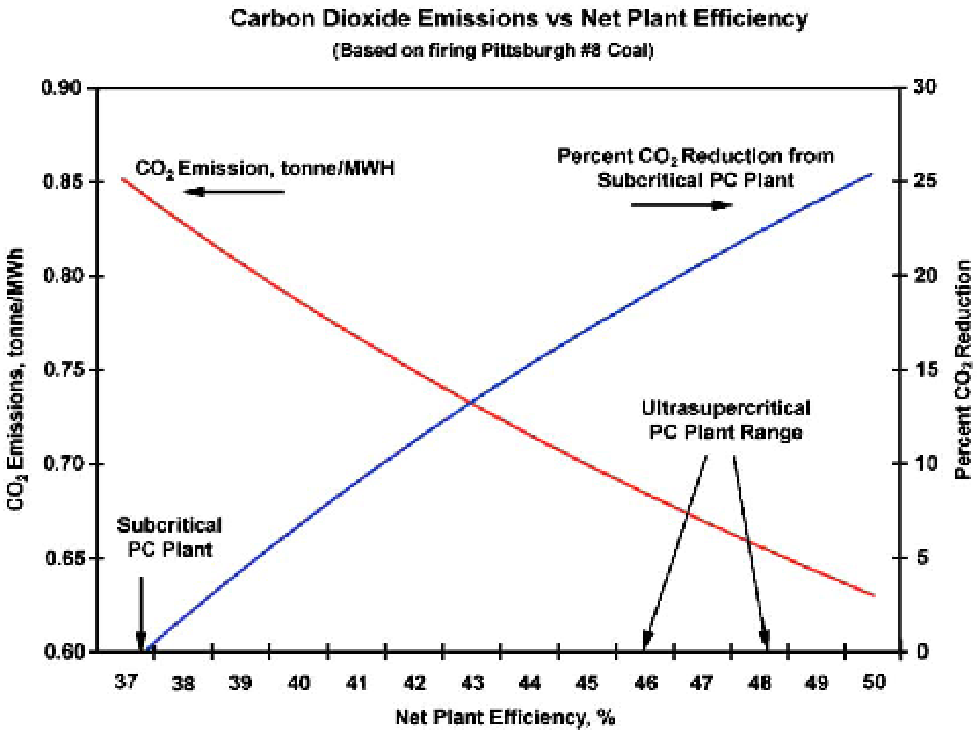


Figure 1.CO_2 Emission vs. Plant Efficiency (HHV) (Booras and Holt (2004)

Performance	Subcritical	PC/Supercritical	PC/Ultra-supercritical
Heat Rate Btu/kWe-h	9950	8870	7880
Gen. Efficiency (HHV)	34.3%	38.5%	43.3%
Coal use (10^6t/y)	1.548	1.378	1.221
CO_2 emitted (10^6t/y)	3.47	3.09	2.74
CO_2 emitted (g/kWe-h)	931	830	738

Assumptions: 500 MW net plant output ; Illinois #6 coal ; 85% Capacity Factor

Table 1. Comparative Coal Consumptions and Emissions of Airblown Pulverized Coal Combustion Technologies without CCS (MIT Coal Study 2007)

In sum, ultra-supercritical coal technology as BACT will improve the efficiency of the existing coal-fueled electric generation fleet and will steadily reduce coal's GHG footprint. The current coal fleet averages efficiencies of 32 percent (lower heating value – LHV). Ultra-supercritical and supercritical plants can achieve efficiencies of 44 percent and 39.1 percent (LHV) respectively. Therefore, an ultra-supercritical coal plant can generate the same amount of electricity as the average current coal plant using 35 percent less fuel, thereby reducing CO_2 emissions by 35 percent.[4]

2. IGCC Plants

IGCC plants operate by partially oxidizing coal to produce a synthetic gas comprised primarily of CO and H_2. Contaminants are removed from the gas, and the gas is then used as fuel in a combustion turbine. The exhaust gas of the steam turbine raises steam in a heat recovery steam generator that is used in a steam turbine-electric generator set. The reuse of the steam improves overall plant efficiency, and the improved efficiency lowers CO_2 emissions per unit of electricity produced.

IGCC technology presents a number of technological and cost challenges that has prevented it from becoming commercially viable in the United States without government subsidies. There are only two demonstration IGCC facilities currently operating. The Polk IGCC facility achieves 35.4 percent efficiency, and the Wabash IGCC facility achieves 40 percent efficiency. The IGCC in Puertollano, Spain achieves 40.5 percent efficiency.

Given the current economic and technical difficulties of IGCC, it does not represent a realistic BACT choice as a substitute for a pulverized coal plant. Nevertheless, with additional research, development and deployment, IGCC could become a promising option for reducing CO_2 emissions in the generation of electricity from coal.

B. BACT as Efficiency for Existing Coal-Fueled EGUs

It is difficult to generalize about the level of efficiency available from the existing fleet of coal generators because of differences in boiler technology, the condition and age of different units, the type of coal burned and other plant-specific factors. Moreover, a key consideration in the efficiency of a unit is how it is operated. Since BACT is determined on a case-by-case basis, the appropriate level of GHG BACT for an existing coal-fueled EGU must be based on a consideration of facility-specific factors.

Nevertheless, opportunities exist for reducing CO_2 emissions from existing coal generators through efficiency improvements. Efficiency can be improved by restoring efficiency that was lost over time through wear and tear. Efficiency can also be improved beyond the original design with technologies developed since the plant was built, including steam turbine improvements and combustion controls. In individual

[4] *Id*. at 107-134.

cases, these types of efficiency improvements can reduce CO_2 emissions by up to 16 percent. An overall fleet improvement of 5 percent appears to be practical.

Thus, meaningful CO_2 emissions reductions can be obtained from the existing fleet, and defining GHG BACT as efficiency for existing units as determined on a case-by-case basis will help accomplish this result.

IV. BACT for Coal-Fueled EGUs is Not Fuel-Switching to Natural Gas

A. Introduction

Legally, fuel-switching to natural gas cannot be deemed to be BACT for a coal-fueled EGU. This issue is specifically addressed in EPA's New Source Review Workshop Manual, which is EPA's basic manual for the PSD program. In specifying that applicants are not required by BACT to redefine the facility they have proposed, the Manual states that "[f]or example, applicants proposing to construct a coal-fueled electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fueled electric turbine, although the turbine may be inherently less polluting per unit product (in this case electricity)."[5]

Despite this clear policy, arguments are being advanced that natural gas should be considered to be BACT for coal-fueled EGUs. Apart from the fact such arguments cannot be supported legally, attempts to utilize the PSD permit process to fuel-switch coal plants to natural gas plants is bad public policy.

Specifically, the notion that coal base load electricity can be replaced by natural gas as a GHG reduction strategy ignores the problems associated with increasing our dependence on natural gas for power generation. With conventional natural gas production projected to decline by more than 33 percent in the next decade**,** shale gas is the only significant viable source of new domestic gas production in the United States. But the unresolved questions relating to shale gas are so profound and far-reaching that any plan to increase our dependence on gas for power generation opens the door to markedly higher costs of electricity.

More importantly, these proposals put reliability of the electric supply system at risk since a shortfall of shale gas will inevitably lead to increased LNG imports in a world where 45 percent of the resource is controlled by Russia, Iran and Venezuela. Far from being a bridge fuel to the future, an unquestioning acceptance of unrealistic and optimistic shale gas projections may be leading us down the path to escalating energy prices and reduced reliability of the most important component of our societal infrastructure—electricity.

[5] Manual at 13.

B. Shale Gas Production Will Not Create Sufficient New Gas Supply to Offset Declining Conventional Production

About 90 percent of electricity in the United States is generated either by coal (49 percent), nuclear power (20 percent) or natural gas (21 percent).[6] Coal and nuclear are the established baseload fuels with natural gas typically serving as an intermediate and peaking fuel. This combination has given the United States one of the most reliable and affordable electric power supply systems in the world, steadily increasing our quality of life and enabling manufacturers to be competitive at the global level.

In large measure, this is because of coal's tremendous domestic abundance—at 94 percent of U.S. proved fossil fuel reserves.

Fossil Fuel – U.S. Proved Reserves

Fuel	BTU	Percent
Coal	5,228,321,124,000,000,000	**94%**
Petroleum	127,587,000,000,000,000	**2%**
Natural Gas	244,355,600,000,000,000	**4%**
Total	5,600,263,724,000,000,000	**100%**

U.S. proven fossil fuel reserves expressed as BOE[7]
BOE = Barrels of Oil Equivalent

Fossil Fuel	Native Units	BOE
Recoverable oil	21.3 billion barrels	21.3 billion BOE
Recoverable natural gas	237.7 trillion cubic feet	42.1 billion BOE
Recoverable reserve base of coal	262.7 billion short tons	906.3 billion BOE
	TOTAL U.S. fossil fuel endowment	969.7 billion BOE

Since 2000, however, more than 90 percent of constructed electricity generation capacity has been natural gas-based. At this pace, natural gas capacity will approach 500 GW by 2013, coal will near 350 GW and nuclear 108 GW. However, while natural gas will make up 50 percent of the name-plate capacity of the three fuels, it will only represent 24 percent of their actual generation because the capacity factor (the ratio of

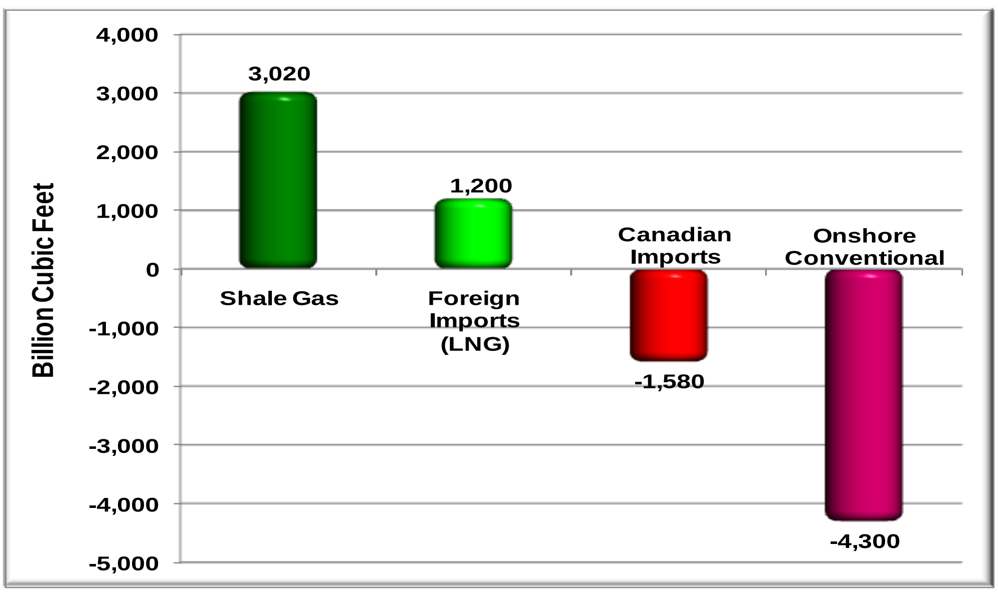
[6] Unless otherwise noted, all data relating to energy statistics, forecast and retrospectives are drawn from the website of the Energy Information Administration, http://www.eia.doe.gov/.
[7] Congressional Research Service, *Terminology, Reporting, and Summary of U.S. Fossil Fuel Resources*, Oct. 20, 2009, pg 17.

actual output and full-time operation at name-plate capacity) for natural gas power plants is about 35 percent, while coal is above 70 percent and nuclear 90 percent. For those reasons, natural gas is generally the last of the three fuels to be dispatched because it is consistently the most expensive and has the greatest price volatility.

In the major report *America's Energy Future* (2009), the National Academy of Sciences warned about the supply issues associated with further reliance on natural gas for power: "it is not clear whether natural gas supplies at competitive prices would be adequate to support substantially increased levels of electricity generation."[8] The North American Electric Reliability Corporation (2009) also warned that, "[c]ontinued high levels of dependence on natural gas for electricity generation in Florida, Texas, the Northeast, and Southern California have increased the bulk power system's exposure to interruptions in fuel supply and delivery."[9]

Claims that shale gas represents a new paradigm shift that will enable the country to utilize ever increasing amounts of natural gas for electric generation at low prices fail to acknowledge that shale gas increases will not offset other declines in other sources of natural gas supply as forecasted by EIA and as shown on the graph below. Indeed, even with shale gas development, overall natural gas supply is projected to decline by more than 4 percent by 2020.

2008 to 2020



Since shale gas is the only substantial source of new domestic fossil fuel supply going forward, proposals to fuel-switch to natural gas are a risky bet on shale gas production and price. This risk is all the more alarming because of the significant number of

[8] National Academy of Sciences, *America's Energy Future* (National Academy Press, 2009).
[9] North American Electric Reliability Corporation, *Key Issues: Natural Gas Dependency*, available at http://www.nerc.com/page.php?cid=4%7C53%7C59.

unknowns that surround shale gas production in regard to cost, sustainability, deliverability, reliability and environmental impact.[10]

C. High Natural Gas Prices and Price Volatility Hurt All Consumers

Natural gas is considerably more expensive than coal. Increased natural gas generation has led to higher electric rates across the nation, from 6.81 cents/kWh in 2000 to 10.02 cents/kWh in 2009. For all consumers, natural gas for power generation will remain more expensive than coal-based generation.

Electricity price volatility adversely impacts consumers and manufacturing alike. Further, a wide variety of manufacturing firms utilize natural gas in the production process—often as an essential feedstock. The impact of natural gas price volatility on these companies is far-reaching. According to Edward Stones, in testimony for Dow Chemical Co. before the U.S. Senate in 2009, "[s]ince 1997, there have been five natural gas price spikes... These price spikes have significantly contributed to the U.S. manufacturing sector losing over 3.7 million jobs."[11] In a peer-reviewed scientific paper in *Environmental Science and Technology*, Professor Jay Apt and Adam Newcomer at Carnegie Mellon University concluded that, with the cancellation of new coal generation, "the amount of time that natural gas generators set the market price of electricity would increase substantially, and other industries that use natural gas may be priced out of the market."[12]

Natural gas prices and increased volatility of those prices over the past decade have severely affected families. In 2000, for example, residential gas prices started at $6.37/mcf but escalated to $13.74 in 2004. They then jumped to $20.24 in 2008 but dropped to $11.25 by the end of 2009. Upwards of 60 percent of the homes in the United States are heated with natural gas. Many of these homes are concentrated in the Midwest and Mid-Atlantic states. During the winter their dependence on natural gas is virtually total since most lack alternative sources of heating. And, of course, during the summer many states are highly dependent upon gas-fired generation to meet peaking cooling demand. In total, 33 states are vulnerable to natural gas price volatility because of heavy reliance on gas for heating and/or electricity generation.

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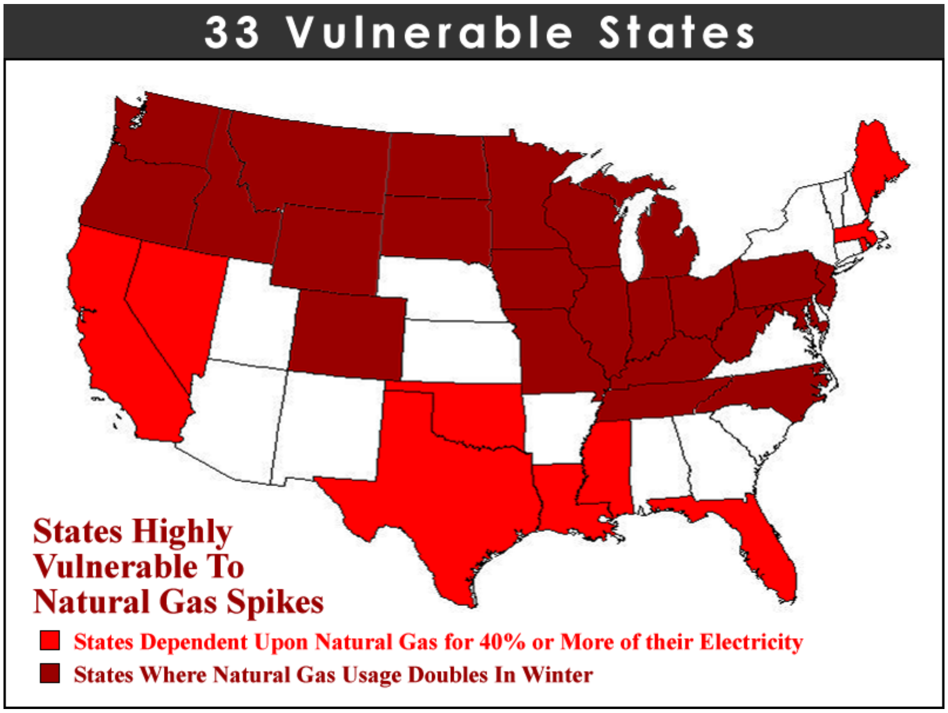
[10] Additional federal and state regulation of shale gas production will significantly change the supply and price profile for shale gas. According to IHS Global Insight, subjecting hydraulic fracturing to the underground injection control requirements of the Safe Drinking Water Act alone would result in a 20 percent reduction in the number of wells drilled and a 10 percent reduction in natural gas production. IHS Global Insight, *Measuring the Economic and energy Impacts of Proposals to Regulate Hydraulic Fracturing* (2009). The prospect of such regulation appears highly likely—according to the Secretary of Energy, "we are going to have some regulations going on [hydraulic fracturing]." Steven Chu, U.S. Sec. of Energy, Address at Georgetown University (March 29,2010).

[11] *The Role of Natural Gas in Mitigating Climate Change: Hearing before the Senate Comm. on Energy & Natural Res.*, 111th Cong. (2009) (statement of Edward Stones, Director of Energy Risk) *available at* http://energy.senate.gov/public/_files/StonesTestimony102809.pdf.

[12] Adam Newcomer and Jay Apt, *Near Term Implications of a Ban on New Coal-Fired Power Plants in the United States, 43 Envtl. Sci. Tech. 3995* (2009).



These costs fall particularly hard on low incomes families, the elderly and the disabled. The Low Income Home Energy Assistance Program (LIHEAP) and similar governmental agencies are chronically overwhelmed with requests for support for utility bills when home heating costs surge. Millions of families cannot sustain the escalating electric rates and home heating costs caused by high and volatile natural gas prices:

- 21 percent of LIHEAP recipients are families with children under five years of age,
- 37 percent are elderly, and
- 50 percent are disabled.[13]

D. Analyses of the Environmental Impacts of Natural Gas Use Must Account for Emissions from Production and Transport

Attempts to define fuel-switching to natural gas as BACT for coal generation for the purpose of significantly reducing GHG emissions cannot be limited to comparisons at the point of combustion. Rather, a lifecycle analysis is a more accurate measure. A preliminary report that compared GHG emissions from coal and gas generation on a lifecycle basis suggests that GHG emissions from gas generation are not 55 percent of those from coal power generation, as often cited, and may even be equivalent.[14]

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[13] Campaign for Home Energy Assistance, *The LIHEAP Databook: A State-by-State Analysis of Home Energy Assistance for FY 2002* (2005) available at http://www.liheap.org/databook02/.

[14] Robert Howarth, *Preliminary Assessment of the Greenhouse Gas Emissions from Natural Gas obtained by Hydraulic Fracturing*, (Cornell University 2010), *available at* http://www.technologyreview.com/blog/energy/files/39646/GHG.emissions.from.Marcellus.Shale.April12010%20draft.pdf.

Natural gas is the source of 60 percent of all energy related methane emissions (coal = 28 percent).[15] Accordingly, the natural gas energy sector produces more than twice the methane emissions of the coal mining sector. And, given that decline rates in shale gas wells can approach 80 percent the first year, the natural gas sector's growth in methane emissions will increase exponentially to keep pace with the faster drilling treadmill needed to replace more rapidly depleted wells. According to one observer, [t]o displace coal with gas, we'd need to complete 30,000 to 50,000 new wells a year for decades to come.[16] The *Wall Street Journal* has reported that the Marcellus shale "will require drilling tens of thousands of wells."[17]

Methane gas leakage during the production, transport, processing and use of natural gas is an important consideration, particularly with reference to shale gas. Methane emissions from gas and oil systems are grossly under-reported due to lack of infra-red equipment[18], as the following graphic indicates.

Naked Eye

Infrared

Further study is needed, but at this point there is no basis to conclude that gas generation will result in significantly lower GHG emissions than coal generation or that increasing gas generation at the expense of coal generation would represent a GHG solution.

Cavalier acceptance of shale gas projections threatens to slow progress toward the rapid development of carbon capture and sequestration (CCS). The International Energy Agency (IEA) has identified CCS as a "critically important technology" in attaining cost-effective reductions in greenhouse gas emissions. An 80 percent reduction in CO_2 emissions while maintaining economic growth is an important goal of the Obama Administration. According to Energy Secretary Chu, "we must make it our goal to advance carbon capture and storage technology to the point where widespread,

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[15] Energy Information Administration, *Emissions of Greenhouse Gases Report: Methane Emissions,* U.S. Department of Energy, Dec. 8, 2009, *available at* http://www.eia.doe.gov/oiaf/1605/ggrpt/methane.html#total.
[16] Randy Udall, *Can natural gas save the world? Well, it's better than coal,* SALT LAKE TRIB., Aug. 18, 2009, *available at* http://www.sltrib.com/opinion/ci_13152405.
[17] Ben Casselman, *Natural-Gas Firms Seek Outlet for Growing Supplies*, WALL ST. J., Aug. 11, 2008, *available at* http://online.wsj.com/article/SB121841402609028471.html.
[18] Andrew C. Revkin and Clifford Krauss, *By Degrees: Curbing Emissions by Sealing Gas Leaks*, N.Y. TIMES, October 14, 2009 *available at* http://www.nytimes.com/2009/10/15/business/energy-environment/15degrees.html.

affordable deployment can begin in 8 to 10 years."[19] CCS, as a critical enabling technology, will be necessary not only for coal powered and natural gas powered electricity generation, but across a broad spectrum of energy-intensive industries as well. According to the IEA, the cost of greenhouse gas reductions would be 71 percent higher without CCS.

E. Current Infrastructure Insufficient to Support Natural Gas as BACT

Existing natural gas pipeline and storage infrastructure is insufficient to support a switch from coal-based to natural gas-based electricity generation, according to a new analysis conducted by the Aspen Environmental Group for the American Public Power Association. The analysis finds the interstate pipeline capacity is insufficient in 21 states "to serve existing demand plus the demand that would result from converting existing coal-fired generation to gas."[20]

"[S]torage facilities are not distributed evenly across the country and many of those facilities are single season reservoirs—rather than higher deliverability salt cavern-based facilities."[21] The total costs to implement a switch from coal to natural gas would be in excess of $700 billion.[22]

F. Reliance on Natural Gas Could Lead to Less Energy Independence

If shale gas does not deliver at scale, LNG inevitably becomes the default fuel for the electricity system not only to meet established power demand but also to back-up renewables such as wind and solar. And LNG will be increasingly linked to world oil prices. As Mohammed al-Sada, the Qatari Minister of Energy, said in March 2010, "Our [LNG] projects are long term [and] linked to oil prices… we are ramping up… we believe that in the coming two or three years there will be a shortage of gas."[23]

The National Energy Technology Laboratory has identified the risks of this path: "…the need for more LNG will create closer links to the world oil price, setting the stage for the marginal price of U.S. electricity to be set by the whims of foreign oil/LNG suppliers, for the first time in U.S. history."[24]

[19] Letter from Steven Chu, U.S. Sec. of Energy (October 12, 2009), *available at* http://www.energy.gov/ media/CCS_Letter_-_Final.pdf.

[20] Aspen Environmental Group ("Aspen"), *Implications of Greater Reliance on Natural Gas for Electricity Generation*, pp 2-3 (July 2010).

[21] Id. at. 3.

[22] Id at 94.

[23] Muriel Boselli and Marie Maitre, *Qatar doesn't plan to cut gas output to buoy price*, REUTERS NEWS, March 25, 2010.

[24] Peter C. Balash, *Natural Gas and Electricity Costs and Impacts on Industry* (National Energy Technology Laboratory, 2008) at 11, *available at* http://www.netl.doe.gov/energy-analyses/pubs/NatGasPowerIndWhitepaper.pdf.

V. CCS is a Promising Technology for Capturing and Storing CO_2 Emissions for Fossil-Fueled EGUs, but is Not BACT at the Present Time

A. Introduction

In order to achieve long-term, sustainable reductions in global GHG emissions, it is essential to rapidly develop, demonstrate and deploy new energy technologies, including CCS. CCS technology applied to a modern conventional coal-based power plant or a natural gas combined cycle plant could reduce carbon dioxide emissions to the atmosphere by approximately 80-90 percent compared to a plant without CCS.

Economic growth is closely tied to energy availability and consumption, particularly lower-cost fuels such as coal. While the use of coal, natural gas and petroleum results in the release of carbon dioxide, CCS technologies have the potential to balance economic growth, energy independence and environmental concern—retaining coal as an affordable source of electricity, liquids and syngas while securing meaningful long term GHG reductions.

CCS technologies have the potential to reduce overall greenhouse gas mitigation costs and increase flexibility in reducing GHG emissions from coal and natural gas. According to the Intergovernmental Panel on Climate Change (IPCC), application of carbon sequestration technologies could reduce the costs of stabilizing carbon dioxide concentrations in the atmosphere by 30 percent or more compared to scenarios where such technologies are not deployed.[25]

Although CCS technology is extremely promising, it has not yet been demonstrated on a widespread scale and is not yet commercially available at a reasonable cost for either coal or natural gas.

B. CCS Specifics

CCS involves four steps: the separation and capture of CO_2 from power plant "fuel gas" or "flue gas," compressing the CO_2 into a liquid form, moving the CO_2 via a pipeline to the location where it will be stored, and injecting the CO_2 into a deep geological formation for long-term storage. All of these steps involve technical challenges and costs that prevent CCS from being BACT at this point.

1. CO_2 Capture

CO_2 capture is technically possible at fossil-fueled power plants. However, none of the existing technologies, however, are cost effective or commercially available at the present time in the context of sequestering CO_2 from power plants.[26]

[25] Intergovernmental Panel on Climate Change, *Special Report on Carbon Dioxide Capture and Storage 44* (Cambridge University Press 2005).

[26] U.S. Department of Energy, *Carbon Capture Research*, available at http://www.fossil.energy.gov/programs/swquestration/capture/index.html.

For pulverized coal plants, post-combustion capture controls can be installed to remove CO_2 from the flue gas stream. For example, an amine solvent can be used to remove the CO_2 from the other flue gases, and the CO_2 can then be stripped from the solvent and compressed for transport. The major barriers to this technology are high cost and high energy penalty. As a result, only three small plants using this technology are in operation in the United States today. Several small scale (10 MW) pilot projects are planned and in development, and several large scale (over 300 MW) demonstration projects are being explored. For post-combustion capture technologies to become feasible, RD&D needs to reduce costs, particularly in the development of better solvents (such as aminies and chilled ammonia) to remove the CO_2 from the flue gas and less energy-intensive CO_2 capture systems.

Oxy-combustion is an emerging technology potentially available for use at pulverized coal plants that produces a concentrated CO_2 stream that can then be more readily captured for storage or use. While similar to conventional pulverized coal generation, oxy-combustion uses pure oxygen instead of air in the boiler. This significantly reduces the dilution of CO_2 in the exhaust gas stream by removing nitrogen (80 percent in air) from the system. Several small-scale (1-3 MW) projects are underway, and two large demonstrations (10-30 MW) have been announced. AEP and SaskPower have also announced that they are exploring larger scale demonstration projects (200-300 MW). R&D is needed to reduce the cost of the oxygen separation systems, lower the cost of CO_2 pressurization, and integrate the oxy-system with the rest of the plant.

For IGCC, pre-combustion capture can be achieved by introducing a water shift reactor to modify the syngas from the gasifier. The shift reactor converts the carbon monoxide in the syngas to hydrogen and CO_2, and the CO_2 can be separated with physical sorbents. Although some existing non-power gasification plants use CO_2 capture today, no IGCC power plants do so. R&D needed to reduce costs includes refrectory improvements (ceramic liner for gasifier), ion transport membranes (improved systems to produce oxygen), warm gas clean-up (to remove H_2S), and hydrogen turbine development.

2. CO_2 storage

A number of potential options are available to dispose of CO_2 once it is captured, but most do not seem to be practical at the present time. For instance, in theory the CO_2 could be stored in the bottom of the ocean, but there are significant environmental uncertainties in doing so. Technologies exist to make a solid out of CO_2, but this would produce a large amount of solids and would entail a significant energy penalty. CO_2, of course, has commercial uses, but not in the amounts that would be produced from widespread capture.

The most promising at-scale option for disposing of CO_2 would appear to be geologic storage, with disposal in saline reservoirs appearing to be the most likely geologic storage option. Disposal of CO_2 in depleted oil & gas reservoirs as a part of enhanced oil recovery or the storage of CO_2 in unmineable coal beds as a part of enhanced coal-bed methane recovery are economical but lesser capacity options.

Geologic storage options have not yet been demonstrated at scale. Although current experience with CO_2 injection has not led to any significant problems, this experience has not entailed the amounts of CO_2 that must be stored to achieve widespread use of CCS. The U.S. Department of Energy has entered into regional carbon sequestration partnerships in 41 states that is hoped will lead to widespread deployment of CCS.

However, the need to demonstrate the technical and engineering feasibility of CO_2 storage at scale is only one of the issues–and possibly not even the most significant issues–that must be resolved before storage can become commercially available. Of particular concern is the lack of a system for permitting and assessing liability for storage sites, and in particular:

- Determining responsibility for post-closure monitoring and liability;
- Avoiding application of the federal Superfund program to injections of carbon dioxide as a waste and CCS activities as waste disposal to avoid triggering expensive "cradle to grave" regulations of the Resource Conservation and Recovery Act;
- Resolving property rights issues, including pore space ownership, trespass and interstate issues relating to carbon dioxide pipeline transportation and placement; and
- Creating an acceptable legal, regulatory, infrastructure and risk management framework for the transport and long-term storage of CO_2.

C. The Way Forward for CCS

The Coal Utilization Research Council (CURC) has partnered with the Electric Power Research Institute (EPRI) to create the CURC-EPRI Clean Coal Technology Roadmap. With successful technology development and increased federal funding, CURC-EPRI project that future pulverized coal and IGCC systems will be highly competitive, and both will be able to cost effectively capture and store CO_2. On the other hand, current research and development funding is inadequate, and demonstration funding is almost non-existent. CURC-EPRI project that CCS can become cost-competitive in the 2020 to 2025 timeframe, assuming necessary funding support. CURC-EPRI project that $17.5 billion is needed to implement their roadmap, with $10.5 billion derived from the federal government and the remaining $7 billion from industry.[27]

Other barriers to CCS technology development must also be removed. At present, uncertainty over siting requirements and long-term liability issues associated with the underground storage of carbon dioxide have deterred project developers, financiers and insurers from moving forward with CCS. CCS as a tool for mitigating CO_2 emissions

[27] Coal Utilization Research Council, *The CURC-EPRI Clean Coal Technology Roadmap.* Further information on the CUR-EPRI Roadmap is available on the CURC website, http://www.coal.org/userfiles/File/Final_CURC-EPRI_Roadmap,_2008.pdf.

and ensuring a secure and affordable energy supply for America represents a vital public interest that merits a federal-level program to clarify and resolve these long-term liability issues and to clear the way for the rapid and widespread commercialization of the technology.

In sum, CCS represents a promising potential option for the future. For the present, however, CCS cannot be defined as BACT for coal-fueled EGUs.

VI. Conclusion

If done right, the BACT process can reduce CO_2 emissions from coal-fueled EGUs. Construction of new coal plants using modern technologies is the key. Over time, more efficient coal plants can replace less efficient ones, leading to declining CO_2 emissions. Eventually, as CCS technology becomes commercially available and cost-effective, more dramatic emissions reductions can be expected.

However, misuse of the BACT process in an attempt to eliminate coal as a fuel for electric generation will expose the American consumer to dramatic electricity price increases and undermine the reliability of the electric supply. These consequences will impact American families and businesses alike. Coal is essential to the U.S. economy, providing affordable electricity to households, manufacturing and industrial facilities, transportation and communications systems, and services throughout our economy. "Policies that encourage the use of natural gas to substitute for coal in power generation could very well lead to spectacular price increases for households and industry."[28] When electricity prices rise, the manufacturing sector and other businesses become increasingly uncompetitive and are forced to move offshore to countries that have lesser or no controls on carbon. This will have the dual impact of exporting high wage American jobs overseas and increasing global greenhouse gas emissions.

According to the Industrial Energy Consumers of America, over 40,000 manufacturing plants have closed over the course of the past decade at a cost of more than 5 million jobs – 3.7 million of which are associated with high natural gas prices.[29] Coal has fueled American economic and industrial growth for generations by keeping electricity prices low. Coal is the backbone of the American electric system, and electricity is the backbone of our economy.

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[28] National Energy Technology Laboratory, *Natural Gas and Electricity Costs and Impacts on Industry, EOE/NETL 2008, page 11*, available at http://www.netl.doe.gov/energy-analyses/pubs/NatGasPowerIndWhitepaper.pdf.
[29] Paul N. Cicio, *Consumers Take a Double Hit*, National Journal (Nov. 9, 2009), available at http://energy.nationaljournal.com/2009/11/should-we-start-swapping-coal.php#1388785.