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Retrofitting Carbon Capture Systems on Existing Coal-fired Power Plants
A White Paper for the American Public Power Association (APPA)

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Summary: It will be necessary to reduce CO_2 emissions from existing coal-fired power plants for the U.S. to reach the goals stated by some legislators for managing global climate change. The major technology choices for existing plants include post-combustion capture systems using chemical sorbents to isolate and concentrate CO_2, and reconfiguring the unit to use pure oxygen rather than air as the combustion oxidant (yielding flue gas with a much higher concentration of CO_2). Both existing technology approaches are costly, and both involve large parasitic power needs that can reduce the output of the existing unit by one-third. The changes introduced by retrofitting carbon capture and storage (CCS) on an existing power plant will raise variable costs, and could thereby lower the unit in the utility's dispatch order.

Capture and storage concepts have been implemented on a small scale, but not on the scale necessary for large coal-fired power plants. Furthermore, most research on CCS is focused on new power plants and not issues that may be more relevant to existing power plants. In addition to overcoming technical issues, CCS retrofits will face as yet undefined regulatory challenges, as well as liability issues related to the underground migration of stored CO_2 over a timescale that exceeds the scope of traditional risk mitigation instruments, like insurance.

These challenges are daunting. Research and policy development are both proceeding, but whether current efforts will be sufficient to result in a solution set that enables the nation to continue to enjoy the benefits of low-cost electric power remains to be seen.

Introduction

Existing coal-fired power plants in the U.S. emitted 1.96 billion metric tons of CO_2 in 2005, or about 27% of total U.S. emissions of greenhouse gases (GHGs).[1] These power plants generate about one-half of the electricity in the U.S., and are in large part responsible for the U.S. enjoying power costs that are among the lowest in the world.[2] Congress has not passed legislation to reduce GHG emissions, but many bills have been introduced and others are under development, with some seeking reductions in U.S. emissions as high as 30% in 2030 and 80% in 2050.[3] The Chairman of the House Energy and Commerce Committee has identified a reduction goal for that committee's legislation of "between 60 percent and 80 percent by 2050."[4] Such large emission reduction goals will not be met without significantly reducing emissions from existing coal-fired power plants.

To date, most discussion of GHG emission mitigation related to coal-based power production has focused on new coal-based power production, and detailed engineering studies have evaluated the cost and performance of various options for those new units.[5] With currently available technologies, CO_2 capture and storage options (in saline formations) from these new units cost \$30 – 70 per ton of CO_2 avoided.[6] [7] The reader is referred to an earlier APPA White Paper for a general overview of carbon capture and storage (CCS) from coal-based power plants.[8] This paper addresses those aspects of CCS that are of particular interest to retrofitting this technology on existing coal-fired power plants.

With respect to retrofitting existing coal units, a 2005 IPCC report concluded: "*Retrofitting existing plants with CO_2 capture is expected to lead to higher costs and significantly reduced overall efficiencies than for newly built power plants with capture. The cost disadvantages of retrofitting may be reduced in the case of some relatively new and highly efficient existing plants or where a plant is substantially upgraded or rebuilt.*" [9]

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1 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1900 – 2005, U.S. EPA, EPA 430-R-07-002, April 15, 2007. Note that the percentage includes non- CO_2 greenhouse gases, and excludes sinks.

2 Electricity Prices for Industry, DOE/EIA, June 2007, http://www.eia.doe.gov/emeu/international/elecprii.html .

3 Climate Change: GHG Reduction Bills in the 110th Congress, Congressional Research Service, Rpt. #RL33846, January 31, 2007.

4 Memorandum from John Dingell, Chairman of Committee on Energy and Commerce, and Rick Boucher, Chairman of Subcommittee on Energy and Air Quality, to Members, Committee on Energy and Commerce, October 3, 2007.

5 See, for example, Cost and Performance Baseline for Fossil Energy Plants, U.S. DOE National Energy Technology Laboratory, DOE/NETL-2007/1281, May 2007.

6 *Ibid.* It should be noted, however, that most publicly available reports on CO_2 capture and storage are based on markets that existing before 2005, and that since that time, power plant capital costs have escalated dramatically. The NETL report states (p.42) that it incorporated escalation through the 3rd Quarter of 2006, but the basic power system costs cited still appear below costs reported by utilities in the news media.

7 Carbon Dioxide Capture and Storage, UNEP/IPCC, 2005, avoided costs projected at 30-70 \$/t CO_2 for new pulverized coal units and 14-53 \$/t CO_2 for new IGCC units, p.347.

8 Carbon Capture and Storage From Coal-based Power Plants: A White Paper on Technology for the American Public Power Association (APPA), L.D. Carter, May 22, 2007 (available from APPA at http://www.appanet.org/files/PDFs/Attachment%20%233.pdf).

9 *Op.Cit.*, Carbon Dioxide Capture and Storage, p.10.

Technology Choices

The vast majority of existing coal-fired power plants are pulverized coal units. Pulverized coal units have two choices for CCS retrofit: post-combustion capture of CO_2 using chemical sorbents, and replacing the existing air-combustion system with an oxygen-fired system, thereby creating a flue gas which is mostly CO_2.[10]

Post-combustion CO_2 capture

Figure 1 depicts a post-combustion CO_2 capture system. In this system, an acid gas sorbent vessel is placed downstream of conventional pollution capture systems. CO_2 is absorbed into an appropriate chemical, such as an amine, which is heated in a separate vessel to release a high concentration stream of CO_2 and the regenerated sorbent. The concentrated CO_2 stream is then pressurized to about 2000 psia, for transport (as a supercritical fluid) via pipeline to an injection field. There it is injected into a stable formation as deep as one mile underground. The process requires large amounts of energy, both to strip the CO_2 from the sorbent and to compress the concentrated CO_2. In a study of capture technology at greenfield, or new, power plants, NETL[11] concluded that whether the plant was subcritical or supercritical in design, the CCS system resulted in about a 12% absolute drop in efficiency (e.g., from 33% to 21%).[12] Figure 2 shows the components responsible for the additional power needs in the CCS-equipped system, based on data in the NETL report for a subcritical power plant. As can be seen from the figure, about one-half the power needs related to CO_2 compression, about one-fourth was attributable to the CO_2 amine system, and most of the rest derived from additional fans and pumps needed for the enlarged generation system (which burns more coal for the same power output) and the greatly enhanced cooling system. The CO_2 capture system (alone) requires about twice as much cooling water as the original power plant.

An additional complexity of the CCS-equipped system is an SO_2 polishing unit. For a high sulfur (IL #6) coal system, even a 98% efficient wet FGD system exhausts flue gas with about 40 ppm SO_2. To suppress formation of heat stable salts in the sorbent, this must be lowered to about 10 ppm. The NETL design accomplishes this at a new unit by using a serial combination of a traditional wet limestone FGD and a sodium hydroxide polishing scrubber.

The various pieces of hardware required for CO_2 capture and compression require space. NETL reports that about one acre of land is needed for each 100 MW of generating capacity.[13] A separate NETL report suggests that land requirements for capture and compression equipment at a 500 MW unit would be 60 acres, or <u>12 times</u> the first estimate.[14] In either case, this space requirement can be a major obstacle to retrofitting CO_2 capture systems on existing units which are already space-limited due to previous retrofits for SO_2, NOx, and mercury control systems.

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[10] An innovative multipollutant ammonia-based capture technology is currently being investigated by U.S. DOE, in collaboration with Powerspan Corporation. The lack of publicly available data on a commercial version of this technology preclude its inclusion in this analysis. Additional information is available at: http://www.netl.doe.gov/publications/factsheets/rd/R&D043.pdf .

[11] NETL is the National Energy Technology Laboratory, which is owned and operated by the U.S. Department of Energy. See: http://www.netl.doe.gov/ .

[12] *Op.Cit.*, <u>Cost and Performance Baseline for Fossil Energy Plants</u>, Exhibit ES-2.

[13] <u>Carbon Dioxide Capture from Existing Coal-Fired Power Plants</u>, DOE/NETL-401/120106, p.xviii, December 2006.

[14] <u>Carbon Sequestration Program Environmental Reference Document</u>, DOE/NETL DE-AT26-04NT42070, August 2007, p.2-42.

Regarding technology readiness, the 2007 NETL report states: "The post-combustion CO_2 removal technology for the PC and NGCC cases is immature technology. This technology remains unproven at commercial scale in power generation applications."[15]

Oxy-combustion approaches

If a pulverized coal power plant is fired with nearly pure oxygen, instead of with air, the nitrogen in the traditional combustion air is eliminated from the flue gas, and the flue gas is composed primarily of CO_2, water vapor, excess oxygen and trace gases like SO2, NOx, and HCl, although air infiltration can reintroduce nitrogen and more oxygen. After removal of water vapor, the flue gas is approximately 80-98% CO_2.[16] As a result, the sorption/desorption equipment needed in the "Post-combustion" example above is unnecessary, although some purification may be needed prior to CO_2 injection and storage. For purposes of this paper, this oxygen-based approach to CO_2 capture will be termed "oxy-combustion", even though it is actually another form of "post-combustion" CO_2 capture.

In the oxy-combustion system, some of the CO_2 from the flue gas (about twice the volume of the oxygen supplied) must be recycled to reduce combustion gas temperatures from 3500 ºC to a boiler tolerant 1900 ºC. Oxy-combustion raises the possibility of reduced cost for downstream cleanup of traditional pollutants, either by storing them with the CO_2 or by reducing the volume of the flue gas stream dramatically through elimination of nitrogen oxide and use of CO_2 recycle.[17] Additionally, the potentially higher combustion temperatures and the improved heat transfer properties of oxy-combustion gases mean that it may be possible to achieve higher thermal efficiencies than possible with other approaches to CO_2 capture.

The major drawbacks to this approach for CO_2 capture are large parasitic power requirements, primarily for oxygen production and CO_2 compression, and the cost of the oxygen production facility. Ongoing research into improved techniques for oxygen production may mitigate these drawbacks to some degree. With current technology, cost and parasitic power needs for oxy-combustion are about the same as for post-combustion CO_2 capture. The potential advantages for oxy-combustion CO_2 capture are speculative at this point. It may be easier to locate an oxygen plant than a CO_2 sorption tower at an existing plant, where access to flue gas is already encumbered by retrofit SO2 scrubbers and other hardware installed after the plant was initially constructed. And the parasitic power needs for an oxy-combustion plant are more electrical than steam, so integration with the existing unit may be simpler.

A cross-platform comparison

A recently published report by DOE/NETL compares a basic new pulverized coal unit both to one with similar power output, but with post-combustion CO_2 capture, and to a coal unit with oxy-combustion CO_2 capture. NETL examined both supercritical and ultra-supercritical designs.[18] Table 1 presents several outputs from the study for the supercritical designs.

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[15] *Op.Cit.*, Cost and Performance Baseline for Fossil Energy Plants, p.40. "PC" refers to pulverized coal power plants, the traditional technology for burning coal to produce electricity. "NGCC" stands for natural gas combined cycle power generation. In a NGCC, natural gas is burned in a combustion turbine (much like a jet engine) that drives a generator to make electricity. Hot exhaust gases from the combustion turbine are used to convert water to steam, which expands through a steam turbine to drive a second generator.

[16] *Op.Cit.*, Carbon Dioxide Capture and Storage, p. 122.

[17] *Ibid.*, p.123.

[18] Pulverized Coal Oxycombustion Power Plants, DOE/NETL-2007/1291, August 2007.

Note that both approaches to CO_2 capture, with current technology applied to a <u>new</u> power plant, nearly doubled the power plant's capital cost and the cost of electricity produced.

Table 1. Comparison of cost and performance of capture systems (new plant).

Parameter	**Base**	**Post-comb'n**	**Oxy-comb'n**
CO2 capture	No	90%	100%
Gross capacity, MWe	584	667	793
Net capacity, MWe	554	549	546
Net plant heat rate, Btu/kwh	8,649	12,538	12,074
Net plant efficiency (HHV), %	39.5	27.2	28.3
Total Plant Cost, $/kw	1563	2857	2930
Levelized cost of electricity, $/MWh	62.9	114.4	113.0
Cost of capture, $/ton CO_2 avoided	n.a.	63	52
SO2 emissions, #SO2/mmBtu	0.085	Negligible	0.003
NOx emissions, #NOx/mmBtu	0.07	0.07	0.07

It should be repeated that the above table relates to *new* power plants. Traditional pollution control technologies designed for new power plants usually have a higher cost per unit of power output when applied to existing units. These cost "retrofit factors" have not been established for carbon capture technology, but for traditional pollutants like SO_2 and NOx, they can be a 25-40% cost increase over the cost of a comparable system at a new facility. The other major distinction for existing units is that they cannot easily be expanded to accommodate the very large amount of parasitic power needed to run the capture systems. Note that for the new units in Table 1, gross generating capacity was increased 15-35% to provide that power. **At a retrofit unit with 33% energy conversion efficiency, a loss of 12% (absolute) efficiency means a loss of more than one-third of the output of the power plant.**

Replacement of this parasitic power, at today's escalated prices for new power plants, will introduce a major cost barrier to retrofitting existing units for CO_2 capture. It could also present limitations on how quickly regulations could be implemented. For example, recall that the 2005 Clean Air Interstate Rule (CAIR) was by necessity introduced in phases (the necessity being that skilled labor limitations precluded a one-step regulatory process).[19] Consider the comparative difficulty of retrofitting CO_2 capture systems on the existing 320 GW coal-fired power plant fleet. **The utility industry would need to install over 100 GW of <u>additional</u> new capacity for replacement power needs (above expected demand growth needs), and simultaneously install 320 GW of CO_2 capture and compression systems, versus roughly 100 GW of SO_2 scrubbers and NOx selective catalytic reduction systems under CAIR.**

A final issue specific to existing units is that a different level of CO_2 capture performance may be appropriate for those units. Most technical studies assume a high level, e.g., 90%, of CO_2 capture for new units[20]. Under either a cap and trade or carbon tax approach to managing greenhouse gas reductions, the best strategy is usually considered to be the one that achieves the desired global emissions reduction at the lowest cost. For existing pulverized coal-fired power plants, it is too early to determine what the most cost-effective level of control will be, but it might be much lower than 90%.

[19] <u>Federal Register</u>, 70FR25197, May 12, 2005.
[20] This level of performance has yet to be demonstrated as either technically or economically feasible.

Operational issues related to CCS

Most generating unit-level analyses of the cost impacts of environmental requirements focus on the levelized cost of electricity (COE) implications of meeting the rules. It is also important to examine dispatching costs (or variable costs) under alternative compliance scenarios, because if variable costs increase significantly, the unit may become too expensive to dispatch, making the capacity factor assumptions in the COE projections (and the COE results) invalid.[21] The costs for CCS retrofits are so large, and impacts on variable costs likewise large, that it is quite possible that a unit in which a large investment was made would not be used very much in an economically dispatched system. One only has to consider the significant amount of idle natural gas combined cycle (NGCC) units in the U.S. to recognize the reality that flawed assumptions with major economic ramifications are not just a theoretical possibility.

The large parasitic power requirements of CCS introduce additional analytical complexity regarding the use of systems equipped with CO_2 capture, particularly retrofit units. Dispatching costs for these units will be much greater due to the higher fuel consumption, and purchase of replacement power. Moreover, if replacement power were purchased from another source, then all of the cost of replacement electricity could be considered a variable cost. Figure 4 compares dispatching costs (or variable costs) for several hypothetical systems, based on cost and performance data reported by DOE/NETL.[22] The NETL costs were adjusted by assuming EIA AEO-2007 costs for natural gas and coal in 2020 (both the EIA reference price and "High Price" scenarios were used for natural gas). In addition, the NETL analysis was for a greenfield, or new power plant. A retrofit factor of 50% was applied to the capital and variable O&M costs for the new plant figures in the NETL report. Figure 4 presents dispatching costs for a range of carbon taxes (0-100 \$/metric ton CO_2), for coal and natural gas. Additionally, the costs in the figure reflect purchase of makeup power to replace the power required to run the CCS system, an issue further discussed below.

Note that the basic coal plant has a variable cost of about 20 \$/MWh and a natural gas plant is about twice that amount, without any CO_2 capture. At 90% capture, variable costs increase to about 60-65 \$/MWh for the coal system and for natural gas combined cycle systems equipped for capture, for a range of natural gas prices. The dashed lines in the figure represent an uncontrolled plant paying the relevant "tax", rather than capturing the CO_2, and a "hybrid" approach of controlling half the CO_2 and paying the tax for the remainder.

These calculations are imprecise, but they indicate that until CO_2 taxes or cap/trade costs exceed about \$50/ton CO_2, coal units without capture (and paying a CO_2 tax) will be dispatched ahead of coal and natural gas units with capture. Other factors, such as subsidies paid to units that capture CO_2 and improvements in the technology, could certainly impact these results dramatically. For perspective, S.1766 (Senator Bingaman's climate change bill), which becomes progressively more stringent over time, begins with a "safety valve" price of 12 \$/ton CO_2 in 2012, and reaches \$50/ton in about 2040.

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[21] For example, most simplistic analyses of technology options assume a constant level of power generation (or capacity factor) across technology alternatives. In practice, however, utilities operate most those units with the least variable costs (which include fuel consumption and variable operation and maintenance costs). If these variable costs increase markedly for some technology options, then the assumption of constant generation across technology alternatives is incorrect, and the resulting COE calculations are likewise in error because fixed costs (such as capital costs) must now be paid with fewer kilowatt-hours of generation.

[22] *Op.Cit.*, Cost and Performance Baseline for Fossil Energy Plants.

A key parameter in these cost comparisons is the cost of replacement power for the CCS system. Replacement power is estimated to be about 30% of the total plant generation for a pulverized coal system, and about one-half that for a natural gas combined cycle (NGCC) system. Who provides the replacement power is also important to dispatching costs. If the power is purchased from another utility, then its costs can be taken entirely as variable costs. If the replacement power is generated by the same utility that is retrofitting the CCS system, then only its variable costs are included in the dispatching costs for the retrofit system. Dispatching costs for this latter case ("self-generation" of replacement or parasitic power) are presented in Figure 5. This differential effect of who supplies the replacement power can be seen in comparing Figures 4 and 5.

The coal-based systems with CCS show a significant reduction in dispatching costs for the "self-generated" replacement power case (Figure 5), relative to the "purchased power" CCS case (Figure 4). Note that the break-even point for coal systems "paying the tax" versus retrofitting CCS has shifted from a tax level of \$50/ton CO_2, to \$20/ton CO_2 for the self-generated replacement power scenario. The NGCC systems are not as sensitive to the source of the replacement power, because most of the cost of NGCC power is the fuel cost, which is a variable cost in either scenario. For the self-generated replacement power scenario, the dispatching costs for a pulverized coal unit retrofit with CCS is about 40-50 \$/MWh over a range of carbon taxes, which makes it comparable to NGCC systems without CCS retrofits. The take-home message here is not the absolute values of these projected costs, but rather the fact that analysts and decision-makers must be careful regarding how these costs are evaluated, and ensure that the assumptions used are appropriate for the system being evaluated, or they can be seriously misled.

A related factor is the impact of parasitic power needs on bulk transmission of electric power to regions that are traditionally "net importers" of power. If a utility has generation capability that exceeds its local needs, it generally tries to sell that power to neighboring power consumers that have insufficient self-generation capacity. If local excess power is eliminated by retrofitting CCS systems on existing coal (and gas) power plants, then those utilities that previously purchased the excess power will quite likely lose that source of electricity. Hence, the sudden broad deployment of the current generation of CCS technology could be disruptive to power systems that do not even operate fossil fuel-fired generators.

Carbon dioxide transport and storage

The cost and performance aspects of carbon dioxide transport and storage are well covered in the literature.[23] The important factors related to transport and storage are:

1. The cost of transport and storage are believed to be a small fraction of the capture costs.
2. There is experience with pipeline transport and injection/storage at relatively small scale, but no experience with storage at the scale of commercial coal-fired power plants (e.g., 3 million metric tons per year for a single 500 MW unit). DOE is now beginning a program for evaluating "1 million TPY" demonstration projects, but results are years away.
3. There is no environmental regulatory framework for addressing the injection and storage of CO_2 in the most likely resource for coal-fired power plants: saline geological formations perhaps one mile below the surface. EPA recently announced its intent to begin development of such a program under the Underground Injection Control program (UIC). See APPA paper on the current UIC program posted at http://www.appanet.org/files/HTM/ccs.html
4. There is likewise no framework for addressing financial liability associated with CO_2 storage. Existing insurance mechanisms are not practical for a system that must maintain its

[23] *Op.Cit.*, Carbon Dioxide Capture and Storage, Chapters 4 and 5.

integrity for hundreds of years. It is unlikely that electric utilities will embrace CCS technology until pragmatic frameworks are established.

Regulatory Issues for Retrofits

Clean Air Act Permits and Federal New Source Review Issues

Aside from the obvious regulatory issues associated with CO_2 capture and storage that include permitting underground injection wells and obtaining rights to underground caverns for disposal,[24] it also is likely that the retrofit of an existing electric generating unit will result in the retrofit being deemed a "major modification of a major Clean Air Act-regulated source."[25] This is because the CO_2 capture system may lead to increases in other pollutants regulated under the Clean Air Act. Major modifications are subject to the federal new source review (NSR) program, which includes lengthy permitting, modeling of air quality impacts, and installation of state-of-the-art pollution control equipment on the retrofitted boiler and ancillary emitting equipment. Under current federal law even environmentally beneficial projects can be subjected to lengthy regulatory processes, public scrutiny which can include legal challenges, and additional costs deriving from analytic requirements for permit preparation and additional pollution controls. It should be noted that NSR may be required for SO_2 and NOx retrofits installed pursuant to the 2005 Clean Air Interstate Rule (CAIR) because the SO_2 and NOx pollution control equipment may lead to small increases of pollutants other than SO_2 and NOx.[26]

However, even if the NSR exemption for "pollution control projects" still existed[27], typical retrofits to existing power plants likely still would require NSR review. The large parasitic power requirements of CCS technology will very likely lead to increases in coal use at existing units.[28] For some pollutants, like SO_2, the additional reduction of that pollutant that occurs as part of the CO_2 capture process will negate the increased amount of combustion. For others, like particulate matter, the situation is not as clear. In addition, some of the components of the CO_2 capture

[24] It is important to note that in some states, ownership of surface rights does not convey ownership of subsurface mineral or other rights needed for the disposal of carbon dioxide underground.

[25] This term "major modification of a major source" has been the subject of extensive historical and ongoing regulatory and litigation controversy. This paper does not attempt to unscramble or recount these controversies, but instead calls to the reader's attention that caution and additional costs associated with federal (and state) Clean Air Act permits will be associated with CCS retrofits.

[26] See, for example, <u>Clean Air Report</u>, Inside EPA, September 20, 2007, p.1; and <u>New Source Review for CAIR and CAMR Projects</u>, August 24, 2007 draft proposal by Indiana agency representatives to the Environmental Council of the States (not adopted by ECOS).

[27] The D.C. Circuit Court of Appeals held that EPA could not exempt pollution control projects from New Source Review regulations, *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2006).

[28] Consider the following simplistic example. An existing coal-fired power plant operates 60% of the year at full load, 30% at half-load, and is down for maintenance 10% of the year. After retrofit for CCS, the amount of coal used (and emissions) are unchanged for the full load and no load portions of the year. But for the 30% of the year historically run at half load, assuming demand remains the same and ignoring dispatching economics, to produce the same amount of megawatt-hours the unit will have to operate at approximately 70% capacity factor due to parasitic power loss. This higher operating level would lead to greater uncontrolled emissions. Increases in operating hours are not an exclusion from NSR if the increase is a direct result of a physical change at the unit. The ultimate determination of whether these circumstances constitute a "major modification" would depend on how State, EPA, and the courts interpret the regulations, as well as possible emission mitigating measures that the retrofit facility might undertake.

system may be sources of fugitive emissions of various pollutants regulated under the Clean Air Act.

NSR Review of CO_2 and Other Green House Gases (GHG)

CO_2 and other GHG also are likely to be regulated NSR pollutants for purposes of NSR review by the end of 2008 pursuant to a decision by the United States Supreme Court that these emissions were Clean Air Act "pollutants."[29] EPA officials announced at the September 2007 meeting of the federal Clean Air Act Advisory Committee that the agency intended to complete regulations limiting CO_2 and five other GHG from motor vehicles and possibly refineries by the end of 2008. The regulation of CO_2 under Clean Air Act requirements (except as a "hazardous air pollutant"[30]) renders these substances a "regulated air pollutant" for purposes of New Source Review and Federal Operating Permits under 40 CFR subparts 51, 52 and 70 (the NSR and Part 70 Operating Permit regulations). EPA officials also announced that they intend to undertake an NSR rulemaking by the time GHG are regulated to define what a "major source" of GHG is, and even more importantly, what "significant increases" of GHG are for purposes of defining the term "major modification."[31]

Assuming CO_2 and other GHG become regulated air pollutants, a significant net increase of any GHG within the facility will trigger NSR. This creates a situation analogous to the previously discussed paradox where environmentally beneficial hardware installed to reduce SO_2 and NOx emissions under the CAIR rule could trigger NSR requirements due to small associated increases in particulate matter emissions. Similarly, the retrofit of traditional pollution control devices, like SO_2 scrubbers, also could trigger "major modification" status for that facility for CO_2, in the absence of the now-defunct "pollution control exemption". This would lead to case-by-case Best Available Control Technology (BACT) reviews for CO_2 emissions.

Reconstruction and Clean Air Act New Source Performance Standards

If a facility retrofit constitutes a "reconstruction" of a facility under the Clean Air Act's New Source Performance Standards (NSPS) regulations, the owner or operator must meet NSPS for the "affected source." Thus, it is important to examine how EPA has interpreted the term,[32] defined in the regulations as:

> 40CRF60.15 (b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:
>
> (1) The fixed capital cost of the new components exceeds 50 percent of

[29] In *Massachusetts v. EPA U.S. 127 S.Ct.1438, 75 USLW 4149* (April 2, 2007), the Court addressed Massachusetts and other states' petition challenging the agency for failing to regulate GHGs under the Clean Air Act's mobile source program. The Court determined that these substances were "air pollutants" under the Act and essentially held that EPA must regulate vehicular emission of CO2 unless the Agency determines that CO2 does not endanger the public's health and welfare. EPA is expected to regulate CO_2 emissions from mobile sources, and that regulation will likely trigger requirements for new or modified major stationary sources such as power plants if they have more than *de minimis* increases in CO_2 emissions.

[30] Note that if CO2 were regulated as a hazardous air pollutant under Title III of the Clean Air Act, PSD would not apply pursuant to section 112(b)(6).

[31] Until EPA defines what a "significant emission increase" is under 40 CFR §§51.166(b)(23) and 52.21(b)(23 of the NSR regulations, "*any*" increase of pollutants will trigger NSR (and BACT) review.

[32] EPA interpretations of NSPS for various affected industries can be searched on the Office of Enforcement and Compliance website on the "Applicability Determination Index" at http://cfpub.epa.gov/adi/.

> the fixed capital cost that would be required to construct a comparable entirely new facility, and
>
> (2) It is technologically and economically feasible to meet the applicable standards set forth in this part.
>
> (c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

Since the addition of a capture system does not fit neatly into the concept of "replacement of components," the applicability of the NSPS "reconstruction" test to CCS is unclear, in part because it is not clear whether the cost of a "pollution control" is included in determining the cost of a facility replacement." Also, "pollution control projects" (PCPs) and "clean coal technology" continue to be exempt from the NSPS definition of "modification" under 40 CFR §60.14(e)(5), even following a Court's ruling that the NSR exemption for PCPs was illegal because it might cause an increase in actual emissions.[33] Nevertheless, even if all of these conditions are met, a regulatory obligation for reconstruction based on CO_2 emissions can only exist after EPA adopts a CO_2 NSPS, under 40 CFR Part 60. Note, that this future rulemaking could create a preference for an oxy-fueled system versus a post-combustion system, depending on how the rules are specified.

Storage Rules

There is general recognition that the current underground injection control (UIC) program for waste injection is not well designed to address issues associated with CO_2 storage in deep saline reservoirs. The Interstate Oil and Gas Compact Commission (IOGCC) recently proposed that states take the lead on this type of regulation, given their extensive regulatory experience with CO_2 -based enhanced oil recovery.[34] Moreover, IOGCC expressed the view that CO_2 should be treated as a resource, rather than as a waste, and that treatment of CO_2 as a waste "would diminish significantly the potential to meaningfully mitigate the impact of CO_2 emissions through geologic storage." Shortly after IOGCC's report and announcement calling for state primacy, U.S. EPA announced that it was beginning a federal rulemaking, under the authority of the Safe Drinking Water Act, to address underground injection of CO_2.[35]

Another local consideration that needs to be considered in the context of CCS is the ownership of surface and subsurface rights. In certain states (and most with significant mineral rights), ownership of underground caverns may be distinct from ownership of surface rights. Careful examination of deeds and other land records may be necessary to establish property ownership and rights of way for transport and sequestration of gases.

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[33] *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2005).

[34] Storage of CO_2 in Geologic Structures – A Legal and Regulatory Guide for States and Provinces, IOGCC, September 25, 2007. "*A key conclusion of that report* [a 2005 IOGCC study] *was that given the jurisdiction, experience, and expertise of states and provinces in the regulation of oil and natural gas production and natural gas storage in the United States and Canada, the states and provinces would be the most logical and experienced regulators of the geologic storage of carbon dioxide."*

[35] "EPA Rulemaking Plan May End States' Bid for Lead Role On CO_2 Storage", Inside EPA, October 12, 2007, citing an Oct 11 announcement by EPA Administrator Stephen Johnson.

Other liabilities
Two additional areas of risk management related to CO_2 storage are:

1. The potential for stored CO_2 to migrate into areas of other valued resources, such as natural gas deposits, and diminish the value of those resources; and
2. The potential for CO_2 migration after closure of the injection site. Injection of CO_2 from an operating plant may last for decades, but for the storage to be effective, the CO_2 must be contained for centuries. This timeframe is beyond the scope of available commercial risk management issues.

Effectively managing these risks may require government participation, and that may require additional legislative authority.

Looking to the future

There is much ongoing activity related to CCS. The Department of Energy is focusing on both capture and storage, and several large storage projects are starting under the Regional Partnerships program. As noted earlier, EPA is beginning to develop rules for CO_2 storage, and initial regulatory responses to *Massachusetts versus EPA* are likely by the end of 2007. Climate change mitigation legislation is receiving much attention in Congress.

Nevertheless, given the significant contribution of existing coal-fired power plants to both the nation's electricity supply and to national greenhouse gas emission rates, and the high cost of currently available mitigation techniques, the resources focused specifically on developing pragmatic solutions for this CO_2 emission group seem quite limited. Additional effort appears warranted to:

- Significantly drive down the cost of CO_2 capture, both through "learning by doing" using current technology, and through additional research.
- Explore ways to modify the existing power plant itself, such as replacing turbines or turbine components, or upgrading boilers, so that the existing plant becomes more efficient and productive. This would provide both a partial cost offset to the increased cost of electricity due to CCS retrofit, and (possibly) reduce the impact of parasitic power needs to drive the CCS hardware.
- Gain experience with storing large quantities of CO_2 in different types of geologic saline structures. The Regional Partnerships program may be a good start, but a few large projects are unlikely to be representative of the full range of geologies in the U.S. that are attractive for CO_2 storage
- Increase our knowledge base and simplify traditional preconstruction permitting procedures to expedite the permitting of CCS retrofit projects.

About the author – Doug Carter is an independent consultant on energy technology and related environmental issues. His current practice focuses on advising clients regarding advanced coal-based technologies and their potential role in mitigating global climate change. Mr. Carter's resume includes 25 years with the U.S. Department of Energy, where he was Director of the Office of Planning and Environmental Analysis, within the Office of Fossil Energy. He had previously served with the Office of Enforcement and Office of Air Quality Planning and Standards at the U.S. Environmental Protection Agency.   Mr. Carter holds degrees in Mechanical Engineering and Environmental Engineering.   He can be reached at Carter2250@comcast.net .

The American Public Power Association is the national service organization representing the nation's more than 2,000 community- and state-owned electric utilities. APPA's website is www.appanet.org The dedicated website address for information on geologic sequestration and carbon capture and geologic sequestration or storage is: http://www.appanet.org/files/HTM/ccs.html
APPA Contact: Theresa Pugh, Director, Environmental Services, 1875 Connecticut Ave, NW, Suite 1200, Washington, D.C. 20009-5715 or at (202) 467-2943

See page 13-16 for figures

Figures

Figure 1. Pulverized coal power plant with carbon capture.

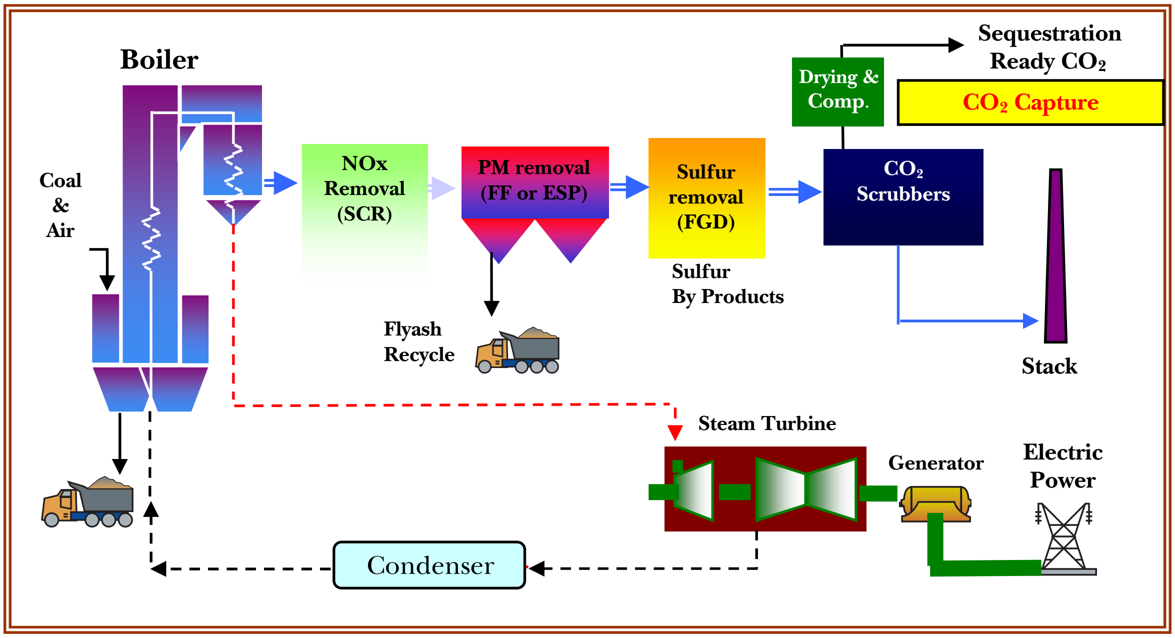

Figure 2. Sources of parasitic power.

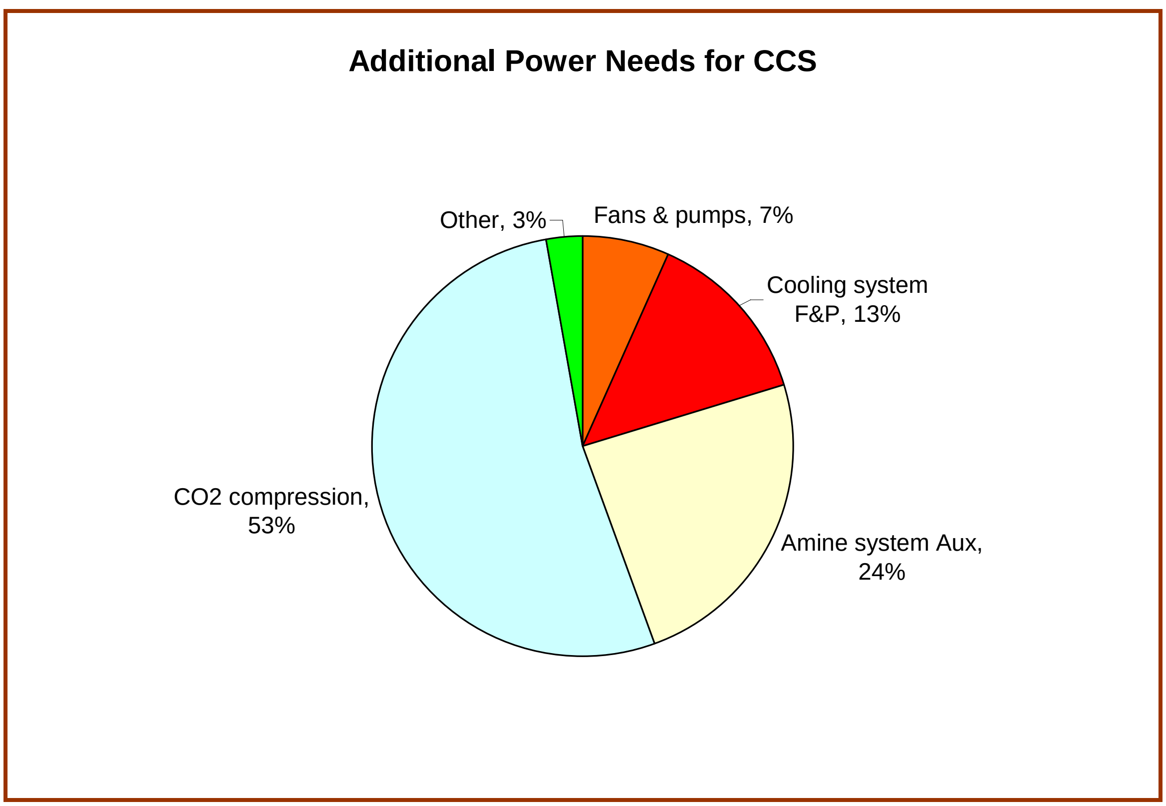

Figure 3. An Oxy-combustion unit with CO2 capture.

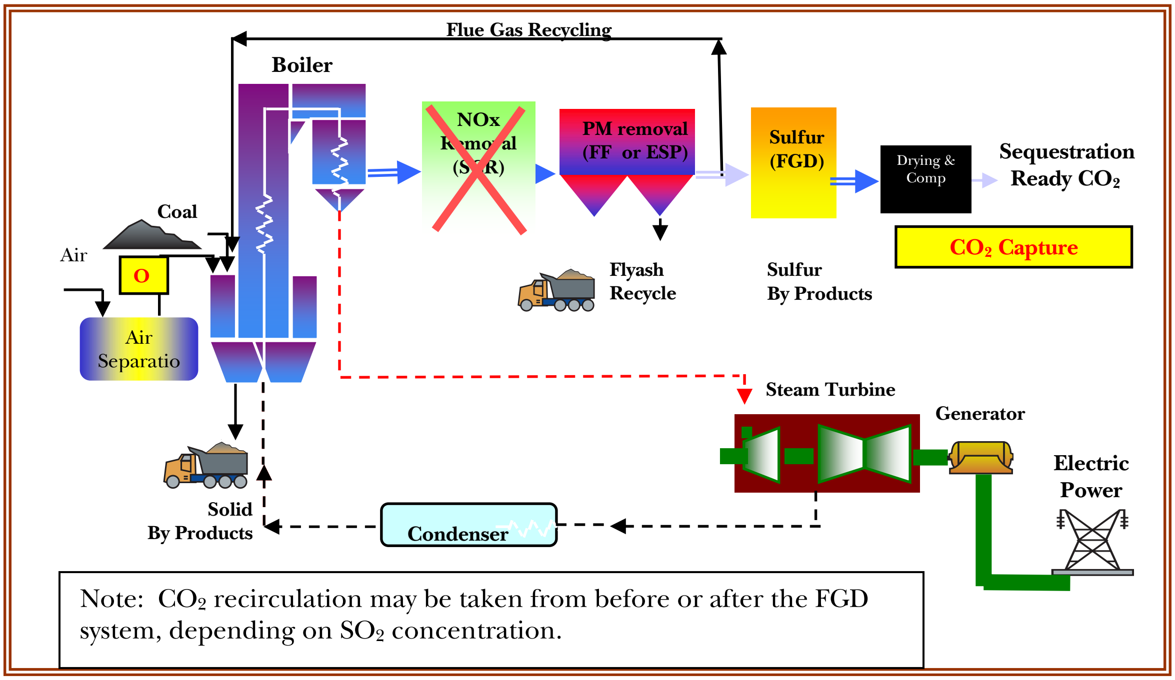

Figure 4. Dispatching costs assuming replacement power is purchased.

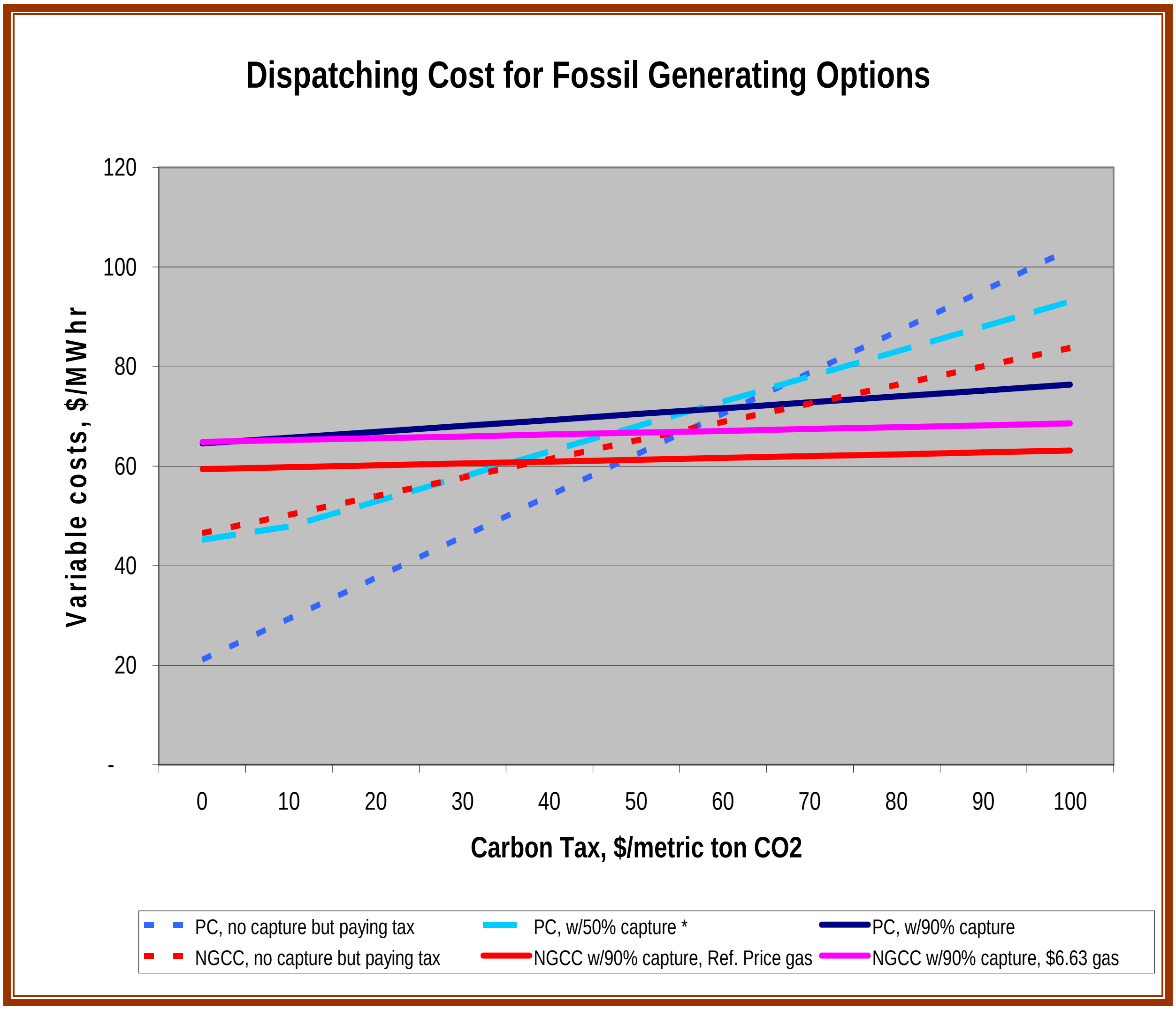

Figure 5. Dispatching costs assuming self-generated replacement power.