Appendix E-7

Repowering/Fuel Substitution Analysis[1]

Carbon emissions from coal-fired power plants are the target of most proposals to reduce greenhouse gas (GHG) emissions. While carbon emissions can be reduced through efficiency improvements in the conversion of coal-to-electricity, such reductions_for example from 260 g/kWh for a 34% efficient pulverized coal boiler, to 210 g/kWh for a 42% efficient integrated coal gasification combined cycle (IGCC) power plant_may not be sufficient to meet future emission targets.

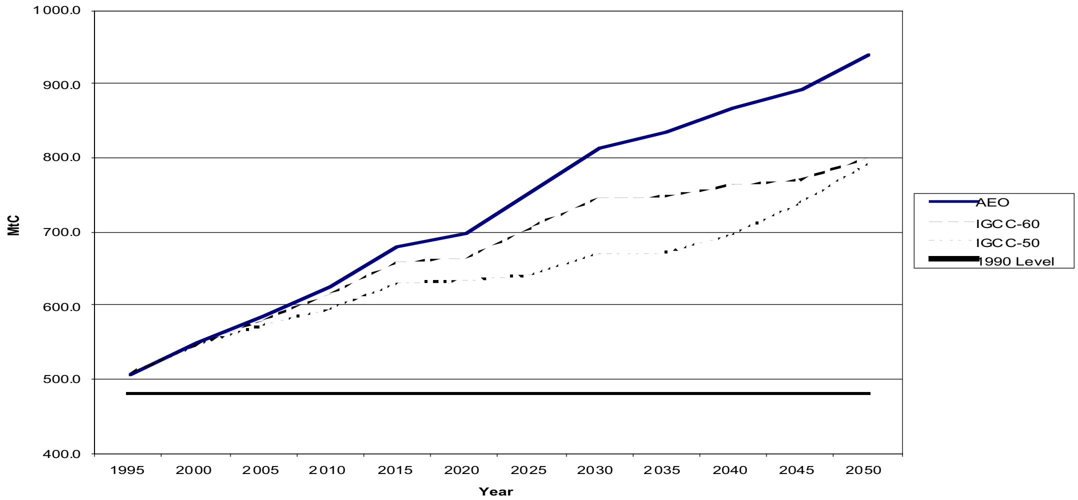
If additional carbon reductions are required, two options exist: 1) substitute coal for a lower carbon content fuel, such as natural gas, or 2) add carbon capture/sequestration technology (when it becomes commercially economic) to the advanced coal-based technology (IGCC).2 This analysis discusses some of the issues associated with coal-to-gas repowering of existing coal-fired power plants for the purpose of reducing their carbon emissions.

<u>Carbon Emissions Impact of Efficiency Improvements and Fuel Switching</u>

Figure 1 illustrates the effect on future electricity-based carbon emissions from total reliance on IGCC for future coal-based electricity generation. The solid line reflects the EIA/Annual Energy Outlook forecast extrapolated to 2050.3 This carbon trajectory assumes that existing pulverized coal systems remain in the generation mix, and that new coal-based capacity is a combination of advanced pulverized coal systems and IGCC. The line labeled IGCC-60 plots the level of carbon emissions that would result if all coal-fired boilers were retired (or repowered) at age 60 with IGCC. The line labeled IGCC-50 plots the same information, but if the replacement occurred at age 50.

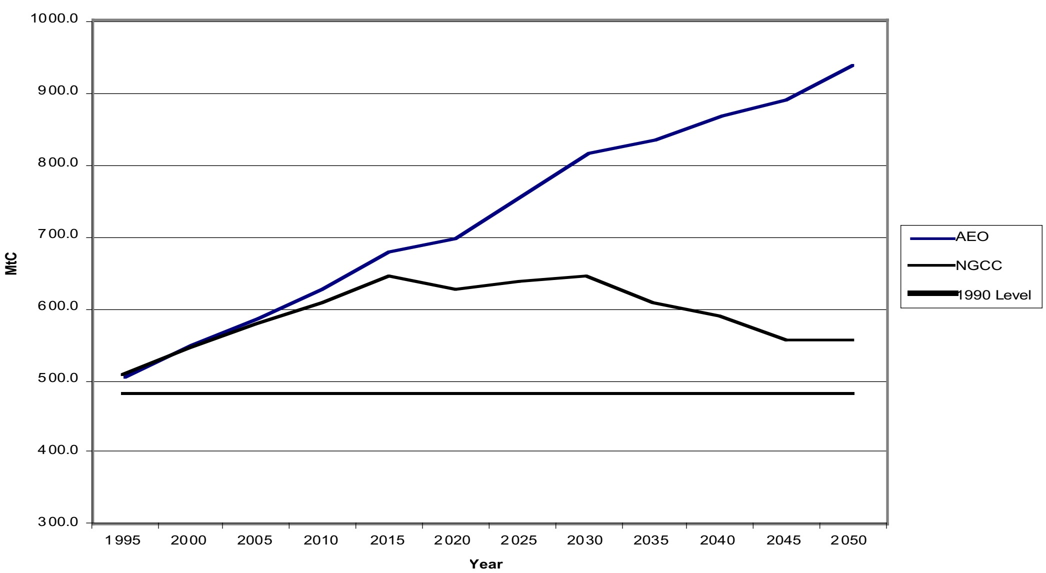
Carbon emissions are approximately 9 percent lower in 2020 when coal plants are replaced with IGCC at age 50, and 5 percent lower when replaced at age 60. As depicted, while greater carbon emissions reduction occurs under the IGCC-50 case, by 2035 all plants are converted and the effect of generation growth causes the IGCC-50 carbon trajectory to increase. In 2050, while exclusive reliance on IGCC for coal-fired generation saves approximately 140 million metric tons of carbon (MtC), carbon emissions still exceed 1990 levels by almost 320 MtC.

Fig. 1. Effect on Carbon Emissions of Advanced Coal Technology Efficiency Improvements



The carbon emissions impact of converting all coal-fired capacity to natural gas is plotted in Figure 2. This trajectory depicts the effect of retiring (or repowering) coal-fired power plants at age 60 and replacing them with natural gas combined cycle (NGCC).[4] It also assumes that all new coal-fired generation (identified in AEO99) is instead built as NGCC. In this scenario, carbon emissions are relatively flat between 2010 and 2025 before declining to approximately 550 MtC in 2050. This level is almost 75 MtC greater than 1990 levels.

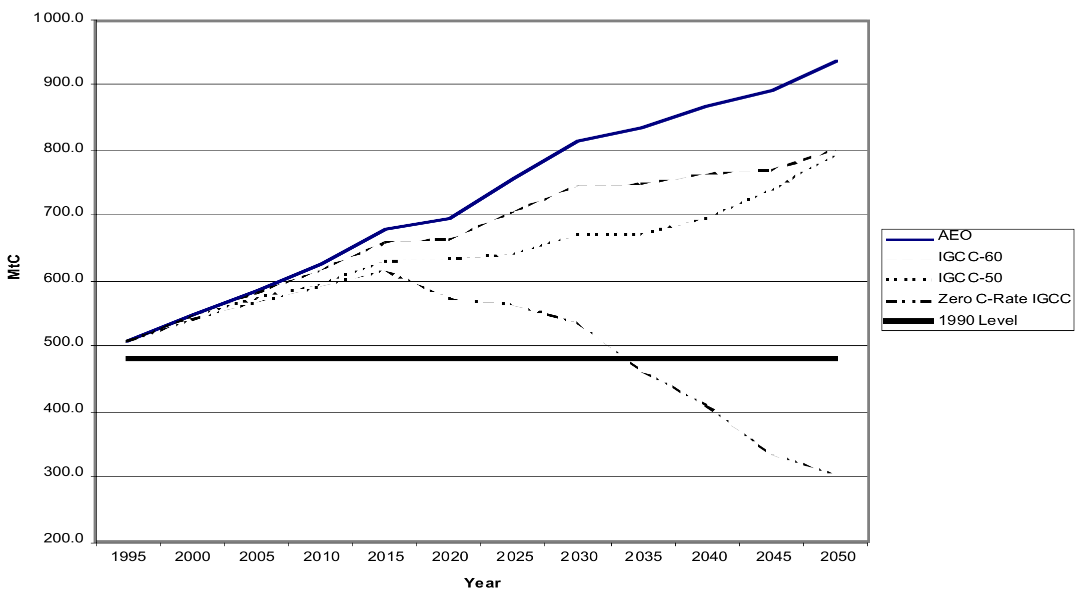
Fig. 2 Effect on Carbon Emissions of Coal-to-Gas Fuel Substitution



Thus, while both efficiency improvements and fuel switching reduce carbon emissions from future coal-based power generation, neither of these actions alone is sufficient to reduce emissions to 1990 levels (or 7 percent below 1990 levels, as stipulated for the U.S. in the Kyoto Protocol). Attempts to accelerate the retirement/replacement of coal-fired generation reduces carbon emissions earlier, but the reduced level is not maintained since growth in generation overcomes than the lower carbon emission rate (IGCC vs PC).

As depicted in Figure 3, only if all new coal capacity and ~120 gigawatts (GW) of coal capacity age 60 had a carbon emission rate of zero could electricity-based carbon emissions approach 1990 levels. Additional existing coal capacity would need a zero carbon emission rate to displace any growth in total generation and maintain emissions below 1990 levels.[5]

Fig. 3 Effect on Carbon Emissions of Zero-Emission Rate Coal-Based Advanced Technology



Coal-Gas Repowering vs Greenfield

As related above, repowering of existing coal-fired units with an advanced coal technology (e.g., IGCC), can reduce carbon emissions by approximately 30 percent, or in approximate proportion to the efficiency (heat rate) improvement. However, such reductions may not be sufficient to lower electricity-based carbon emissions to 1990 levels (or below). To approach this level of emission reduction requires a lower carbon content fuel, such as natural gas.

Coal-gas repowering was examined extensively in *Scenarios of U.S. Carbon Reductions*.[6] It found that of the 335 GW of coal-fired capacity, approximately 26 GW (~8%) could be candidate for coal-gas repowering at less than $50/tC if the coal-gas price differential was $0.72/MMBtu and there were no credit for SO_2/NO_x emission reduction from the conversion. More than 63 GW (~19%) could be candidate for coal-gas repowering if low externality values were assigned to the SO_2/NO_x emissions reduced.

However, while coal-gas repowering has some potential to reduce carbon emissions from coal-based power plants, there are limitations in the number of plants where it is applicable. These limitations relate to site-specific issues:

- Age and condition of steam turbine
- Efficiency loss in interconnecting existing steam turbine with new gas turbine and heat recovery steam generator (HRSG), due to differences in steam pressure/temperature.
- Distance and cost to interconnect with gas pipeline

Table 1 compares the cost of electricity for two cases: coal-gas repowering and greenfield gas. It relates that while there a capital cost savings ($/kW) it is almost negated by the heat rate differential. The cost of electricity (COE) is only $0.50-1.00/MWh lower for repowering, depending on the capacity factor. Given the other uncertainties in repowering a plant this cost differential is not sufficient to chose repowering over greenfield.

Table 1 Comparison of Coal-Gas Repowering and Gas Greenfield Economics

	Repowering			Greenfield		
Capacity Factor	50%	75%	85%	50%	75%	85%
Cost ($/kW)	$424	$424	$424	$569	$569	$569
Capital Charge Rate	0.089	0.089	0.089	0.089	0.089	0.089
Heat Rate	7,600	7,600	7,600	7,200	7,200	7,200
Fuel ($/MMBtu)*	$3.21	$3.21	$3.21	$3.21	$3.21	$3.21
Capital ($/kW/yr)	$38	$38	$38	$51	$51	$51
O&Mf ($/kW/yr)	$12.43	$12.43	$12.43	$11.19	$11.19	$11.19
Capital ($/MWh)	$8.61	$5.74	$5.07	$11.56	$7.71	$6.80
O&Mf ($/MWh)	$2.84	$1.89	$1.67	$2.55	$1.70	$1.50
Fuel ($/MWh)	$24.40	$24.40	$24.40	$23.12	$23.12	$23.12
O&Mv ($/MWh)	$1.24	$1.24	$1.24	$1.24	$1.24	$1.24
Fixed Cost ($/MWh)	$11.5	$7.6	$6.7	$14.1	$9.4	$8.3
Marginal Production Cost ($/MWh)	$25.6	$25.6	$25.6	$24.4	$24.4	$24.4
COE ($/MWh)	$37.1	$33.3	$32.4	$38.5	$33.8	$32.7

Source: American Electric Power (AEP), February 1999

Not included in the above economic comparison is the value of emission credits. Emission credits_for SO_2 and NO_x_would be earned if a coal-fired power plant is repowered with natural gas. Those credits not needed to offset the additional generation at plant (post-repowering)[7] could be sold to reduce the cost of the coal-gas repowering. At present the market price for SO_2 credits is ~$200/ton and for NO_x credits is ~$800/ton.

While a repowered plant could generate these extra credits based on the difference in emissions between the coal-fired and the repowered plant, a greenfield NGCC plant would need to purchase offsets (credits) equivalent to its projected emissions. Depending on the location of the plant_both region of the country, and whether it is located in an attainment or nonattainment area_these offsets could add considerable cost to operate the greenfield plant on an annual basis. For example, NO_x emissions credits in the Ozone Transport Region (OTR) during the 1999 ozone season (May 1 thru September 30) cost between $3,000 and $8,000 per ton.[8] At these prices, emission credits would add $6-15/MWh to the cost of electricity.

Infrastructure Requirements of Coal-Gas Substitution

Whether a coal-fired power plant is repowered with NGCC, or it is retired and replaced with NGCC, the infrastructure effect is the same_there is increased demand for gas deliverability. A comprehensive analysis was undertaken in *Scenarios of U.S. Carbon Reductions*[9] to determine the amount and cost of natural gas infrastructure expansion to accommodate the additional demand arising from conversion of coal-fired power plants to natural gas.

Since that analysis a more detailed study has determined that to provide the delivery infrastructure for a 30 trillion cubic feet (TCF) natural gas industry, between 2,000 and 2,100 miles of new gas transmission pipeline would be needed each year.[10] The required capital expenditures for this gas transmission and storage from 1998 to 2010 would be between $32.2 billion and $34.4 billion. While substantial new pipeline and storage infrastructure would be needed, it is not outside recent experience levels.[11]

Summary

Substitution of gas for coal in the generation of electricity will have an impact on the carbon trajectory. However, even when all retired and new coal are replaced by NGCC, carbon emissions are not reduced to 1990 levels (or 7 percent below, as required for the U.S. in the Kyoto Protocol). The reason is that fuel substitution of natural gas for coal only reduces carbon emissions by 110-160 g/kWh (50-60%), depending on the coal technology.

Continued reliance on coal could result in zero carbon emissions, if coal generation is linked with carbon capture/sequestration. Coal could also continue to generate electricity in a carbon-constrained world, if there is a larger share of non-emitting baseload technology.

Repowering of coal plants to natural gas could accelerate the reduction in carbon emissions, and facilitate the re-use of existing power plant sites. Some of the plant sites have implicit locational value due to transmission interconnections and airshed emission constraints. For example, repowering a coal-fired power plant with gas could reduce air pollutant and greenhouse gas emissions (even with increased generation, post-repowering). Extra air emission credits could be produced for sale; with the revenue used to subsidize the cost of repowering the plant.

Alternatively, a greenfield NGCC plant needs to purchase offsets equal to its projected emissions. The cost of these offsets becomes an element in its annual production cost. In particular regions, purchase of NO_x offsets alone can raise the production cost by $5-15/MWh.

The infrastructure needed to serve an expanded natural gas generation market (30 TCF) is estimated to cost $32.2 billion and $34.4 billion between 1998 and 2010. While more than 2,000 miles of gas transmission line would need to be constructed annually, recent evidence indicates that this level of construction is achievable. What is at issue, however, is whether the rights-of-way are available, and any rent-seeking would both increase the difficulty and cost of expanding the pipeline capacity.

At present, no incentives exist to promote coal-gas repowering. However, recent restructuring legislation may provide a production tax credit when emissions are reduced from a power plant efficiency improvement. As currently drafted it is unclear if coal-gas repowering would qualify for this incentive.

Other incentives proposed to date relate to accelerated deployment of clean coal technologies (CCTs). Three recent studies derived the level of CCT incentives necessary to be cost-competitive with NGCC.[12] The Coal Utilization Research Council (CURC) determined that the following incentives are necessary for the first 1,500 MW of each type of CCT:

- Investment tax credit: tax credit equal to 20% of owner s equity investment, applicable to first 4 years of construction.
- Production tax credit: tax credit based on design average net heat rate, with an incentive (1.30-0.70 cents/kWh depending on heat rate) for years 1-5, and a lower incentive (0.45-1.10 cents/kWh depending on heat rate) for years 6-10. The production tax credit would apply to the years 1-10 of operation.
- Financial Risk Pool: the Federal government would establish a financial risk pool applicable in years 1 thru 3 of operations to offset costs arising from technology non-performance (relative to design) during start-up and initial operation. The total amount of recoverable costs is limited to 5% of total project installed cost.

While these financial incentives are determined necessary to make CCTs competitive with NGCC (using a cash flow analysis), the level of incentives exceed the carbon value targets inherent in the Moderate and Advanced scenarios of this CEF study ($25/tC and $50/tC). For example, a production tax credit of $0.25/kWh over 10 years is equivalent $24/tC, and a $0.50/kWh production tax credit is equal to $48/tC. Thus, implementation of the full set of incentives proposed by CURC would translate into a carbon value greater than $200/tC.

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2 For a discussion of carbon capture/sequestration technology see U.S. Department of Energy, 1992, *Screening Analysis of CO2 Utilization and Fixation, Final Report*, DOE/FE/61680-H2, and U.S. Department of Energy, 1993, *The Capture, Utilization and Disposal of Carbon Dioxide from Fossil Fuel-Fired Power Plants*, DOE/ER-30194.

3 To extend the AEO forecast from 2020 to 2050, the average fuel shares during the period 2015-2020 were held constant.

4 The EIA/NEMS model does not model coal-gas repowering. One can assume that the level of NG generation projected in AEO is a combination of greenfield and some replacement of retired coal via coal-gas repowering.

5 A zero carbon emission rate could be achieved by reliance on IGCC with carbon capture/sequestration, or by replacing coal-based generation with an appropriate baseload non-carbon emitting technology.

6 See Chapter 7.2 in ORNL et al, 1997, *Scenarios of U.S. Carbon Reductions, Potential Impacts of Energy Technologies by 2010 and Beyond.*

7 Depending on the type of coal-gas repowering performed, capacity (and thus generation) could increase by 30-40 percent.

8 The future price of emission credits is predicated on the supply and demand for credits. One factor that influence the supply is the continued operation of nuclear and hydroelectric power plants. As non-emitting

sources of generation, if they were to retire and be replaced by another baseload technology (coal or gas), some proportion of the fixed annual allocation of emission allowances would be used by this replacement generation. Consequently, the other generating capacity would receive fewer allowances—with the result being higher priced allowances for trade, higher cost of compliance for existing sources, and a higher entry barrier for a new greenfield plant.

[9] See Chapter 7.2 and Appendix G-4 in ORNL et al, 1997, *Scenarios of U.S. Carbon Reductions, Potential Impacts of Energy Technologies by 2010 and Beyond*

[10] Energy and Environmental Analysis, 1999, *Pipeline and Storage Infrastructure Requirements for a 30 TCF U.S. Gas Market*, prepared for the INGAA Foundation Inc. (F9901).

[11] In 1991 and 1992 over 3,000 miles of new gas transmission line were built (AGA Gas Facts).

[12] See: South, D.W. et al, 1995, *Analysis of Incentives to Accelerate First-of-a-Kind (FOAK) Clean Coal Technologies*, prepared for U.S. Department of Energy (October); Spencer, D.F., 1996, *An Analysis of Cost Effective Incentives for Initial Commercial Deployment of Advanced Clean Coal Technologies*, prepared for U.S. Department of Energy (May); and Coal Utilization Research Council, 1998, *Incentives for Clean Coal Technology Research & Development, and Deployment Program* (May).