Electricity from Fossil Fuels Without CO_2 Emissions: Assessing the Costs of Carbon Dioxide Capture and Sequestration in US Electricity Markets

Timothy L. Johnson (tjohnson@Andrew.cmu.edu; 412-268-5605) and,
David W. Keith (keith@cmu.edu; 412-268-2678)

Department of Engineering and Public Policy,
Carnegie Mellon University,
129 Baker Hall,
Pittsburgh, PA 15213-3890.

ABSTRACT
The decoupling of fossil-fueled electricity production from atmospheric carbon dioxide emissions via CO_2 capture and sequestration (CCS) is increasingly regarded as an important means of mitigating climate change at a reasonable cost. Engineering analyses of CO_2 mitigation typically compare the cost of electricity for a base generation technology to that from a similar plant with CO_2 capture and then compute the carbon emissions mitigated per unit of cost. It can be hard to interpret mitigation cost estimates from this plant-level approach when a consistent base technology cannot be identified. In addition, neither engineering analyses nor general equilibrium models can capture the economics of plant dispatch. A realistic assessment of the costs of carbon sequestration as an emissions abatement strategy in the electric sector therefore requires a systems-level analysis. We discuss various frameworks for computing mitigation costs and introduce a simplified model of electric sector planning. Results from a "bottom-up" engineering-economic analysis for a representative U.S. NERC region illustrate how the penetration of carbon capture and sequestration technologies and the dispatch of generating units vary with the price of carbon emissions, and thereby determine the relationship between mitigation cost and emissions reduction.

N.B., This paper has been submitted to the *Journal of the Air & Waste Management Association* for review as part of the *Electric Utilities Environmental Conference* (Tucson, AZ; January 2001) proceedings.

INTRODUCTION

The need to reconcile stabilization of atmospheric carbon dioxide (CO_2) with an energy infrastructure dependent on fossil fuels presents a fundamental challenge to industrial society. While the CO_2 emissions per unit of electricity generated in the US has decreased by roughly twenty-five percent in the last half century, the amount of power generated has grown eleven-fold and electricity generation is now responsible for one-third of annual US CO_2 emissions.[1,2] Over the next half century substantial reductions in CO_2 emissions will likely be needed to stabilize atmospheric CO_2 concentrations at acceptable levels, the agreed goal of the Framework Convention on Climate Change (ratified by the US in 1992). Continuing gradual increases in generating efficiency are not likely to yield sufficient reductions in CO_2 production, and sweeping technological change will likely be required – a particular challenge for the electricity sector given the long lifetimes of the energy infrastructure. The costs of conversion and uncertainties in the performance of alternative technologies preclude easy replacement of fossil-electric power generation.

Carbon capture and sequestration (CCS) offers a more immediate response to this dilemma by providing a means to separate the energy value of fossil fuels from atmospheric CO_2 emissions at a reasonable cost.[3,4] Because it is highly compatible with the existing fossil electric infrastructure, and because many of the component technologies are already in use, it is plausible that CCS could offer a significantly cheaper near-term path to CO_2 mitigation than is possible with non-fossil renewables. New CCS electric plants could match existing units with respect to sizing and dispatch, and retrofits of existing coal-fired capacity is possible. While we do not include them in the analysis presented here, we recognize the potential importance of non-fossil renewables, new nuclear power, and distributed co-generation to the mitigation of CO_2 emissions. Forecasting energy futures is a highly uncertain venture, and we do not offer such forecasts; rather, our focus is on describing the methodology that is necessary to evaluate the role of CCS technologies.

Analyses of carbon sequestration have either taken a top-down, macroeconomic perspective,[5,6] or focused on estimating abatement costs at the plant level.[7,8] Few attempts have been made to assume an intermediate perspective and assess the costs of adopting CCS in tandem with changes already occurring in energy markets. In particular, a systems-level analysis is needed of CCS as a carbon mitigation strategy in the electric sector – one that considers the interacting effects of sunk capital investment, the economics of plant dispatch, and the dynamics of fuel-switching. Analyses of CCS-related mitigation costs[7,8,9] typically compare the cost of electricity for a base generation technology to figures from a similar plant with carbon capture, and then compute the carbon emissions mitigated per unit of cost. As the authors of these assessments note, a plant-level approach is misleading when a consistent base technology cannot be identified and necessarily ignores both the weight of sunk capital and the economics of plant dispatch in determining actual mitigation costs.

This paper explores the costs of CCS in the US electric market. Our goal is to describe the need for an electric system economic analysis rather than make a robust estimation of mitigation costs. The limitations of the plant-level approach to cost calculation are first discussed. We then present a simplified model of electric power production to illustrate the importance of considering competition between technologies and the economics of plant dispatch in analyzing mitigation costs. This energy systems model combines a limited suite of power generation technologies, plant vintages, and fuel types in a "bottom-up" engineering-economic analysis for a representative US NERC region. Model results illustrate how both the diffusion of carbon capture and sequestration technologies and the dispatch of generating units vary with the price of carbon emissions, and thereby determine the relationship between mitigation cost and emissions reduction.

CALCULATING THE COST OF CARBON MITIGATION

The starting point for estimating mitigation costs is the relationship between cost of electricity and intensity of CO_2 emissions for various technologies. Figure 1 illustrates this relationship for the total cost of electricity including variable expenses (fuel and O&M) and the cost of capital given a 75% plant utilization.

The slope of the line connecting a given "base" generation plant to its equivalent with CO_2 capture determines the mitigation cost associated with building a CCS plant in preference to a conventional unit. This slope also corresponds to the carbon price (achieved by a carbon tax or equivalent regulatory mechanism) that makes the cost of electricity from the technologies equal. The simplest way to estimate mitigation costs is therefore to consider that a CCS plant must use the same fuel as the base plant, while holding all else constant. We call this the "static fuels" approach. Given the data in Figure 1, the static fuels mitigation cost for a new pulverized coal plant (PC) is approximately 100 $/tC, while that for a new natural gas combined cycle unit (NGCC) is 225 $/tC. All other things being constant, for instance, a carbon tax of slightly greater than 100 $/tC would induce generators to build new coal-fired plants with CCS in preference to new conventional coal-fired units. These estimates depend (of course) on fuel costs, plant utilization, and the uncertain cost and performance of CCS technologies.

In the real world, however, generating units are coupled with other plants in an integrated electric power system, thus ensuring that "all other things" are not constant. The existing capacity, the flexibility of plant dispatch order, and – for new plants – the competition between fuels, all affect the evolution of the generation mix and constrain its response to carbon taxes, thereby influencing the cost of mitigation.

While bottom-up technology cost estimates based on the static fuels approximation provide insight into the cost of mitigation, they cannot answer key questions that emerge from the dynamics of electricity markets. What carbon tax threshold, for instance, is required to induce the initial adoption of CCS technologies? Which technologies enter first? And how does the price of natural gas influence the cost of mitigation and the adoption of CCS?

Before describing the construction of mitigation supply curves, we review three fundamental limitations of the single-technology static fuels approach to estimating CO_2 mitigation costs. First, a plant-level focus ignores fuel switching and assumes that a given generating technology will be replaced with the same technology incorporating carbon capture. Recent years, however, have witnessed the replacement (when it occurs) of aging coal plants with combined-cycle gas units.[10] Hence, it is not clear from the analysis of Figure 1 what base technology is relevant when fuel-switching from coal to gas competes with CCS as a CO_2 abatement strategy. In selecting a base technology, therefore, one picks a mitigation cost.

Second, one cannot ignore the importance of sunk capital. Most importantly, the dynamics governing the retirement of the existing US coal fleet will play a central role in mediating the entry of any new generation technology. The cost of electricity used in Figure 1 is for *new* plants, and includes a capital charge based on an assumed capital charge rate and lifetime for the plant. New CCS power plants, however, will compete with existing facilities that have been "paid off" but remain competitive due to their lower overall generating costs. A realistic assessment of CCS-related CO_2 mitigation must consider this sunk capital investment.

One of the key factors mediating the current competition between coal and natural gas has been the increasing utilization of the old coal fleet.[10] Once again, the issue of selecting an appropriate base technology cannot be ignored.

Finally, the static fuels approach assumes comparable and constant levels of plant utilization, ignoring the economics of plant dispatch. Even in a world of stable fuel prices this assumption is questionable. The flexibility of lower capital, higher marginal cost gas plants, for instance, is typically relied upon to cover peak demand, while lower operating cost coal units – with higher O&M expenses that are offset by cheaper fuel prices – supply base load. A more realistic accounting of plant dispatch – reducing the load factor of gas plants to, say, forty percent – places the NGCC costs on par with those of coal units in Figure 1 as lower utilization increases the capital contribution per unit of energy produced.

More specifically, plant dispatch considerations affect CCS-related CO_2 mitigation cost estimates in two ways. First, the use of lower emission natural gas plants to meet base load – a "carbon-ordered" dispatch strategy of the type discussed in the U.S. Department of Energy's "Five-Labs" study[11] – competes with the introduction of CCS as a mitigation option and so *raises* the carbon-tax threshold at which CCS enters. Second, if new CCS plants are added to the generating mix they will have relatively low operating costs (in the face of a carbon tax) and will displace existing units in the dispatch order. Thus a new CCS plant will be utilized more than a new non-CCS plant. This effect will *lower* the threshold for introducing CCS as compared to the static approach in which equal utilization of base and CCS plants is assumed.

In this paper we present model results that address the three key issues described above: fuel switching, sunk capital, and dispatch. In order to build a robust understanding of the role of CCS technologies, however, it will be necessary incorporate many of the following issues into future analyses:

- CCS retrofits of existing plants;
- learning and CCS cost reductions;
- uncertainties in CCS costs and performance specifications;
- the effects of volatility in natural gas prices;
- and the impact of distributed generation on CCS as a mitigation option.

MITIGATION SUPPLY CURVES

The economics of CO_2 emissions abatement may be summarized by a supply curve that relates the marginal cost of mitigation to the amount of emissions reduction demanded. Such data are useful for broader assessments of CO_2 mitigation in which supply curves for various sectors of the economy are compared in order to estimate the overall cost of abatement and to devise strategies that mitigate emissions at least cost. Supply curves for electric sector CO_2 abatement, however, are a product – among other things – of assumptions made about the future price of factor inputs, competition between technologies, and baseline scenario.

As an illustration, consider a supply curve for a new energy system with constant factor prices and demand, no existing capacity, and no consideration of plant dispatch. If Figure 1 depicted the full suite of available options and no carbon tax was levied, utilities would install the cheapest power generation technology available – or all NGCC plants. Taking the CO_2 output of the all NGCC system as a baseline, there would be no reduction in emissions below a carbon price of 225 \$/tC. Above this tipping point

NGCC plants with carbon capture would be installed and the baseline CO_2 emissions would decrease by the CCS capture efficiency. The solid line in Figure 2 depicts this scenario.

Now consider a world with only coal fired generating capacity and the same cost structure as above. This would be a world out of equilibrium: absent a carbon tax and transition costs, generating facilities would be retired in favor of new NGCC plants. Taking the carbon output of the existing coal system as a baseline, mitigation costs would remain negative (a "free lunch") until the difference in emissions between the PC and NGCC systems was reached. Above this abatement level, a carbon tax of 225 \$/tC would be required to induce investment in NGCC technology with carbon capture.

If different electric generating technologies met demand independently (rather than in a competitive market) then it would be possible to construct a bottom up supply curve by first calculating the mitigation cost for each class of generating technology using the static fuels approximation and then sorting the results and plotting them against their cumulative carbon emissions to yield a stepwise abatement supply curve similar to that of Figure 2. A supply curve constructed in this manner would offer tentative answers to the questions about CCS as an abatement strategy identified earlier. An initial response to the first question – the point at which CCS technologies become competitive – would be when the "free lunch" of a mitigation supply curve like that of Figure 2 has been consumed and abatement costs become positive. Once the transition from coal to gas units has taken place, further reductions in carbon emissions would require investment in CCS technologies. Yet this may not be the case if plant utilization is considered: increasing carbon tax rates will encourage a carbon-ordered dispatch strategy.[11] The static fuels approach to cost calculation misses this important subtlety of electric sector economics.

In response to the second question – which CCS technologies begin to diffuse first? – the static fuels approximation would point to technologies with the cheapest mitigation costs – those occupying the lowest steps on an emissions abatement curve. Once again, however, changes in plant dispatch and the implicit choice of a non-CCS "base" technology affect the operating expenses on which these mitigation calculations depend. What is needed, therefore, is a model that captures the interactions between carbon taxes, the economics of dispatch, and investment in new generating capacity. We present such a model next.

CCS MITIGATION COSTS IN A DYNAMIC ENERGY SYSTEMS MODEL

Electric sector planning involves a coupled decision process: investment in additional generating capacity is made taking into account how installed capacity – existing and new – will be used (or eventually retired). Over a planning horizon, owners of generating assets will seek to minimize the net present value of future capital outlays, operating expenses, and fuel costs.[12] This optimization framework expands easily to accommodate assessment of CCS-related CO_2 mitigation costs. CCS technologies, for instance, compete with standard NGCC and PC plants as investment options; likewise, taxes on carbon emission and the costs of CO_2 sequestration become additional terms in the calculation of marginal operating costs.

In this analysis, we take a regional perspective and examine the diffusion of CCS technologies into a representative US NERC region. Table 1 describes the model. The linear programming framework employed here assumes perfect foresight, simultaneously determining the new capacity to be added in each time interval as well as per-period utilization of installed capacity over the full planning horizon. Six generic classes of generating technologies are considered: pulverized coal (PC) and PC units with carbon capture (PC+CCS); single- (GT) and combined-cycle gas turbine (NGCC), plus NGCC plants with carbon capture (NGCC+CCS); gasified coal combined-cycle plants with carbon capture (IGCC+CCS); and nuclear units. As discussed above, the analysis presented here does not include renewable technologies or new nuclear capacity, nor does the model consider CCS retrofits of existing units. The assessment begins with five existing vintages of installed capacity, and is run over a forty-year investment horizon divided into eight five-year periods. Technology-specific heat rates and variable O&M costs are vintage-dependent.

U.S. Department of Energy forecasts[13] supply fuel prices and electricity demand for each time step. Per-period demand is stratified into six segments (peak through base loads), but seasonal variation in this load-duration profile is ignored. Technology-related costs and performance specifications come from academic[8] as well as industrial[9] sources, and reflect proven capture technologies (e.g., monoethanolamine scrubbing of post-combustion flue gasses). Note that both variable and capital costs are constant over time, with modest improvements in heat rates assumed for all plants. This analysis is conservative about mitigation costs because it ignores both demand-price interactions and learning effects.

Finally, the CCS plant operating costs incorporate a 25 \$/tC sequestration cost. Actual sequestration expenses are uncertain and will be site-specific. Current costs are negative due to the economic value of CO_2 in such industrial applications as enhanced oil recovery. The large quantities of CO_2 that would be recovered in electricity generation, however, exceed present market needs, necessitating disposal in, for instance, depleted oil and gas reservoirs or deep saline aquifers – leading to a positive sequestration cost. The 25 \$/tC figure we utilize in this analysis reflects these considerations and is included to provide a fair accounting of the true costs of CCS in power generation.

Figure 3 depicts the relationship between the price of emissions and reduction in carbon output for this simplified electric sector model. Three scenarios are illustrated: a “baseline” that includes the full suite of new capacity options described above; a “no CCS” case restricted to conventional generating units without carbon capture; and a “gas + 1 \$/GJ” scenario equivalent to the baseline, but with period 1 gas prices set roughly thirty-percent higher (gas prices increase five-percent per period under all scenarios). Each scenario's supply curve is the result of a series of model runs – with a given execution corresponding to a constant carbon price (e.g., an emissions tax), and prices varying in 10 \$/tC increments from 0 to 200 \$/tC. The discrete points on each supply curve reflect the difference in aggregate carbon emissions under a given carbon price and a 0 \$/GJ base run, expressed as a fraction of that scenario’s base run emissions.

In the dynamic model CCS technologies enter the generating mix at a carbon price of 60 \$/tC. For lower carbon prices, the economics favor changes in the dispatch order of installed capacity and the addition of conventional generating units regardless of the availability of CCS technologies as an investment option. When CCS is not available, emissions reductions are constrained to roughly forty-percent of the 0 \$/GJ aggregate carbon output, while the CCS option allows reductions up to two-thirds of base emissions at a marginal mitigation cost of roughly 110 \$/tC.

It is instructive to compare the 60 \$/tC threshold at which coal fired CCS plants enter the mix in the dynamic model with the static results derived from Figure 1. In year zero of the base case the mean utilization of the coal fleet is 81%. If we use this figure to compute the cost of electricity for PC and PC+CCS plants using a static fuels approach, we find that a carbon price of 84 $/tC is needed to make the CCS plant preferable to the PC plant. Yet in the dynamic model CCS enters in preference to PC at a carbon price of only 60 $/tC because at that carbon price the utilization of the coal fleet has declined from 81 to 28%.

The decline in dispatch of the coal capacity with increasing carbon price that occurs before introduction of CCS technologies shows the model adopting a carbon-ordered dispatch strategy – a trend consistent with conclusions of the "Five-Labs" study.[11] Figure 4 provides snapshots of utilization versus the price of carbon for two of the supply curve scenarios and illustrates this trend: generating units with the lowest carbon output provide base load capacity as emissions become more costly.

When CCS technologies are not available, NGCC plants displace coal units and less-efficient single-cycle gas turbines as the price of carbon emissions increases. The economic response in this situation involves a mix of investment in conventional technology to replace less efficient vintages, increased dispatch of less carbon-intensive generating units, and toleration of slightly higher marginal operating costs. This strategy does not yield large reductions in carbon emissions, but it does provide an initial response that also competes with CCS as an approach to carbon mitigation. When CCS units are available, for instance, investment in gasified coal combined-cycle plants and NGCC units with carbon capture begins only when the price of carbon emissions reaches 60 $/tC; CCS plants supply the entire non-nuclear base load once the price exceeds 100 $/tC.

The balance between reordering plant dispatch and investment in new technology as competing responses to rising carbon prices is strongly dependant on the price of natural gas. To illustrate this dependence we ran a scenario in which gas prices were increased by 1 $/GJ (Figure 3). In this high gas price scenario the emissions are larger in the absence of a carbon tax than they are in the base case because the generating mix is tilted to favor coal. Figure 5 captures this effect: the high-gas scenario (upper dotted curve) has consistently greater carbon emissions than the baseline (solid curve). CO_2 emission reductions under the high-gas scenario are initially *more* expensive as the fuel-switching and dispatch re-ordering options are less attractive. But CCS technologies enter the generating mix earlier in the high-gas scenario – in this case at 50 $/tC – and the marginal cost of emissions reduction in the high-gas case becomes *lower* than in the reference case as the former has greater carbon emissions in the absence of a carbon price (Figure 5).

Finally, note that the model begins *out* of economic equilibrium, in a situation analogous to that demonstrated by the "free lunch" scenario of Figure 2. Owners of generating capacity have an economic incentive to replace early-vintage, less-efficient coal plants with new NGCC units – even in the absence of a price on carbon emissions. Such fuel switching leads to an early reduction in CO_2 output (emissions then increase with electricity demand). The baseline scenario of Figure 5, which represents carbon emissions as a function of time when atmospheric releases are unregulated, illustrates this side benefit. In our model the generating mix starts with higher carbon emissions – due to the large existing fleet of coal-fired plants – than it would have if it were in equilibrium under constant factor prices. This non-equilibrium initial condition makes the cost of carbon mitigation lower than it would be in a world where old coal-fired plants had already been replaced by NGCC units.

CONCLUSION

In assessing the role of carbon capture and sequestration technologies in emissions abatement for the electric sector, we have taken a perspective intermediate to macro-economic assessments and plant-level analyses of mitigation costs. While the energy system model we present does not include the demand-price interactions or economy-wide fuel substitution dynamics of the former approach, it does capture some of the key process that will likely govern the adoption of CCS technologies in the electric sector. Relatively modest carbon taxes, for instance, are seen to promote both the diffusion of CCS technologies into the electric sector and the movement to carbon-ordered dispatch of existing generating units. Our model confirms the assumption that the existence of CCS technologies can substantially lower the cost of making deep reductions in electric sector CO_2 emissions.

This analysis demonstrates the central importance of natural gas prices in determining the cost of mitigation in the electric sector. At the gas prices prevailing a year or two ago, coal-fired generating plants were slowly being replaced by natural gas combined-cycle units.[10] This trend reduces the CO_2 emissions intensity of the generating mix at no cost. The trend to gas, however, makes the generating system increasingly vulnerable to fluctuations in gas prices, and recent history has supported predictions about the volatility of gas prices relative to coal. If real climate policy accelerates this trend, and increases demand for gas in the electric sector and elsewhere across the economy, then gas prices may increase further. This presents real risk under a gas-based strategy for CO_2 emissions reduction. If coal-based CCS technologies are technically and politically viable, then they may provide a critical element in the generating mix: high capital cost generating capacity that is insensitive to the price of gas or the price of carbon emissions.

ACKNOWLEDGEMENTS

We wish to thank Hadi Dowlatabadi, Alex Farrell, and Peter Reinelt of Carnegie Mellon University, as well as Howard Herzog of MIT, for their insights. This research was made possible through support from the Center for Integrated Study of the Human Dimensions of Global Change. This Center has been created through a cooperative agreement between the National Science Foundation (SBR-9521914) and Carnegie Mellon University, and has been generously supported by additional grants from the Electric Power Research Institute, the ExxonMobil Corporation, and the American Petroleum Institute.

REFERENCES

1. Hirsh, R. *Power Loss: The Origins of Deregulation and Restructuring in the American Electric Utility Industry*; MIT Press: Cambridge, MA, 1999.

2. U.S. Energy Information Administration, Office of Energy Markets and End Use, U.S. Department of Energy. *Annual Energy Review 1998*; DOE/EIA-0384(98); U.S. Government Printing Office: Washington, DC, 1999.

3. Parson, E.A.; Keith, D.W. Fossil Fuels Without CO_2 Emissions; *Science* **1998**, 282, 1053-1054.

4. Eliasson, B.; Riemer, P.; Wokaun, A., Eds. *Greenhouse Gas Control Technologies: Proceedings of the 4th International Conference on Greenhouse Gas Control Technologies*; Pergamon: Amsterdam, 1999.

5. Biggs, S.; Herzog, H.; Jacoby, H.; Reilly J.(2000). Economic Modeling of CO_2 Capture and Sequestration; Presented at the *Fifth International Conference on Greenhouse Gas Control Technologies*, IEA Greenhouse Gas R&D Programme, Cairns, Australia, 13-19 August 2000.

6. Edmonds, J.; Dooley, J.; Kim, S. Long-Term Energy Technology: Needs and Opportunities for Stabilizing Atmospheric CO_2 Concentrations; In *Climate Change Policy: Practical Strategies to Promote Economic Growth and Environmental Quality*; Walker, C.; Bloomfield, M.; Thorning, M., Eds.; American Council for Capital Formation Center for Policy Research: Washington, DC, 1999; pp 81-107.

7. Herzog, H.; Drake, E.; Adams, E. CO_2 Capture, Reuse, and Storage Technologies for Mitigating Global Change: A White Paper, Final Report; DOE Order Number DE-AF22-96PC01257; Energy Laboratory, Massachusetts Institute of Technology: Cambridge, MA, 1997.

8. Herzog, H.; Vukmirovic, N. (1999). CO_2 Sequestration: Opportunities and Challenges; Presented at the *Seventh Clean Coal Technology Conference*, Knoxville, TN, June, 1999.

9. Simbeck, D. (1999). A Portfolio Selection Approach for Power Plant CO_2 Capture, Separation and R&D Options; In *Greenhouse Gas Control Technologies: Proceedings of the 4th International Conference on Greenhouse Gas Control Technologies*; Eliasson, B.; Riemer, P.; Wokaun, A., Eds.; Pergamon: Amsterdam, 1999; pp 119-124.

10. Ellerman, A. D. The Competition Between Coal and Natural Gas: The Importance of Sunk Costs; *Resources Policy* **1996**, 22, 33-42.

11. Interlaboratory Working Group on Energy-Efficient and Low-Carbon Technologies. *Scenarios of US Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond*; ORNL/CON-444, LBNL-40533; Lawrence Berkeley National Laboratory: Berkeley, CA, 1997.

12. Turvey, R.; Anderson, D. *Electricity Economics: Essays and Case Studies*; The Johns Hopkins University Press: Baltimore, 1997.

13. U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy. *Annual Energy Outlook 2000 With Projections to 2020*; DOE/EIA-0383(2000); U.S. Government Printing Office: Washington, DC, 1999.

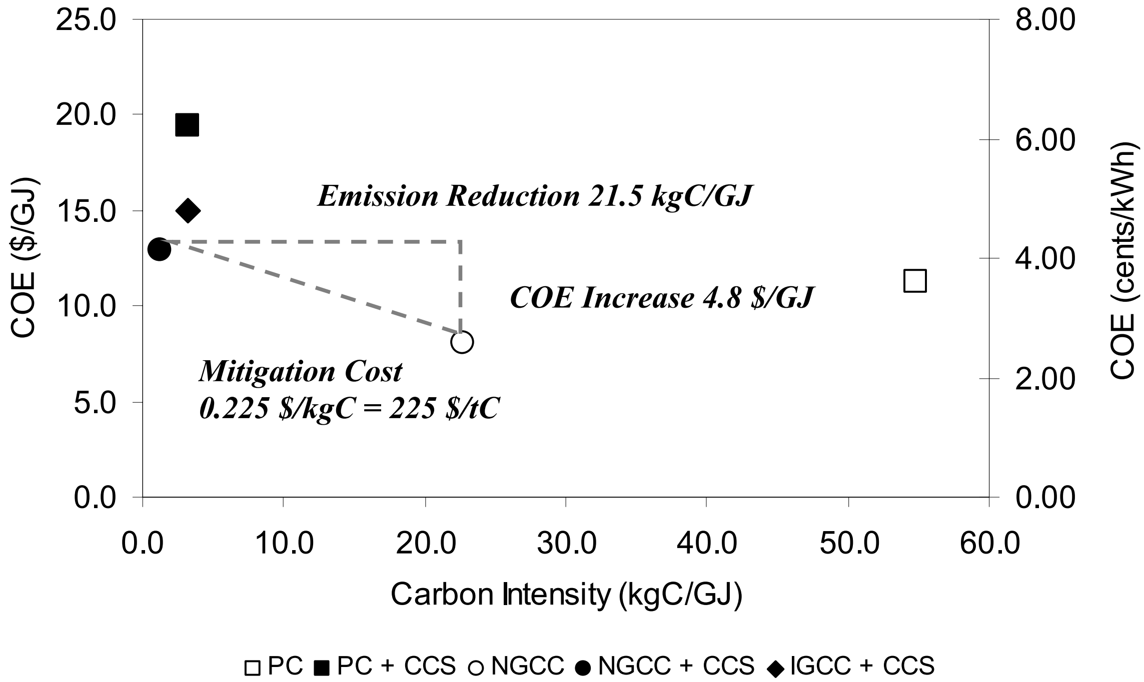

Figure 1. Cost of electricity (COE) versus CO_2 emissions. Technology specifications, capital and operating costs are from Herzog and Vukmirovic[8]; fuel prices are EIA[13] estimates. A twenty year lifetime, an annual capital change rate of 12%, and a load factor of 75% are used. Generating units include pulverized coal (PC), natural gas combined-cycle (NGCC), and gasified coal combined-cycle (IGCC) plants. CCS costs include carbon capture and pressurization for pipeline transportation, as well as a 25 $/tC sequestration expense.

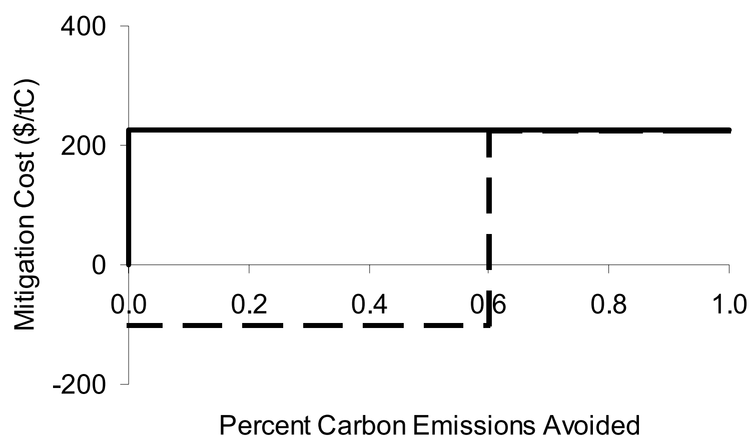

Figure 2. Carbon emissions mitigation supply curve for two scenarios as discussed in the text: de novo construction of an energy system (solid line) and a non-equilibrium "free lunch" scenario (broken line). Data are from Figure 1.

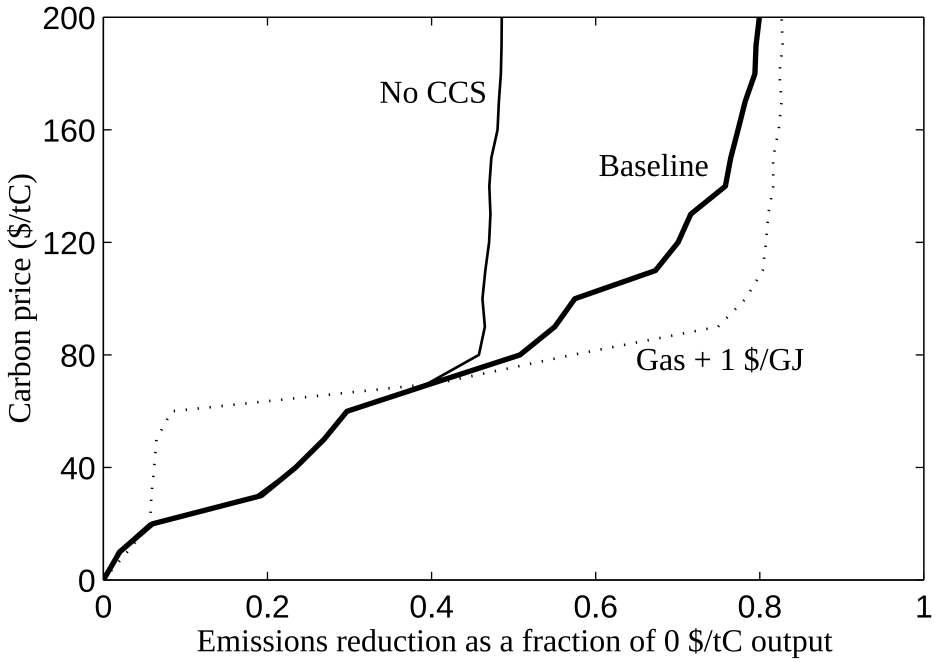

Figure 3. Carbon mitigation supply curves for the ECAR NERC region under three scenarios. Each point on the graph reflects the difference in aggregate carbon emissions under a given carbon price from the zero-price case, expressed as a fraction of the zero-price emissions. See the text and Table 1 for model details.

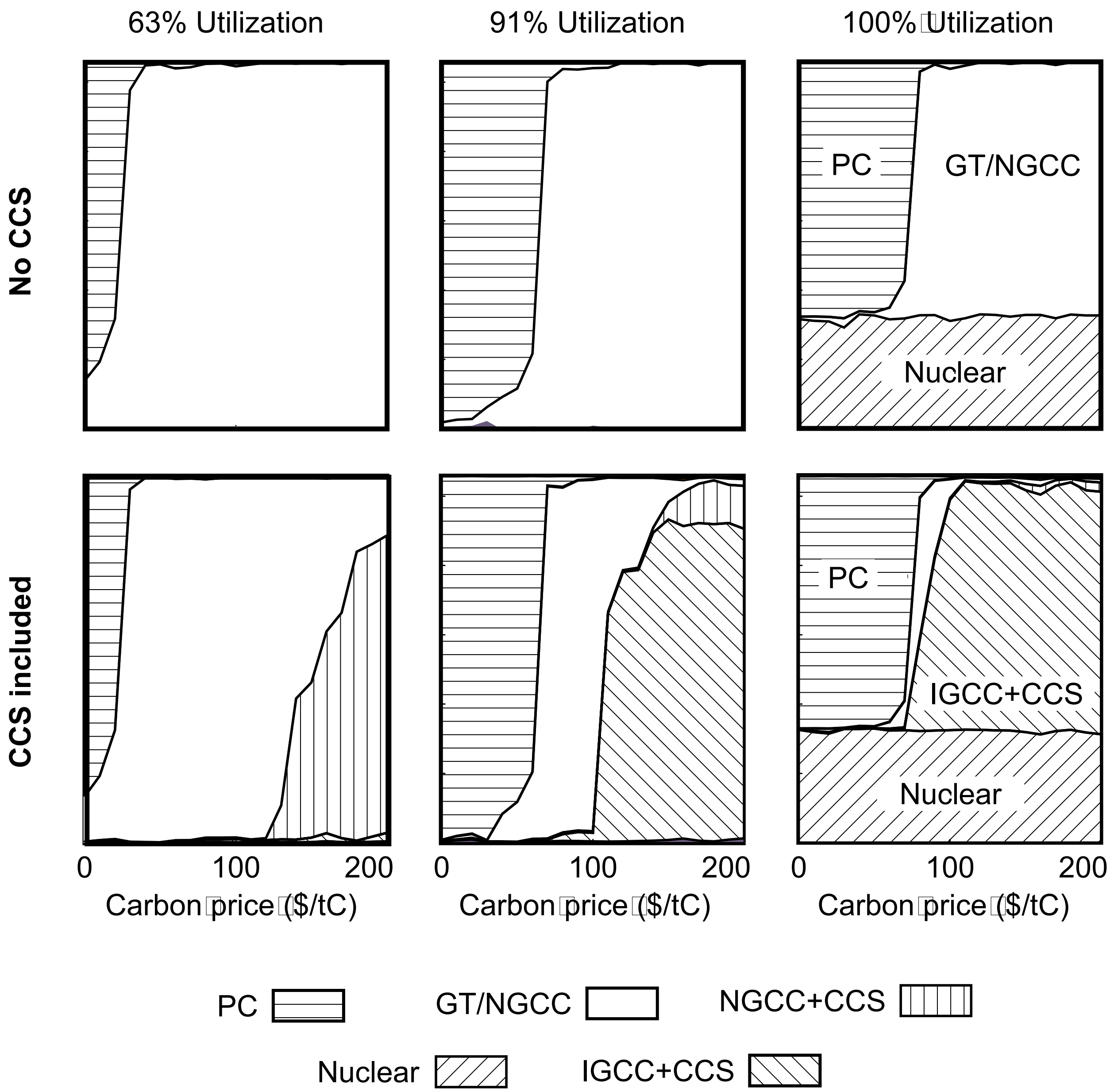

Figure 4. Plant dispatch versus carbon price in period 8 (2035-2040) when CCS technologies are included (bottom row) and when capacity is restricted to non-CCS units (top row). The load-duration curve is stratified into six segments, each of which requires a fixed amount of power (~25 GW), but which vary in their fractional utilizations from 750 to 8760 hours per year. The right-hand column shows the one-sixth of the generating mix that is dispatched 100% of the time; the middle and left columns illustrate the next highest levels of the discretized load-duration curve. Natural gas plants supply nearly all capacity to meet demand for the remaining (uppermost) three segments of the load-duration curve for both scenarios and are not shown.

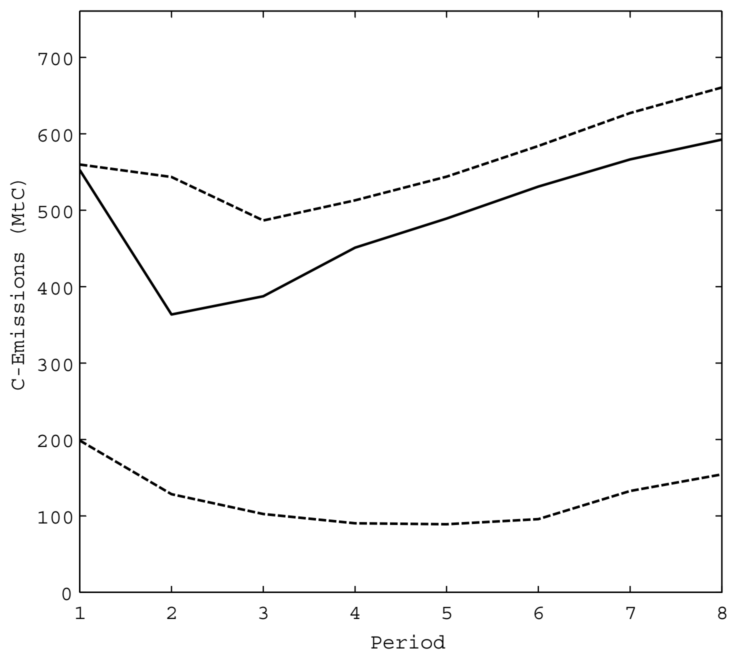

Figure 5. Carbon emissions versus period for three scenarios: a baseline without a price on carbon emissions and period 1 natural gas at 3.15 \$/GJ (solid line); the same scenario with gas prices starting at 4.15 \$/GJ (top dashed line); and the higher gas price combined with a 100 \$/tC tax on carbon emissions (lower dashed line). Gas prices increase 5% per five-year period in each scenario. Note that carbon emissions decline even in the absence of a carbon tax as fuel switching from coal to gas occurs for strictly economic reasons in early periods of the base scenario – reflecting the effects of an initial disequilibrium. Emissions rise in subsequent periods with increasing power demand.

Table 1

Inputs and Parameters	
Technologies	Pulverized Coal (PC), Single and Combined Cycle Gas Turbine (GT and NGCC), PC + CCS, NGCC + CCS, Gasified-Coal Combined Cycle with CCS (IGCC + CCS), Nuclear
Existing Vintages	pre-1960, 1960s,1970s, 1980s, 1990s
Performance and Cost Specifications	Variable O&M and heat rates are vintage-dependent; capital costs for new plants are constant (specifications and costs are based on published surveys[8,9])
Discount Rate	0.10; no inflation is assumed
Domain	
Spatial Aggregation	US NERC level (data are for the ECAR region)
Demand Representation	Load-duration curve discretized into six 16.25 GW load segments with durations of 500, 1000, 3000, 5500, 8000, and 8760 hours/year; seasonal variation is ignored (data are from EIA forecasts[13])
Demand and Price Effects	Demand, fuel prices, and rates of increase are exogenous (based on EIA forecasts[13])
Investment Horizon	40 years (2000 to 2040)
Time Step	5 year periods
Implementation	
Environment	MATLAB
Framework	Linear optimization (assumes perfect foresight)
Objective	Minimize aggregate capital expenditure and operating costs over investment horizon
Outputs	Per-period capital investment, plant utilization, costs, and carbon emissions
Decision Variables	Per-period new capacity and utilization (1920 total)
Constraints	Utilization > Demand, Utilization < Installed Capacity, New Capacity Added < Rate of New Capacity Installation, Non-negativity (1904 total)