Electricity Without Carbon Dioxide: Assessing the Role of Carbon Capture and Sequestration in US Electric Markets

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Please feel free to contact me with questions or requests for additional information. I am also more than willing to share the *MATLAB* subroutines for the model described and illustrated in Chapters 3 to 5.

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Carnegie Mellon University

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A Dissertation Submitted to the Graduate School in Partial Fulfillment of the Requirements for the Degree of

Doctor of Philosophy

in

Engineering and Public Policy

by

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Abstract

Stabilization of atmospheric greenhouse gas concentrations will likely require significant cuts in electric sector carbon dioxide (CO_2) emissions. The ability to capture and sequester CO_2 in a manner compatible with today's fossil-fuel based power generating infrastructure offers a potentially low-cost contribution to a larger climate change mitigation strategy. This thesis fills a niche between economy-wide studies of CO_2 abatement and plant-level control technology assessments by examining the contribution that carbon capture and sequestration (CCS) might make toward reducing US electric sector CO_2 emissions. The assessment's thirty year perspective ensures that costs sunk in current infrastructure remain relevant and allows time for technological diffusion, but remains free of assumptions about the emergence of unidentified radical innovations.

The extent to which CCS might lower CO_2 mitigation costs will vary directly with the dispatch of carbon capture plants in actual power-generating systems, and will depend on both the retirement of vintage capacity and competition from abatement alternatives such as coal-to-gas fuel switching and renewable energy sources. This thesis therefore adopts a capacity planning and dispatch model to examine how the current distribution of generating units, natural gas prices, and other industry trends affect the cost of CO_2 control via CCS in an actual US electric market. The analysis finds that plants with CO_2 capture consistently provide significant reductions in base-load emissions at carbon prices near 100 $/tC, but do not offer an economical means of meeting peak demand unless CO_2 reductions in excess of 80 percent are required. Various scenarios estimate the amount by which turn-over of the existing generating infrastructure and the severity of criteria pollutant constraints reduce mitigation costs.

A look at CO_2 sequestration in the seabed beneath the US Outer Continental Shelf (OCS) complements this model-driven assessment by considering issues of risk, geological storage capacity, and regulation. Extensive experience with offshore oil and gas operations suggests that the technical uncertainties associated with OCS sequestration are not large. The legality of seabed CO_2 disposal under US law and international environmental agreements, however, is ambiguous, and the OCS may be the first region where these regulatory regimes clash over CO_2 sequestration.

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I owe so much to so many, but will stick here to thanking those who have helped make this thesis possible.

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I would also like to thank my committee members: Howard Herzog, Granger Morgan, and Ed Rubin. Their input and feedback have ensured that this thesis addresses what it should, without claiming to say anything more. Alex Farrell at Carnegie Mellon and Hadi Dowlatabadi, now at the University of British Columbia, deserve thanks for the practicality of their suggestions and – perhaps even more – for the reliability of their encouragement. And because I have always wanted to write this line: while much of the help and advice I have received made its way into this thesis, any remaining imperfections are my unique contribution.

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Finally, as I stare at her picture – my companion over the last few months of writing – I dedicate this dissertation to my buddy (and daughter), Kyra Illies Johnson. You are a source of joy that will forever keep the rest of this in perspective.

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1.1 Introduction: A Missing Perspective

Substantial reductions in carbon dioxide (CO_2) emissions will likely be needed over the next half century to stabilize atmospheric concentrations at a level sufficient to minimize the risk of an adverse climate response – the agreed goal of the 1992 *United Nations Framework Convention on Climate Change*.[1] Limiting CO_2 concentrations to a doubling of pre-industrial levels, for instance, would require a cut in annual global emissions of at least 50 percent from their business-as-usual trajectory by 2050 (Wigley, Richels, and Edmonds, 1996). Reconciling a reduction of this magnitude with an energy infrastructure currently dependent on fossil fuels would present a fundamental challenge to industrial society.

It is uncertain how the necessary emission reductions would be distributed across the economy, but – should they be required – the electric sector is likely to be an important target for any US CO_2 mitigation effort. The combustion of coal, petroleum, and natural gas, for instance, presently supplies nearly 70 percent of the nation's electricity and generates over 2 billion tons of CO_2 per year – more than one-third of net US emissions (EIA, 2000). While CO_2 emissions per unit of electricity produced in the US have decreased by roughly one-fifth over the last two decades, electricity consumption has grown by more than 65 percent (EIA, 2000). Continuing gradual increases in end-user and generating efficiencies are therefore not likely to yield substantial reductions in net CO_2 emissions, and more comprehensive technological change would be required to meet a significant carbon constraint. Increased use of nuclear generation, as well as wind, biomass, and other renewable energy sources, for instance, would provide valuable near-term options. The limitations inherent in these

[1] The Objective (Article 2) of the 1992 *United Nations Framework Convention on Climate Change* reads: "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner." Note that the Convention is an agreed goal – not a formal obligation. In addition, the Convention does not specify a preference regarding sources or sinks of CO_2 and other greenhouse gasses (Bodansky, 1996).

technologies, however, combine with a long infrastructure lifetime to preclude rapid abandonment of fossil energy.

Atmospheric releases of CO_2, however, are not an inevitable consequence of fossil-electric power generation. Currently in use on industrial scales, the processes required to separate CO_2 from fossil fuels either before or after combustion exist as mature technologies. Furthermore, an improved understanding of relevant geological issues and a continuing assessment of analogous practices are increasing confidence in the ability to isolate CO_2 from the atmosphere on a centuries-long timescale. The integration of carbon capture and sequestration (CCS) with electricity generation may therefore provide *an additional* route to achieving significant reductions in CO_2 emissions over the next few decades.[2] Estimates of the extent to which CCS might lower electric sector mitigation costs, however, are uncertain.

The cost of electric sector CO_2 control via CCS will vary directly with the utilization of carbon capture plants in actual power-generation systems, where the dispatch of individual plants depends on the marginal operating costs of all available units. The current distribution of generating units, as well as trends in natural gas prices, electricity demand, and the regulation of criteria pollutants must therefore be considered. Moreover, the contribution that CCS might make toward reducing CO_2 emissions will depend on the competition between CCS and abatement alternatives such as coal-to-gas fuel switching, a carbon-ordered dispatch regime, and non-fossil renewables. Incorporating this level of specificity requires an electric market focus.

Previous studies of carbon sequestration, however, have either included a less detailed representation of CCS technologies in economy-wide studies of CO_2 abatement (e.g., Biggs, et al., 2001; Edmonds, et al., 1999), or have addressed mitigation costs on an individual plant basis (e.g., David, 2000; Herzog and Vukmirovic, 1999; Simbeck, 2001a). Macroeconomic models, for instance, seek to balance production and consumption across all sectors of the economy and are typically constrained by computational requirements from including plant dispatch and a detailed characterization

[2] As discussed below, the term “carbon sequestration” includes enhancing CO_2 removal from the atmosphere – by, for instance, increasing the amount of CO_2 fixed by terrestrial vegetation and soil or speeding ocean uptake – in addition to “industrial carbon management” which aims to reduce anthropogenic CO_2 emissions. This thesis is exclusively concerned with the latter.

of existing generating capacity in their assessment of CO_2 mitigation costs (Hourcade, et al., 1996). Plant-level assessments, in contrast, 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 studies clearly note, a plant-level approach is necessarily limited to parametric consideration of sunk capital and unit dispatch (see, e.g., David, 2000). An assessment of how specific CCS generating technologies would be used in an actual electric power system is therefore required.

Incorporating these analytical needs, this thesis takes a perspective intermediate to existing assessments and looks at CCS in the context of a centrally dispatched regional electric market. The analysis examines how the potential integration of CCS technologies depends on both internal factors like the natural turn-over of generating capacity and external cost drivers such as fuel prices and regulation of criteria pollutants, and assesses the impact of CCS on the cost of CO_2 control. As important as context, however, is the timeframe under consideration. Falling between that of the Kyoto Protocol (now less than a decade) and century-long studies of global climate change, the assessment's twenty-five to thirty year perspective ensures that costs sunk in current infrastructure remain relevant and allows time for technological diffusion, but remains free of assumptions about the emergence of unidentified radical innovations.

Four sets of questions motivate this analysis:

(1) Given CCS cost and performance specifications, by how much does the availability of CCS reduce the cost of electric-sector CO_2 control in a particular electric market? At what mitigation cost (in, e.g., \$/tC) does CCS become competitive with other abatement options?

Consideration of plant dispatch becomes particularly important in answering this first pair of questions. Increased use of both existing and new gas plants, for instance, will likely be the least-cost alternative for moderate reductions in CO_2 output. When the cost of carbon emissions is high enough that CCS becomes competitive, however, capital-intensive carbon capture plants would enter the generating mix with the lowest marginal operating costs and displace existing fossil-energy units. The use of conventional coal plants in particular would then decline as their operating costs increase with both the price of CO_2 emissions and the corresponding reduction in load factors.

These shifts in the dispatch order affect mitigation cost estimates, though the magnitude of this effect depends on how all available generating units interact to meet a specific demand profile when both demand and factor prices vary with time. Chapter 2 discusses how the construction of supply curves for electric sector CO_2 mitigation must therefore take into account more than the operating characteristics of isolated technologies. The need for a capacity planning and dispatch model grounded in data from an actual electric market is identified. Chapter 3 takes up this need and combines a suite of power generating technologies, plant vintages, and fuel types with demand and fuel price projections in a model for a specific US electric market. Chapters 4 and 5 then use this energy-systems model to examine how dispatch dynamics drive mitigation costs and affect the role CCS plays in electric sector CO_2 control under a variety of scenarios.

(2) How does the composition of existing generating capacity affect CO_2 mitigation costs? How do assumptions about natural gas prices influence these estimates?

The existing electric power system is not "optimized" for the current economic, technological, and regulatory environment. In particular, vintage coal-fired plants, with little of their original capital investment left to be recovered, often remain competitive with newer and more efficient plants (Ellerman, 1996). The long lifetimes of these plants preserve an infrastructure that does not match what would be built given more recent technology and factor (especially fuel) prices. The gradual turnover of this infrastructure, coupled with a trend toward the increased use of natural gas and the availability of more efficient coal technologies will yield a "free lunch" emissions reduction absent a constraint on CO_2, and therefore lower mitigation costs. The economic attractiveness of coal-to-gas fuel switching, however, and, with it, the free lunch effect are vulnerable to gas price volatility. A modeling framework in which sunk costs matter is needed to capture these dynamics. The first section of Chapter 5 therefore makes further use of the Chapter 3 energy-systems model to examine how the free lunch emissions reduction and gas prices affect mitigation costs.

(3) How might stricter limits on criteria pollutants (e.g., sulfur dioxide, nitrogen oxides) affect CCS economics?

The increase in capital and operating costs due to CCS would likely be less for baseline plants that have stronger controls for criteria pollutants than for those that do not. Inclusion of such controls would lower the marginal cost of CO_2 reduction, and under plausible scenarios of US environmental regulation this multi-pollutant interaction could significantly accelerate the adoption of CCS technologies and lower CO_2 mitigation costs. The timing of these controls, however, is important. Stricter regulation of criteria pollutants without CO_2, for instance, could lock electric power generators into an unfavorable technological path in the face of a later carbon constraint. Higher CO_2 mitigation costs would result. The last section of Chapter 5 begins to explore these interactions in a modified version of the Chapter 3 model.

(4) How do the near-term prospects of CO_2 sequestration compare to those of carbon capture?

Recognizing that the technical, economic, and regulatory uncertainties associated with CO_2 sequestration are likely to be significant, the thesis departs from this modeling framework and its assessment of mitigation costs to examine the technical feasibility and regulation of sequestration in a region that has received comparatively little attention: the seabed beneath the US Outer Continental Shelf (OCS). The separation between OCS geological reservoirs and areas of human habitation is the source of the site's benefits as well as its drawbacks. While distance and the cover of ocean waters reduces health, safety, and even environmental risks, it also reduces access – increasing both sequestration costs and the difficulties of monitoring injection sites. Extensive experience with offshore oil and gas operations, however, suggests that the technical uncertainties associated with OCS sequestration are not large. The question, therefore, is not necessarily whether OCS sequestration is technically feasible; rather, the major uncertainties are political and perceptual. The legality of seabed CO_2 disposal under both US domestic regulations and international environmental agreements, for instance, is ambiguous, and the OCS may be the first region where these regulatory regimes clash over CO_2 sequestration. Chapter 6 explores these issues.

The remainder of this chapter picks up on the issues introduced in this section and places CCS in an electric sector context. The following section (1.2) examines electric sector CO_2 mitigation more generally, while Section 1.3 describes CCS as a concept. Section 1.4 discusses the particular advantages of CCS, and Section 1.5 provides an overview of the associated research. The chapter concludes (Section 1.6) with a more detailed overview of the thesis.

1.2 Electric Sector CO_2 Mitigation

Electricity at its point of use is carbon free. The popularity of electric power – long established in industrialized nations, and increasing throughout the developing world – has been a major factor contributing to the decarbonization of energy at its point of consumption (Nakicenovic, 1996). As a secondary source of energy, electricity is clean, relatively safe, available on demand, and easily managed (Smil, 1991; EIA, 2000). Compared to a 25 percent increase in total US energy use since 1980, electricity consumption has increased by nearly two-thirds (EIA, 2000). Electricity generation, however, continues to rely on the combustion of fossil fuels and, like other secondary energy sources, reductions in its carbon intensity (i.e., carbon emissions per unit of electricity generated) have been less than the increase in production (Victor, 1998). The result – with its environmental and economic uncertainties – has been a 30 percent increase in electric sector CO_2 emissions over the last two decades (EIA, 2000).

Should significant cuts in CO_2 emissions be demanded, the technological structure and institutional arrangement of the electric sector combine to ensure that the industry would be a primary focus of CO_2 mitigation efforts (Keith, 2001). US electricity generation, for instance, depends on a large fleet of coal plants – centralized point sources that burn the most carbon-intensive fossil fuel and account for a third of the nation's energy-related CO_2 emissions (EIA, 2000).[3] Compared to the distributed sources of emissions in, say, the transportation sector, these plants make easy targets for CO_2 abatement initiatives that would have minimal impact on consumers (beyond cost increases). At its point of use, electricity would "look" the same. Hence, the need to change both the means of supply and use – a coupled "chicken and egg" problem – would be avoided. CO_2 abatement might therefore be both less expensive and more rapid in the electric power industry than other sectors of the economy.

Similarly, the centralized ownership and management of the electric utility industry facilitates regulation. The industry has also gained considerable experience over the last three decades with increasingly tighter controls on conventional pollutants – analogues to CO_2. And unlike emission-intensive manufacturing industries that would also be penalized by a CO_2 constraint, "power generators cannot move to China" (Simbeck, 2001b, p. 2). Owners of fossil-electric generating plants are therefore likely to be called upon to make substantial, near-term cuts in their CO_2 emissions should serious action be taken to mitigate the risk of climate change.

Such reductions may be achieved via a number of routes, though all have their limitations and no single approach would likely be sufficient. Electric sector CO_2 emissions, for instance, are a function of the amount of energy produced, the carbon content of the primary energy used in its generation, and the efficiency of the conversion process (Hoffert, et al., 1998). Each part of this relationship provides a focus for CO_2 mitigation efforts.

A slower rate of economic growth or population expansion, for instance, would reduce electricity consumption and therefore lower CO_2 emissions. More favorably, increased end-use efficiency would also reduce electricity needs. It is doubtful, however, whether such improvements can compensate for growing electricity consumption. In addition, initial efforts to cut new capacity requirements through demand side management programs have now largely been replaced by an effort to let market forces motivate production efficiencies (Hirsch, 1999).

As Hirsch (1999), however, further notes, the steady improvements in central station coal plant generating efficiency that marked the first half century of the electric industry's history leveled off by the late 1960s. Used primarily for meeting baseload demand, coal plants dominate electricity generation, and therefore electric sector CO_2

[3] In 1999, US anthropogenic CO_2 emissions amounted to 1.51 GtC. The electric sector contributed 0.56 MtC to this sum, with coal plants generating 56% of the nation's electricity but producing 81% of the

emissions. Hence, even small improvements in the process of converting carbon-intensive coal to electricity will lower aggregate emissions. A combination of reliability issues, thermodynamic limits, and economics, however, has kept the average thermal efficiency of US coal plants below 35 percent (see Figure 3.1 in Hirsh [1999, p. 57] and the sources cited there).

Fuel-switching from coal-fired to more efficient and less carbon-intensive natural gas plants therefore offers an opportunity to achieve substantial CO_2 abatement. When motivated strictly by economic considerations, fuel-switching may even yield what amounts to a "free lunch" reduction in CO_2 emissions. Promising improvements in the efficiency of natural gas combined-cycle units, as well as the potential of combined heat and power generation ("co-generation") using gas turbines at distributed sites, could add to this important side-benefit.

Recent volatility in natural gas prices, however, may provide a near-term disincentive to large-scale fuel switching. In addition, the marginal cost advantages of "old," amortized coal plants are leading owners to keep these units in service long past their anticipated lifetimes, with investment in new, more efficient, generating technologies undertaken primarily to meet growing demand (Ellerman, 1996). And while natural gas in its usable form is less carbon-intensive than coal, its production and cleaning typically result in CO_2 releases of their own. When one also takes into account the supply and distribution constraints (and, hence, price increases) that would result from a significant increase in demand for natural gas, it becomes apparent that fuel switching alone is unlikely to provide a cost effective means of achieving the levels of CO_2 abatement required to reduce the risk of serious climate change.

While natural gas is less carbon intensive than coal, the ideal would a carbon-free source of primary energy for electric power. Nuclear generation and renewables like hydro, wind, and solar power occupy this niche to varying degrees in the electric sector, and could therefore be called upon in an effort to reduce CO_2 emissions.   A significant investment in modern nuclear technology, for instance, could achieve substantial levels of CO_2 mitigation. Although there are no (publicly available) plans for new plant construction, owners of nuclear generating units have been seeking license renewals

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utility industry's emissions (EIA, 2000).

(Moore, 2000). Extending the useful life of existing nuclear facilities will slow the rate at which electric sector CO_2 emissions increase over the coming decades. Waste disposal problems, the political consequences of negative public perception, and – more recently – concern with nuclear proliferation and even terrorism, however, are likely to diminish the role atomic power might play in reducing US CO_2 emissions.

This leaves the expanded use of renewables among the mitigation options traditionally considered. From the renewable technology suite, however, only wind generation has the potential to meet a substantial fraction of current electricity demand. The costs of solar-electric generation, for instance, remain uncompetitively high, and environmental concerns have prompted the removal of dams rather than their construction. The economics and technical performance of wind turbines, on the other hand, have increased steadily in recent years (McGowan and Connors, 2000). But while cost of wind power is now on par with nuclear, problems with intermittency and the resulting need for an extensive storage and transmission network pose near-term obstacles to its widespread adoption and raise effective prices. Once again, none of the traditional means of reducing electric sector CO_2 emissions is likely to suffice by itself.

1.3 CO_2 Mitigation Via Carbon Capture and Sequestration

Despite increases in end-use efficiency and the adoption of carbon-free or low-carbon sources of primary energy, it is therefore unlikely that the world will make deep reductions in CO_2 emissions without fundamental changes in its energy infrastructure. The long lifetime of the existing fossil-energy infrastructure and the costs of its premature replacement combine with the advantages of coal, petroleum, and natural gas – their relatively low costs, current availability and reserve capacities, plus convenient transportation and storage – to leave other forms of primary energy at a competitive disadvantage (DOE, 1999; McVeigh, et al., 1999). Decoupling atmospheric carbon emissions from the productive use of fossil energy has therefore emerged as a promising means of moderating climate change, with CCS providing an economically-competitive CO_2 control option (Parson and Keith, 1998). Before discussing the strengths and weaknesses of carbon capture, however, it is necessary to distinguish electric-sector CCS from other concepts beneath the “carbon sequestration” umbrella.

Marchetti (1977) first proposed ocean sequestration as an alternative to atmospheric release of power plant CO_2 emissions. Interest in CCS began to increase by the early 1990s as entities such as the International Energy Agency (IEA) and government organizations including the US Department of Energy (DOE) and Japan's Research Institute of Innovative Technology for the Earth (RITE) began to focus their attention on the potential for CO_2-induced climate change (Herzog, Drake and Adams, 1997). Through research funding and administrative coordination, these and other institutions have supported conferences and produced studies examining the economic, scientific and engineering details of various CCS proposals. The role that CCS could play in reducing CO_2 emissions has also been recognized in international environmental agreements – most notably the Kyoto Protocol, which calls for "[r]esearch on, and promotion, development and increased use of, new and renewable forms of energy, of carbon dioxide sequestration technologies and of advanced and innovative environmentally sound technologies" (Article 2, Section 1(a)(iv)).[4]

Figure 1.1 illustrates the growing interest in CCS over the last decade as evidenced by citations in the literature. As indicated in Table 1.1, the range of subjects either using the "carbon sequestration" label or affiliating themselves with it is extensive – moving well beyond the capture of CO_2 emissions in electricity generation. Moreover, the list includes activities such as ocean fertilization that are more commonly associated with "geoengineering" (Keith, 2000).

Even within the context of "industrial" applications of carbon sequestration – those concerned with preventing anthropogenic CO_2 emissions associated with non-agricultural economic activity – the term can refer to a variety of concepts. In the long-term, for instance, CCS is perhaps best suited to an economy that uses hydrogen (H_2) as its primary energy carrier. H_2 produced from fossil fuels with sequestration of the

[4] The Seventh Session of the Conference of the Parties (COP7) to the UNFCCC, meeting 29 October to 10 November 2001 in Marrakech, Morocco, provided more explicit endorsement of electric sector CCS. With respect to meeting their Kyoto Protocol commitments, for instance, Parties to the 1992 *United Nations Framework Convention on Climate Change* "should give priority . . . to [c]ooperating in the development, diffusion and transfer of less greenhouse gas-emitting advanced fossil-fuel technologies, and/or technologies relating to fossil fuels that capture and store greenhouse gases, and encouraging their wider use; and facilitating the participation of the least developed countries and other Parties not included in Annex I in this effort" (Decision 9/CP.7, "Matters relating to Article 3, paragraph 14, of the Kyoto Protocol," in Addendum 1 to the COP7 Report: FCCC/CP/2001/13/Add.1, 21 January 2002).

Table 1.1 – Subjects commonly affiliated in the literature with the “carbon sequestration” label (Sources: DOE, 1997; DOE, 1999; Hanisch, 1998; Herzog, Drake, and Adams 1997; IEA, 1998).

• Prevention of anthropogenic CO_2 emissions in electricity generation and industrial activities
• Removal of CO_2 from the atmosphere via enhancing terrestrial uptake in biomass, soil, and the oceans
• Disposal of CO_2 in ocean waters via direct injection (from fixed or towed pipelines), as dry ice, or in pools on the ocean floor (where the density of CO_2 is greater than seawater)
• Terrestrial CO_2 sequestration in geological formations, including: deep saline aquifers, depleted oil and gas reservoirs, sub-seabed reservoirs and aquifers
• Various economic applications, including use of CO_2 as a fuel feedstock, in enhanced oil and coal-bed methane recovery, or in horticulture (as a fertilizer); plus utilization of solid carbon as an advanced, light-weight construction material (for, e.g., buildings and automobile bodies)

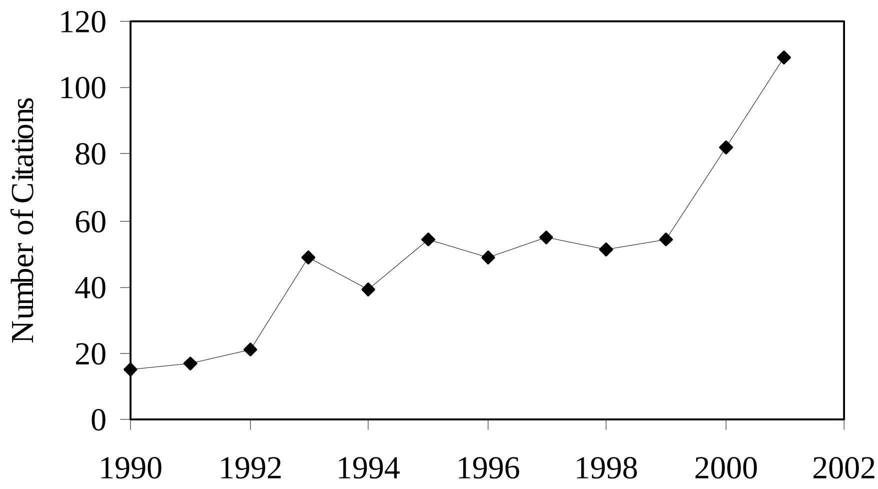

Figure 1.1 – The growth of CCS-related literature citations. Shown are the number of citations per year from the Online Computer Library Service’s “ArticlesFirst” database listed under a keyword search of “carbon and (sequestration or separation or capture) not monoxide” (26 February 2002). Searches of related databases yielded similar results.

resulting CO_2 is likely to be less expensive than H_2 generated by electrolysis (which, in an equivalent "CO_2-free" scheme, would first require the generation of electricity from a renewable energy source) (Keith, 2001). Moreover, centralized H_2 production – and CO_2 collection – would allow CCS to move (indirectly) into areas of the economy that are currently responsible for a significant share of atmospheric CO_2 emissions, but that are not characterized by the large point sources that dominate the modern electric sector. The infrastructure evolution required to provide fuel to H_2-powered vehicles, distributed electricity generators, or various heating and industrial applications, however, all but eliminates the near-term feasibility of this route to CCS.

An important issue in an analysis of CCS therefore concerns the scope of carbon capture and sequestration as a concept. In addition, separating concrete proposals (e.g., CO_2 capture from coal-fired power plants with sequestration in deep saline aquifers) from more controversial possibilities (e.g., ocean fertilization) will likely be important in gaining public acceptance of CCS as a climate mitigation option. As used here, CCS refers exclusively to the decoupling of atmospheric CO_2 emissions from the energy function of fossil fuels used in electricity generation. The following section examines in more detail why CCS might play a significant role in US CO_2 mitigation efforts.

1.4 Carbon Capture and Sequestration in the Electric Sector: Advantages and Drawbacks

The fundamental advantage of CCS as a CO_2 control strategy is its compatibility with today's centralized electric power infrastructure and corresponding point sources of CO_2 emissions. New generating units with carbon capture, for instance, would be comparable to conventional fossil-electric plants in terms of their generating capacity, siting requirements, and availability for dispatch. CCS retrofits of existing plants – particularly the large US fleet of economically competitive coal-fired units – are also possible. Moreover, as new CCS plants would be built around familiar technologies, they could make use of existing construction techniques, managerial training, and equipment suppliers. The ability to capitalize on this end-to-end industry experience may encourage early electric sector support for CCS should significant reductions in CO_2 emissions be required (Keith and Morgan, 2001).

Emerging estimates also suggest that CCS might offer the prospect of lower electric sector CO_2 mitigation costs than alternatives such as non-fossil renewables (e.g., see Simbeck, 2001a, or the studies cited in David, 2000). In addition, the existence of niche markets and technical synergies – the ability, for example, to provide CO_2 for enhanced oil recovery or the compatibility of carbon capture with the polygeneration of synthetic fuels – may facilitate adoption of CCS technologies. The compatibility and maturity of CCS system components therefore affords the possibility of more rapid near-term CO_2 emissions abatement than might be the case if the technology was in an earlier phase of the innovation-development process.

Counterbalancing this optimism are the fact that CCS as an integrated system remains at the top of its learning curve (see the following section), as well as the political and legal uncertainties associated with CO_2 sequestration.[5] The long-term ability of deep saline aquifers or depleted oil and gas wells to contain CO_2, for instance, has not been demonstrated (Holloway, 2001). Issues related to monitoring and verification, public perception and acceptance, and the place of CO_2 sequestration in the current regulatory regime must also be confronted before investors will risk capital on CCS projects. Moreover, environmental organizations have raised legitimate concerns that CCS – an "end of the pipe" approach to climate mitigation – may incur significant opportunity costs, displacing resources and attention that would be better directed to the development of renewable and other sustainable energy resources (see, e.g., Hawkins, 2001). And, finally, because CCS technologies have their own energy requirements and therefore lead to the production of additional CO_2, failure to contain sequestered CO_2 would lead to higher atmospheric concentrations than if CCS had not been pursued as a mitigation option.

Assuming that these uncertainties and objections can be adequately addressed – a non-trivial "if" – the adoption of CCS technologies will depend on their costs and

[5] More generally, the uncertainties associated with demand growth, regulation of criteria pollutants, and technological learning in an evolving electric market will have a significant impact on the adoption of any new energy technology (Grubler, et al., 1999).

performance. The following section turns to the latter and reviews relevant findings from the literature.

1.5 Electric Sector Carbon Capture and Sequestration: A Review of the Research

The processes of separating CO_2 from other gasses and sequestering it from the atmosphere are not unfamiliar technologies. Absorption of CO_2 using monoethanolamine (MEA) solvents, for instance, is an established step in natural gas processing (Herzog, 1999). Similarly, the injection of CO_2 into oil wells for enhanced oil recovery (EOR) is currently in use at over 70 fields worldwide (Socolow, 1997; DOE, 1999).[6] The fossil-fuel industry also has experience with coal gasification and long-range pipeline transport of CO_2 – additional technologies associated with CCS. Not surprisingly, the literature contains numerous analyses of the individual technologies and processes involved in carbon capture and sequestration, from different absorption, adsorption, and membrane technologies for CO_2 separation, to studies of the capacity of geological formations and the efficacy of injecting CO_2 into the oceans.

1.5.1 CO_2 Capture: Technology and Economics

Electric sector CO_2 capture may take one of three generic routes (see e.g., DOE, 1999; IEA, 2001; and Keith, 2001). Analogous in concept to flue gas desulfurization (for sulfur dioxide [SO_2] emissions) or selective catalytic and noncatalytic reduction (for oxides of nitrogen [NO_X]) is post-combustion CO_2 capture (PCC). The need to separate acid gasses such as CO_2 and hydrogen sulfide (H_2S) from methane led to the development of amine absorption in the 1950s (Herzog, et al., 1997). Owing to its maturity as an industrial process, gas stripping via the use of solvents such as monoethanolamine (MEA) has been thought of as an early route to electric sector CCS, particularly for coal plant retrofits. The energy requirements of MEA capture and CO_2 pressurization, however, can be as high as 25% of base plant output (David, 2000). In addition, conventional flue gas separation must deal with an exhaust stream containing a variety of impurities (such as SO_2 and other combustion products) but less than 15% CO_2

[6] EOR typically uses CO_2 recovered from natural (geological) sources. CO_2 produced for commercial needs amounts to about 1% of fossil fuel related CO_2 emissions (Socolow, 1997).

(Keith, 2001). Various absorption, adsorption, and membrane technologies for flue gas CO_2 separation are therefore either under development or have been proposed as a means of overcoming these obstacles to post-combustion capture (see, for instance, DOE, 1999).

A second route to CO_2 capture also relies on flue gas separation, but uses pure oxygen – rather than air – for combustion. The flue gas from such an "Oxyfuel" plant consists only of CO_2 and water (with trace impurities). The disadvantage of this route to electric sector CCS is, once again, its energy requirement – in this case that of the up-front oxygen separation process. In addition, combustion in pure oxygen produces a flame temperature higher than that tolerated by existing generating equipment. CO_2 recycling or water injection into the combustion chamber is therefore required (Keith, 2001).

Finally, CO_2 may be separated from a fuel stream prior to combustion. Pre-combustion decarbonization (PCDC) schemes rely, for instance, on steam reforming of methane or coal gasification to produce syngas (mainly hydrogen and carbon monoxide [CO]); a shift reaction then converts the CO into a high pressure CO_2 stream. The resulting hydrogen would then fire a gas turbine, while the CO_2 is available for sequestration. While industry is probably least familiar with the PCDC concept as a whole, component technologies – such as hydrogen production via steam reforming of methane – are mature (IEA, 2001; Keith, 2001), and CO_2 capture via pre-combustion separation could eventually become the low-cost approach to electric sector CCS.

Table 1.2 summarizes the results of several studies that examine the costs and performance of electric power plants with carbon capture. Capital and operating costs, as well as performance characteristics, of course, are difficult to specify for a novel and untried technology. The CCS literature reports estimates that vary from highly optimistic (e.g., Nawaz and Ruby, 2001) to conservative (see, for example, the studies reviewed in David, 2000). The real uncertainty, however, is probably less than the range of cited estimates as different assessments employ dissimilar baselines and make widely different assumptions about when CCS technology will be ready (Keith and Morgan, 2001).

Table 1.2 – A survey of results from representative plant-level CCS studies in the literature. Note that the cost figures are as reported and have not been adjusted to a common base year. (PC = pulverized coal, IGCC = integrated coal gasification combined-cycle, NGCC = combined-cycle gas turbine; PCC = post-combustion CO_2 capture, Oxyfuel = PCC with combustion in pure oxygen, PCDC = pre-combustion fossil fuel decarbonization; COE = cost of electricity; LHV = lower heating value.)

Study	*Fuel Cycle*	*Capture Method*	*Energy Penalty (%)*[a]	*Thermal Efficiency (% LHV)*	*COE (c/kWh)*	*COE Increase (c/kWh)*[b]	*Capital Cost ($/kW)*	*$/t CO_2 Avoided*
Freund and Thambimuthu (1999)	NGCC	PCC	19	42	5.3	1.8	-[c]	55
	NGCC	Oxyfuel	20	41	5.5	2.0	-[c]	50
	NGCC Steam Reforming	PCDC	19	48	3.6	1.1	1040	37
	NGCC Partial Oxidation	PCDC	15	50	3.4	9.0	940	27
Simbeck (2001a)	PC Retrofit	PCC	30	25	4.0	2.8	921	33
	PC Retrofit	Oxyfuel	19	29	3.6	2.4	1049	28
	PC Retrofit	PCDC	0	39	3.4	2.2	1466	25
David and Herzog (2000)	IGCC	PCDC	15	36	6.7	1.7	1909	26
	IGCC 2012	PCDC	9	44	5.1	1.0	1459	18
	PC 2000	PCC	25	31	7.7	3.3	2090	49
	PC 2012	PCC	15	36	6.3	2.2	1718	32
	NGCC 2000	PCC	13	48	4.9	1.6	1013	49
	NGCC 2012	PCC	10	54	4.3	1.2	894	41
Audus (2000)	NGCC	PCC	16	47	3.2	1.0	-[c]	32
	NGCC	Oxyfuel	14	48	3.1	0.9	-[c]	29
	NGCC	PCDC	14	48	3.4	1.2	-[c]	39
	PC	PCC	28	33	6.4	2.7	-[c]	47
	IGCC	PCDC	17	38	6.9	2.1	-[c]	37

(Table 1.2 continues on the following page.)

Table 1.2 (Continued)

Study	*Fuel Cycle*	*Capture Method*	*Energy Penalty (%)*[a]	*Thermal Efficiency (% LHV)*	*COE (c/kWh)*	*COE Increase (c/kWh)*[b]	*Capital Cost ($/kW)*	*$/t CO_2 Avoided*
Herzog and Vukmirovic (1999)	IGCC	PCDC	9 - 22	35 - 39	6.2 - 6.3	1.1 - 1.7	1700 - 1920	18 - 27
	PC	PCC	16 - 23	32 - 37	7.0 - 7.4	2.3 - 3.1	2022 - 2073	39 - 45
	NGCC	PCC	12 - 15	45 - 53	5.2 - 5.8	1.9 - 2.1	1135 - 1317	53 - 77
Riemer, et al. (1994)	PC	PCC	28	29	7.4	2.5	1842	35
	NGCC	PCC	19	42	5.3	1.8	1367	55
	IGCC	PCC	33	28	11.2	5.9	3254	87
	PC	Oxyfuel	9	30	9.4	1.6	3102	16
	IGCC	PCDC	14	36	6.3	1.0	2400	23
Davison, et al. (2001)	PC	PCC	27	33	6.0 - 11.0	2.5 - 4.0	-[c]	50 - 75
	IGCC	PCDC	20	37	5.5 - 11	3.0 - 4.5	-[c]	45 - 58
	NGCC	PCC	15	47	2.0 - 4.5	1.0 - 1.5	-[c]	37 - 57
David (2000)	PC	PCC	16 - 34	24 - 37	6.9 - 10.4	2.3 - 5.7	1856 - 2484	39 - 73
	NGCC	PCC	10 - 16	44 - 53	4.3 - 5.9	1.0 - 2.1	786 - 1317	29 - 77
	IGCC	PCDC	7 - 22	30 - 39	6.2 - 8.2	1.1 - 2.4	1767 - 2204	18 - 42

Notes to Table 1.2:
a. The energy penalty reflects the share of base plant generating capacity required for CO_2 capture and typically includes CO_2 compression for pipeline transportation.
b. The cost of electricity increase is relative to an equivalent plant without CO_2 capture.
c. The study did not cite an estimate for this figure.

1.5.2 CO_2 Sequestration: Disposal Alternatives and Capacities

The figures in Table 1.2 reflect the increase in the cost of electricity generation due to carbon capture; the costs associated sequestrating avoided CO_2 emissions are not included.[7] The economics of sequestration are largely site-specific and the literature therefore generally contains first-order estimates. Sequestration, however, typically accounts for less than 25 percent of estimated CCS costs (DOE, 1999). Herzog, et al. (1997), for instance, estimate that geological disposal of CO_2 from power plants – including pipeline transport up to 100 km – would add $5 to $15 per ton CO_2 sequestered; Socolow, (1997), gives a similar figure of $7 per ton, assuming a 200 km pipeline. The IEA (1998) provides the most detailed breakdown of sequestration costs, estimating initial capital outlays of nearly $29 million (for a 30 km pipeline, well systems, project development expenses, and land) and yearly operating expenses of $3.6 million to transport and inject up to 3.9 million tons of CO_2 per year into an aquifer. Note that the variation in these estimates has more to do with location differences than technical uncertainties.

The most promising storage sites for electric sector CO_2 include underground geological formations such as depleted oil and gas reservoirs, deep (i.e., greater than 800 m) saline aquifers, and active oil fields as part of EOR; injection of CO_2 into coal-beds to enhance the extraction of methane adsorbed on the coal's surface is another possibility (DOE, 1999; Wong, et al, 2000).[8] The oil and gas industries have years of experience with geological storage, holding natural gas in underground formations during off-peak seasons and using EOR at less productive oil fields (Herzog, et al., 1997; Holloway, 2001). Identified formations are said to be located within 200 km of every US power plant (DOE, 1999), and Bergman and Winter (1996) estimate that over 65 percent of US power plant CO_2 emissions could be sequestered in deep aquifers.

More specifically, capacity estimates for terrestrial sites range from 100 to 1000 GtC in deep saline aquifers, 100 to 500 GtC in depleted oil and gas reservoirs, and 100 to

[7] Herzog, et al. (1997) estimate that US industry uses the equivalent of 1 to 5 percent of the CO_2 emitted from US power plants. In the absence of new economic uses of carbon, therefore, sequestration is the only feasible disposal alternative for power plant CO_2 emissions.
[8] A further approach to CO_2 sequestration seeks to replicate what takes place naturally, only much faster. Akin to the weathering of rock, industrial processes that would react CO_2 with dissolved minerals are under

300 GtC in coal beds (Gunter, et al., 1998; Holloway, 2001; Socolow, 1997; Wong, et al, 2000).[9] Likely retention times vary between decades for EOR in active fields,[10] to a range extending many thousands of years for other geological formations (Gunter, et al., 1998).

More controversial in terms of its environmental effects and the public reaction it might engender is ocean sequestration of CO_2. Although the oceans could sequester an estimated 1000 to 10000 GtC, near the point of injection the pH of ocean water would drop from an average of 8 to as low as 4 – an increase in acidity that could have a detrimental impact on marine life (Haugan, 1997; Caldeira, et al., 2001; Seibel and Walsh, 2001). Different means of ocean disposal might overcome such effects. Isolation of CO_2 as a "lake" on the ocean bottom (where its density is greater than that of sea water) is one alternative to injection from a fixed pipeline, gradual dispersion of CO_2 from a towed pipe is another (Herzog, et al., 2001). It is likely, however, that ocean sequestration would violate the 1972 London Convention which prohibits waste dumping at sea. While not mentioned explicitly, initial interpretations suggest that CO_2 from fossil-electric plants fits the Convention's definition of "industrial waste" and could therefore not be disposed of in ocean waters (see Johnston, et al., [1999] and Chapter 6 of this thesis).

1.5.3 CCS in Practice: The Intersection of Technology and Policy

The feasibility of CO_2 sequestration will therefore depend on the resolution of several issues that lie at the point where politics and society intersect with science and technology. The allowable rate of CO_2 leakage, for instance, remains uncertain from both scientific and policy standpoints. Localized and rapid releases of CO_2 from terrestrial sequestration sites would pose the risk of asphyxiation, while a more general failure of geological formations to contain injected CO_2 would lead to higher atmospheric concentrations of CO_2 than would be the case if mitigation strategies other than CCS had been pursued. Unlike nuclear waste, however, some seepage may be tolerated –

development. The resulting carbonates would sequester the carbon for a period measured on a geological timescale (see Lackner, et al., 1995).

[9] By way of comparison, estimates of biomass CO_2 sequestration include 100 GtC in forests and 50-125 GtC in agricultural lands (Gunter, et al., 1998).

especially if CCS is part of a larger transition away from dependence on fossil energy and not merely a long-term kludge.

It is also unclear which agencies would have jurisdiction over CO_2 sequestration – or even which parts of the current regulatory regime serve as useful analogues. Government entities at the Federal, state and local levels, for instance, would ultimately be involved with the licensing process, though how responsibility would be devolved is unclear. It is also possible that international environmental regulations could clash with US law. More generally, while verification and long-term monitoring of injection sites would almost certainly be required, the extent and costs of these activities remain unknown. Issues related to the devolution of risk and liability (e.g., insurance underwriting) and ownership of sequestration credits must also be resolved.

Contributing to the political process will be the opinion of a public that is now only dimly aware that CO_2 may someday be captured and sequestered in deep geological formations that may also lie beneath their homes. By including more controversial schemes such as ocean disposal of CO_2 in analyses that also examine electric sector CCS, researchers and funding organizations risk alienating the public. The DOE's CCS "roadmap" (DOE, 1999), for instance, touches on most of the concepts listed above in Table 1.1, and it is not hard to see how CO_2 capture and sequestration could come to be associated in the public mind with past proposals to modify the earth's weather and climate. Prudently, the DOE – which has set a target of sequestering 4 billion tons of carbon (roughly 14.5 billion tons of CO_2) per year by 2050 – has included "public acceptance" as one of its roadmap criteria (DOE, 1999). In a similar vein of thought, Socolow (1997, p. 10) states, "Defining the objectives of sequestration programs will require the integration of physical understanding of the global environment with ethical reasoning."

Despite these uncertainties, "industrial" carbon capture and sequestration has moved from concept to practice. The first and perhaps best known example of CCS involves sub-seabed injection of CO_2 from an offshore natural gas operation run by Norway's Statoil in the North Sea. Costs are reported to be in the range of 55 $US/tC (15

[10] CO_2, of course, could be separated from produced oil and reinjected in active fields.

US/tCO_2$) avoided, making carbon sequestration a worthwhile investment in the face of that country's 183 $US/tC (50 US/tCO_2$) emissions tax; the project sequesters the equivalent of nearly 0.3 MtC annually (Herzog and Vukmirovic, 1999; Holloway, 2001). More akin to electric sector CCS is Pan Canadian's use of CO_2 for EOR in its Weyburn oil field. The CO_2 used in this project originates at Dakota Gasification's synthetic fuels plant in North Dakota, and is transported 325 km by pipeline to the oil fields in Saskatchewan; the recovery operation's consumption corresponds to approximately 0.5 MtC per year (Hattenbach, et al., 1999; Keith and Morgan, 2001).

1.6 The Thesis: Carbon Capture and Sequestration from an Electric Sector Perspective

The foregoing discussion implies that CCS, if permitted, could play a significant role in reducing electric sector CO_2 emissions. Until recently, however, assessments of CCS from a *systems* perspective have been lacking, and a comprehensive look at the role of CCS in CO_2-constrained electric markets has yet to be produced. This thesis both examines what such an analysis requires and applies these needs in an assessment of electric sector CO_2 mitigation costs.

Chapter 2 concerns the construction of supply curves for electric sector CO_2 mitigation. The chapter begins by grounding the calculation of abatement costs in a traditional microeconomic framework. The translation of this framework into the context of an actual electric market is then described, and a detailed discussion of the limits of a plant-level perspective points to the need for an energy-systems dispatch model. The chapter concludes with a caution about the limits of an electric sector focus and "bottom-up" modeling as a means of assessing CCS-related mitigation costs.

Chapter 3 takes up the needs identified in the previous chapter and illustrates how a optimization-based capacity planning and dispatch model addresses the questions regarding CCS posed in Section 1.1. The chapter describes the model – its structure, technology specifications, cost parameters, and data sources. An important part of this discussion concerns the assumptions necessary to capture electric sector dynamics and the adoption of a novel generating technology (CCS) in a tractable analytical framework.

Chapter 4 illustrates baseline model results, focusing first on time dynamics before exploring how the price of carbon emissions affects patterns of investment and dispatch. The construction of CO_2 mitigation supply curves provides a basis for discussing the role of CCS technologies in emission reduction. The chapter concludes with an extended look at a number of market- and technology-related scenarios, thereby providing a parametric check on the model's sensitivity to key assumptions.

Chapter 5 then takes up three issues that are likely affect the cost of electric sector CO_2 control in a world with CCS. First is the role of natural gas prices and the possibility of a "free lunch" reduction in CO_2 emissions. The existing mix of generating plants is out of equilibrium with respect to current factor prices. Under moderate gas prices, increased reliance on gas-fired generation will lower CO_2 emissions even in the absence of a carbon constraint. CO_2 mitigation cost estimates will therefore be lower in an assessment that includes this gradual transition away from existing ("sunk") capital. Recent volatility and the resulting uncertainty in gas prices, however, must be included in this picture. The first section of Chapter 5 explores this dynamic.

Addressing a second issue that involves existing generating capacity, Chapter 5 next examines the range of cost and performance specifications that carbon capture retrofits of existing coal plants must achieve in order to be competitive as a mitigation option. Coal plant retrofits could provide an important route to early adoption of CCS. Finally, the third section of Chapter 5 places CCS in a multipollutant framework. The increase in capital and operating costs due to CCS is likely to be less for base plants that must meet tighter limits on criteria pollutants in addition to CO_2. The section takes an initial look at how the integration and timing of multipollutant controls lowers marginal CO_2 abatement costs, and how multi-pollutant interactions could accelerate the adoption of CCS technologies. Conversely, piecemeal regulation carries the risk of lock-in to a sub-optimal technology path and, ultimately, higher CO_2 mitigation costs. Chapter 5 provides a first-order look at these dynamics.

Recognizing that CO_2 sequestration will likely pose a set of technical, economic, and regulatory challenges equally to that of carbon capture, Chapter 6 departs from the modeling framework of the previous chapters and takes a detailed look at the complexities of sequestration in a site that has received comparatively little attention: the seabed beneath the Outer Continental Shelf (OCS) in US territorial waters. The reasons for considering offshore sequestration are discussed first. A lower-bound assessment of the sequestration capacity of the US seabed follows, and the chapter concludes with detailed assessments of how OCS sequestration of CO_2 would fit into the current domestic and international regulatory regimes. The conclusions place the uncertainties associated with sequestration on par with those of CO_2 capture.

Finally, Chapter 7 first draws together the different strands of the thesis and summarizes key findings. The chapter then concludes with a discussion of several issues that either transcend the bounds of the analysis or have been deliberately excluded. Particular attention is paid to the manner in which these omissions might affect electric sector mitigation costs and the role of CCS in controlling CO_2 emissions.

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Chapter 2: Calculating the Costs of Electric Sector Carbon Mitigation

2.1 Chapter Overview

The economics of CO_2 emissions abatement may be summarized by supply curves that relate 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 reduce emissions at least cost. While the technologies and policy alternatives from which these curves are constructed often span multiple sectors of the economy, the concept is applicable to a more limited assessment of routes to electric sector CO_2 abatement.[1]

This chapter examines the assessment of electric sector CO_2 mitigation costs. Section 2.2 describes the economic theory underlying the construction of mitigation "supply curves," while the following two sections translate this theory into the context of an actual electricity market. Section 2.3 discusses mitigation cost assessment at the plant level – the basis for a "bottom-up" analysis. This plant-level approach provides the

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[1] The 1992 US National Academy of Sciences (NAS) report *Policy Implications of Greenhouse Warming* (NAS, 1992), for instance, sketches out a number of multi-sector mitigation supply curves. Emissions reductions of up to 18 GtC per year are seen to be possible at an expected cost of nearly 185 $/tC (and an estimated range of 37 to 330 $/tC). The least expensive mitigation options – involving residential and commercial energy efficiency – produce net savings (i.e., negative costs); changes in the nation's energy supply add the highest incremental cost. Difficulties in estimating mitigation costs – including market imperfections; social, technical, and environmental uncertainties; and the need to make evaluations across time and place – are examined. The Academy report discusses the need to measure externalities, the secondary costs and benefits of substitutions, and benefits that may accrue in years distant from initial outlays, in addition to direct mitigation expenses. The possibility that initial costs may be negative (i.e., that the benefits of a particular CO_2 reduction are greater than its costs) is noted, and the authors examine reasons for the failure to invest in these options (e.g., lack of information, high discount rates, resistance to change).

The US Department of Energy's "Five-Labs" study (Interlaboratory Working Group, 1997; Brown, et al., 1998) produced results similar to the NAS study. Improvements in building efficiency yield negative mitigation costs, while changes to the electric supply – including repowering coal plants and adopting renewable forms of energy production – contribute to the upper end of the supply curve. Focusing on electric-sector CO_2 mitigation, the study constructs supply curves for different combinations of carbon permit prices, criteria pollutant externality values, and coal-natural gas price differentials.

Weyant (2000) compares CO_2 mitigation supply curves from several integrated climate assessment models. More specific to the electric-sector, Arthur Rosenfeld and his colleagues at the Lawrence Berkeley Laboratory popularized the use of "conservation supply curves" to compare strategies for reducing electricity consumption (see Hirsch, 1999). Stoft (1995), in turn, critiques these and other attempts to assess conservation costs. Section 2.2 of this chapter adapts Stoft's approach to the construction of cost curves for electric-sector CO_2 mitigation.

starting point to the discussion in Section 2.4 of the analytical issues an assessment of electric sector CO_2 mitigation costs must consider. Section 2.5 examines how existing mitigation cost assessments meet these requirements – a discussion that points to the need for a model like that described in Chapter 3. The chapter concludes (Section 2.6) by placing the electric-sector focus adopted in this thesis into a larger context.

2.2 Mitigation Supply Curves for Electric Sector CO_2 Abatement

Supply curves for electric sector CO_2 abatement are a product – among other things – of assumptions made about energy demand, input factor prices, the availability of generating technologies, and the baseline scenario.[2] A traditional microeconomic assessment of electric sector CO_2 mitigation costs embeds these assumptions in a production function isoquant, which represents the cost of generating a fixed amount of electricity as a function of carbon emissions for a particular time period.[3] Figure 2.1 provides a generic illustration of this trade-off between total costs and carbon emissions.[4]

Note that the points on this curve represent the minimum cost to meet a certain carbon output, given static energy demand and factor prices. The generating technologies employed to "meet" this carbon output, of course, vary along the isoquant, with less-efficient fossil-energy plants dominating the right portion of the curve, and zero-emission – but higher cost – nuclear, renewable, and carbon capture units supplying electricity under a tight CO_2 constraint. In addition, an actual generating system would fall above this isoquant as cost minimization is but one factor weighting on investment decisions and long capital lifetimes ensure that the electric power infrastructure cannot evolve with

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[2] Other factors affecting mitigation costs include the natural rate of capital turn-over, regulatory requirements, the effects of learning and experience on technology costs and performance characteristics, the pattern of demand growth, and investors' response to the uncertainties and risks inherent in an evolving electric market.

[3] Though conventional microeconomic theory (e.g., Varian, 1992), the line of reasoning presented here closely follows Stoft's (1995) analysis of electric sector energy conservation supply curves. Production function isoquants typically relate the amount of two factor inputs (e.g., labor and capital) to meet a given output. Figure 2.1 is equivalent in treating CO_2 (i.e., the carbon content of fuel, which is converted to CO_2 and has a factor price corresponding to the cost of emissions) as an input to the electricity generation process. Expressing the required quantities of all other factor inputs (e.g., capital, fuel, labor, and administration) as monetary values (and, again, assuming static factor prices) allows their aggregation and representation on a two-dimensional plot (see Stoft, 1995).

[4] Total costs do *not* include the price of carbon emissions. Note that the curve may slope up on the far right as further CO_2 production would require deliberate investment in CO_2-intensive technologies (Stoft, 1995).

changing input factor prices.[5] As discussed in Chapter 5, a "free lunch" reduction in carbon emissions (i.e., a vertical movement toward the curve in Figure 2.1) may also occur, for instance, whenever old coal plants are replaced with lower-cost – and lower-emission – gas-fired units (Ellerman, 1996).

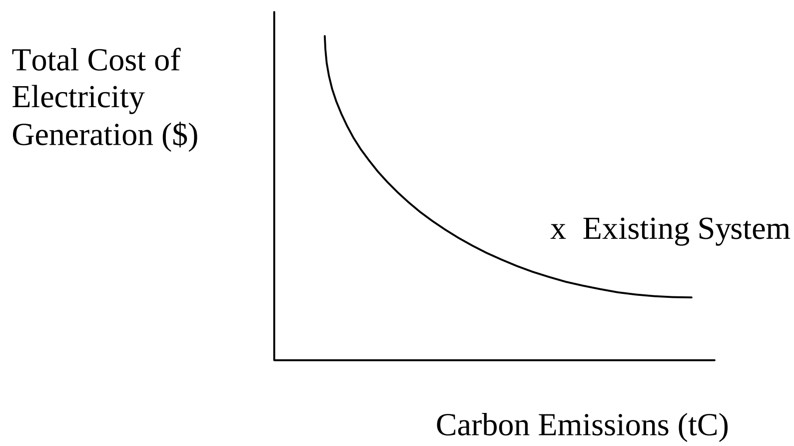

Figure 2.1 – Theoretical electricity production function isoquant. The curve illustrates the minimum cost to produce a given electricity output as a function of carbon emissions, where the latter is considered an explicit factor of production and all other factors are expressed in terms of their total costs and aggregated. Note that the existing generating system represented here ("x") does not lie on the isoquant and is therefore inefficient. (Adapted from Stoft, 1995.)

A "cost of carbon reduction" curve (to adapt Stoft's [1995] terminology) can be mapped by plotting the increase in generating costs corresponding to a given reduction from baseline carbon emissions. Figure 2.2 presents such a curve, which is really a mirroring and rescaling of the total cost curve in Figure 2.1. As economic efficiency requires the equation of marginal generating costs with the marginal price of emission reduction, the slope of this curve is equivalent to the emission price (in, e.g., $/tC) needed to induce a given reduction in carbon output. A carbon mitigation supply curve is

[5] The advent of competitive electric markets and consequent restructuring of asset ownership will presumably move the electric sector toward its production function isoquant, although the long lifetimes of its infrastructure will slow this movement considerably.

therefore a plot of the slope of the cost of carbon reduction curve as a function of the cut in emissions (Figure 2.3).[6]

Note that there are two – equivalent – ways to interpret a mitigation cost curve constructed in this manner. The most straight-forward interpretation is to see the mitigation cost as a carbon tax or similar emission price (such as that generated in a cap-and-trade program). In a pure optimization model, however, an identical curve results if emissions are progressively constrained, in which case the mitigation cost measures the (marginal) increase in generating costs required to meet a tighter CO_2 constraint. In either case, the focus here is on control costs alone and, beyond assuming sufficient time for the generating infrastructure to turn-over, does not include the cost of overcoming other market imperfections.

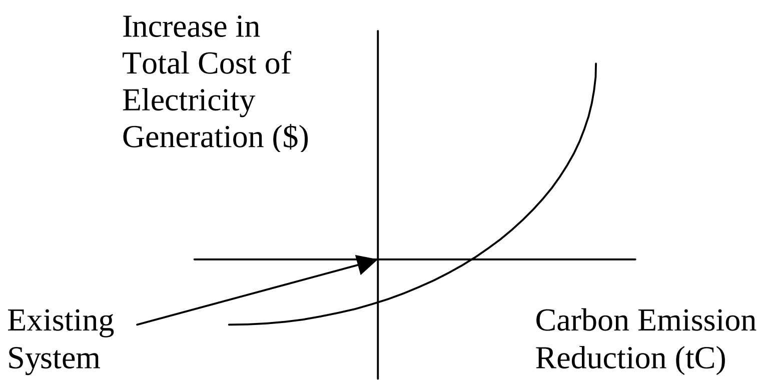

Figure 2.2 – Cost of carbon reduction curve illustrating the increase in total generating costs as a function of decreasing emissions for the existing electric power system indicated in Figure 2.1. All terms are defined with respect to this base case, with a given reduction in emissions ($CE_{base} – CE_i$) giving rise to an increase in total costs ($TC_i – TC_{base}$). The existing generating system therefore lies at the plot's origin. (Adapted from Stoft, 1995.)

[6] Note, however, that this is not a true "supply curve" as used in the economic literature. Rather, according to Stoft (1995), it "is actually an unusually oriented conditional factor-demand function (p. 119)." Given all other input factor prices as well as electricity demand, the mitigation supply curve plots the marginal cost of a reduction in carbon emissions, where carbon emissions are thought of as an additional factor of production.

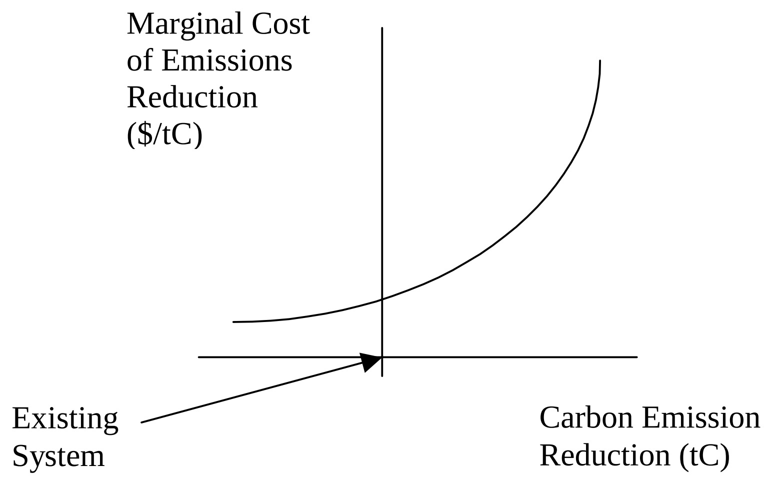

Figure 2.3 – Mitigation supply curve illustrating the marginal cost of reducing carbon emissions. The curve is simply the slope of the cost of carbon reduction curve shown in Figure 2.2. (Adapted from Stoft, 1995.)

This approach to mitigation cost assessment also ignores temporal dynamics such as technological learning or changes in input factor prices. The cost reductions and performance improvements that come with experience, for instance, would shift the mitigation cost curve down and to the right, depending on assumptions made about specific technologies. The effect of a change in factor prices is dependent on similar assumptions. If renewable, nuclear, or "zero-emission" coal units, for instance, provided the only CO_2-free generating technologies, a decrease in natural gas prices would lower total costs for moderate levels of emission abatement, though mitigation costs under all gas price scenarios would converge as gas plants would not play a role in achieving the most severe cuts in carbon output.

The discussion of electric-sector CO_2 mitigation supply curves has thus far been theoretical: given a level of CO_2 output, it is assumed that there is some combination of generating technologies that will produce that level of emissions at minimum cost. The electricity production isoquant, cost of carbon reduction and mitigation supply curves are therefore continuous. Actual electric markets, however, consist of discrete generating technologies with economic and engineering limits on their minimum size. Rather than a continuous function, a realistic production isoquant will consist of a set of discrete points. The carbon reduction and mitigation supply curves derived from this function will be stepped in reflection of the evolution from one distinct set of generating technologies to another (i.e., the cost of emissions reduction will be flat until the next most efficient set of technologies becomes economically feasible). The following sections examine what the construction of a CO_2 mitigation supply curve for an actual electric markets requires.

2.3 A Plant-Level Approach to Mitigation Cost Calculation

The starting point for estimating electric-sector mitigation costs is the relationship between the cost of electricity and intensity of CO_2 emissions for various technologies. Figure 2.4 illustrates this relationship for the total cost of electricity, including variable expenses (fuel plus operating and maintenance costs) and amortized capital investment. Producers of electricity will be concerned primarily with the vertical dimension; minimization of the cost to generate a unit of electricity is, after all, a rational business strategy. An environmentally-conscious perspective, however, will include electricity generation's less immediate cost: the production of CO_2. In an ideal world, the generating infrastructure would evolve toward the graph's origin: low-cost electricity production coupled with zero carbon emissions.

Figure 2.4, in fact, is a mirrored image of an electric sector production isoquant – the individual generating technologies tracing out the least-cost emission alternatives (with all quantities, in this case, expressed on a per-kWh basis). Before discussing how one might derive the associated supply curve, however, a digression on calculating CO_2 mitigation costs is necessary.

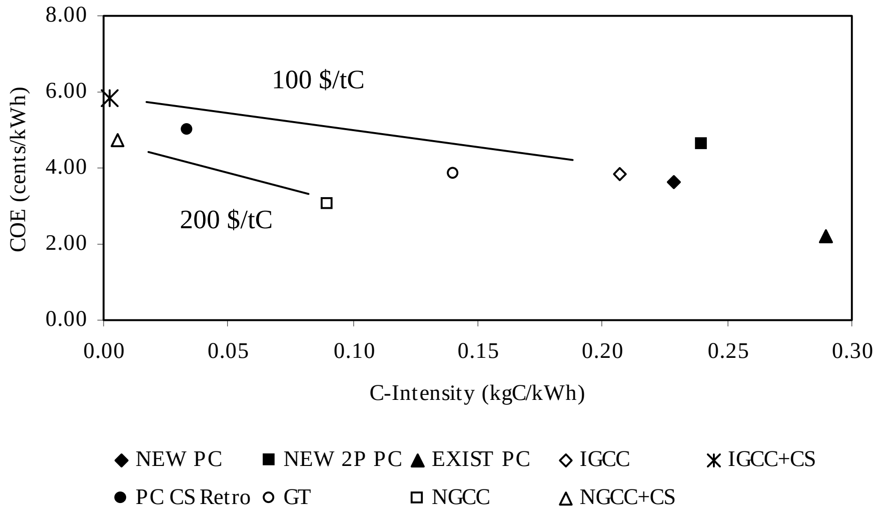

Figure 2.4 – Total cost of electricity (i.e., marginal operating costs plus a capital recovery charge) versus carbon emissions per unit of energy generated. The slope of the line connecting a given plant (defined by generating technology and fuel choice) with its CO_2-capture equivalent is the emissions price threshold above which the latter is preferred. A 75 percent load factor is assumed for all technologies; fuel prices and technology specifications are that of the unconstrained carbon emission base model described in Chapter 3 (see Tables 3.3 and 3.4). ("NEW PC" = new conventional pulverized coal plant; "NEW 2P PC" = new conventional pulverized coal plant with controls for SO_2 and NO_X; "EXIST PC" = average existing amortized pulverized coal plant (see Chapter 3); "IGCC" = integrated gasified (coal) combined cycle; "PC CS Retro" = carbon capture retrofit of existing pulverized coal plant; "GT" = natural gas-fired turbine; "NGCC" = combined cycle natural gas turbine; "+CS" = with carbon capture and sequestration.)

Assessing the costs of CCS as a CO_2 control strategy would be straightforward if competing mitigation alternatives were unavailable and the only choice to be made was that between a conventional fossil-electric plant and its counterpart with CO_2 capture. The slope of the line connecting a given 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. Such comparisons form the basis of a “static fuels” assessment of plant-level CO_2 mitigation costs (e.g., Herzog and Vukmirovic, 1999; David, 2000).

Given the data in Figure 2.4, for instance, a new conventional coal plant would be less expensive to build and operate until the value of CO_2 exceeds 100 $/tC, beyond which coal with carbon capture is preferred. Likewise, CO_2 capture is not economical for new gas units until the carbon price approaches 200 $/tC; with carbon emissions (on a per-kWh basis) roughly half that of coal plants, gas plants have a proportionally higher conventional-to-CCS threshold. Note, however, the importance of what is assumed about the base technology. The CO_2 mitigation cost of a coal-fired unit, for instance, decreases with reduction of criteria pollutants: the addition of SO_2 and NO_X control technologies increases variable operating costs, while the internal energy needs (and associated plant derating) of the control technologies increases carbon emissions on a per-kWh basis.[7]

Returning to the construction of a “static fuels mitigation supply curve,” consider first a new energy system with constant factor prices and demand, no existing capacity, and no consideration of plant dispatch. If Figure 2.4 depicted the full suite of available options and no carbon tax was levied, utilities would install the cheapest (new) 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 200 $/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 2.5 depicts this scenario.

[7] A new coal plant, of course, would not be built without controls for SO_2 and NOx emissions; this example, however, points to the interactions between CO_2 mitigation and control of criteria pollutants – an important issue explored in Chapter 5.

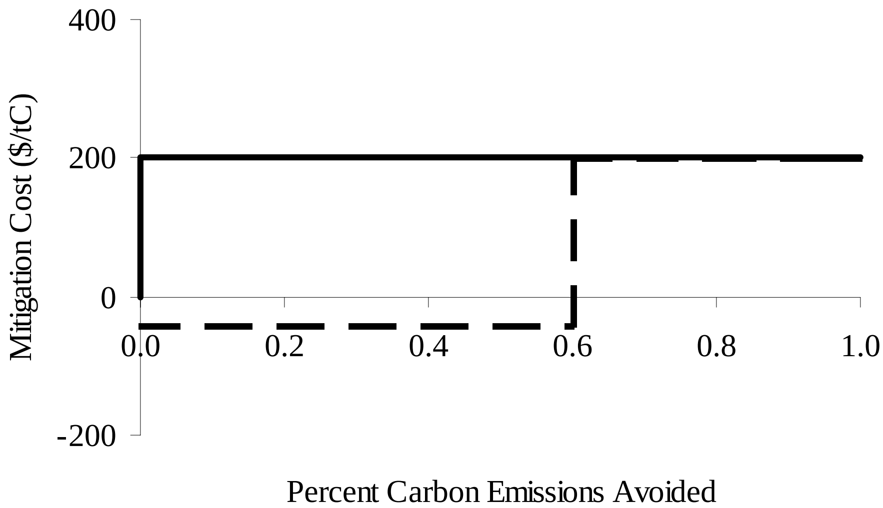

Figure 2.5 – Carbon emissions mitigation supply curves for two scenarios as discussed in the text: de novo construction of an energy system (solid line) and a non-equilibrium “free lunch” scenario (broken line). Data are from Figure 2.4.

Now consider a world with only coal fired generating capacity, represented by the new plant data from Figure 2.4 (i.e., coal plants with a capital charge remaining on the books). This would be a world out of equilibrium: absent a carbon tax and transition costs, coal would be phased out in favor of cheaper new NGCC plants. Taking the carbon output of the existing coal system as a baseline, mitigation costs would remain negative (a 40 $/tC “free lunch”) until the difference in emissions between the PC and NGCC systems was reached. Once fuel switching was complete an emissions price of 200 $/tC would once again be required to induce investment in NGCC technology with carbon capture. Note, however, the existence of path-dependent effects: if the price of carbon was *initially* around 50 $/tC, the economic choice would be to move from PC units directly to NGCC units with capture.

If different electric generating technologies met demand independently (rather than with economic dispatch), it would be possible to construct a stepwise abatement supply curve for a mixed-fuel system by first calculating the mitigation cost for each class of generating technology using the static fuels approximation, sorting the results and plotting them against their cumulative CO_2 reductions. The individual plants in a competitive, centrally-dispatched electric market, however, do not operate independently. Moreover, the existing infrastructure's age matters: while older plants are typically less efficient than new, where initial capital investment has been "paid off," their total cost of electricity may be lower as well. An assessment of electric sector CO_2 mitigation costs must therefore move beyond a plant-level perspective. The following section addresses this need.

2.4 The Cost of CO_2 Mitigation and the Need for an Electric Market Dispatch Model

Plant-level assessments of CO_2 control technologies aim to estimate the cost of making specific emission reductions *given* a set of assumptions about the plant and its environment. As the authors of plant-level studies are therefore careful to note, a static fuels approach necessarily treats the world beyond the plant gate parametrically. *Electric sector* mitigation costs, however, depend on how all units in a power pool interact to meet demand. Competition between fuels, the natural turn-over of existing capacity, and the flexibility of the plant dispatch order all affect the evolution of the generating mix and constrain its response to a price on carbon emissions. These factors interact to influence the cost of CO_2 mitigation and, for at least four reasons, are difficult to specify exogenously. Consideration of these challenges points to the need for an electric market dispatch model.

First, the choice of new capacity is not simply one between a given plant and its closest technological equivalent with CCS, as operators must also choose between gas and coal. Recent years, in fact, have favored combined-cycle gas units over coal plants to meet growing electricity demand (Ellerman, 1996). Hence, it is not clear from the analysis of Figure 2.4 what basis 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, 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 2.4 is for new plants, and includes the cost of capital based on an assumed capital charge rate and lifetime for the plant. New CCS power plants will compete with existing base-load facilities that have been "paid off" but remain competitive due to their lower overall generating costs. One of the key factors mediating the current competition between coal and natural gas has been the increasing utilization of the old coal fleet (Ellerman, 1996), and a realistic assessment of CCS-related CO_2 mitigation must consider this sunk capital investment. Using the Figure 2.4 numbers, for instance, replacement of an existing (amortized) PC unit with a new CCS coal plant costs $125 per ton carbon mitigated – a figure that drops to 100 $/tC when the choice is between *new* coal plants with or without CCS. Once again, the choice of a baseline technology can be significant.[8]

Third, as new generating units are integrated into an existing power pool, and as electricity demand and factor prices change with time, the utilization of individual plants will vary.[9] 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 US Department of Energy's "Five-Labs" study (Interlaboratory Working Group, 1997; Brown, et al., 1998) – provides an alternative to CCS as a mitigation option and may yield substantial emissions reductions at relatively low costs (on a $/tC avoided basis). Gas-fired units will therefore fall to the bottom of the dispatch order and displace coal plants as carbon prices begin to rise.

As carbon prices rise further, however, a CCS plant will eventually have the lowest marginal cost of all base-load fossil units and will thus operate with a considerably higher utilization than that of a conventional coal plant. This shift in utilization means that coal CCS will dominate new conventional coal at a lower carbon price than that suggested by the static picture depicted in Figure 2.4.[10] Figure 2.6 illustrates how carbon

[8] A further way to think about the influence of existing capacity on mitigation costs is to recognize that the distribution of installed capacity – especially the fleet of old coal-fired plants – was "optimized" for an economy with much higher gas prices than those prevailing over the last decade. Consequently, as the electricity generating infrastructure does turn-over (however slowly), coal plants are often replaced with gas-fired units. This natural evolution toward a lower emission generating technology yields a "free lunch" reduction in CO_2 emissions, absent a price on carbon emissions. Chapter 5 examines this issue, and its interaction with gas prices, in greater detail.

[9] Bernow, et al. (1996) comment on the need to consider dispatch in assessing mitigation costs.

[10] With a price on CO_2 emissions the non-fuel variable costs for conventional coal plants will increase. Moreover, as gas-fired units then become more competitive, and as CCS units are built, electricity

price and utilization affect technology choice. There is no reason, of course, that a static analysis could not specify different levels of utilization, but one would have to specify a value for the base plant. A new CCS unit would be dispatched up to its available capacity, but base plant dispatch would depend on how all available generating units interact to meet a specific demand profile when both demand and factor prices vary with time. Incorporation of these dynamics lies outside the goals of a plant-level analysis.

Finally, the need to account for CCS retrofits poses several analytical challenges. Conversion of existing coal-fired units for carbon capture, for instance, would lead to a reduction in plant output due to the energy requirements of the CO_2 separation process. The desirability of the retrofit option would be a function of this energy penalty, the base plant efficiency, and the means through which the plant derating is offset. New generating capacity could compensate for the loss in output, or units currently reserved to meet peak demand might be dispatched more often.[11] An adequate assessment of the role of CCS retrofits, therefore, also requires a framework that captures the dynamics of plant dispatch.

In summary, while technology cost estimates based on the static fuels approximation provide insight into the cost of mitigation, they are not intended to answer key questions that emerge from a broader electric-market perspective. What carbon price threshold, for instance, is required to induce the initial adoption of CCS technologies? A static fuels answer would be when the "free lunch" of a mitigation supply curve like that of Figure 2.5 was consumed and abatement costs became positive. Once the transition from coal to gas units had taken place, further reductions in carbon emissions would require investment in units with carbon capture. Yet this may not be the case if plant utilization is considered: increasing emission prices will also encourage a carbon-ordered dispatch strategy which, in turn, will affect the ordering of mitigation costs on which the supply curve is based.

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generation at "old" coal plants will drop, therefore driving up the contribution of fixed costs on a per-kWh basis.

[11] Simbeck (2001a and 2001b), for instance, makes up for lost plant capacity by adding a new combined-cycle natural gas unit. An assessment of CCS-related mitigation costs must account for the operating costs, emissions, and dispatch of both this unit and the retrofit coal plant.

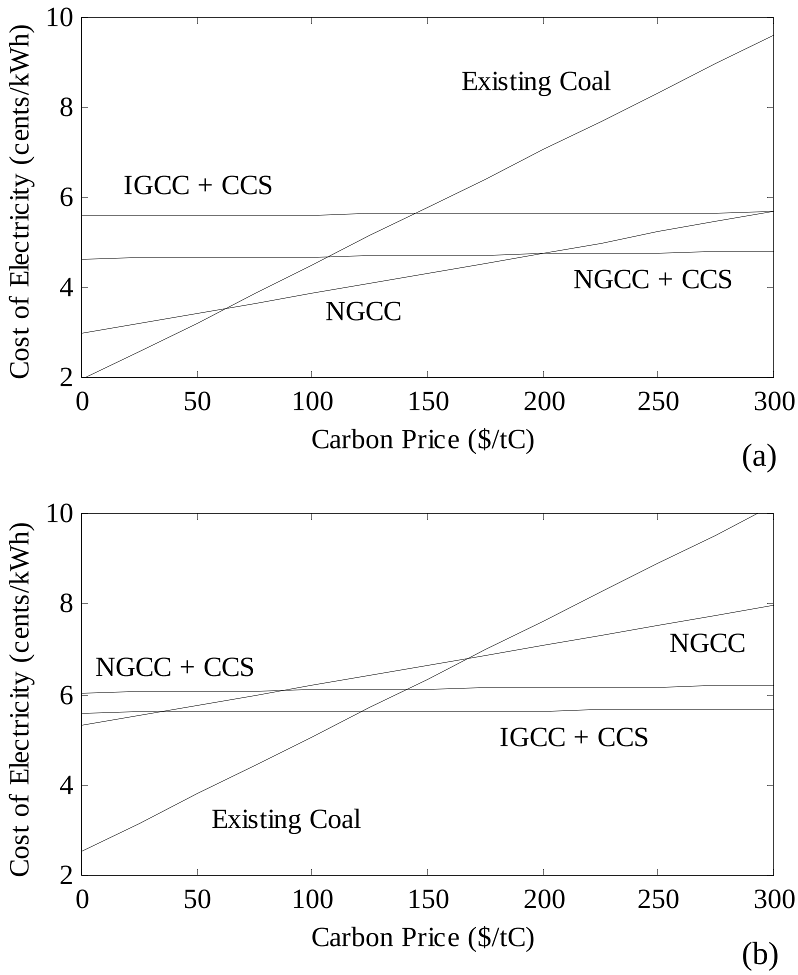

Figure 2.6 – Cost of electricity versus carbon price under different dispatch assumptions. The top panel (a) assumes a 75 percent load factor for all generating technologies; panel b, in contrast, approximates actual plant utilizations (0.3 for existing coal, 0.4 for NGCC with CCS, 0.75 for IGCC with CCS, and 0.2 for NGCC). The transition from conventional generating units to CCS does not occur until the carbon price exceeds 200 $/tC in the constant capacity factor case, but occurs at 120 $/tC in the realistic utilization case with coal (IGCC capture plants) instead of gas the preferred option.

Likewise, one might wonder about which CCS technologies enter first, how their availability affects the utilization of other generating units, or how factor prices – especially the price of natural gas – influence the adoption of CCS and related CO_2

mitigation costs. A static fuels analysis 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.

The costs of CCS as a mitigation strategy therefore depend on the path from one technology to the next – a path that cannot be disentangled from how the technologies will be used.[12] Needed is a model that captures interactions between the economics of unit dispatch, retirement of vintage capacity, and investment in new generating technologies under different constraints (or prices) on CO_2 emissions. The following section places these needs in the context of existing analytical frameworks.

2.5 Existing Models of CO_2 Mitigation and a Niche for Assessments of CCS

The previous discussion used a plant-level approach to CO_2 control cost calculation as the starting point for a description of the issues a more comprehensive assessment of electric sector CO_2 mitigation must address. This section locates the "middle ground" niche that the required electric market capacity planning and dispatch framework occupies relative to existing analyses, and then justifies the use of mathematical optimization as a solution technique.

Assessments of CO_2 mitigation conveniently distinguish between "top-down" and "bottom-up" modeling strategies (see NAS, 1992; Hourcade, et al., 1996; Edmonds, et al., 2000; and Weyant, 2000 for overviews). The former approach employs a macroeconomic (general equilibrium) framework and seeks to balance production and consumption across all sectors of the economy. Relevant to electric sector CO_2 mitigation, for instance, top-down models represent demand-price elasticity effects for electricity, fuel, and other factor inputs, as well as economy-wide substitutions among energy sources. The trade-off in capturing these interactions is a less detailed representation of the performance, costs, and dispatch of power generating units in actual electricity markets. While *MIT-EPPA* (Biggs, et al., 2001), *MiniCAM* (Edmonds, et al., 1999), and other top-down models have included CCS technologies, the intent of the

[12] Richels and Edmonds (1995) note the importance of path dependent effects on mitigation costs.

underlying analysis generally combines with computational requirements to exclude the level of technological detail that the previous section of this chapter argued is necessary for estimating technology-related electric sector mitigation costs.

In contrast to top-down models, bottom-up frameworks such as the plant-level approach described in Section 2.3 provide a technology-rich starting point for electric sector CO_2 mitigation assessments.[13] Not all bottom-up energy system models, however, are restricted to individual technologies or exogenous specification of load factors and other key inputs.[14] "Sectoral" models of the electric power industry, for instance, examine how the fuel-cycle distribution of generating units interacts with the availability of specific – and reasonably well-characterized – technologies, but remain computationally tractable by treating consumer demand and fuel prices as exogenous inputs and ignoring cross-sector effects such as the substitution of electricity for natural gas (or vice-versa; see Hourcade, et al., 1996). Through their ability to incorporate the economics of plant dispatch, retirement of vintage capacity, and competition between new generating technologies, these engineering-economic models come closest to meeting the analytical needs identified in the last section.

In practice, the distinction between top-down and broader bottom-up analytical frameworks provides an incomplete characterization of CO_2 mitigation assessments. Both frameworks, for instance, typically rely on mathematical optimization techniques to identify least-cost policy and technology alternatives (Hourcade, et al., 1996).[15] In addition, the questions being asked, rather than model structure, determine timeframe and regional perspective. Top-down and bottom-up frameworks, for instance, both provide the basis for global assessments spanning several decades – if not a century or more (see Edmonds, et al., [2000] and Weyant [2000] for reviews). Edmonds, et al., (2000) also remark that – independent of modeling strategy – results depend on basic assumptions about technology costs and performance, the rate of technological change (including "learning-by-doing"), baseline emissions, and policy scenarios.

[13] David (2000), Herzog and Vukmirovic (1999), and Simbeck (2001a and 2001b) offer examples of plant-level, bottom-up CCS technology assessments.
[14] Common bottom-up energy system models include *MARKAL* (Manne and Wene, 1992) and *Message* (Grubler, et al., 1999).

Regarding electric sector CO_2 control and existing assessments of mitigation costs, the analytical needs identified in Section 2.4 point to two "middle ground" niches that an evaluation of CCS must occupy. The first is represented by the sectoral, engineering-economic perspective described above: a computationally tractable model with more technology than most top-down assessments, but with more endogenous economics than plant-level estimates of CO_2 control costs. A capacity planning and dispatch model, focused on a particular electric market, meets this need.

The second niche concerns timeframe and the need to look at a period that falls between that of the Kyoto Protocol (now less than a decade) and the much longer (100 year) modeling horizons associated with many integrated assessments of climate change. This timescale is crucial for understanding CO_2 mitigation: it is short enough that boundary conditions – the costs sunk in current infrastructure – remain relevant and the prospect of radical technological change can be plausibly discounted, yet it is of sufficient length to allow substantial diffusion of new generating technologies.

Finally, the practical need to minimize the cost of CO_2 abatement, as well as the fact that CCS will be pursued only where it offers an economically competitive means of CO_2 control, point to the need for an optimization model. It is fair, however, to ask what an optimization framework adds to a "static" spreadsheet analysis. Given the generating capacity available in a particular time period, determining the dispatch order involves no more than a sort based on operating costs and demand. The problem is that investment and retirement decisions must also be made, and these interact with how installed capacity is used over time in a multi-period analysis. The least-cost technology path depends not only on selecting the cheapest new capacity to meet growing demand or to replace uncompetitive existing capacity; the cheapest new plant may or may not lower global costs depending on how its introduction alters the place of other plants in the dispatch order. In addition, dispatch reordering may provide a lower-cost means of achieving modest emission reductions than investment in new CO_2 control technologies (e.g., additional gas-fired units, fossil plants with CO_2 capture, or renewable energy sources). Consideration of these issues requires a capacity planning and dispatch model

[15] Simulation models provide an alternative to optimization-based frameworks. While the former are useful for describing and understanding possible futures, the prescriptive nature of the latter is better suited for

in an optimization framework. Chapter 3 introduces such a model, though the following caveat is worth repeating.

2.6 The Electric Sector in Context

As Hourcade, et al., note (1996, p. 281), “mitigation cost studies are meaningful primarily at the margin of a given development path, which, in turn, means that they are valid . . . [a]s long as historical development patterns and relationships among key underlying variables hold constant for the projection period . . . [and] there are no important feedbacks between the structural evolution of a particular sector in a mitigation strategy and the overall development pattern.” In other words, the mitigation cost perspective adopted here assumes that nonlinear changes in prices, available technologies, or demand do not occur, and that the electric sector can be isolated from the larger context of CO_2 abatement. Under a CO_2 constraint, of course, electric prices would rise in tandem with generating costs, affecting patterns of electricity consumption. Likewise, a relatively sudden increase in gas-fired electricity production would result in significantly higher natural gas prices – at least until the development of previously uneconomical gas reserves realigned supply with the increased demand.

While Chapter Four examines these issues, an engineering-economic analysis such as this cannot fully capture the cross-fuel substitution and other consumption effects such changes might have. It is conceivable, for instance, that a carbon tax or equivalent regulatory mechanism might actually result in *greater* electricity demand if it was applied unevenly across sources and users of fossil energy, or if electric-sector mitigation costs were lower than those, say, for domestic natural gas consumers. As Dowlatabadi, et al. (1993, p. 266) conclude, “the short-term response to carbon taxes is likely to lead to a reduced demand for electricity. Unfortunately, prediction of the sign, let alone the magnitude, of the long-run response is far more difficult.” While the authors note that demand-side responses to electric sector CO_2 mitigation efforts are least predictable, they also stress that opportunities for fuel-switching, induced technological innovation, and changing patterns of economic activity will have uncertain effects on both electricity production and consumption. A rigorous inclusion of the broader economic, social, and

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policy design and technology evaluation (see, e.g., Hourcade, et al., 1996).

political factors affecting CO_2 mitigation lies beyond this thesis' more focused look at the electric sector's adoption of carbon capture technologies and their associated mitigation costs.

2.7 References to Chapter 2

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Chapter 3: Carbon Capture and Sequestration in an Electric Market Dispatch Model

3.1 Chapter Overview

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). In increasingly competitive electric markets, owners of generating assets will seek to minimize future capital outlays, operating expenses, and fuel costs over a given planning horizon. As described in this chapter, such an optimization framework expands easily to accommodate assessment of the CO_2 mitigation costs associated with carbon capture and sequestration (CCS). CCS technologies, for instance, compete with standard fossil-electric plants as investment options; likewise, a price on carbon emission and the costs of CO_2 sequestration become additional terms in the calculation of marginal operating costs.

The first part of this chapter (Section 3.2) introduces the modeling framework: its domain, time horizon, and mathematical structure. Section 3.3 then describes demand and fuel-related inputs, while Section 3.4 covers technology-specific parameters. The chapter concludes (Section 3.5) with a discussion of the model's limitations. Chapter 4 presents baseline model results and examines the impact of departures from the assumptions spelled out here.

3.2 Model Domain, Timeframe and Implementation

The cost of mitigating CO_2 emissions associated with a particular electric-sector CO_2 control technology is a function of its capital and operating characteristics as well as its utilization in an integrated electric supply system. As discussed in the previous chapter, understanding the cost of CO_2 abatement via carbon capture and sequestration therefore requires a perspective greater than that of the individual plant. While investment decisions within a power pool are increasingly made by multiple independent entities, coordination of plant dispatch remains centralized even in competitive wholesale electric markets. The domain of this assessment is accordingly that of a centrally dispatched power pool: the Mid Atlantic Area Council (MAAC) region of the North American Electric Reliability Council (NERC) – the largest integrated power pool in

North America (under the centralized control of the PJM Independent System Operator; see Figure 3.1).

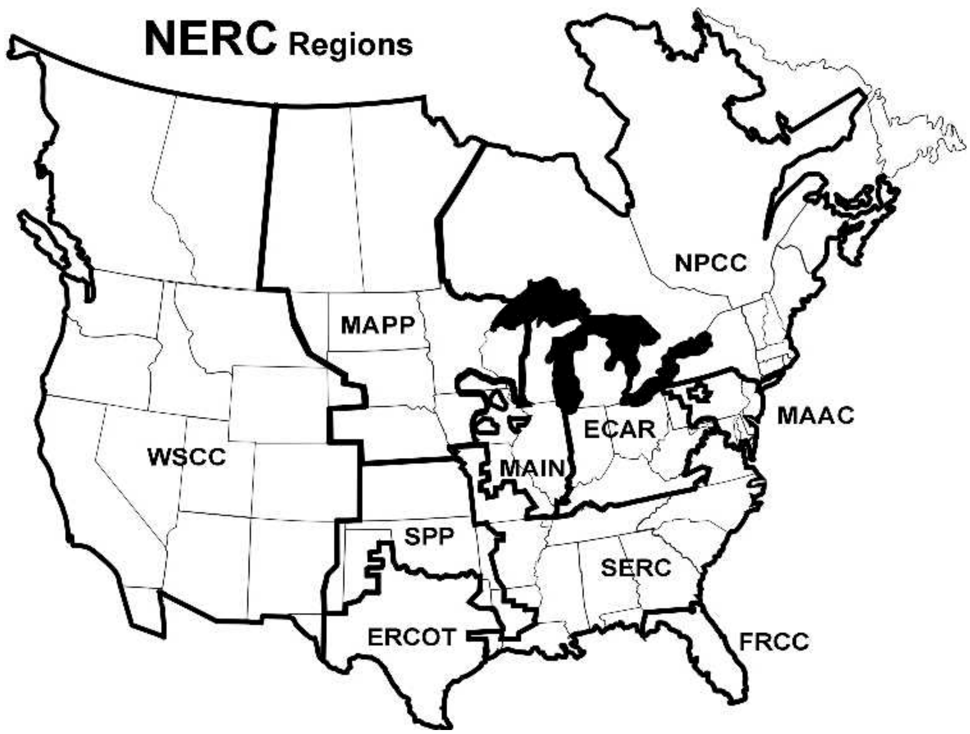

Figure 3.1 – Location of the Mid Atlantic Area Council (MAAC) in the North American Electric Reliability Council (NERC) regional framework. Coincident with the PJM (*P*ennsylvania, New *J*ersey, *M*aryland) independent system operator, MAAC covers the eastern three-fourths of Pennsylvania, much of Maryland, and all of New Jersey, Delaware, and the District of Columbia (map source: NERC, 2001).

Table 3.1 outlines the model domain. The modeling framework represents a single power pool with perfectly efficient electricity transmission, but without imports or exports of electric power.[1] Model parameters – including the distribution of existing capacity and demand projections – are closely based on the MAAC region, which is assumed to be large enough to permit the aggregation of installed capacity into generic plant categories. With its technology-specific representation and exogenous treatment of

[1] Inter-regional NERC transmission involving the MAAC region was 6.3 TWh in 1994, 9.5 TWh in 1995, 15 TWh in 1996, 10.6 TWh in 1997, and –4.3 TWh in 1998 (positive values imply net imports, negative

demand and factor prices, the model resembles other "bottom-up" engineering-economic frameworks, although its larger consideration of electric market dynamics is more typical of partial-equilibrium "sectoral" models.[2]

Table 3.1 – Model domain and implementation.

Model Domain and Time-Related Parameters	
Spatial aggregation	US NERC level (data are for the MAAC region – PJM-ISO)
Planning horizon	40 years (2001-2040)
Time step	5 year periods
Basis for cost figures	Period 1 (2001-2005) dollars
Discount rate	7.5 %; no inflation is assumed
Implementation	
Modeling environment	Microsoft *Excel* (2000) and Mathworks *MATLAB* (Version 5.3), Optimization Toolbox (Version 2)
Framework	Linear programming (7040 decision variables and 1260 constraints solved with 55 Mflops in 1 minute on a 300 MHz Pentium II)
Objective	Minimize the net present value of aggregate capital and operating costs over the planning horizon assuming "perfect foresight"

The analysis adopts a classical utility planning perspective in which investment decisions aim to minimize the net present value of investment and operating costs while meeting demand over a specified planning horizon (Turvey and Anderson, 1977; Marsh, 1980; Eden, et al., 1981; Munasinghe, 1990).[3] Individual operators in real electric

values net exports). This amounted to 6.3, 4.4, and 1.6 percent of total MAAC electricity generation for 1996 through 1998, respectively (EPA, 2001).

[2] See the discussion in Chapter 2.

[3] The capacity planning and dispatch model described in this chapter is a simplified version of those the cited references describe – and the electric power industry employs. The following sections note simplifying assumptions of this framework, which shares more with longer time horizon planning models than those concerned with day-to-day system operation. The latter, for instance, must take into account the operating cycles and dispatch flexibility of individual plants, consider how these dynamics interact with

markets, of course, will seek to maximize profit, and the resulting investment pattern may not minimize the cost of generation. This framing, however, is suitable for estimating the *social* costs of CO_2 controls. In addition, recent and continuing US electric market restructuring – with its financial separation of generation assets from the transmission and distribution infrastructure, and concomitant movement to centralized and independent system dispatch (see, e.g., Hirsch, 1999) – arguably increase the realism of a simplified dispatch model.

The analysis assumes a forty-year planning horizon (2001 to 2040) – a period that falls between that of the Kyoto Protocol (now less than a decade) and the century-long perspectives associated with many integrated assessments of climate change. This timescale is crucial for understanding CO_2 mitigation: it is short enough that boundary conditions – the costs sunk in current infrastructure – remain relevant and the prospect of radical technological change can be plausibly discounted, yet is of sufficient length to allow substantial diffusion of new generating technologies. Note that while the analytical focus is on the next few decades, the model runs through 2040 to avoid confounding end effects with results of interest (see Section 3.4.2). A 7.5% discount rate is assumed.[4]

A linear programming (LP) optimization model provides the necessary framework for representing concurrent investment and dispatch decisions.[5,6] Capacity planning is driven by twin dynamics: increasing electricity consumption and the replacement of uneconomical power plants require investment in new generating

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hourly dispatch needs, ensure system reliability and the maintenance of a reserve margin, and include transmission constraints.

[4] Note that the uncertainties in electric market restructuring and risks inherent in adopting new technologies (e.g., CCS plants) might lead to a higher cost of capital and discount rate (Bernow, et al., 1996; Azar and Dowlatabadi, 1999). A 7.5% discount rate is representative of that used in electric sector planning; Chapter 4 examines the effects of variations from this assumption.

[5] The appendix to this chapter (Section 3.7) describes the LP model's objective function and constraints, as well as key cost calculations. Appendix 1 to the thesis provides full details concerning the model's programming implementation: its structure, inputs and outputs, and key internal variables. Appendix 2 contains the Microsoft *Excel* "front-end" (with the model parameter values) plus the underlying Mathworks *MATLAB* computer routines.

[6] See the justification for the use of an optimization-based model in Chapter 2. Note that the Electricity Market Module of the US Energy Information Agency's *National Energy Modelling System* (NEMS) is very similar to the framework described here (see, e.g., EIA, 2001b). Both, for instance, employ linear programming optimization algorithms, contain a technologically-rich suite of generating technologies, and adopt a NERC region focus. NEMS, however, makes use of a finer-grained (i.e., daily) load-duration profile, includes transmission and electricity trading, and incorporates technological learning. The flexibility and computational convenience of a simpler framework justified development of the model outlined in this chapter.

capacity, while available units must be dispatched to meet demand. These drivers are not independent; although capital investment involves a longer planning horizon than day-to-day dispatch considerations, capital recovery requires expectations of how new facilities will be used. Electric system capacity planning and dispatch therefore occur simultaneously in the model, and perfect foresight is assumed in that decisions for all time periods are make concurrently with full knowledge of future conditions.[7]

In words, the optimization routine seeks to minimize the sum over all time periods and generating technologies of capital and operating costs (discounted and expressed in year 2000 dollars). Model constraints ensure that per-period demand is met and that generation does not exceed installed capacity; limit the rate of growth of wind, gas, and CCS technologies; and govern the coal plant CCS-retrofit process. The "decision variables" in this optimization framework consist of the new capacity of a given type added each time period (in MW), as well as the utilization of installed capacity, indexed by time period, segment of the load-duration curve (see Section 3.3), and type and vintage of generating technology (also in MW).[8]

3.3 Demand and Fuel-Related Inputs

Unlike top-down, macroeconomic assessments of CO_2 abatement (e.g., Biggs, et al., 2001; Edmonds, et al., 1999), demand and factor prices are exogenous to this analysis: given fuel prices plus cost and performance specifications for each class of generating technology, the model dispatches installed capacity to meet the six-layer discretized approximation to the MAAC load-duration curve (LDC) shown in Figure 3.2b. The LDC is a (reversed) cumulative plot of actual hourly load data for the MAAC region in 2000 (the histogram in Figure 3.2a), and represents the fraction of the year that hourly electricity demand in 2000 exceeded a given level (both are derived from PJM

[7] See Weyant (2000) for a comparison of "myopic" models with those that assume perfect foresight. Weyant also discusses modeling assumptions regarding flexibility in selecting and modifying capital. This model adopts a "putty-semi-putty" framework, with complete flexibility regarding new capital investment, but limited (and expensive) retrofitting of the existing infrastructure. A "putty-clay" framework allows flexibility in initial capital investment but does not permit subsequent modifications, while a "putty-putty" model assumes that existing capital evolves in tandem with technological and economic dynamics.

[8] "Utilization" as used here can be thought of either as the equivalent of installed capacity (in MW) multiplied by a load factor (between 0 and 1), or as the average per-period electricity generation (in MWh divided by hours).

[2001]). It is assumed that the LDC maintains its shape over all time periods.[9] Note that while the model does not distinguish between winter and summer demand profiles, this construction of the LDC implicitly captures seasonal differences in peak loads.[10]

Between 2001 and 2040 annual electricity demand in the model increases approximately 70 percent, from 278 TWh in the first period to 476 TWh per year between 2036 and 2040 (Figure 3.3). This trend is an extrapolation of MAAC projections (MAAC, 2001) and, while somewhat higher in magnitude, is also consistent with the growth rate assumed in the Reference Scenario of the US Energy Information Administration's (EIA) *Annual Energy Outlook* (EIA, 2001a).[11] In terms of power, peak loads increase from 52 GW to 89 GW between the first and last model periods.

The same EIA scenario (EIA, 2001a) also furnishes the starting point for fuel cost assumptions. The baseline price of natural gas sold to electricity generators, for instance, increases from 3.20 to 4.20 $/GJ between 2001 and 2040 (approximately 0.8 percent annually, or 4 percent per model period in year 2000 dollars), while the prices of coal, oil, and uranium remain constant (see Figure 3.4 and Table 3.2). Associated with each fuel class is a heating value (in GJ/kg-fuel) and a carbon intensity (in kg-C/kg-fuel).

Of the available fuels, the supply of natural gas is most likely to be constrained by its distribution infrastructure, and therefore subject to price increases as economy-wide demand increases (EIA, 2001a). Determining the magnitude and rate of this increase, however, would be difficult even in the absence of the price volatility of the last few years. Further volatility due to unforeseen events may be more significant than regular trends, and attempting to attain even greater precision by specifying the price of natural gas delivered to the electric sector in a particular region of the US is unwarranted. 3.20 $/GJ reflects the gas price currently charged to MAAC electric utilities and is in line with EIA assumptions for the 2001-2005 period (EIA, 2001a). The 40 year model growth

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[9] A comparison of peak load (in GW) and energy demand (in TWh) projections provides a quick check on this assumption. As the area under the LDC represents energy consumption, a constant ratio implies no change in the LDC profile. Yearly MAAC projections through 2010 (MAAC, 2001) support this assumption, with annual energy to peak load ratios between 5.0 and 5.1 (in 1000 hours). This ratio is maintained in the extrapolations used here.

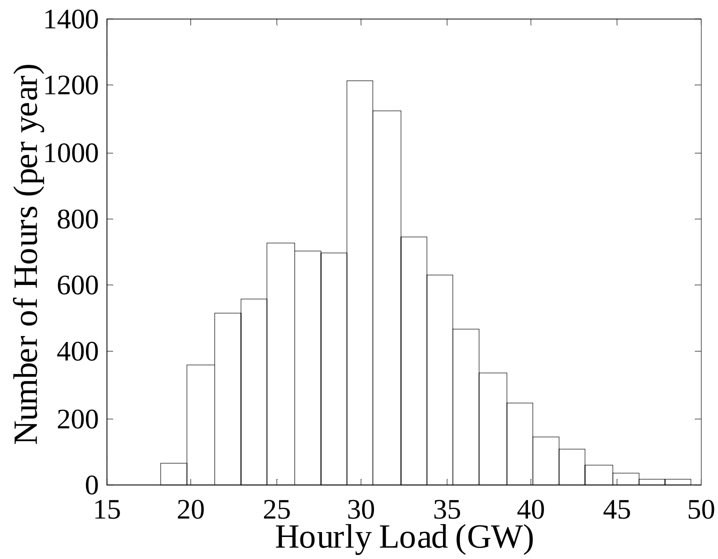
[10] Note that the discretization reflects a balance between accuracy of representation and computational convenience; see the discussion of model scaling in Appendix 1.

[11] The EIA (2001a), for instance, assumes an average 1.5% annual increase in electricity demand for the MAAC region between 2000 and 2020. The baseline model maintains this growth rate through 2040, converted to a five-year period increase of 7.7%.

rate, however, is less than the EIA's current Reference Case assumption of a 1.6% annual increase in wellhead prices through 2020, but is in line with the scenario's much smaller rate of increase in the end-user cost of natural gas (which comes at the expense of producer profit margins). A flat coal price, by contrast, is actually conservative given the large economically-recoverable reserves in the US and history of declining prices (due largely to a drop in rail transportation expenses and improved mining productivity; see EIA, 2000 and 2001a).

Table 3.2 – Fuel properties: price and growth rate assumptions, plus heating values and carbon intensities.

Fuel	*Energy-intensity* *(kg fuel/GJ)*	*C-intensity* *(kgC/kg fuel)*	*Growth Rate* *(per period)*	*Period 1 Price* *($/GJ)*
Coal	34.1	0.707	0.00	1.10
Natural Gas	18.9	0.723	0.04	3.20
Oil	22.4	0.850	0.00	4.10
Uranium	0.0005	0.000	0.00	0.10



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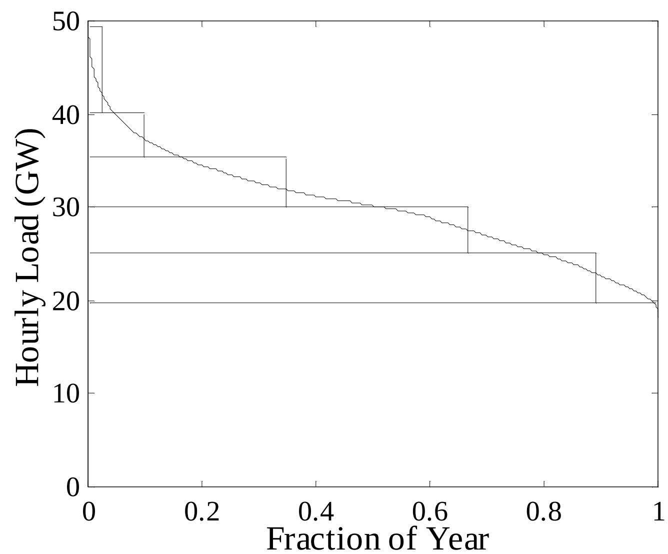

(b)

Figure 3.2 – Histogram of year 2000 hourly power demand in the MAAC NERC region (a) and the derived load duration curve with its discretized approximation (b) (PJM, 2001).

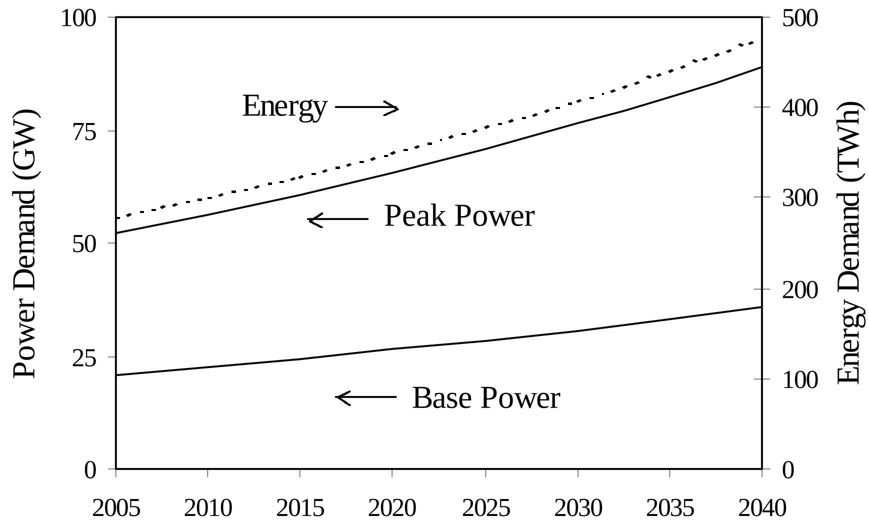

Figure 3.3 – Demand assumptions for the MAAC NERC region through 2040 (based on EIA, 2001a and MAAC, 2001).

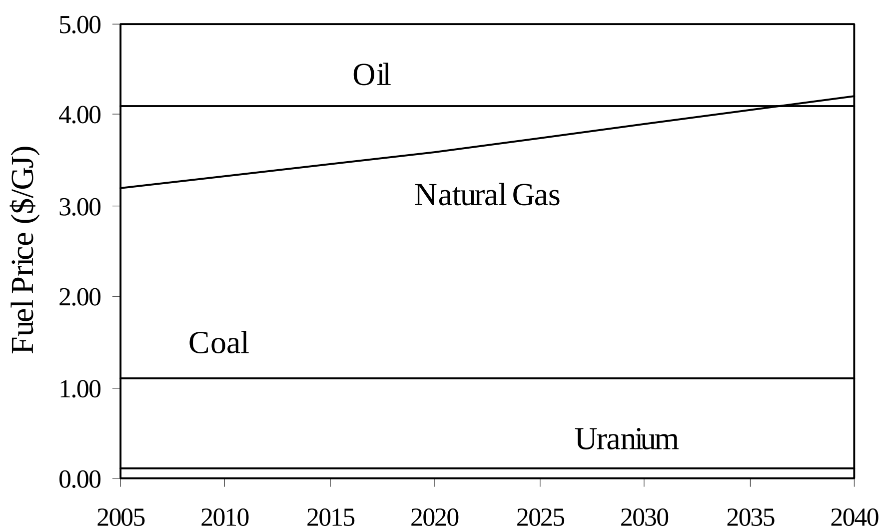

Figure 3.4 – Fuel price assumptions through 2040 (based on EIA, 2001a).

3.4 Technology Specification, Performance and Cost Parameters

3.4.1 Generating Capacity

The analysis groups current MAAC generating capacity into one of eight fuel cycle categories: three classes of pulverized coal (PC) units, single- and combined-cycle gas turbines (GT and NGCC, respectively), oil-fired combustion turbines, plus nuclear and hydro-electric plants (Figure 3.5 and Table 3.3). Each technology corresponds to a pre-existing vintage except for coal units, which the model stratifies into three classes to approximate the thermal efficiency distribution of MAAC region coal plants (Figure 3.6; EIA, 1999; EPA, 2001).[12] The base model includes only those coal plants with a nameplate capacity greater than 100 MW; co-fired units are assigned to the fuel that accounted for the greatest share of electricity generation in 1999 (EPA, 1999).

Five additional technologies – including state-of-the-art PC and integrated (coal) gasification combined-cycle (IGCC) plants, both IGCC and NGCC plants with carbon capture, as well as wind turbines – are available only as new capacity. CCS retrofits of the three "old" coal plant categories are also investment options. New capacity added in each of the eight time periods plus the pre-existing plants yield a total of nine plant vintages for the individual generating plant categories (except hydro-electric and nuclear, as discussed below).[13] Table 3.3 provides cost and performance specifications for the seventeen plant types, while Table 3.4 identifies the primary sources for this data.

While the analysis assigns costs and operating specifications to these technologies, it may be best to think of this relationship in reverse. Rather than examining how an IGCC plant will contribute to electricity generation in 2025, for instance, it is more reasonable in a modeling exercise such as this to ask how a generating technology with certain cost and performance attributes (that happen to be similar to what

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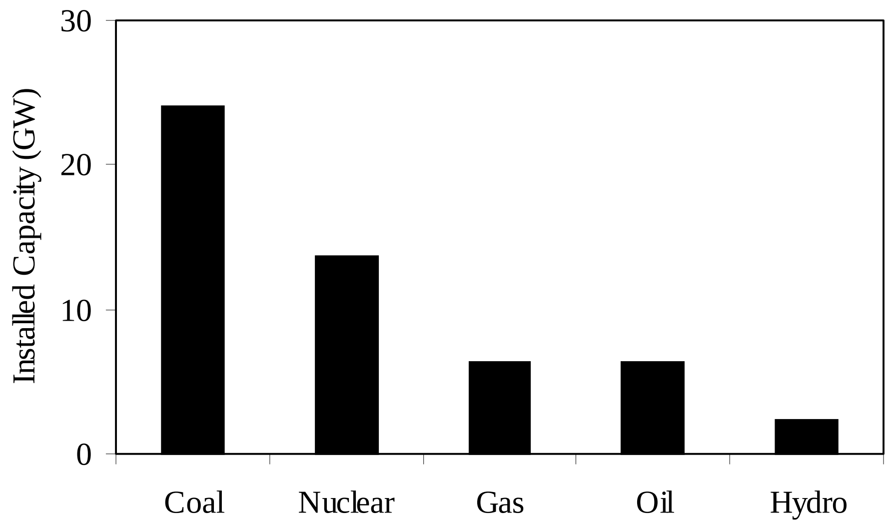
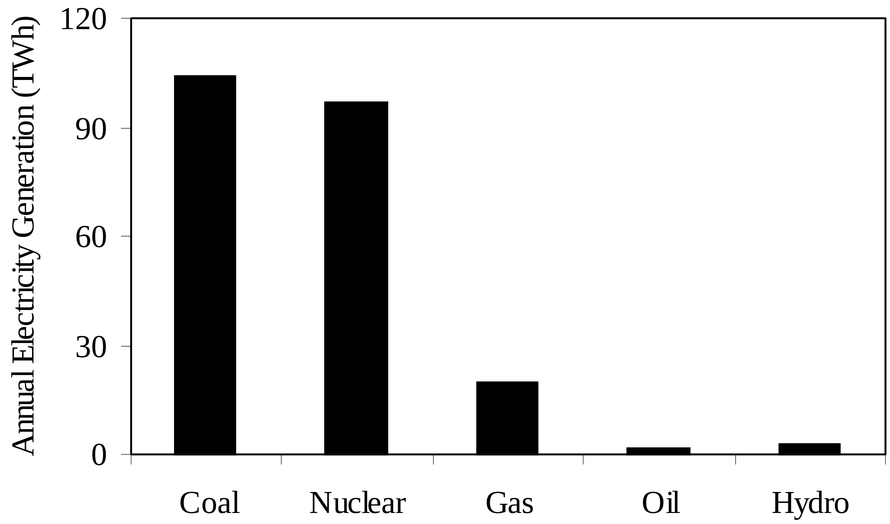
[12] A weak relationship exists between thermal efficiency and the year the oldest operating boiler went on-line for the 24 MAAC coal plants included here. In terms of the three aggregate coal plant classes in Table 3.3, the average on-line years are: 1952 for PC1 (efficiency = 0.27), 1962 for PC2 (0.30), and 1967 for PC3 (0.34). Nearly all MAAC coal plants were built before 1970, although newer boilers exist at some facilities (EIA, 1999; EPA, 2001).

[13] It is important to note once again that the model does not "see" individual plants, only aggregate capacity associated with a particular vintage and fuel-cycle category (e.g., wind capacity added in period 3 or pre-existing single-cycle gas turbines). "Plants" or "units" as used here therefore refer to the addition or dispatch of a flexible portion of this capacity.

might be expected of an IGCC plant) will compete with alternative technology specifications. Even though the analysis uses the technology labels for convenience, this perspective should be kept in mind.



(a)



(b)

Figure 3.5 – Current fuel-cycle distribution of existing generating capacity (a) and actual electricity generation (b) in the MAAC region (EIA, 2001a; EPA, 2001; MAAC, 2001).

Table 3.3 – Base model technology cost and performance parameters. CCS specifications represent what might be expected in 2015 for a cumulative CCS MAAC region installation of 5 GW. See Table 3.4 for sources. (PC = pulverized coal, IGCC = integrated coal gasification combined-cycle, GT = single-cycle gas turbine, NGCC = combined-cycle gas turbine; O&M = operating and maintenance costs; CCS = carbon capture and sequestration; HHV = higher hearing value.)

Technology	*Capital Cost ($/kWe)*	*Variable O&M (cents/kWhe)*	*Fixed O&M ($/kWe)*	*Thermal Efficiency (% HHV)*	*Base Year Installed Capacity (GW)*
PC 1	-	0.50	30.0	27	7.6
PC 2	-	0.45	30.0	30	9.3
PC 3	-	0.40	25.0	34	8.0
PC 4	1200	0.40	25.0	38	0.0
IGCC	1400	0.20	40.0	42	0.0
IGCC+CCS[a]	1900	0.35	55.0	36	0.0
GT	300	0.05	7.0	23	6.5
NGCC	450	0.05	15.0	50	1.7
NGCC+CCS[a]	900	0.15	25.0	45	0.0
Oil[b]	-	0.05	7.0	20	6.4
Nuclear[b]	-	0.40	57.0	30	13.7
Hydroelectric[b]	-	0.00	25.0	-	2.3
Wind[c]	1500	0.80	15.0	-	0.0
PC 1-CCS Retrofit	700	0.80	65.0	22	0.0
PC 2-CCS Retrofit	625	0.75	65.0	24	0.0
PC 3-CCS Retrofit	550	0.70	60.0	27	0.0
PC 4-CCS Retrofit	500	0.70	60.0	30	0.0

Notes:
a. All CCS plant O&M figures include the cost of compressing CO_2 to a suitable pressure for transport (approximately 100 atm).
b. The model excludes the addition of new oil, nuclear, and hydro-electric capacity.
c. See the text for a description of wind specifications.

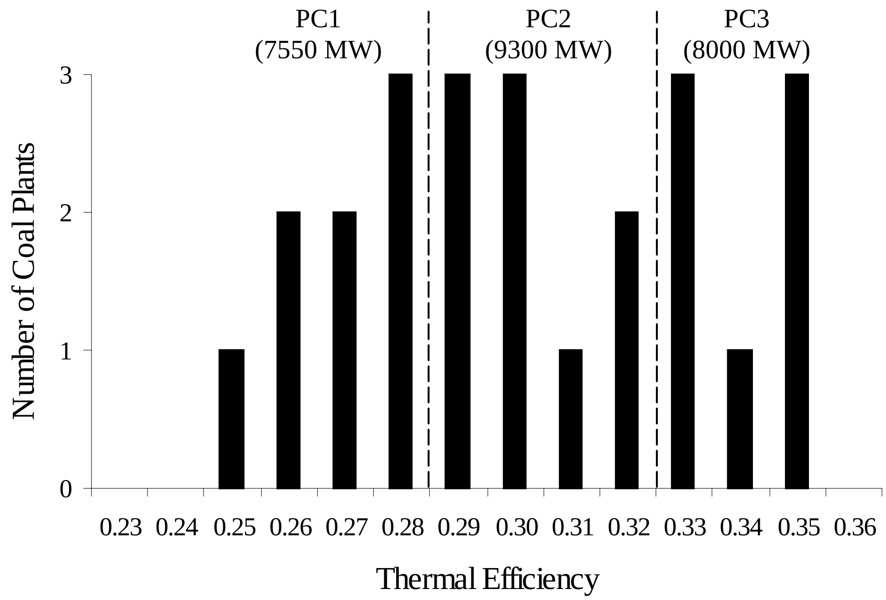


Figure 3.6 – Current distribution of thermal efficiencies for existing MAAC region coal plants and corresponding model technology classifications with installed capacities (EPA, 2001).

Table 3.4 – Data sources for the base model technology cost and performance parameters.

Model Input	*Sources*
MAAC region demand and load-duration curve profile	EIA, 2001a; MAAC, 2001; PJM, 2001
Fuel prices and parameters	EIA 2001a; Howes and Fainberg, 1991
Distribution of existing MAAC region generating capacity	EIA, 1999; EIA, 2001a; EPA, 2001; MAAC, 2001
Capital costs	David, 2000; EIA, 2001b; IECM, 2001; McGowan and Connors, 2000; Simbeck, 2001a, 2001b
Operating costs	Beamon and Lecky, 1999; David, 2000; EIA, 2001b; IECM, 2001; McGowan and Connors, 2000; Simbeck, 2001a, 2001b
Thermal efficiencies	David, 2000; EIA, 1999; EIA, 2001b; EPA, 2001; IECM, 2001
CCS technology costs and performance specifications	David, 2000; Simbeck, 2001a, 2001b; Simbeck and McDonald, 2001

3.4.2 Generating Technology Cost and Performance Specification

Associated with each class and vintage of plant is a cost of new capital, a fixed operating and maintenance cost (FOM), a non-fuel variable operating cost (VOM), and a thermal efficiency (expressed as percent higher heating value, or HHV).[14] Table 3.3 summarizes these parameters, which are typical of existing US electric power plants and are in line with the findings in Beamon and Leckey (1999) as well as the assumptions used by the EIA in producing its *Annual Energy Outlook* (EIA, 2001b). Minor adjustments improved the fit between model output and projections for the MAAC region (EIA, 2001a; MAAC, 2001).[15] To reflect the lack of experience with newer generating technologies and therefore avoid unrealistic single-period additions of new capacity, the model also includes a rate-of-growth cap on gas, wind, and CCS units.[16]

Capital costs are incurred when new capacity is added, and there is no lag reflecting the actual construction process. This is not unrealistic in a model that assumes perfect foresight (as the planning process implicitly does), and is in keeping with a focus on global cost minimization rather than the specific means of recovering capital investment.[17] But while capital costs are not assumed to change over the model's time horizon (see Section 3.5), the need to avoid serious "end effects" requires special treatment of capital costs in later time periods. Capacity added, for instance, between 2031-2035 will continue to function beyond the end of the model's planning horizon in 2040. In order not to penalize this addition by "charging" the full capital cost for what amounts to less than ten years of use, the model scales the associated capital expense by the fraction of the book life corresponding to the time remaining in the model run (e.g., for an assumed plant life of 25 years, capacity added in the 2031-2035 period would incur a capital charge of 10/25 that of a plant built in, say, the first time period).

[14] VOM and FOM refer to variable and fixed operating costs, respectively. The model aggregates these terms to produce a "per-kWh" marginal operating cost for each class and vintage of generating capacity; see the appendix to this chapter for details (Section 3.7). "O&M" is a shorthand reference to this composite figure.

[15] Coal plant non-fuel O&M costs are based on the analysis in Beamon and Leckey (1999), which provides a distribution of costs by age for all US coal-fired units.

[16] The appendix to this chapter (Section 3.7) describes the new capacity growth constraints. In short, the per-period limits for each group of technologies (gas, CCS, and wind) are an exponentially smoothed function of the aggregate capacity "added" by an unconstrained run of the model.

[17] It is assumed, however, that capital costs include all contingency and finance-related expenses.

Note that the model does not explicitly "retire" installed capacity. Dispatch occurs on a marginal cost basis: the model calculates total operating costs (i.e., VOM plus FOM) for each generating technology as a function of vintage and time period, and the optimization framework ensures that vintages with the lowest operating costs are utilized most.[18] The model therefore includes a fixed O&M escalation rate as a "tuning parameter," set to limit the "life" of combustion turbines to no more than three decades and remove pre-existing coal plants from the generating mix over the first five periods of the baseline model run (depending on the presumed age of each class of coal capacity). Chapter 4, which describes the baseline model results, illustrates these dynamics for key plant vintages.

An "availability" parameter limits the dispatch of each class and vintage of generating technology to 80 percent of its installed capacity (25 percent for wind, reflecting the MAAC region wind class; see Section 3.4.5). This limit recognizes the need for planned downtime associated with annual maintenance, as well as the fact that electric generators need to retain a reserve capacity for those periods in which demand exceeds long-term planning forecasts (demand in this model, however, is not stochastic). Note that a model with explicit plant retirement could incorporate reserve capacity needs directly through constraints that ensure installed capacity in each period exceeds anticipated demand by, say, a 15 percent margin. In this framework, however, uneconomic plant vintages, though not used, are never taken "off the books," and this approach primarily recognizes that excess initial capacity (i.e., the reserve margin) is not available to meet increasing demand in early time periods.

An additional dispatch issue concerns coal and nuclear units that, unlike gas turbines, cannot be economically switched on and off to meet peak loads for relatively brief periods of a day ("load following"). The model prevents unrealistic dispatch from occurring by stratifying coal and nuclear plant thermal efficiencies by segment of the load-duration curve. The decrease in efficiency reflects the fact that as a steam plant moves up the dispatch order, the fuel used to bring the boilers up to temperature and

[18] Marginal operating costs include fuel, CO_2 emission, CO_2 sequestration, and non-fuel VOM costs, as well as FOM. The first three terms are derived in part from each generating technology's fuel type and thermal efficiency, while VOM and FOM are technology-specific model inputs. See the appendix to this chapter (Section 3.7) for details.

pressure increases relative to that actually consumed in producing steam for electricity generation.

3.4.3 CCS Retrofits

In addition to new CCS plants, the model permits retrofits of *existing* coal units. In their baseline configuration, these retrofits represent CO_2 capture via amine flue-gas scrubbing and are parameterized by five generic variables: step increases in VOM and FOM of 0.3 cents per kWh and 35 $/kW (respectively), a capital cost of 150 $/kW (thermal), an energy penalty of twenty percent, and a CO_2 capture efficiency of 90 percent (derived from IECM, 2001, and Simbeck and McDonald, 2001). Note that the model specifies retrofit capital cost as $/kW thermal (gross) since power output – and, hence, the capital cost in $/kW of net electrical output – vary with both base-unit efficiency and the retrofit energy penalty derating of the original plant. Division of this generic capital cost (in $/kW thermal) by an existing coal plant's thermal efficiency and one minus the retrofit energy penalty yields the plant-specific retrofit capital cost in $/kW net output. Likewise, the thermal efficiency of the retrofitted plant is decreased by one minus the retrofit energy penalty. Note that new coal capacity cannot be modified, an assumption justified by the model's "perfect foresight" in making future investment decisions.

3.4.4 CO_2 Sequestration Costs

In order to give a fair accounting of all CCS-related expenses, the baseline model assumes an additional cost of 30 $/tC (8.2 $/t$CO_2$) for CO_2 transport and sequestration. The actual cost of CO_2 sequestration would be site-specific, subject to significant regulatory uncertainties, and likely to increase as more economic sequestration sites reach capacity.

Sequestration costs may be negative, however, where CO_2 can be used for CO_2-enhanced oil and gas recovery or enhanced coal bed methane production (ECBM). Within and immediately to the west of the MAAC region, for instance, lie the Northern Appalachian coal beds (with significant gas resources), as well as the smaller Pennsylvania Anthracite fields located near the region's center (see, for example, Milici, 2001). A significant fraction of the coal-fired generating capacity in the MAAC region either overlies or is within 300 km of these coal fields. While the potential for ECBM has not been seriously assessed for this region, it seems likely that it is significant and that with gas prices of 4 \$/GJ and higher ECBM might be able to pay as much as 0.5 \$/Mcf for CO_2 (approximately 35 \$/tC) (Wong, Gunter, and Mavor, 2000). As a reference, CO_2-enhanced oil recovery operations in the Permian basin and elsewhere in North America routinely run pipelines for several hundred kilometers, and are profitable with CO_2 costs over 1 \$/Mcf. Conversely, more pessimistic assessments of CO_2 sequestration in aquifers suggest that costs could exceed 50 \$/tC. A sequestration cost of 30 \$/tC is a reasonable estimate, while actual values might range from –25 \$/tC near ECBM sites to near +50 \$/tC on the Atlantic Coast.

3.4.5 Non-Fossil Generating Technologies

The baseline model includes three non-fossil generating technologies: nuclear, hydro-electric, and wind. The first two enter only as existing capacity. Because of their questionable social acceptability,[19] the analysis assumes that no new nuclear or hydro plants will be installed over the investment horizon; neither, however, is forcefully retired. Wind generation therefore provides the only new source of non-fossil energy in the model.

Capital and operating costs for wind turbines are derived from McGowan and Connors (2000) and EIA modeling assumptions (EIA, 2001b) (see Table 3.3). The analysis takes into account the limited MAAC region wind resources by restricting wind generation to 25 percent of its installed capacity – a capacity factor corresponding to a wind class of IV (see McGowan and Connors [2000] for a discussion of the relationship between wind class and availability for dispatch). Wind farms in the Great Plains and other areas of the US would likely supply power to MAAC if demand for this renewable source of electricity became substantial, with those regions' greater wind resources and, hence, lower-cost power output partially offsetting the expense of long-distance transmission. In ignoring transmission costs, the analysis is friendly to wind. Note, however, that the model ignores important issues related to power back-up and storage.

[19] See the discussion in Chapter 1.

The cost and performance specifications are similar to what wind generation “looks like” in a more inclusive analysis (e.g., DeCarolis and Keith, 2001), though the model dispatches wind capacity without explicit consideration of these factors. In a sense, wind serves as the model’s proxy renewable energy source.

3.5 Model Limitations: The Need to Simplify Reality and Predict the Future

In addition to the foregoing caveat about the model’s characterization of wind generation, it is important to be clear about what the baseline model does not include and does not attempt to represent. From a technical standpoint, for instance, the model does not consider inter-regional electricity trading, and the need to maintain reserve capacity is captured implicitly by reducing the availability of individual generating technologies for dispatch. Likewise, the model never truly retires existing capacity, though operating cost escalation drives the utilization of individual technology vintages to zero monotonically over a reasonably realistic timeframe. It is also worth repeating that the modeling framework includes flexibly divisible blocks of generating capacity rather than individual plants. Capacity investment and dispatch decisions are made simultaneously and with perfect foresight for the entire 40 year time horizon.

More generally, trends in electricity demand, fuel prices, or the costs and performance of individual generating technologies are difficult to predict and are driven by forces that lie outside of this modeling framework. Changes in lifestyles and the structure of the economy, for instance, will interact with technology development to shape patterns of energy consumption. Political and environmental concerns will further affect this evolution. Natural gas prices, in turn, will depend on demand, increases in recoverable reserves, and distribution infrastructure constraints. Within the electric sector, learning-by-doing and economy-of-scale effects will continue to lower capital and operating costs and lead to improvements in plant efficiencies.

Forecasting the pace and magnitude of technological change, and determining how it will affect both electric market dynamics and specific generating technologies, however, is a notoriously unreliable exercise. The baseline model therefore takes a conservative stance, projecting linear increases in electricity consumption and fuel prices but ignoring demand and factor price elasticity effects. In addition, the model does not include endogenous technological change ("learning" or "experience" effects), and simply assumes that generating unit capital costs and efficiencies do not vary over time. The following chapters examine several of these assumptions parametrically.

Note that the task of determining cost and performance specifications is especially challenging for a novel technology like CCS. The literature, for instance, reports estimates that vary from highly optimistic (e.g., Nawaz and Ruby, 2001) to conservative (see, for example, the studies reviewed in David, 2000). The real uncertainty, however, is probably less than the range of cited estimates as different assessments employ dissimilar baselines and make widely different assumptions about when CCS technologies will be ready (Keith and Morgan, 2001). The CCS cost and performance specifications used here are based on academic and industry assessments (e.g., David, 2000; Simbeck, 2001a and 2001b), and reflect what might be expected around 2015 for a cumulative CCS installation of 5 GW in the MAAC region. These estimates are therefore conservative for the entire 2001-2040 timeframe, especially when one considers the learning-by-doing and economy-of-scale cost reductions that would accompany significant world-wide adoption of CCS technologies.

Chapter 4 presents baseline model results. It is important, however, to keep the intentions behind the analysis in mind. The model neither sets out to say what will actually happen in the MAAC region over the next few decades, nor does it purport to predict CCS technology costs. Rather, the intent is to estimate the costs of electric sector CO_2 control in a world where carbon capture and sequestration is a mitigation option. As Chapter 2 discussed, doing so requires an analytical framework that takes into account both the structural and temporal dynamics of electricity generation. The optimization-based model presented here provides one such framework.

3.6 References to Chapter 3

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3.7 Appendix to Chapter 3: Details of the Baseline Linear Optimization Dispatch Model

This appendix describes the mathematics behind the linear optimization capacity planning and dispatch model described in Chapter 3. Key cost calculations are also presented. Appendix 1 (to the thesis) describes the model's actual implementation in an integrated Microsoft *Excel*-Mathworks *MATLAB* programming environment, while Appendix 2 contains the software code.

3.7.1 Decision Variables and Notation

Mathematical optimization is the process of determining values for a set of "decision variables" that minimize a specified objective function, subject to a series of constraints. The optimization framework underlying the capacity planning and dispatch model of Chapter 3 assumes that both objective and constraint equations are linear functions of the decision variables. These variables fall into two categories that refer, respectively, to the addition and utilization of generating capacity – or "what to build and how to use what is available." What the model "sees," however, is free of this interpretation. While all decision variables are indexed by time period, for instance, "time" has no meaning from a mathematical perspective; the optimization routine successively examines complete sets of decision variables without regard to their ordering, searching for the combination that minimizes the model's objective while satisfying all constraints. In terms of what the model represents, the decision making process corresponding to the optimization framework therefore has "perfect foresight."

With that caveat, this section briefly reviews the decision variables and other parameters as they appear in the objective function (Section A3.2) and constraint equations (Section A3.3). Table 3.5 describes the decision variables. Note that both new capacity (*NC*) and utilization (*U*) have units of power (MW), not energy (e.g., kWh). The objective function coefficients combine with the decision variables to yield a figure in (discounted, year 2001) dollars. As utilization is specific to a particular segment of the load-duration curve, which has dimensions of power (GW) and time (hours/year), electricity demand (i.e., energy) is implicitly met.

Table 3.5 – Decision variable interpretation for the baseline capacity planning and dispatch linear optimization model.

Decision Variable	*Units*	*Indices*	*Interpretation*
New Capacity (*NC*)	MW	technology (*j*) time period (*t*)	The amount of new capacity for each generating technology added in a given time period
Utilization (*U*)	MW	technology (*j*) tech. vintage (*v*) time period (*t*) LDC segment (*p*)	The extent to which each class of generating technology available in a given time period contributes to meet demand for a specific layer of the load-duration curve

Note that utilization is also indexed by technology vintage, in addition to technology type. This is necessary as several vintages of a single generating technology may exist in a given time period – one for each time period up to and including the "present," plus whatever initial capacity is available in existing vintages at the start of the model run. Hence, for each technology class there are as many vintages as there are time periods plus one (for existing capacity). Table 3.6 describes the model indices, while Table 3.7 lists other variables that appear in the optimization equations.

Table 3.6 – Indices used in the baseline capacity planning and dispatch model.

Index	*Maximum*	*Interpretation*
t	8	Number of time periods (t = 1 is the period beginning in year 2001)
p	6	Number of segments in the discretized load-duration curve (p = 1 is always peak demand; $p = pmax = 6$ always reflects base load)
j	16	Number of power generation technologies
v	9	Number of technology vintages (= number of pre-existing vintages + $tmax$); v = 1 corresponds to plants built prior to 2001; vintages correspond to $v = t + vtdiff$ beginning t = 1
$vtdiff$	1	Number of pre-existing vintages (= $vmax – tmax$ = 1)
f	4	Number of fuel types

Table 3.7 – Key variables used in the baseline capacity planning and dispatch model (see Table 3.6 for a description of model indices).

Variable	*Units*	*Indices*	*Interpretation*
		Time Related	
discount_rate	(fraction)	(scalar)	Annual discount rate
period_length	years/period	(scalar)	Length of time period *t*
D	MW/year	*p, t*	Yearly demand
Q	hours/year	*p*	Length of load-duration segment *p*
fuel_price	\$/GJ (HHV)	*f, t*	Fuel price
dNCdt	MW/period	*j,t*	Maximum new generating capacity allowed per period for each technology
growthrate	MW/period	(3 aggregate classes)	Rate of new capacity growth for gas, CCS, and wind generating technologies
		Cost Related	
capital_cost	\$/MW	*j, t*	Discounted cost of new capital
VOM	cents/kWh	*v, j*	Non-fuel marginal O&M
FOM	\$/kW-year	*v, j*	Annual fixed O&M
FOM_escalation	(fraction/period)	*v, j*	Non-fuel O&M Escalation Rate
C_price	\$/tC	*t*	CO_2 emissions price
C_seq_cost	\$/tC	*t*	Cost of carbon sequestration (including transportation and injection)
		Technology Related	
EC	MW	*j, v*	Installed capacity at time $t = 1$
thermal_eff	(fraction)	*j,v*	Thermal efficiency
availability	(fraction)	*j,v*	Per-period dispatch availability
C_capture_efficiency	(fraction C)	*j*	CO_2 capture efficiency
energy_penalty	(fraction)	*j*	Coal plant CCS retrofit power derating
E_intensity	GJ/kgFuel	*f*	Energy intensity of fuel
C_intensity	kgC/kgFuel	*f*	Carbon intensity of fuel

3.7.2 Objective Function (in discounted year 2001 $): "Minimize the net present value of aggregate capital and operating costs."

minimize

$$\sum_{t=1}^{t\max} \sum_{j=1}^{j\max} capital\_cost(j,t) \cdot NC(j,t) + \sum_{t=1}^{t\max} \sum_{j=1}^{j\max} \sum_{v=1}^{v\max} \sum_{p=1}^{p\max} MOC(j,v,t,p) \cdot U(j,t,v,p)$$

Notes:

1. See section 3.7.4 of this appendix for calculation of the marginal operating cost matrix *MOC*.

3.7.3 Constraint Equations (all are in MW):

3.7.3.1 Demand: "Utilization must meet or exceed demand"
(For all *t* and *p*; a total of *tmax***pmax* constraints)

$$\sum_{j=1}^{j\max} \sum_{v=1}^{v\max} U(j,t,v,p) \geq D(t,p)$$

3.7.3.2 Dispatch: "Cannot dispatch more capacity than is installed"
(For all *j*, *t*, and *v*; a total of *jmax***tmax***vmax* constraints)

$$\sum_{p=1}^{p\max} U(j,t,v,p) \leq \left(EC(j,v) + NC(j,t)\right) \cdot availability(j,v)$$

Notes:

1. The right hand side of the constraints corresponding to retrofit technologies is also multiplied by (1- *energy_penalty*(*j*)) to reflect the capacity derating.
2. For a given technology (*j*), the *v* by *t* utilization matrix (*U*) has the following schematic form (Figure 3.7). The dispatch constraints fall into three groups, as indicated.

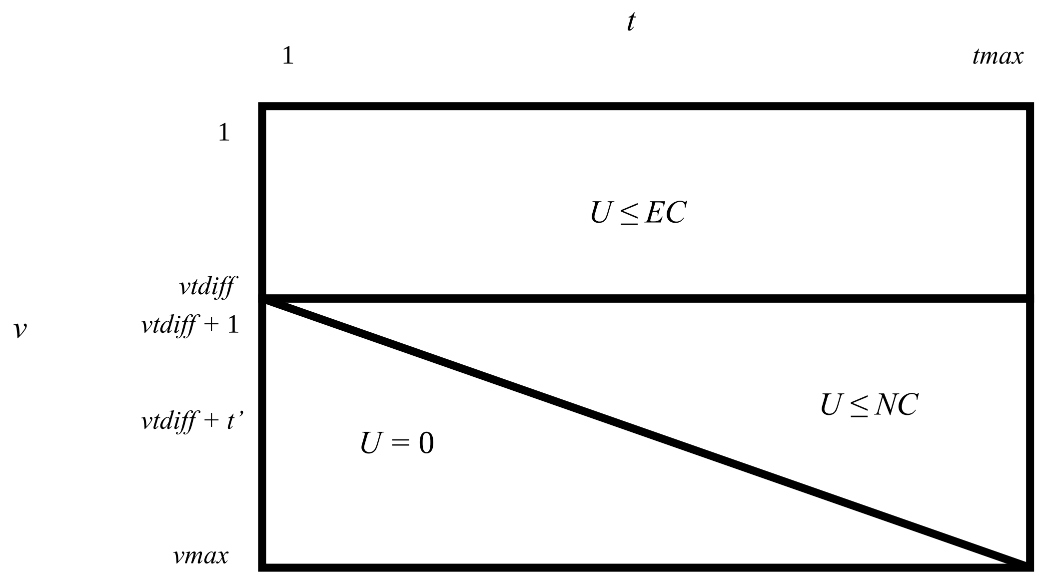

Figure 3.7 – Schematic form of the aggregate utilization matrix (*U*) for a given technology (i.e., the sum of utilization over all load-duration curve segments (*p*)). The constraints on the decision variable *U* depend on time period (*t*) and technology vintage (*v*). For each pre-existing vintage ($v \leq vtdiff = 1$), *U* must be less than the original installed capacity (*EC*). Likewise, the utilization of a new generating unit must be less than its installed capacity (*NC*), while the utilization of vintages added in a given time period must necessarily be zero in all preceding periods. Note that $v = vtdiff + t'$ corresponds to the new capacity vintage added in period $t = t'$.

3.7.3.3 Growthrate of Gas, CCS, and Wind Technologies: "New capacity in a given period cannot exceed some fraction of installed capacity of the same type"
(For each *set* of technologies *j_class*, over all *t*; a total of 3**tmax* constraints)

$$0 \leq NC(j\_class, t) \leq growthrate(j\_class) \cdot \sum_{t'=0}^{t-1} NC(j\_class, t')$$

Notes:
1. Here *j_class* refers to the following *categories* of generating technologies: all gas (including gas CCS), all CCS (including retrofits), and wind.
2. An initial "period 0" existing capacity (*NC(j,0)*) is assumed for aggregate CCS and wind.
3. The growthrate constraints ensure that maximum new capacity additions for each technology class increase gradually with time. *growthrate* and the "period 0" capacity are therefore parameters from an exponential function, fit "by eye" to yield the same aggregate capacity as an unconstrained baseline model run. Figure 3.8 illustrates how these constraints increase with model period.

4. The new capacity limits for wind in the early model periods exceed what is perhaps realistic for the MAAC region. Wind power from other regions of the US could supply MAAC demand, though the model does not include the additional cost of transmission. Actual electricity generation from wind, however, is restricted to 25 percent of installed capacity to reflect the energy resource's intermittency.

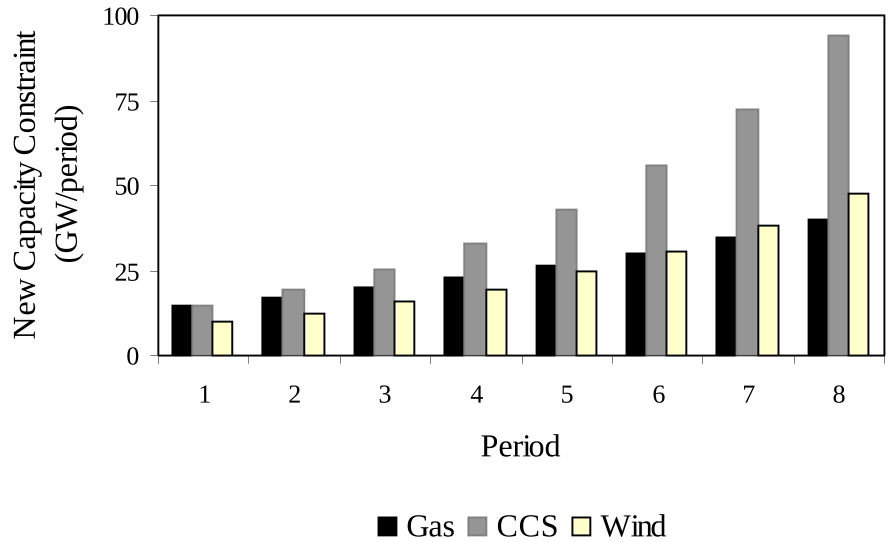

Figure 3.8 – Per-period new capacity constraints for gas, CCS, and wind generating technologies.

3.7.3.4 CCS Retrofits – These constraints are of two types:
1. "Cannot retrofit more coal plants than pre-existing installed capacity"
(A total of 4 constraints, one for each vintage coal plant category *j_original*)

$$\sum_{t=1}^{t\max} NC(j\_retrofit, t) \leq EC(j\_original, 1)$$

2. "Cannot dispatch more pre-existing capacity than was originally installed, less that which has been retrofitted"
(For each vintage coal plant category *j_original* and all *t*; a total of 4**tmax* constraints)

$$\sum_{p=1}^{pmax} U(j\_original, t, 1, p) \leq EC(j\_original, 1) - \sum_{t'=1}^{t} NC(j\_retrofit, t')$$

Notes:
1. Only pre-existing coal plant vintages (v = 1 or *j_original*) are available for retrofit.

2. A unique retrofit (*j_retrofit*) corresponds to each original coal plant vintage (*j_original*).
3. The right-hand side of the second constraint equation is multiplied by *availabilty(1,j_original)*.
4. As retrofits are a distinct technology (*j_retrofit*), they are subject to the other constraints described in this section.

3.7.3.5 Lower and Upper Bounds:
(There are as many lower and upper bounds as there are decision variables)

$$0 \le NC(j,t) \le dNCdt(j,t)$$

$$0 \le U(j,t,v,p) \le 10000000$$

Notes:
1. Lower and upper bounds on all decision variables are required by the *MATLAB* optimization routine; hence, the upper bounds on the $U(j,t,v,p)$ are set arbitrarily high. Note that the other constraints actually ensure that:

$$0 \le D(t,p) \le U(j,t,v,p) \le EC(j,v) + NC(j,t)$$

3.7.4 Marginal O&M Cost Calculations ($MOC(j,v,t,p)$ in discounted cents/kWh)

The following calculations are repeated for every class (j) and vintage (v) of technology, load-duration curve segment (p), and period (t); indices are noted, but have been omitted in the actual equations for clarity.

3.7.4.1 Preliminary Calculations

- Fuel consumption (v, j, p) (in kg fuel / kWh)

$$fuel\_consumption = E\_intensity * thermal\_efficiency^{-1} * (\text{GJ}/1000\text{MJ}) * (3.6 \text{ MJ / kWh})$$

- Carbon emissions (v, j, p) (in kgC/kWh)

$$C\_output = fuel\_consumption * C\_intensity * (1 - C\_capture\_efficiency)$$

- Carbon captured (v, j, p) (in kgC/kWh)

$$C\_captured = fuel\_consumption * C\_intensity * C\_capture\_efficiency$$

3.7.4.2 Intermediate Cost Calculations

- Fuel (v, j, t, p) (in cents/kWh)

$var\_fuel = fuel\_price * thermal\_efficiency^{-1} *$ (100cents/\$) $*$ (GJ/1000MJ) $*$ (3.6 MJ/kWh)

- Carbon sequestration (v, j, p) (in cents/kWh)

$var\_Cseq = C\_captured * C\_seq\_cost *$ (t/1000kg) $*$ (100cents/\$)

- Carbon emissions (v, j, t, p) (in cents/kWh)

$var\_Cprice = C\_output * C\_price *$ (t/1000kg) $*$ (100cents/\$)

3.7.4.3 Total Variable Operating Costs (j, v, t, p) (in discounted cents/kWh)

$$VOC = \{VOM + var\_fuel + var\_Cseq + var\_Cprice\} / (1 + discount\_rate)^{period\_length * (t-1)}$$

3.7.4.4 Fixed Operating Cost Calculation (j, v) (in discounted \$/kW)

$$FOC = FOM * (1 + FOM\_escalation)^{(t-1)} * period\_length / (1 + discount\_rate)^{period\_length * (t-1)}$$

3.7.4.5 Final Marginal Operating Cost Calculation (j, v, t, p) (in discounted \$/MW)

$$MOC = (VOC * Q * (1000\ \text{kW/MW}) * (\$/100\text{cents}) * period\_length) + FOC * (1000\ \text{kW/MW})$$

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Chapter 4: Analysis of Baseline Model Results

4.1 Chapter Overview

This chapter presents and examines baseline results for the electric sector capacity planning and dispatch model described in Chapter 3. Section 4.2 focuses on time dynamics, providing a look at how the model performs absent a price on carbon emissions. Section 4.3 then examines model behavior under an emissions price and assesses the role CCS plays in reducing the generation of CO_2 (Section 4.3). The chapter concludes with a look at several scenarios that depart from key modeling assumptions (Section 4.4).

4.2 Baseline Model Time Dynamics

Figures 4.1 to 4.5 illustrate the baseline model's time dynamics. Coal-fired plants continue to dominate electricity generation (Figure 4.1a), although new capacity additions are split between coal and gas units (Figure 4.2a and the first column of Table 4.2). New plants become economical as existing units near their typical lifetimes and are "phased out," resulting in fairly substantial capacity additions between 2015 and 2025 (Figures 4.2 and 4.3; see the discussion of O&M cost escalation in Chapter 3). Table 4.1 compares installed capacity and electricity generation at the end of period 1 (2001-2005) in the baseline model with MAAC projections for 2005 (EIA, 2001a; MAAC, 2001); with the exception of the model's greater use of gas-fired generation, the correspondence is reassuringly close.

Average generating costs under the baseline model remain relatively flat, with a slight dip in the fifth period reflecting the phasing out of inefficient coal capacity (Figure 4.4).[1] As calculated here, the cost of electricity for a given period is the sum of separate marginal and capital cost calculations. The former is simply the (undiscounted) sum of all fuel and non-fuel O&M as well as carbon emission and sequestration costs for a given period, divided by the corresponding electricity generation (with appropriate conversions

[1] Note that the average electricity costs shown here do not include charges for existing capital or expenses for overhead above the plant level; actual MAAC region "generating" costs (i.e., everything but transmission and distribution) therefore exceed these figures by as much as 3 cents/kWh, though plant-level operating costs do not (Beamon and Leckey, 1999; EIA, 2001a and 2001b).

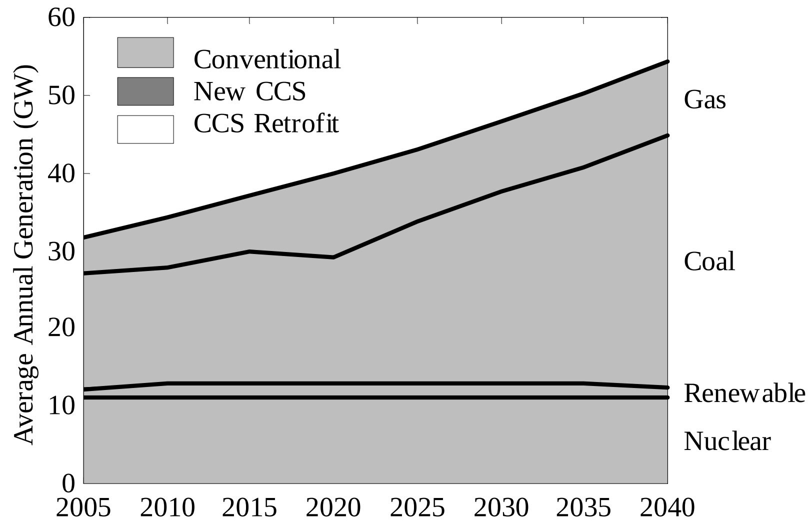
factors that produce a figure in cents/kWh). The capital component, in contrast, seeks to spread investment costs out over the forty-year model time horizon, taking into account the per-period increase in electricity generation. In words, this "levelized" charge is the constant cost (again in cents/kWh) that when multiplied by each period's electricity production and discounted equals the net present value of actual per-period capital costs.[2]

Finally, Figure 4.5 illustrates the baseline trend in CO_2 emissions. Emissions do not rise substantially with increasing demand over the first few periods, reflecting the movement first to newer natural gas units and later to more efficient coal-fired plants. CO_2 emissions then climb in tandem with growing demand over later periods. The baseline model therefore starts with higher carbon emissions than it would have if installed capacity (i.e., in 2001) could be "optimized" to reflect current factor prices and technology. This non-equilibrium initial condition lowers the cost of carbon mitigation from what it would be in a world where old coal-fired plants had already been replaced. The following section examines the interaction between CCS and mitigation costs, while Chapter 5 explores this "free lunch" in greater detail.

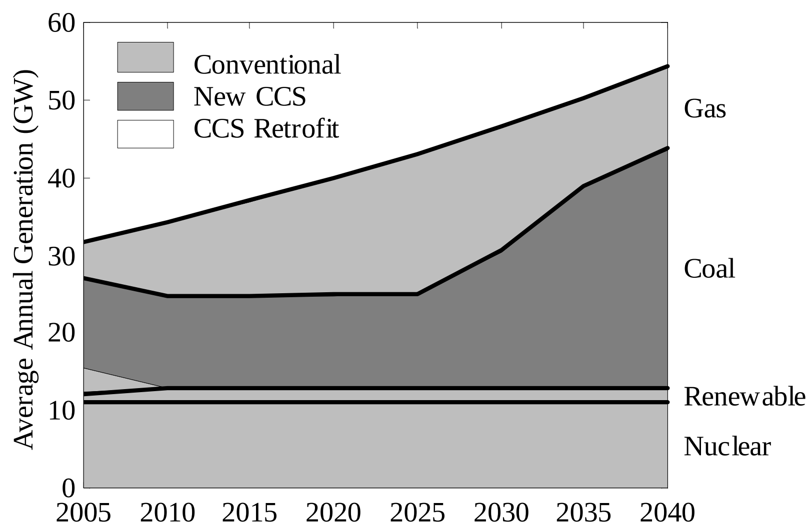
Table 4.1 – Comparison of model behavior at the end of period 1 (2001-2005) with EIA and MAAC projections for 2005 (EIA, 2001a; MAAC, 2001).

	Installed Capacity (GW)		*Electricity Generation (TWh)*	
	Projection	*Model*	*Projection*	*Model*
Coal	27	25	126	129
Gas	15	23	20	40
Oil	5	6	1	1
Nuclear	13	14	103	96
All Renewable	3	2	12	11
Total	63	70	262	277

[2] In mathematical notation, the capital cost component, COEcap (in cents/kWh), is the constant charge that satisfies $\Sigma\, E(t) * COEcap / (1 + dr)^{t-1} = \Sigma\, NC(j,t) * CapCost(j) / (1+dr)^{t-1}$, where: E(t) is the electricity produced in period t (in MWh), dr is the discount rate, NC(j,t) is the new capacity of type j added in period t (in MW), CapCost(j) is the corresponding capital cost (in $/kW), the summations are over time (periods t = 1 to 8), and conversion units are not shown.

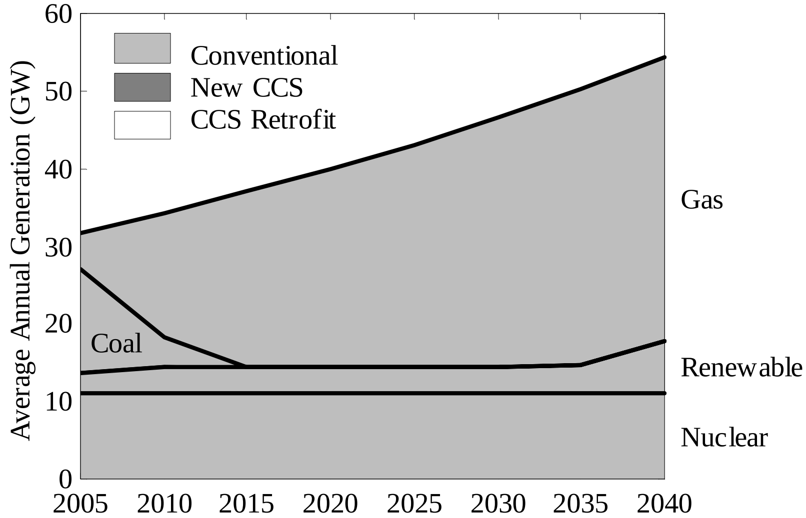


(a)



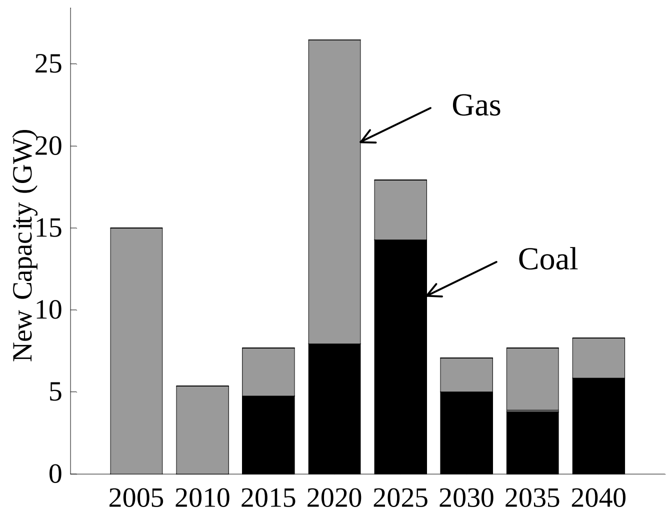
(b)

Figure 4.1 – Baseline average annual generation as a function of time for the MAAC region. The three panels compare the fuel mix used to meet demand over the eight-period investment horizon in the absence of a price on CO_2 emissions (panel a), as well as under a 150 $/tC carbon price when CCS technologies are and are not available (panels b and c, respectively). In each plot the heavy lines separate fuels, while the shading denotes CCS technology as indicated; note that CCS retrofits do not enter the generating mix for the range of carbon prices illustrated here.

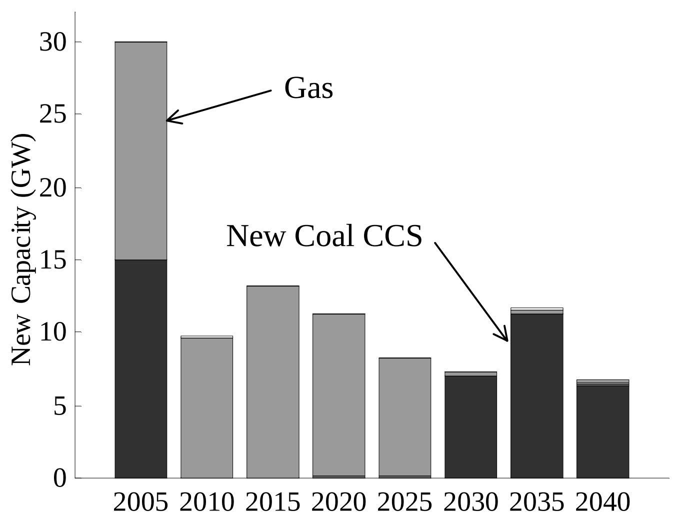


(c)

Figure 4.1 (Continued)

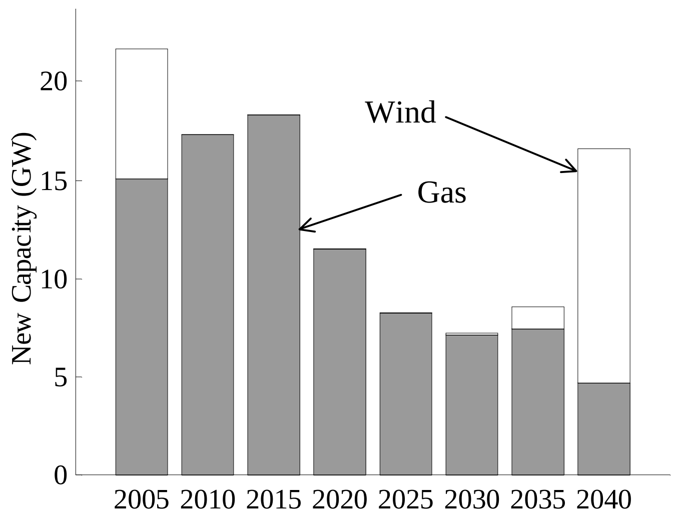


(a)



(b)

Figure 4.2 – Baseline new capacity additions as a function of time for the MAAC region. The three panels compare capital investment over the eight-period investment horizon in the absence of a price on CO_2 emissions (panel a), as well as under a 150 $/tC carbon price when CCS technologies are and are not available (panels b and c, respectively). Compare the pattern of new capacity additions with the time course of existing capacity retirements illustrated in Figure 4.3.



(c)

Figure 4.2 (Continued)

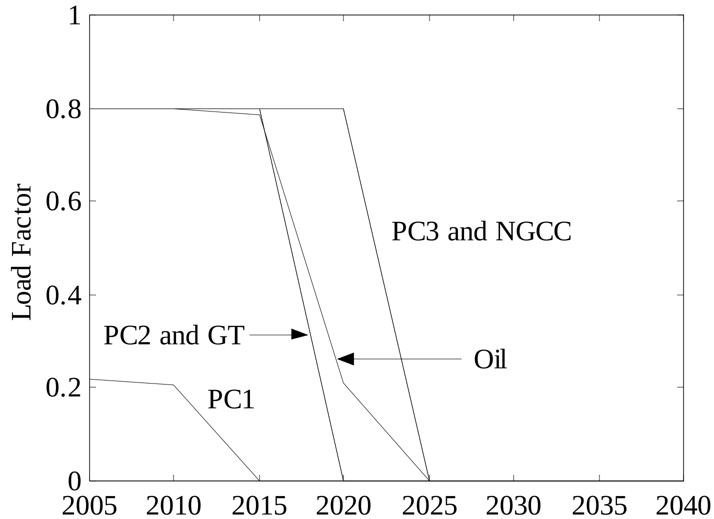


Figure 4.3 – Baseline model load factors as a function of time period for initial generating capacity. Existing single-cycle gas turbines are “phased-out” within two decades, while their more modern combined-cycle counterparts operate somewhat longer. Existing coal plant vintages drop out of the generating mix in order of their thermal efficiencies, with the least efficient (and presumably oldest) units leaving first. The lifetimes of plant vintages added over the eight periods of the model’s time horizon approximate what one would expect of new plants: roughly 25 years for new gas units and no “retirement” of coal capacity added after 2001.

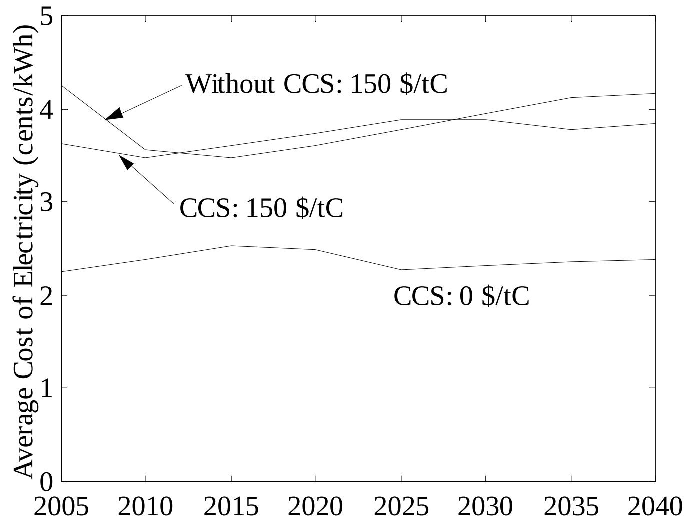


Figure 4.4 – Average cost of electricity as a function of time, carbon emissions price, and the availability of CCS technologies. See the text for details regarding the calculation of average generating costs.

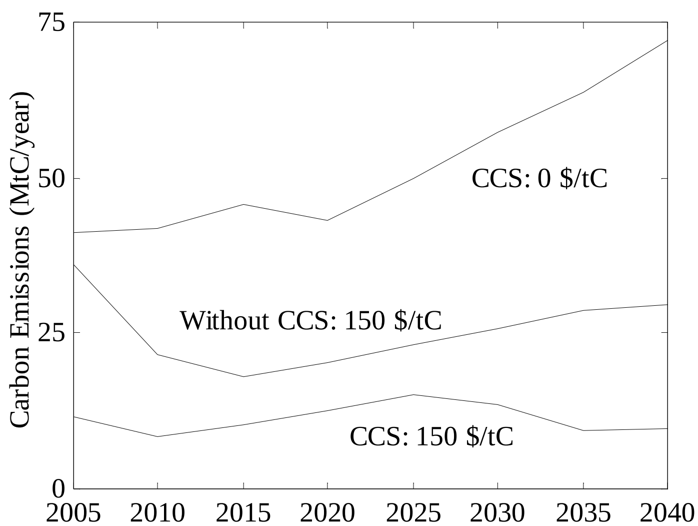


Figure 4.5 – Carbon emissions as a function of time, carbon emissions price, and the availability of CCS technologies. Note that EIA projections for the MAAC region vary between 34 and 39 MtC/year over the first model period (2001 to 2005) (EIA, 2001a).

4.3 CCS and CO_2 Mitigation Prices

This section adds a dimension to the previous look at baseline model time dynamics, examining how the choice and dispatch of generating technologies evolve with the price of carbon emissions before turning to an assessment of actual mitigation costs. Figure 4.6 addresses the first topic and illustrates how the optimal technology mix changes as the cost of emissions increases. Figures 4.1, 4.2, 4.4, and 4.5 provide a comparison of time dynamics at the 0 and 150 $/tC levels, while Tables 4.2 and 4.3 summarize new capacity additions for several carbon prices.

A look at the manner in which the model achieves CO_2 reductions provides a useful starting point for this analysis.[3] Fuel switching from coal to gas, for instance, occurs for moderate carbon prices (Figure 4.6). As the cost of emissions increases, however, the model returns to coal for baseload generation. New coal units with carbon capture become competitive near 75 $/tC, though the option of retrofitting existing coal-fired capacity for post-combustion carbon capture – which Chapter 5 examines in more detail – is uncompetitive below 300 $/tC. Note that the availability of CCS units does not lead to an earlier turn-over of conventional coal capacity (compare panels a and b of Figure 4.6). As illustrated in the following chapter, however, the balance between fuel-switching and CCS as a mitigation alternative is dependant on the price of natural gas.

In comparison to coal-fired capacity, gas plants with carbon capture do not enter the generating mix until the price of carbon emissions exceeds 175 $/tC. More efficient (non-CCS) gas units, used primarily to meet intermediate and peak demand, are penalized less than baseload conventional coal as the cost of emissions increases. Moreover, with fewer kWh over which to "spread" capital costs, CCS technologies only supply peak electricity loads when high levels of CO_2 abatement are necessary.

Stepping back from the details, two processes are visible in these results. First, the pattern of entry for separate carbon capture technologies is typical of dispatch dynamics more generally: high capital, low marginal cost generating technologies (coal CCS) supply baseload demand while units with lower capital requirements but higher

[3] Much of the subsequent analysis focuses on the role of CCS in 2026-2030 (period 6). This time frame gives ample opportunity for CCS technologies to enter the generating mix, and is in keeping with the thesis' focus on near-term electric sector CO_2 mitigation (see the first section of Chapter 1). The model

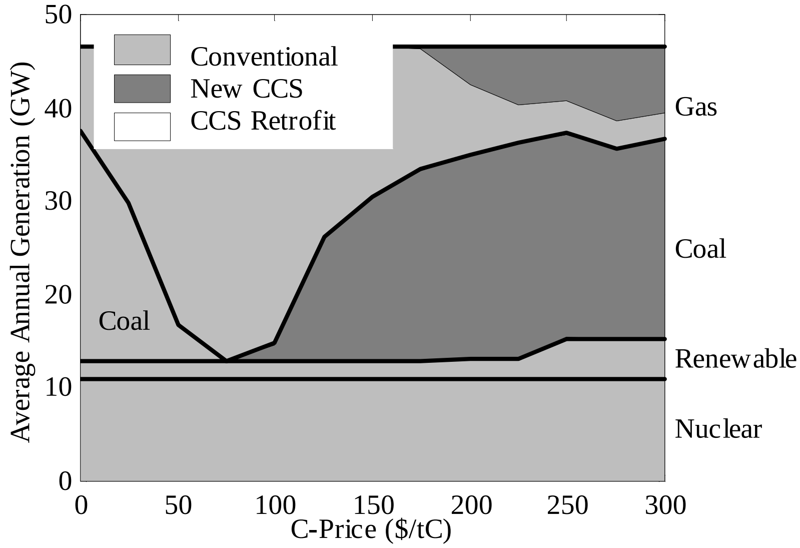
Table 4.2 – Baseline model total (2001-2040) new capacity additions by generating technology for select carbon emissions prices when CCS technologies *are* available. (PC = pulverized coal, IGCC = integrated coal gasification combined-cycle, GT = single-cycle gas turbine, NGCC = combined-cycle gas turbine, CCS = carbon capture and sequestration.)

Total New Capacity (GW)							
	Carbon Emissions Price ($/tC)						
Technology	*0*	*50*	*100*	*150*	*200*	*250*	*300*
PC 1	0	0	0	0	0	0	0
PC 2	0	0	0	0	0	0	0
PC 3	0	0	0	0	0	0	0
PC 4	36	1	0	0	0	0	0
IGCC	6	27	0	0	0	0	0
IGCC+CCS	0	0	27	40	39	36	39
GT	33	29	29	26	25	23	22
NGCC	21	46	49	31	24	21	15
NGCC+CCS	0	0	0	0	7	12	16
Oil	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0
Wind	0	0	0	0	2	11	10
PC 1 Retrofit	0	0	0	0	0	0	0
PC 2 Retrofit	0	0	0	0	0	0	0
PC 3 Retrofit	0	0	0	0	0	0	0
PC 4 Retrofit	0	0	0	0	0	0	0

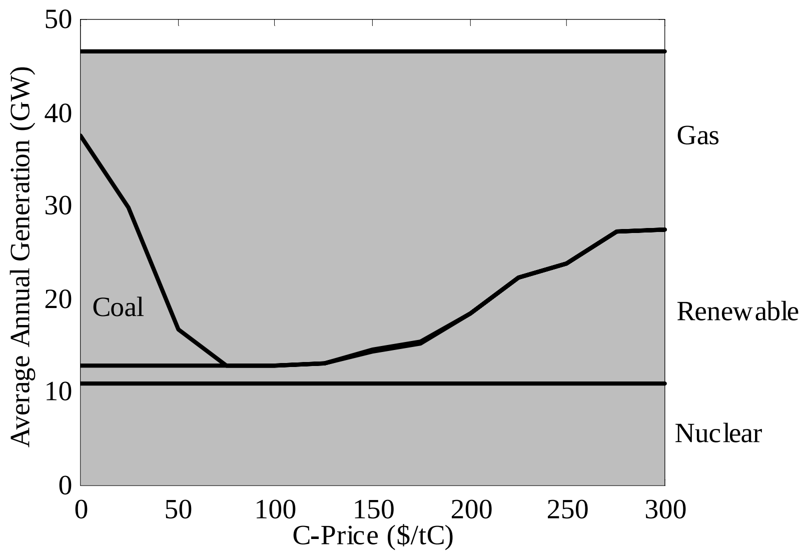
time horizon continues for an additional two periods (to 2040) in order not to conflate "end effects" with the results of interest.

Table 4.3 – Baseline model total (2001-2040) new capacity additions by generating technology for select carbon emissions prices when CCS technologies *are not* available. (PC = pulverized coal, IGCC = integrated coal gasification combined-cycle, GT = single-cycle gas turbine, NGCC = combined-cycle gas turbine, CCS = carbon capture and sequestration.)

Total New Capacity (GW)							
	Carbon Emissions Price ($/tC)						
Technology	*0*	*50*	*100*	*150*	*200*	*250*	*300*
PC 1	0	0	0	0	0	0	0
PC 2	0	0	0	0	0	0	0
PC 3	0	0	0	0	0	0	0
PC 4	35	1	0	0	0	0	0
IGCC	7	28	0	0	0	0	0
IGCC+CCS	0	0	0	0	0	0	0
GT	33	28	32	31	27	22	21
NGCC	21	46	63	59	51	45	41
NGCC+CCS	0	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0
Wind	0	0	1	20	58	92	114
PC 1 Retrofit	0	0	0	0	0	0	0
PC 2 Retrofit	0	0	0	0	0	0	0
PC 3 Retrofit	0	0	0	0	0	0	0
PC 4 Retrofit	0	0	0	0	0	0	0



(a)



(b)

Figure 4.6 – Average annual generation in period 6 (2026-2030) as a function of carbon price when CCS technologies are (a) and are not (b) available. Note that CCS retrofits do not enter the generating mix for carbon prices below 300 $/tC.

operating costs (gas CCS) are reserved for short-term peak needs.[4] In particular, the lower operating costs of the former combine with the need to recover capital investment to ensure maximum use. Second, as the price of carbon emissions increases, marginal cost and carbon-ordered dispatch strategies begin to coincide – a trend consistent with conclusions of the "Five-Labs" study (Brown, 1998; Interlaboratory Working Group, 1997). Figure 4.7 provides snapshots of utilization versus the price of carbon emissions for successive layers of the load-duration curve and illustrates this trend for the baseline model: generating units with the lowest CO_2 output – and therefore marginal costs – provide baseload capacity as emissions become more expensive.

These trends combine in a dynamic model to yield a lower threshold for CCS entry than that given by a static approach which assumes equivalent levels of dispatch for base and CCS plants (see Figure 2.4 and the surrounding discussion).[5] When a new CCS plant enters the generating mix it will have the lowest operating costs (except, in this case, for existing nuclear), and will therefore displace existing conventional units in the dispatch order. The resulting difference in base plant and CCS utilization lowers the mitigation cost at which CCS becomes competitive. That trend is visible here (Figures 4.7 and 4.8), and explains why CCS enters at a carbon price 25 percent lower than the static Chapter 2 estimate.[6]

This result leads directly to the current section's second focus: the assessment of actual mitigation costs. Figures 4.9 and 4.10, respectively, show how total costs and carbon emissions vary with emissions price. Note that both costs and emissions are 2001-2040 totals, and that "total costs" is equivalent to the minimum value of the

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[4] The operating flexibility of a gas turbine, of course, is much greater than that of a steam-cycle coal or nuclear plant. Gas units are therefore relied upon to follow the daily demand cycle for a combination of technological and economic reasons.

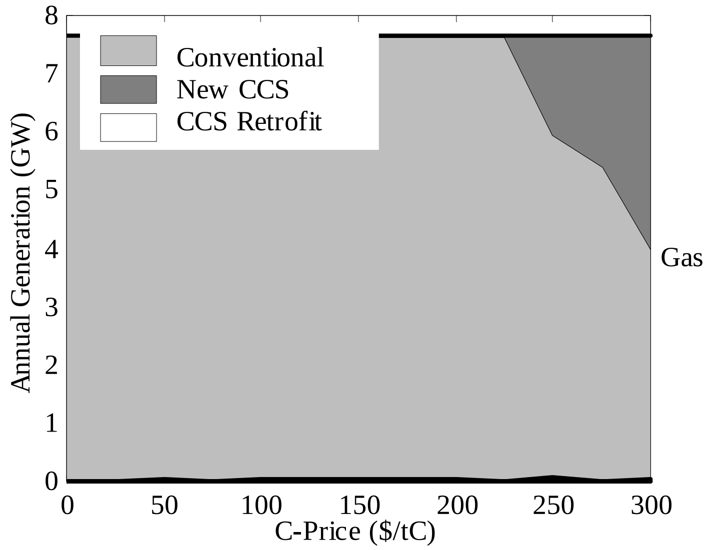
[5] There is no reason, of course, that a static analysis could not specify different levels of utilization. The trick, however, would be specifying a value for the base plant. A new CCS unit would be dispatched up to its available capacity, but base plant dispatch would depend on how all available generating units interact to meet a specific demand profile when both demand and factor prices vary with time. A dynamic model such as this is therefore needed.

[6] A plot of load factors versus emissions price would be more revealing than Figure 4.8. Load factors, however, are not well-defined in this modeling framework without reference to a specific vintage (e.g., Figure 4.3). Moreover, generating "units" are never truly retired, though they no longer contribute to meeting electricity demand when their operating costs become uncompetitively high – either as a result of O&M escalation ("retirement") or the cost of CO_2 emissions. As it is difficult to disentangle the effects of these dynamics on a given vintage's declining load factor, the fraction of electricity generated by conventional and CCS technologies is used to illustrate the emergence of a carbon-ordered dispatch regime.

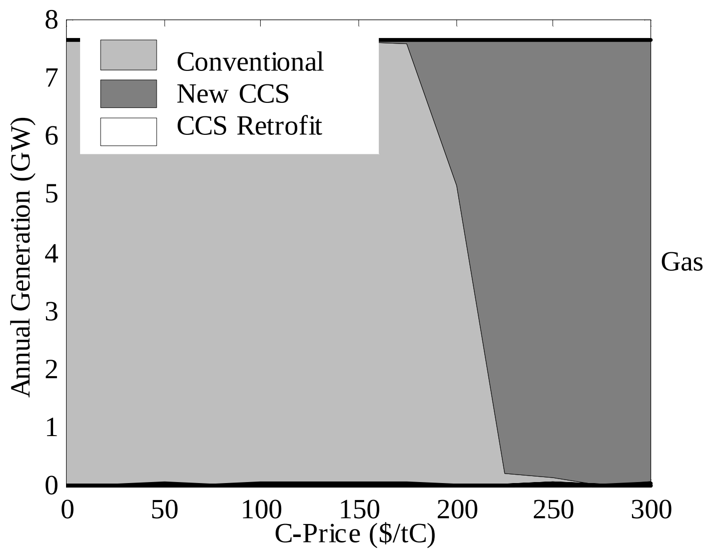
model's objective function: the net present values of aggregate capital and operating costs (see Chapter 3). Figure 4.11 combines these relationships in the empirical equivalent of the theoretical electricity production function isoquant shown earlier in Figure 2.1.

Derivation of the mitigation cost curve within a dispatch modeling framework, however, is more direct than the theoretical approach of Chapter 2 and overcomes the difficulties associated with empirical mitigation calculations identified in that chapter. Figure 4.12 depicts the CO_2 mitigation cost curve derived from the capacity planning and dispatch model's baseline scenario. Two conditions are illustrated: the baseline model that includes the full suite of new capacity options described above and a "no CCS" case restricted to conventional generating units without carbon capture. 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 25 [DK1]$/tC increments from 0 to 300 $/tC.[7] 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 the 0 $/GJ run emissions.

Several features of Figure 4.12 are worth noting. First, as was seen in Figures 4.6 and 4.7, increased reliance on natural gas units and dispatch re-ordering are the preferred mitigation alternatives for moderate carbon prices, and CCS enters the generating mix only for CO_2 reductions greater than 40 percent. Second, for a given reduction in CO_2 emissions, the extent to which CCS lowers the cost of abatement corresponds to the difference between the two supply curves. Without new nuclear or hydro-electric capacity or sufficient wind resources (see Sections 4.4.5 and 4.4.6 below), this decrease in mitigation costs is significant. And last, note that the "Without CCS" case moves toward zero emissions only at high cost as wind generation – the model's "green" backstop technology – becomes economically competitive. Taken together, these features illustrate how CCS-related mitigation cost estimates depend on context: the competition between alternative abatement options and their utilization in an integrated electric power system. The next section examines how elements of this context influence mitigation costs.



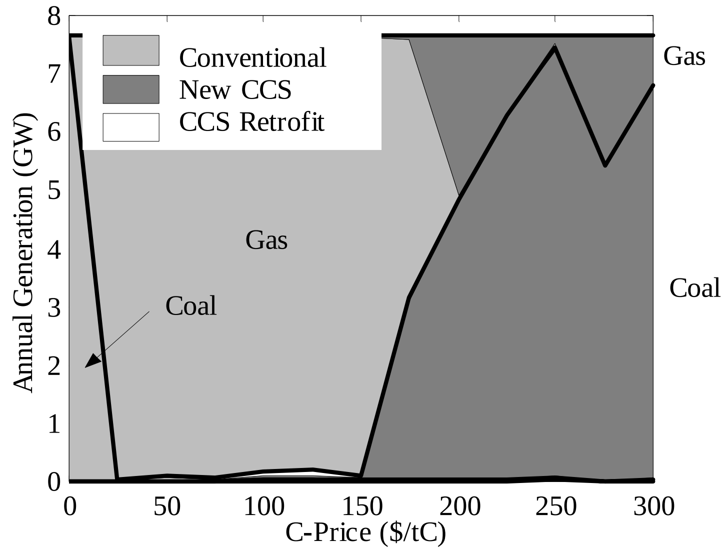
(a) 3100 hours/year



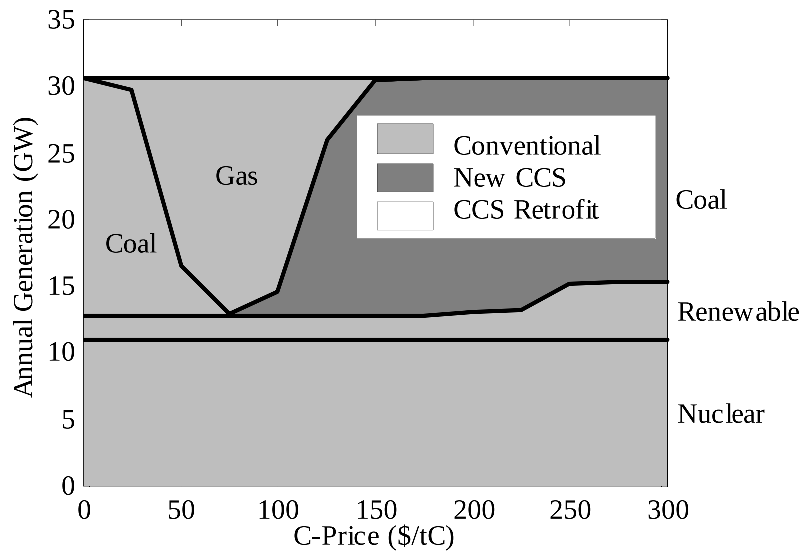
(b) 5800 hours/year

Figure 4.7 – Annual generation in period 6 (2026-2030) as a function of the price of carbon emissions, stratified by segment of the load-duration curve (see Figure 3.2b). The four bottom layers are shown: 3100 hours/year (a), 5800 hours/year (b), 7900 hours/year (c), and base load or 8760 hours/year (d). Conventional gas units meet demand for the top two segments (not shown). Note that coincidence of marginal-cost and carbon-ordered dispatch strategies with increasing carbon price.

[7] Note that, as discussed in Chapter 2, this approach to generating a mitigation supply curve is equivalent to imposing a constraint on CO_2 emissions and plotting the increase in undiscounted total costs as a function of the corresponding emissions reduction.



(c) 7900 hours/year



(d) 8760 hours/year

Figure 4.7 (Continued)

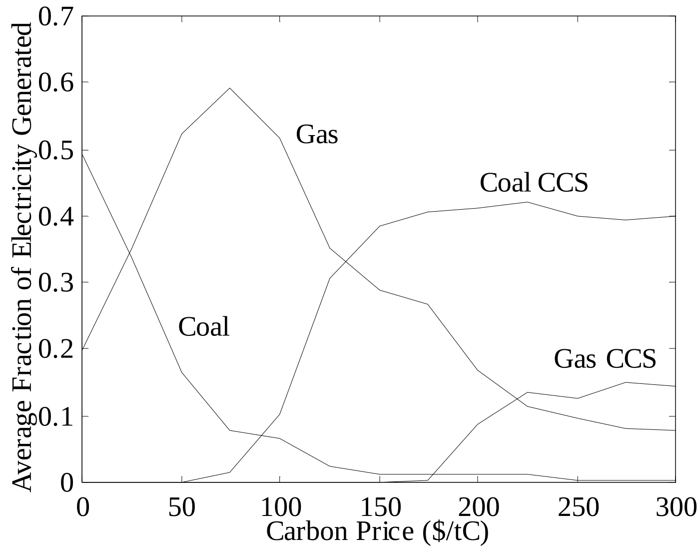


Figure 4.8 – Average fraction of electricity generated (from 2001 to 2040) versus carbon price for conventional coal- and gas-fired units and their carbon capture (“CCS”) counterparts. Not shown are nuclear generation (which remains constant at 27 percent) and the contribution from renewable sources (which increases at 250 $/tC from 5 to 10 percent).

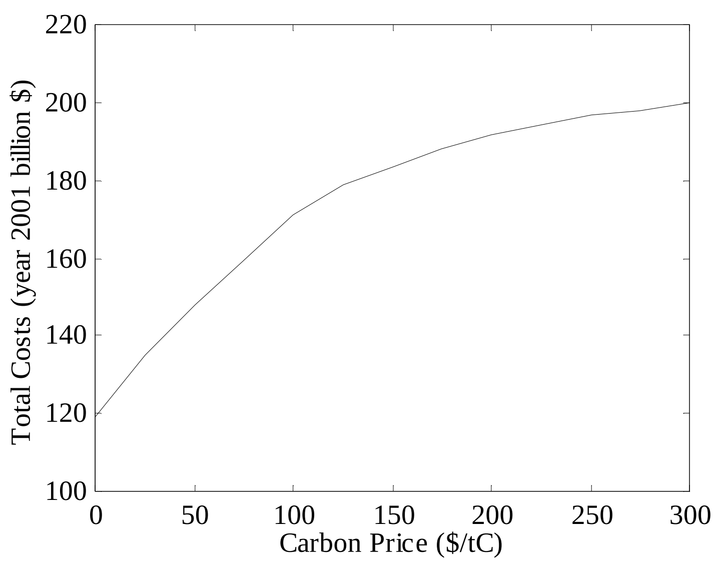


Figure 4.9 – Net present value of aggregate capital and marginal operating costs as a function of carbon emissions price. Equivalent to the minimum value of the LP optimization model’s objective function (see Chapter 3), the total cost figure represents the discounted sum of per-period new capacity expenses plus fixed and variable O&M costs.

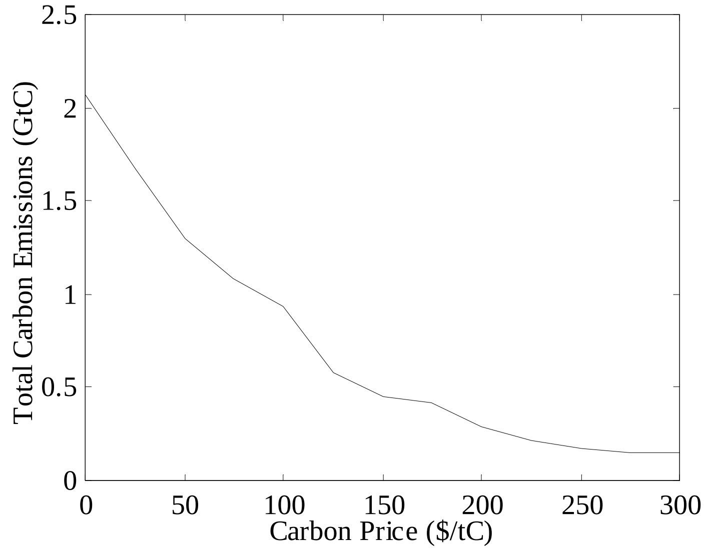


Figure 4.10 – Total (2001 to 2040) carbon emissions as a function of carbon emissions price.

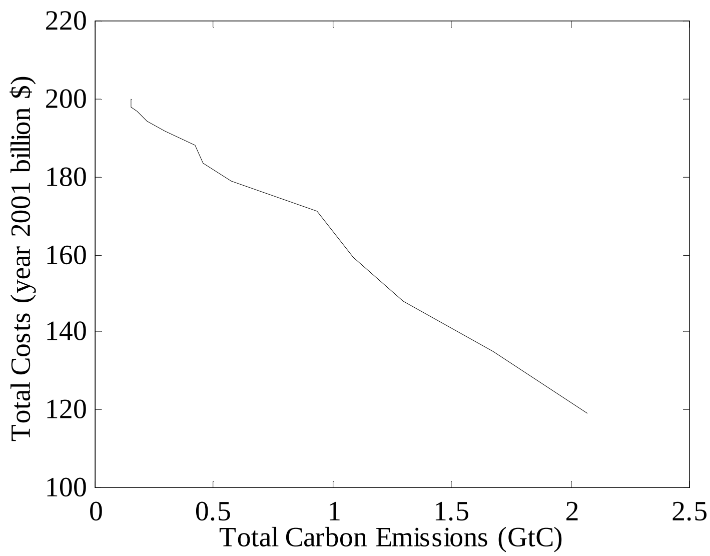


Figure 4.11 – Net present value of aggregate capital and marginal operating costs as a function of carbon emissions. The figure is the empirical counterpart to the theoretical electricity production function isoquant illustrated in Figure 2.1.

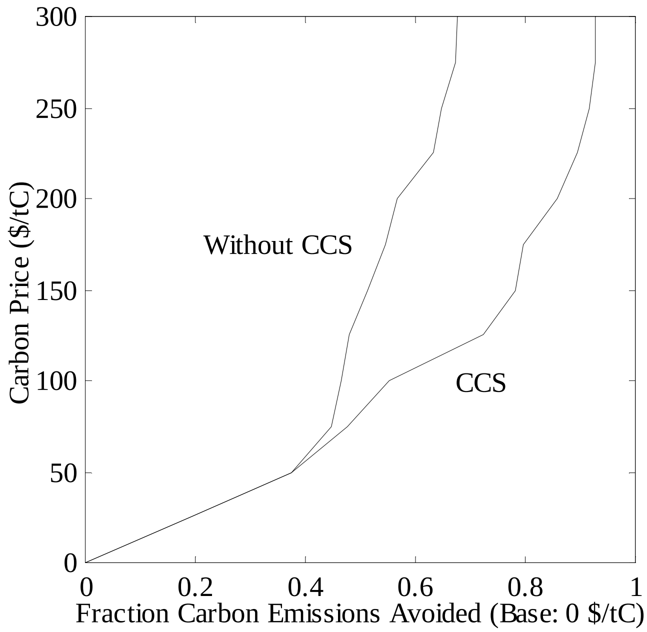


Figure 4.12 – Carbon mitigation cost curves when CCS technologies are available ("CCS") and when they are not ("Without CCS"). The mitigation cost curves represent a series of model runs, with carbon prices increasing from 0 to 300 $/tC in 25 $/tC increments. The discrete points on the curve reflect the reduction in 2001-2040 emissions under a given carbon price and 0 $/tC, expressed as a fraction of the latter (2.07 GtC).

4.4 Departures from Baseline Model Assumptions

4.4.1 Approaches to Scenario Analysis

The results from any modeling exercise depend on the model – its structure as well as the values of key parameters and inputs. Prudence therefore requires an examination of these assumptions and the extent to which outputs are sensitive to changes in model inputs and their interactions. Probabilistic methods (e.g., Monte Carlo simulation) provide one approach to assessing sensitivity; parametric analysis offers another (see, e.g., Morgan and Henrion, 1990). While gas prices, CCS technology costs, and future plant efficiencies, for instance, are uncertain and therefore lend themselves to characterization by some probability distribution (over which results from iterations of the model can be compared statistically), a parametric approach is adequate for the goals of this analysis – examining the extent to which particular model assumptions drive model results.

Two sets of assumptions are relevant here. On the one hand are parameters such as the discount rate and CCS technology specifications that affect overall model results, but do not interact with the modeling framework's representation of electric sector dynamics. In contrast are assumptions regarding natural gas price trends or multipollutant regulation that directly affect the attractiveness of CCS as a mitigation strategy. This division, of course, defines the ends of a spectrum, with the dividing line reflecting what is singled out for special attention.

The remainder of this section focuses primarily on the first set of assumptions and provides a needed check on the sensitivity of model results to more general changes in the baseline analysis. Scenarios examining the discount rate, demand-price interactions, load-duration curve profile, retirement of nuclear capacity, and performance of wind power are presented. The section also includes a parametric analysis of CCS technology specifications and carbon sequestration costs, and concludes with a brief look at a different NERC region. Chapter 5 then considers how particular assumptions regarding existing generating capacity, natural gas prices, and multipollutant regulation affect the adoption of CCS and associated mitigation costs. Table 4.4 summarizes results from this first set of analyses, with the two gas price scenarios from Section 5.1 added for convenience.

4.4.2 Discount Rates

Uncertainties related to electric market restructuring or the adoption of a novel technology like CCS may increase the cost of money, and therefore provide some justification for discount rates higher than the baseline model's 7.5 percent (Bernow, et al., 1996; Azar and Dowlatabadi, 1999). The three discount rate scenarios in Table 4.4 illustrate the effect of departures from this baseline. Note that gas-fired generation at low mitigation costs becomes more prevalent as the discount rate increases, and coal plant CCS retrofits enter the generating mix for higher levels of CO_2 abatement (Figure 4.13). The capital cost disadvantage of gas units in particular becomes less important under a

Table 4.4 – Scenario analysis results: entry of CCS technologies plus mitigation costs, average cost of electricity, and 2026-2030 fuel mix for 0, 50, and 75 percent emission reductions under various departures from the baseline model scenario (see the notes following the table for a definition of symbols and scenarios).

	Scenario	Baseline Model	Without CCS	5 % Discount Rate	10 % Discount Rate	15 % Discount Rate	Demand-Elasticity[a]	Flatter LDC[b]	Nuclear Retirement[c]	Better Wind[d]	Better Wind w/o CCS[d]
1st CCS ($/tC)[k]	*Coal*	75	n/a	75	75	75	75	75	75	75	n/a
	Gas	200	n/a	200	200	225	200	200	200	200	n/a
	Retrofit	*	n/a	*	*	175	*	*	*	*	n/a
0 % CO_2 Reduction	*Ave COE (c/kWh)*	2.37	2.38	2.37	2.38	2.40	2.33	2.29	2.62	2.38	2.37
	% Coal[l]	53	53	53	50	41	51	58	77	53	53
	% Gas	19	19	19	22	32	19	14	19	19	19
	% Renewable	27	27	27	27	27	30	28	4	27	27
50 % CO_2 Reduction	*Mitig. Cost ($/tC)*	83	141	79	99	124	79	75	73	76	82
	Ave COE (c/kWh)	3.30	3.78	3.24	3.42	3.66	3.17	3.18	3.66	3.24	3.28
	% Retrofit[l]	0	n/a	0	0	1	0	0	0	0	n/a
	% CCS	1	n/a	2	0	2	0	0	0	0	n/a
	% Coal	1	0	2	0	2	0	0	1	1	0
	% Gas	71	70	70	72	71	70	72	95	71	68
	% Renewable	27	30	28	27	28	30	28	4	29	31
75 % CO_2 Reduction	*Mitig. Cost ($/tC)*	137	#	120	163	175	139	129	130	131	243
	Ave COE (c/kWh)	3.67	#	3.47	3.89	4.18	3.54	3.55	4.07	3.57	3.82
	% Retrofit[l]	0	n/a	0	1	4	0	0	0	0	n/a
	% CCS	33	n/a	33	35	36	32	28	37	20	n/a
	% Coal	33	#	33	35	36	32	28	37	20	0
	% Gas	39	#	39	37	37	39	44	59	40	25
	% Renewable	28	#	28	28	27	30	28	4	40	75

(Table 4.4 continues on the following page.)

Table 4.4 (Continued)

	Scenario	Baseline Model	Worse CCS[e]	Better CCS[f]	45 $/tC Sequestration[g]	15 $/tC Sequestration[g]	+ 20 $/tC Sequestration[h]	ERCOT[i]	ERCOT w/o CCS[i]	2.50 $/GJ Gas[j]	4.20 $/GJ Gas[j]
1st CCS ($/tC)[k]	*Coal*	75	175	50	100	75	25	75	n/a	125	75
	Gas	200	*	100	225	175	150	175	n/a	175	250
	Retrofit	*	*	50	*	*	25	*	n/a	*	125
0 % CO_2 Reduction	*Ave COE (c/kWh)*	2.37	2.38	2.38	2.37	2.38	2.37	2.71	2.70	2.27	2.53
	% Coal[l]	53	53	53	53	53	53	39	39	11	57
	% Gas	19	19	19	19	19	19	53	53	62	17
	% Renewable	27	27	27	27	27	27	8	8	27	26
50 % CO_2 Reduction	*Mitig. Cost ($/tC)*	83	140	45	109	69	21	118	217	140	86
	Ave COE (c/kWh)	3.30	3.77	2.91	3.52	3.14	2.61	3.93	4.65	3.48	3.63
	% Retrofit[l]	0	0	9	0	0	20	0	0	0	1
	% CCS	1	0	18	2	6	33	13	0	17	22
	% Coal	1	0	26	2	9	41	13	0	17	44
	% Gas	71	70	47	71	64	32	79	68	56	29
	% Renewable	27	30	27	28	28	27	8	32	28	28
75 % CO_2 Reduction	*Mitig. Cost ($/tC)*	137	211	72	165	109	49	166	#	187	99
	Ave COE (c/kWh)	3.67	4.26	3.11	3.90	3.42	2.83	4.20	#	3.69	3.72
	% Retrofit[l]	0	0	10	0	0	22	1	#	0	1
	% CCS	33	20	46	30	35	52	62	#	44	44
	% Coal	33	20	46	30	35	52	44	#	26	46
	% Gas	39	44	27	43	38	20	48	#	46	26
	% Renewable	28	36	27	28	27	27	8	#	28	28

(Table 4.4 continues on the following page.)

Table 4.4 (Continued)

Symbols Used in Table 4.4:

n/a Not applicable ("Without CCS" scenarios)

* Technology does not enter the generating mix below a 300 $/tC mitigation cost

A 75 percent emission reduction is not achieved for scenario below 300 $/tC

Notes to Table 4.4:

a. Demand reduced by 7.3% to reflect the increase in end-user electricity prices resulting from a 75 percent CO_2 emission reduction.
b. Non-constant load duration curve profile; peak demand grows slower than baseload, though per-period electricity generation remains at baseline levels.
c. Phase-out of existing nuclear capacity by the end of period 5 (2021-2025).
d. 20 percent reduction in wind capital, variable, and fixed O&M costs.
e. 20 percent increase in CCS capital, variable, and fixed O&M costs coupled with a 20 percent reduction in CCS generating efficiencies.
f. 20 percent reduction in CCS capital, variable, and fixed O&M costs coupled with a 20 percent increase in CCS generating efficiencies.
g. Cost of CO_2 sequestration, including transportation.
h. An unlimited amount of CO_2 may be sold for a market price of 20 $/tC.
i. Model revised for the Electric Reliability Council of Texas NERC region.
j. Period 1 (2001-2005) gas prices; prices increase at baseline 4% per period rate.
k. "1st CCS" is the mitigation cost (in $/tC) at which the generation from a particular CCS technology exceeds an annual average of 1 GW.
l. Period 6 (2026-2030) electricity generation by technology/fuel.

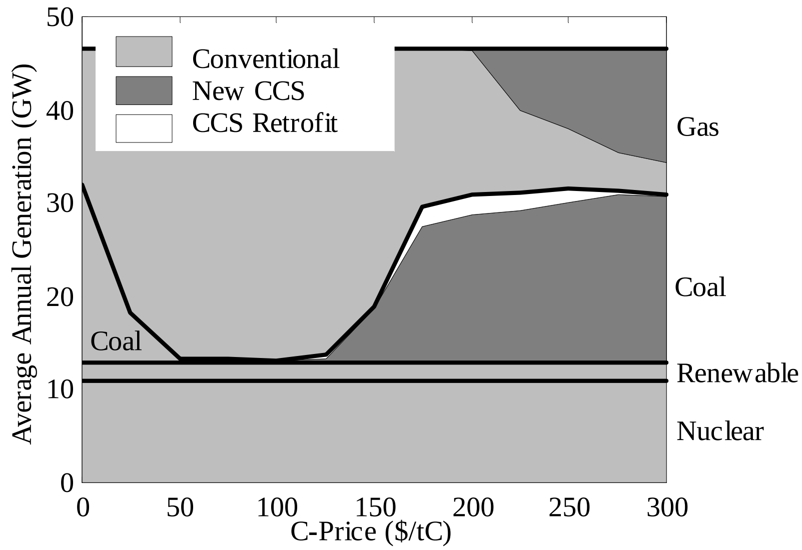


Figure 4.13 – Average annual generation in period 6 (2026-2030) as a function of carbon price for a 15 percent discount rate (compare to figure 4.6a).

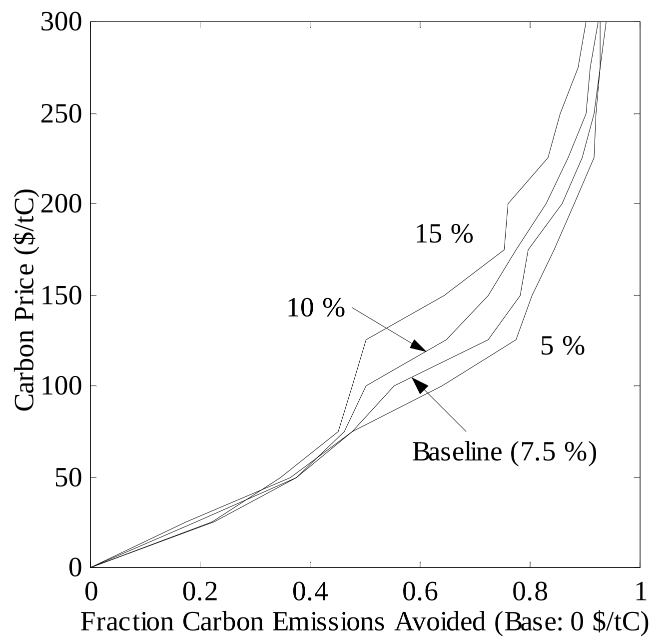


Figure 4.14 – The cost of carbon mitigation as a function of discount rate. Mitigation costs are shown for three discount rates (5, 10, and 15 percent) relative to the baseline model 7.5 percent. See Figure 4.12 for details concerning figure calculations.

higher discount rate, especially in later model periods when existing capacity looses its economic advantage.

Larger discount rates also increase mitigation costs (Figure 4.14). As discussed in Chapter 5, a reduction in the relative cost of gas-fired electricity generation lowers total costs only for moderate levels of CO_2 control. With a combination of renewable, nuclear, and near-zero emissions IGCC plants necessary to achieve emission reductions above 95 percent, total costs as a function of CO_2 mitigation will converge to baseline levels. Plotted against CO_2 reduction, the total cost curve under a gas-friendly scenario will therefore rise more steeply, and mitigation costs – the derivative of the total cost curve – will be correspondingly greater.

4.4.3 Demand Elasticity Effects

A significant constraint on CO_2 emissions will lead to a substantial increase in the cost of electricity, and one is therefore led to ask about the impact of this increase on electricity consumption. While the issue is addressed here, note that a bottom-up model such as this cannot capture the cross-fuel substitution and other consumption effects such a change might have. As discussed at the end of Chapter 2, a price on carbon emissions could result in greater electricity demand if the tax (or similar regulatory mechanism) was applied unevenly across fuel sources, or if mitigation costs were lower for electricity producers than, say, domestic users of natural gas. In exploring demand elasticity, the goal is therefore not to attempt a general equilibrium analysis but to determine whether elasticity effects significantly alter the general findings regarding CCS.

Returning to the base model, a 75 percent emissions reduction (approximately equivalent to a 140 \$/tC carbon price) increases the average cost of generating electricity from 2.37 to 3.67 cents/kWh. Taking into account that transmission and distribution through the MAAC region contribute an additional 3 cents/kWh (EIA, 2001a), this represents a 24 percent increase to the end-user price of electricity. Assuming a short-run demand elasticity of –0.30 for electricity (an estimate from the middle of the range cited by Bohi [1981], and similar to values reported by Branch [1993] and Hsing [1994]), one would expect to see consumption decrease nearly 7.3 percent. A model run with demand reduced accordingly produces only marginal changes in CO_2 mitigation costs (Figure

4.15; see the "Demand-Elasticity" scenario of Table 4.4). To the first order, therefore, short-run demand-price interactions do not significantly affect the outcome of the analysis.[8]

The long-run elasticity of electricity demand, of course, is much greater. Bohi (1981) provides estimates on the order of –1.30, which translates into a 32 percent decrease in electricity consumption, *all else being equal*. Carbon emissions will decrease in tandem with demand, and the costs of achieving an emissions reduction equivalent in magnitude to baseline scenario will be significantly greater. This line of reasoning is incomplete, however, since a carbon constraint would likely affect energy prices across all sectors of the economy and the direction of the assumed energy substitutions is difficult to predict. Long-run electricity consumption, despite higher end-user prices, could increase at the expense, say, of domestic natural gas. A general equilibrium model is needed to address these complex economic interactions.

4.4.4 Load-Duration Curve Profile

A related demand issue concerns not the total amount of electricity generated, but the pattern of that generation. Time-of-day pricing or other demand-side management strategies, for instance, could be used to limit new capacity requirements or expensive purchases of power during short-duration periods of high demand. Though total electricity generation might not change, peak power loads over the course of a day would. The baseline model's assumption a constant load-duration curve profile (i.e., a constant peak power to total electricity ratio) could therefore be misleading.

[8] A more complete analysis of demand-elasticity effects would involve several iterations, stopping when the increase in average COE arising from (in this case) a 75 percent cut in baseline CO_2 emissions produces a sufficiently small decrease in electricity consumption. In addition, a more ideal analysis would estimate the changes in demand over time corresponding to per-period changes in generation costs (rather than the average COE increase). This level of accuracy, however, also requires consideration of more complex energy-source substitutions (e.g., natural gas for electricity, or vice-versa) that depend on policy and economic factors that lie outside of this analytical framework.

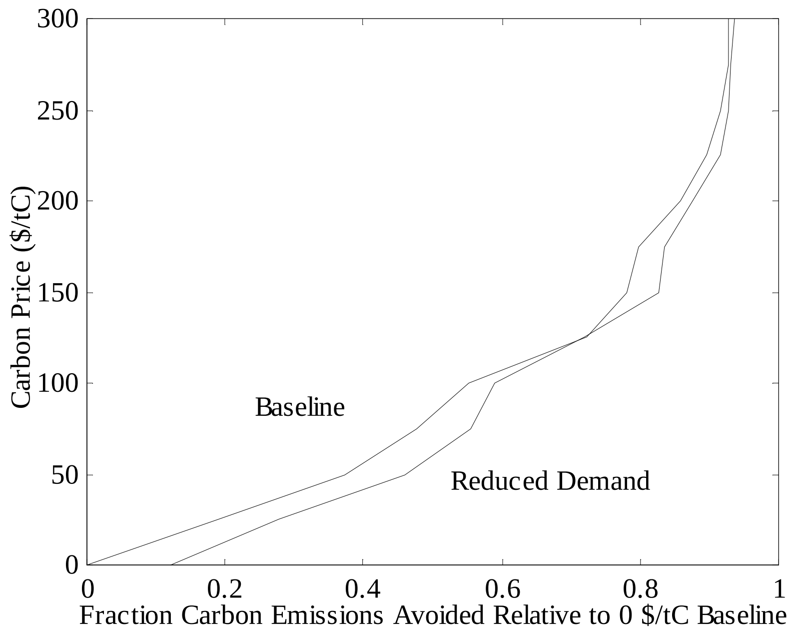


Figure 4.15 – The effect of demand-price elasticity effects on CO_2 mitigation costs. "Reduced Demand" reflects a 7.3 percent decrease in per-period electricity consumption from that assumed in the baseline scenario (see the text for calculations). Note that the 0 $/tC emissions level of the baseline run is used to calculate the fraction of CO_2 avoided for both scenarios. The horizontal distance between the curves at 0 $/tC therefore estimates the extent to which demand changes alone reduce emissions. See Figure 4.12 for details concerning figure calculations.

The "Flatter LDC" scenario of Table 4.4 examines the implications of assuming a static LDC profile. Starting from the baseline model's period 1 demand profile (see Figure 3.1), the individual strata of the revised scenario's LDC increase unevenly with time – from a peak power growth rate of 0.02 per-period to 0.10 for base load (compared to a uniform 0.08 per-period baseline rate). The revision cuts peak power demand by 18 percent in 2036-2040, though per-period energy production remains the same. Beyond the slightly lower generating costs that result from reductions in new capacity, however, the flatter LDC profile does not have a significant effect on mitigation costs. Operating costs remain roughly the same, while discounting reduces the benefit of lower capital costs in later periods.

4.4.5 Nuclear Power

The future of nuclear power in the US is uncertain. A substantial CO_2 constraint would certainly prompt serious discussion about new nuclear construction. Whether an expansion of nuclear power could overcome its associated political hurdles would depend on the attractiveness of renewable energy and gas-fired generation, at least partial resolution of the waste disposal issue, and a significant shift in public perception – not to mention the feasibility of CCS. The baseline model excludes new nuclear capacity, but maintains existing plants – a trend compatible with current industry-wide relicensing plans (Moore, 2000). Used exclusively for baseload generation (see Figures 4.1 and 4.6), existing MAAC region nuclear plants are a significant CO_2-free source of electricity.

Table 4.4 includes a scenario ("Nuclear Retirement") in which the MAAC region's 13.7 GW of nuclear capacity is phased out by 2025 (the end of period 5). Overall mitigation costs do not change, though the average cost of generating electricity increases with the need to build replacement capacity. Additional coal-fired units are favored at all mitigation costs, in both conventional and CCS guises. With early nuclear retirement, CO_2 emissions are nearly 25 percent higher than the baseline model's 0 \$/tC profile (shown in Figure 4.5), but coincide for carbon prices above 125 \$/tC. CCS plant operating costs are on par with nuclear generation, and the capital expenditure required to replace nuclear capacity falls too far out in the (discounted) future to have a significant effect on mitigation costs.

4.4.6 Wind Power as a Competitor to CCS

While new nuclear plants could provide a technically viable alternative to CCS, renewable energy sources are often thought of as the preferred means of achieving long-term electric sector CO_2 reduction (McGowan and Connors, 2000). The model includes wind technologies – next to biomass perhaps the most feasible renewable option currently available. Under baseline specifications, however, CCS dominates wind economically (compare Figures 4.6a and b), and one is therefore led to ask how much better the assumptions about wind turbines must be before wind power becomes competitive with CO_2 capture.[9]

Figure 4.16 provides an answer to this question by illustrating how a 20 percent improvement in baseline wind costs (capital and marginal) reduces adoption of new coal-fired CCS plants (compare this generating mix to the Figure 4.6a baseline profile). The substitution of wind for CCS, however, has little effect on mitigation costs (see the "Better Wind" scenario in Table 4.4), *except* when CCS technologies are not available (Figure 4.17). Relative to CCS, the more significant constraint on wind-generated electricity in this model is its availability, not cost *per se*. MAAC region wind resources (at best, class IV) limit dispatch to 25 percent of installed capacity (see McGowan and Connors [2000] for the relationship). Increasing this availability by half (effectively cutting the $/kW capital cost by a third), for instance, nearly drives out all CCS when coupled with the same 20 percent cost improvements.

[9] Recall from Chapter 3 that the baseline model provides a reasonably accurate representation of wind costs and performance specifications, but does not explicitly consider power storage or back-up. This section does not address these issues further.

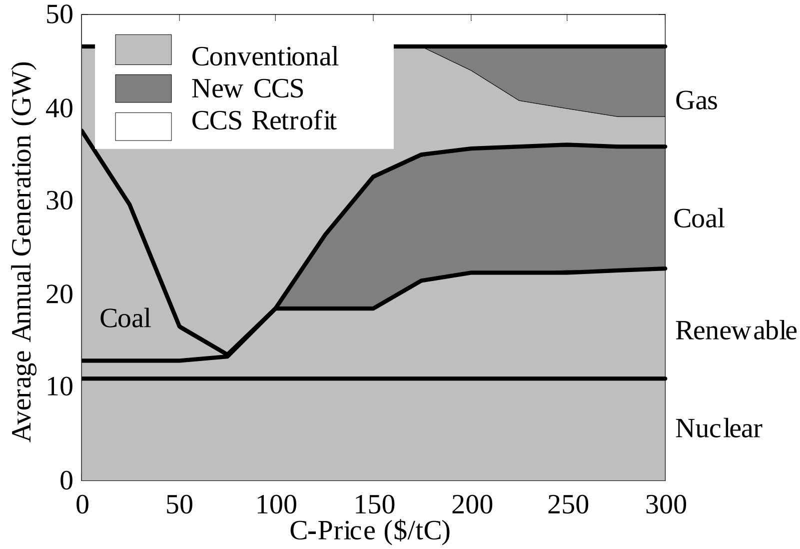


Figure 4.16 – Average annual generation in period 6 (2026-2030) as a function of carbon price for a 20 percent reduction in all wind costs (capital as well as fixed and variable O&M). Compare to Figure 4.6a.

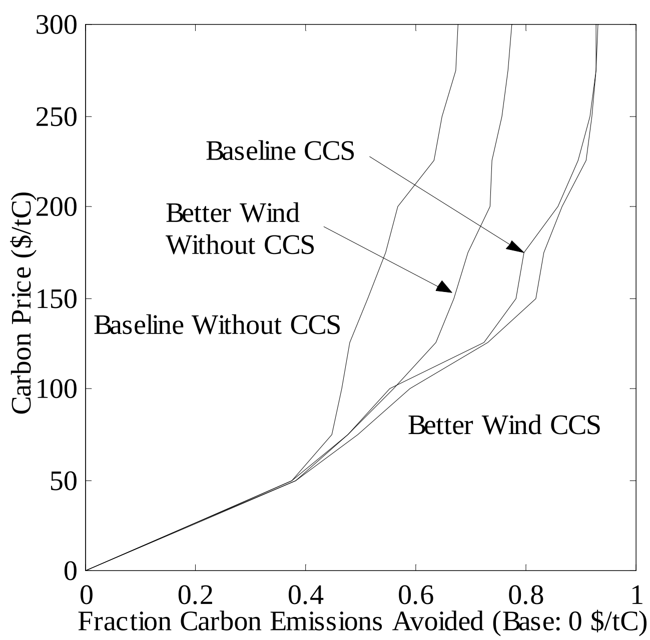


Figure 4.17 – CO_2 mitigation supply curves for a 20 percent reduction in all wind costs (capital as well as fixed and variable O&M) compared to the baseline model. Cheaper wind generation only affects mitigation costs in the absence of CCS technologies (the "Without CCS" scenarios). See Figure 4.12 for details concerning figure calculations.

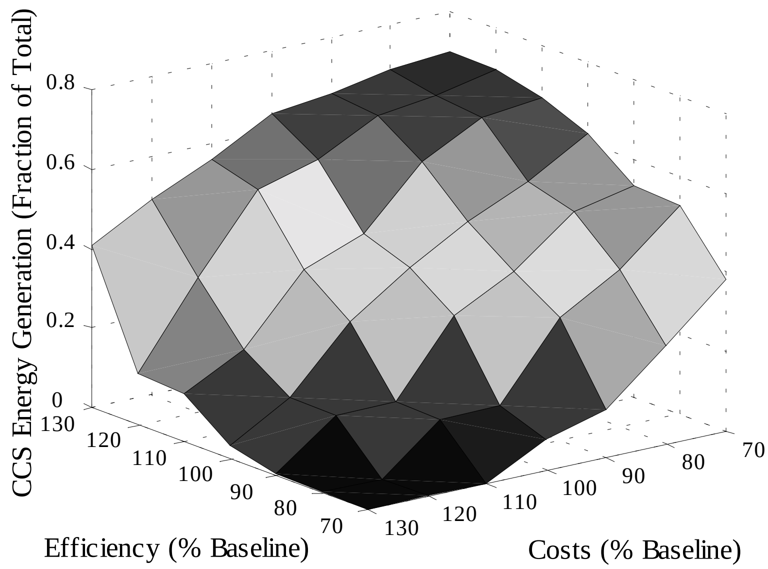
4.4.7 CCS Cost and Performance Specifications

Among the more intuitive drivers of mitigation costs in a world with CCS are the operating characteristics of generating plants with CO_2 capture. Confronted with the need to make assumptions about a novel technology in an uncertain future, the sensitivity of baseline model performance to CCS costs and efficiencies therefore requires examination. A modeling framework such as this is particularly suited to such an analysis as it allows one to (at least conceptually) work backward and focus on the range of model parameters over which CCS technologies achieve, for instance, a given market penetration. Working from this direction eliminates the need to specify in advance a range of likely parameter values. Figures 4.18 and 4.19 take this approach and illustrate how both the share of CCS electricity generation and aggregate carbon emissions vary with departures from baseline CCS costs and plant efficiencies.[10] Figure 4.20 provides more detail about how these departures affect mitigation costs.

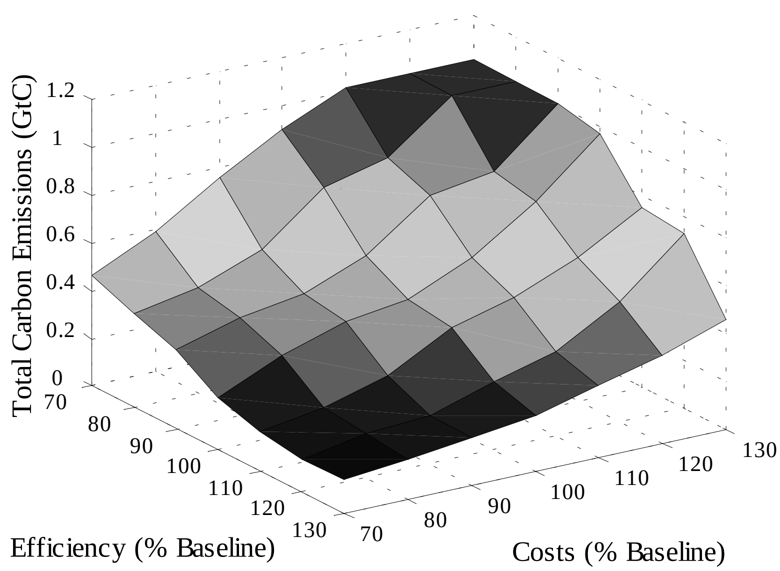
Note that all CCS units (new coal and gas, plus coal retrofits) meet nearly 40 percent of the baseline model's 2026-30 electricity demand under a 150 \$/tC emissions price (for which the results are shown). As Figure 4.18 illustrates, the share of CCS-generated electricity is less sensitive to potential pessimism regarding assumed CCS costs and efficiencies than excessive optimism, though opposing changes in these parameters tend to negate any effect. A more detailed analysis of CCS cost assumptions (Figure 4.19) shows that CCS adoption and total emissions are more sensitive to variation in baseline capital requirements than equivalent changes in operating costs. Under a significant emissions price, CCS continues to offer the lowest-cost baseload electricity generation (excluding existing nuclear), even when marginal costs are higher than anticipated.

Mitigation costs, however, are equally sensitive to positive and negative deviations from CCS cost and technology assumptions (Figure 4.20). Corresponding to Figure 4.20, the "Better CCS" and "Worse CCS" scenarios of Table 4.4 provide additional detail. These scenarios confirm the asymmetric impact positive and negative departures from baseline assumptions have on the share of CCS-generated electricity, but

[10] Note that as retrofit capital costs depend on the associated energy penalty (and, hence, retrofit plant efficiencies), CCS costs and efficiencies as shown here are not truly independent.

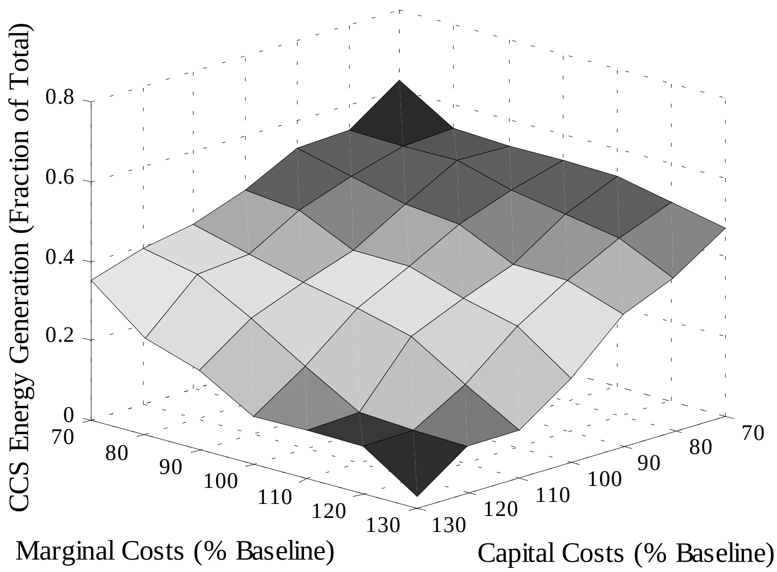


(a)

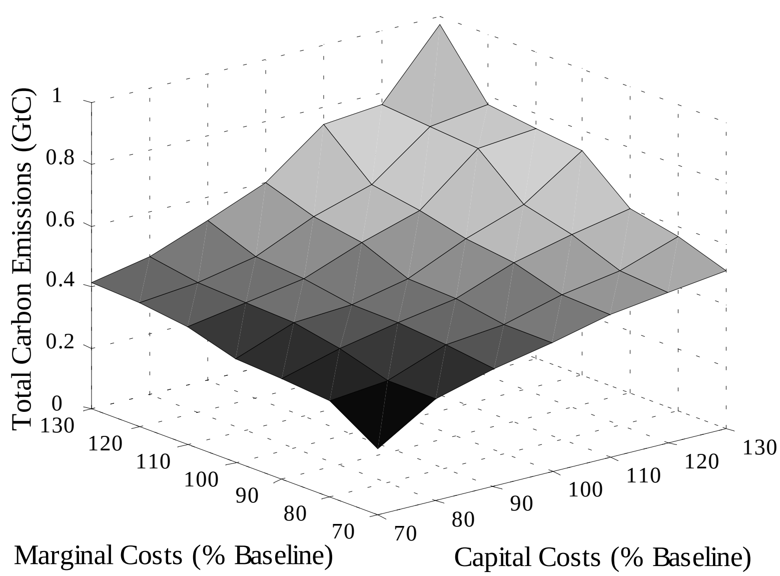


(b)

Figure 4.18 – Fraction of electricity produced by all CCS generating units in period 6 (2026 to 2030) (a) and aggregate (2001 to 2040) carbon emissions (b) as a function of CCS costs and efficiencies under a 150 $/tC emissions price. Costs include capital plus fixed and variable O&M, and both sets of model parameters are shown as a percentage of their baseline specifications. Note the shift in axis orientation between the two figures.



(a)



(b)

Figure 4.19 – Fraction of electricity produced by all CCS generating units in period 6 (2026 to 2030) (a) and aggregate (2001 to 2040) carbon emissions (b) as a function of CCS capital and marginal operating costs under a 150 \$/tC emissions price. Marginal costs include fixed and variable O&M, and both sets of model parameters are shown as a percentage of their baseline specifications. Note the shift in axis orientation between the two figures.

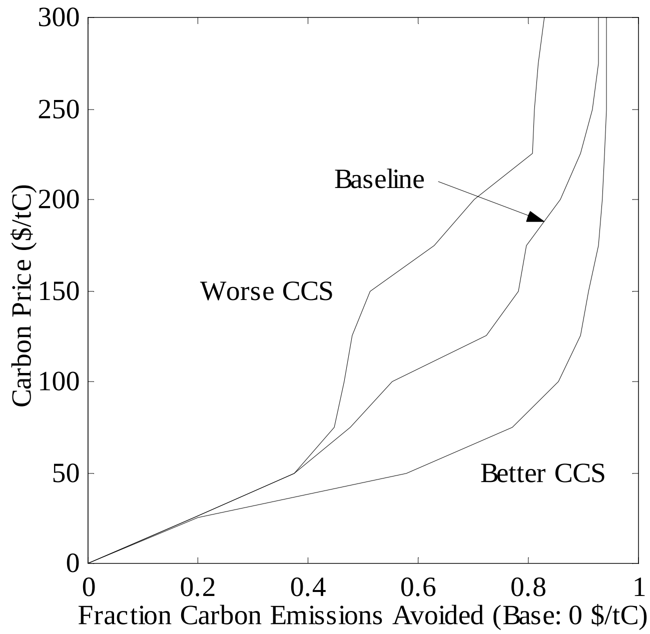


Figure 4.20 – The cost of carbon mitigation as a function of deviations from baseline CCS performance. The scenarios shown reflect a 20 percent reduction in assumed variable and fixed CCS costs coupled with a 20 percent improvement in CCS plant efficiencies ("Better CCS"), and an equivalent increase in costs coupled with the same reduction in efficiency ("Worse CCS"). See Figure 4.12 for details concerning figure calculations.

also illustrate how an improvement (20 percent) in CCS technology specifications significantly lowers cost estimates even for modest levels of CO_2 abatement. Over time, efficiency improvements and (in particular) cost reductions on this order are not unreasonable when one takes into account the learning-by-doing that typically results from accumulated experience with a new technology.

4.4.8 CO_2 Sequestration Costs

Like capture costs, assumptions made about the feasibility of sequestering CO_2 affect mitigation cost estimates. Actual sequestration cost assessments, however, must take into account a greater variety of nontechnical considerations and are site-specific

(Herzog, Drake, and Adams, 1997). Significant uncertainties exist, for instance, concerning the physical capacity and stability of reservoirs, the regulatory environment for sequestration, the long-term costs of monitoring and verification, and the public's willingness to accept underground CO_2 injection. While these issues could lead to sequestration costs much greater than the baseline model's 30 $/tC, CO_2 may also be sold for enhanced oil recovery (EOR) or enhanced coalbed methane extraction (ECBM). Where feasible, such uses could supply important and early niche markets for CO_2 produced by fossil-electric power plants, thereby encouraging development of CCS technologies. Subsequent experience-related cost reductions and performance improvements would then encourage longer-term industry adoption of CCS.[11]

Figure 4.21 and Table 4.4 illustrate how baseline model performance varies with sequestration cost, including a scenario in which an unlimited amount of CO_2 may be sold for 20 $/tC.[12] Mitigation costs are most sensitive to sequestration price for emission reductions above 40 percent (near the point at which CCS units enter the generation mix), although they converge as capture technology costs dominate sequestration expenses for abatement levels above 90 percent. When CO_2 has economic value, however, CCS retrofits enter the generating mix without the inducement of an emissions price and overall mitigation costs decrease substantially. While current demand for CO_2 in the eastern US is minor and sequestration costs are likely to be near the baseline level, this is not the case in oil-producing regions like Texas where the ability to capture and sell CO_2 could fundamentally alter the economics of near-term electric sector emissions abatement.

[11] See, e.g., Grubler, Nebojsa, and Victor (1999) for a discussion of the importance of niche markets in technology development and diffusion.

[12] CO_2 from natural sources currently sells for approximately 20 $/tC, although transportation costs increase this price for CO_2 injected at more remote locations (Stevens and Gale, 2000). As mentioned in Chapter 1, however, commercial and industrial demand for CO_2 is much lower than what the electric sector could supply with widespread CCS adoption. A flat selling price for CO_2 ignores this disequilibrium and more realistic demand-price interactions.

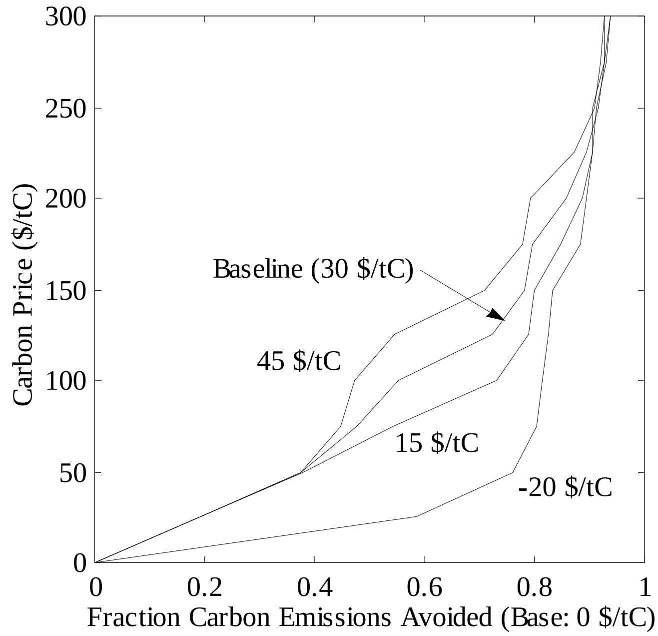


Figure 4.21 – The cost of carbon mitigation as a function of CO_2 sequestration cost. The "-20 $/tC" curve reflects a scenario in which an unlimited amount of CO_2 may be sold for 20 $/tC; all other curves treat sequestration as an expense. See Figure 4.12 for details concerning figure calculations.

4.4.9 Regional Differences

That CO_2 mitigation costs may be at least partly region-dependent points to the need for a look at CCS in electricity generation outside the MAAC region of the eastern US. Aside from geographical variations in sequestration costs, electric markets will differ in the age and fuel-cycle distribution of their existing plants, prices for both coal and natural gas, demand patterns and growth projections, the extent of market restructuring, and the stringency of conventional pollutant regulation. This scenario analysis therefore concludes with a brief look at a second NERC region, the Electric Reliability Council of Texas (ERCOT).

Covering all but the western-most parts of Texas (see Figure 3.1), ERCOT – like MAAC-PJM – is both a NERC region and an independent systems operator. ERCOT's greater reliance on gas-fired electricity generation (Table 4.5), more convenient natural gas supplies and lower prices, and potentially profitable demand for captured CO_2, however, provide a good contrast to MAAC. In a further departure from MAAC, approximately three-fourths of ERCOT's gas-fired generating units are steam cycle plants rather than combustion turbines. Complementing a smaller coal and nuclear fleet, natural gas therefore plays a larger role in meeting ERCOT base-load electricity demand.

Table 4.5 – Comparison of existing generating capacity in the MAAC and ERCOT NERC regions *as represented* in the baseline model (EIA, 2001a; EPA, 2001).

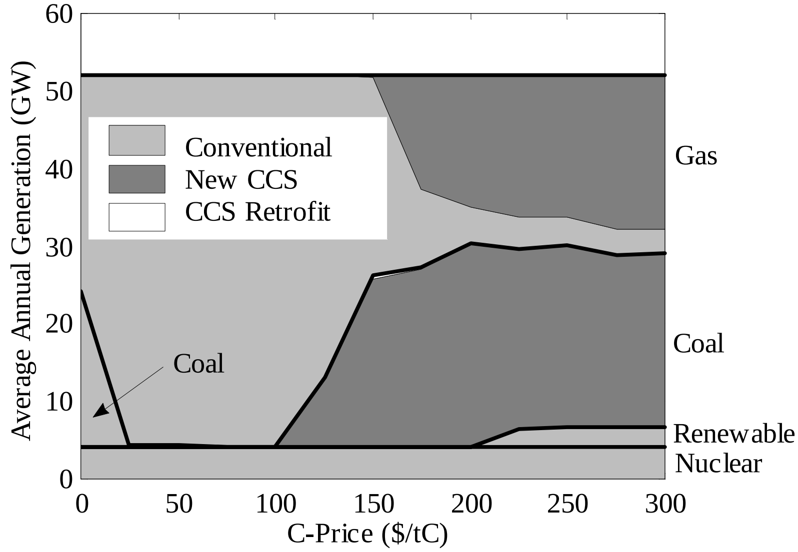
	Current Installed Capacity (GW)	
Generating Technology	*MAAC*	*ERCOT*
Pulverized Coal Steam Plant	24.9	17.4
Single-cycle Gas Turbine	6.5	9.6
Combined-cycle Gas Turbine	1.7	0
Gas-fired Steam Plant	0	31
Single-cycle Oil Turbine	6.4	0
Nuclear	13.7	5.1
Hydro-electric	2.3	0.5

Beyond changes in the initial fuel-cycle distribution of generating units, the revised "ERCOT model" begins from a lower period 1 price for natural gas sold to utilities (2.75 $/GJ versus 3.20 $/GJ, following EIA [2001b] projections), though the rate of increase maintains its baseline level. Peak demand in ERCOT begins at 58 GW (11.5 percent higher than MAAC), with the Figure 3.2b load-duration curve scaled accordingly and the original 8 percent per-period growth rate left unchanged. At 20 $/tC in the revised model, sequestration costs are lower than that assumed for the eastern US, reflecting the ability to sell at least some CO_2 for EOR and the fact that the region's depleted oil and gas reservoirs provide both accessible and well-characterized injection sites. Finally, cost and performance specifications for the ERCOT gas-fired steam cycle plants are from Beamon and Leckey (1999); all other generating unit parameters maintain their baseline values.[13]

Figures 4.22 and 4.23 as well as Tables 4.6 and 4.7 summarize key results from the capacity planning and dispatch model as tailored for ERCOT. The greater role played by gas-fired generation in both conventional and CO_2-capture guises is apparent, though CCS technologies enter the generating mix at the same mitigation cost (compare Figures 4.6 and 4.22, as well as Tables 2 and 6). Relative to MAAC, the cost of reducing ERCOT CO_2 emissions is greater (Figure 4.23) – a result due in part to the latter region's smaller nuclear baseload, as well as the greater competitiveness of gas-fired generation (versus CCS) at more modest levels of CO_2 control.

The ERCOT and MAAC mitigation cost profiles, however, are similar and actually converge for CO_2 reductions above 80 percent when expressed as a fraction of each region's 0 $/tC emissions. As illustrated in this chapter, dispatch dynamics as well as technology-specific factors drive mitigation cost estimates. The first section of Chapter 5 returns to the MAAC region and builds on this analysis, examining in greater detail how the initial fuel-cycle distribution of installed capacity and gas prices interact with electric sector dynamics to affect the adoption of CCS and cost of CO_2 control.

[13] More specifically, the revised model includes two pre-existing vintages of gas-fired steam cycle plants, stratified by thermal efficiency: 13 GW at 29 percent and 18 GW at 34 percent (EIA, 1999; EIA2001b; EPA, 2001). Common to both plant categories, variable and fixed O&M cost figures of 25 cents/kWh and 20 $/kW, respectively, are adapted from Beamon and Leckey (1999). The revised model does not include new gas-fired steam cycle units, avoiding the need to make capital cost assumptions. Regarding pulverized



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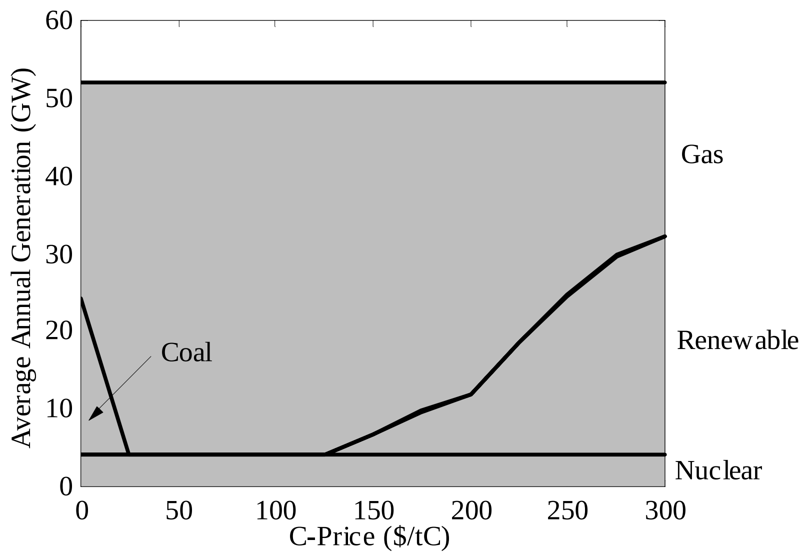

(b)

Figure 4.22 – Average annual generation in period 6 (2026-2030) for the ERCOT NERC region as a function of carbon price when CCS technologies are (a) and are not (b) available.

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coal plants, the assumed ERCOT distribution breaks down as: 4.3 GW of PC1, 12 GW of PC2, and 1.1 GW of PC3 (EIA, 1999; EIA2001b; EPA, 2001).

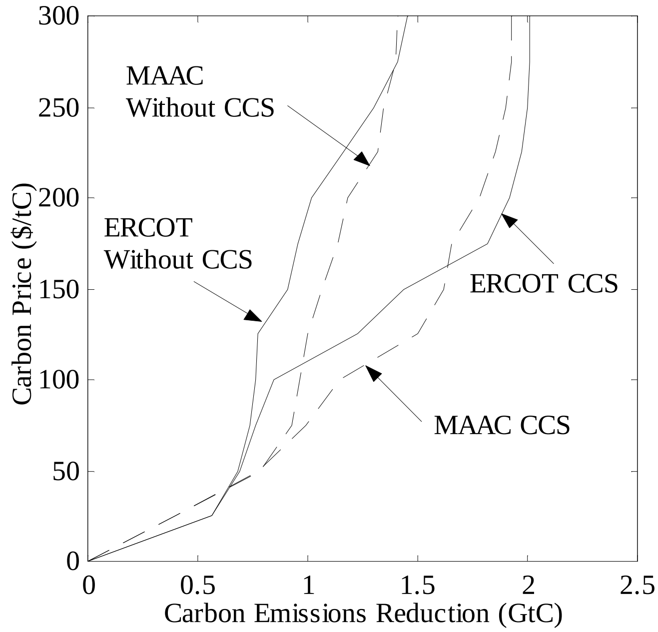

Figure 4.23 – Carbon mitigation cost curves for the ERCOT and MAAC NERC regions (solid and broken lines, respectively), when CCS technologies are available ("CCS") and when they are not ("Without CCS"). Mitigation costs are shown as a function of actual emission reductions as the uncontrolled bases differ for the regions (2.24 GtC for ERCOT and 2.07 GtC for MAAC at 0 $/tC). See Figure 4.12 for details concerning figure calculations.

Table 4.6 – ERCOT model total (2001-2040) new capacity additions by generating technology for select carbon emissions prices when CCS technologies *are* available. (PC = pulverized coal, IGCC = integrated coal gasification combined-cycle, GT = single-cycle gas turbine, NGCC = combined-cycle gas turbine, CCS = carbon capture and sequestration.)

Total New Capacity (GW)							
	Carbon Emissions Price ($/tC)						
Technology	*0*	*50*	*100*	*150*	*200*	*250*	*300*
PC 1	0	0	0	0	0	0	0
PC 2	0	0	0	0	0	0	0
PC 3	0	0	0	0	0	0	0
PC 4	41	0	0	0	0	0	0
IGCC	16	6	0	0	0	0	0
IGCC+CCS	0	0	22	56	57	54	54
GT	23	36	34	24	23	22	21
NGCC	53	76	70	50	20	18	17
NGCC+CCS	0	0	0	0	26	29	32
Oil	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0
Wind	0	0	0	0	0	9	8
PC 1 Retrofit	0	0	0	0	0	0	0
PC 2 Retrofit	0	0	0	0	0	0	0
PC 3 Retrofit	0	0	0	1	0	0	0
PC 4 Retrofit	0	0	0	0	0	0	0

Table 4.7 – ERCOT model total (2001-2040) new capacity additions by generating technology for select carbon emissions prices when CCS technologies *are not* available. (PC = pulverized coal, IGCC = integrated coal gasification combined-cycle, GT = single-cycle gas turbine, NGCC = combined-cycle gas turbine, CCS = carbon capture and sequestration.)

Total New Capacity (GW)							
	Carbon Emissions Price ($/tC)						
Technology	*0*	*50*	*100*	*150*	*200*	*250*	*300*
PC 1	0	0	0	0	0	0	0
PC 2	0	0	0	0	0	0	0
PC 3	0	0	0	0	0	0	0
PC 4	42	0	0	0	0	0	0
IGCC	16	6	0	0	0	0	0
IGCC+CCS	0	0	0	0	0	0	0
GT	23	37	36	36	33	27	23
NGCC	54	76	81	71	64	48	44
NGCC+CCS	0	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0
Wind	0	0	5	32	59	126	165
PC 1 Retrofit	0	0	0	0	0	0	0
PC 2 Retrofit	0	0	0	0	0	0	0
PC 3 Retrofit	0	0	0	0	0	0	0
PC 4 Retrofit	0	0	0	0	0	0	0

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Chapter 5: Factors Affecting the Cost of CO_2 Control Via CCS

5.1 Chapter Overview

This chapter extends the baseline model analysis (Chapter 4) by discussing three topics that are likely to affect the role CCS might play in electric sector CO_2 mitigation. Section 5.2 begins by examining natural gas prices and the "free lunch" emissions reduction accompanying turn-over of the existing electric power generating infrastructure. The current mix of plants is out of economic equilibrium in that it does not reflect current factor prices and technological capabilities; Section 5.2 assesses the extent to which both this non-optimal starting point and gas prices affect electric sector mitigation cost estimates. Addressing a second issue that involves existing generating capacity, Section 5.3 looks at CCS retrofits of vintage coal plants. Retrofits in their baseline model guise do not enter the generating mix for mitigation costs below 300 $/tC; the analysis therefore examines the range of cost and performance specifications that the retrofit option must achieve in order to be competitive as a mitigation option. Finally, Section 5.4 places CCS in a multipollutant framework. The increase in capital and operating costs due to CCS is likely be less for base plants that have stronger controls for criteria pollutants. The section takes an initial look at how consideration of multipollutant controls lowers the marginal cost of CO_2 abatement, and how, this multi-pollutant interaction could accelerate the adoption of CCS technologies.

5.2 A Free Lunch CO_2 Reduction, Natural Gas Prices, and Mitigation Costs

Two points must be kept in mind when assessing the impact of natural gas prices on CO_2 mitigation costs and the adoption of CCS. First, the low natural gas prices prevailing through the 1990s combined with improvements in gas turbine technology to narrow the difference between coal and gas plant generating costs and encourage the adoption of gas units to meet growing demand (Ellerman, 1996; Hirsch, 1999).[1] Second, the CO_2 emissions per unit of energy produced from a natural gas plant are roughly half that of a typical coal plant. Absent a price on carbon emissions, this evolution toward natural gas with its lower carbon intensity therefore yields a "free lunch" reduction in CO_2 emissions – a side benefit that becomes more pronounced when gas prices are low and when the initial distribution of generating capacity is dominated by old, and relatively inefficient, coal plants.[2]

Free lunch effects in general are more typical in technology-rich "bottom-up" models than in their "top-down" general equilibrium counterparts (NAS, 1992; Brown, et al., 1998; Edmonds, et al., 2000). This difference is largely due to perspective and assumptions. Engineering-economic models tend not to "rationalize" the market imperfections that result in apparently inferior technology choices – those, in other words, that lie above a production function isoquant and therefore fail to minimize total costs (or input requirements) for a given level of output (see the discussion in Chapter 2). A broader economic perspective, however, will give greater weight to the transition costs, regulatory hurdles, and other infrastructure externalities that, in this case, "lock-in" a particular set of generating technologies.

The sectoral modeling framework adopted here straddles these perspectives by incorporating a moderately detailed characterization of individual generating technologies that is also a function of both time and utilization (dispatch). The distinction between short- and long-term responses to economic and technological change – especially as it relates to the diminishing utilization of *pre-existing* generating capacity – is therefore recognized. On the one hand, infrastructure turn-over (a long-term response) is constrained both by the "weight" of capital outlays and limits on the rate of new capacity growth, while per-period (short-term) production expenses are minimized for a given suite of available generating technologies by accounting for the interaction

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[1] The average (nominal) cost of natural gas delivered to electric utilities between 1990 and 1999 was 2.31 $/GJ; the actual delivered prices do not exhibit a consistently increasing trend and range between 1.91 $/GJ in 1995 and 2.64 $/GJ in 1997 (EIA, 2000).

[2] The replacement of vintage coal plants with modern – and more efficient – coal units will likewise yield a reduction in CO_2 emissions. The difference in efficiencies between coal and gas fired plants, however, is significantly greater than that between existing and new coal plants. Combined with the substantially lower carbon intensity of natural gas, coal-to-gas fuel switching will therefore yield a greater free lunch CO_2 reduction than coal-to-coal replacement. The price of natural gas, of course, will affect the economically preferred technology path. In addition, as Bernow, et al. (1996) note, the extent to which a coal-to-gas transition might contribute to a free lunch CO_2 reduction will vary with the cost and performance of coal plant multipollutant emissions controls and the stringency of related regulation. Section 5.4 addresses this dynamic in greater detail.

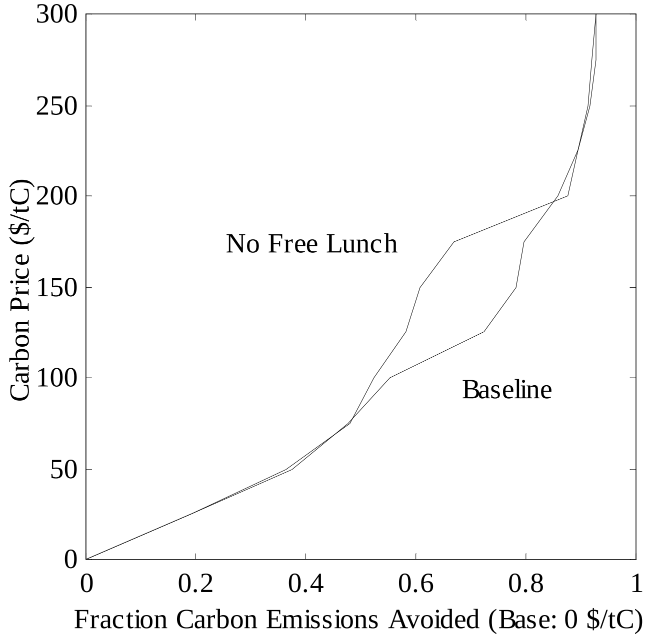
between changing dispatch and operating costs. Neither response is optimized in isolation.

Continuing with the previous chapter's regional focus, one would therefore expect to see a free lunch CO_2 reduction: at moderate natural gas prices the MAAC fuel mix would continue to evolve from its current reliance on old coal plants to new gas units, with a concomitant emissions reduction. In a world with constraints on CO_2 emissions, this free lunch effect would lower the cost of CO_2 control, providing a benefit that would be absent if the distribution of generating capacity could be continually "re-optimized" to reflect current operating costs. Initial conditions in the form of long-lived sunk capital therefore need to be considered when estimating electric sector mitigation costs.

A scenario in which there is no preexisting generating capacity and in which demand and factor prices remain fixed at their baseline period 1 levels provides the starting point for determining the extent to which initial conditions matter and the free lunch effect reduces mitigation costs.[3] The capacity added in this scenario represents what one would expect to see as initial capacity if the system was optimized for conditions prevailing before the more recent gas price volatility: approximately 19.4 GW of single-cycle and 45.6 GW of combined-cycle natural gas units (GT and NGCC, respectively). A normal run of the baseline model with this equilibrium distribution of existing capacity yields the "No Free Lunch" supply curve of Figure 5.1 and the carbon emissions profile of Figure 5.2. Mitigation costs are indeed higher without the free lunch reduction in CO_2 emissions for emission reductions between 50 and 80 percent.

Natural gas prices, of course, have recently peaked at levels much higher than their 1990's average, and future costs are uncertain. With a serious initiative to reduce CO_2 emissions, for instance, the price of gas would likely rise as economy-wide demand increased. Figures 5.3 and 5.4 examine the impact of gas prices by comparing CO_2 mitigation costs and the generating technology mix for alternative period 1 gas price

[3] Note that the baseline model's treatment of nuclear capacity becomes relevant in this context. The analysis thus far has excluded new nuclear generation, in keeping with the assumption that social and political issues, coupled with the higher capital costs, render new construction undesirable. The existing 13.7 GW MAAC nuclear capacity, however, provides a significant share of CO_2-free baseload electricity generation, and its removal works against any coal-to-gas fuel-switching and efficiency related emission reductions. Consequently, the following free lunch analysis includes this generating asset.



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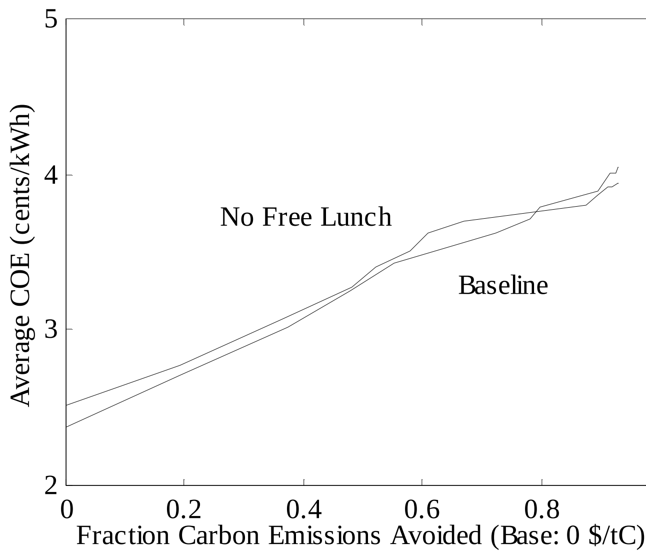


(b)

Figure 5.1 – Carbon mitigation cost curves (a) and average cost of electricity generation (b) for the baseline model ("Baseline") and a scenario in which the free lunch CO_2 reduction of coal-to-gas fuel switching is removed ("No Free Lunch").

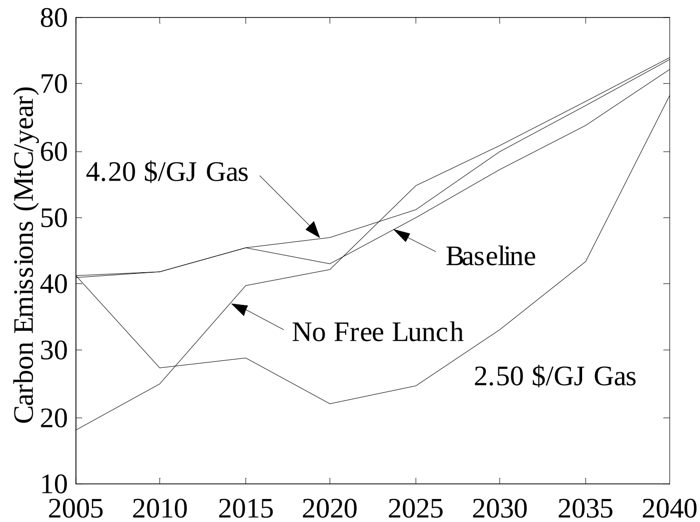


Figure 5.2 – Carbon emission profiles for the baseline model ("Baseline"), the baseline model without the free lunch CO_2 reduction ("No Free Lunch"), and the baseline model with period 1 gas prices of 2.50 and 4.20 $/GJ (the first two scenarios assume an initial gas price of 3.20 $/GJ). No carbon price is imposed.

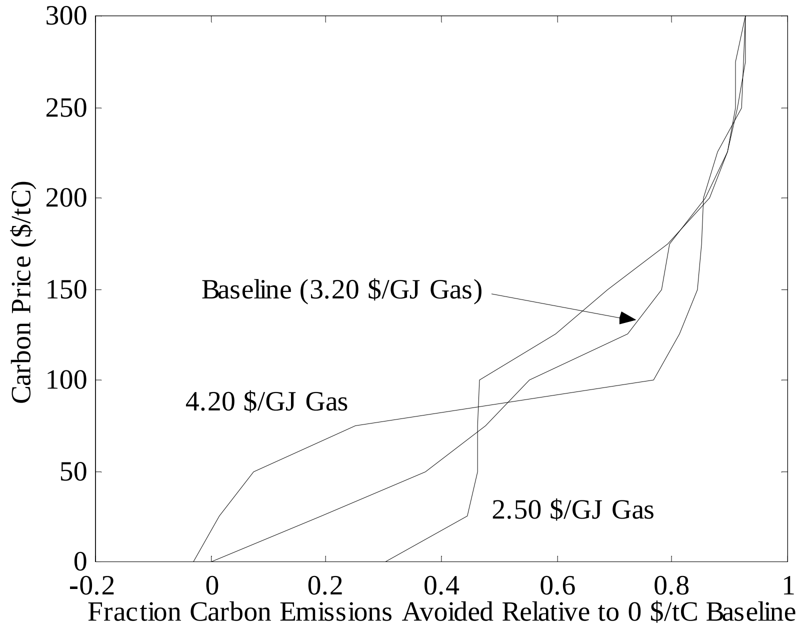
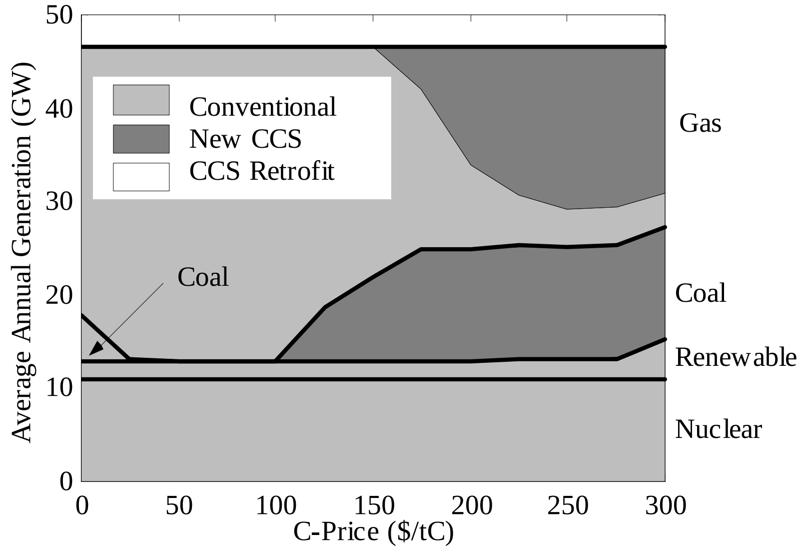
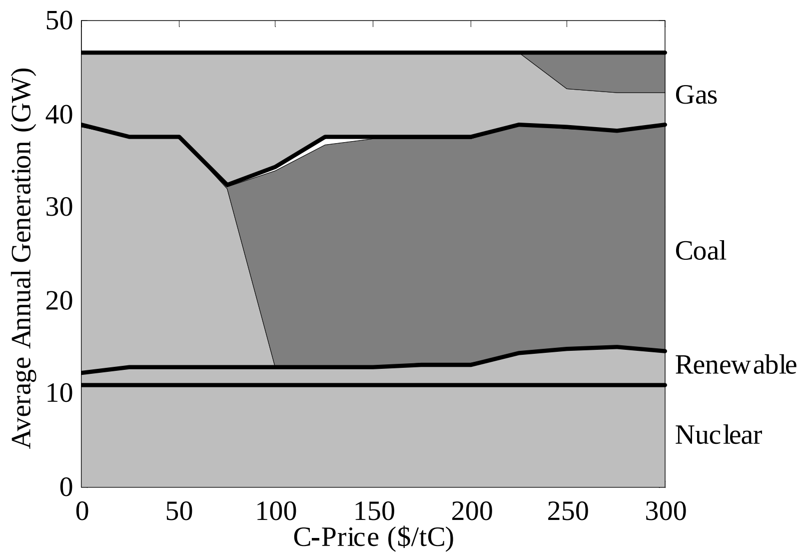


Figure 5.3 – CO_2 mitigation supply curves for alternative period 1 gas price scenarios. Note that the zero-carbon price emissions level of the 3.20 $/GJ base run (2.07 GtC) provides the basis used to calculate the fraction of CO_2 avoided for all three scenarios. Gas prices increase at the baseline 4 percent per-period growth rate.



(a) 2.50 $/GJ Period 1 Gas Price



(b) 4.20 $/GJ Period 1 Gas Price

Figure 5.4 – Average annual generation in period 6 (2026-2030) as a function of carbon price for period 1 natural gas prices of 2.50 $/GJ (a) and 4.2 $/GJ (b). Compare these figures to the 3.20 $/GJ baseline scenario (Figure 4.6). Gas prices increase at the baseline 4 percent per-period growth rate under both scenarios. Note that CCS retrofits do not enter the generating mix for carbon prices below 300 $/tC.

scenarios.[4] Note that the unconstrained emissions run of the 3.20 \$/GJ baseline scenario is used to calculate the fraction of CO_2 avoided in each case. The low gas price scenario therefore achieves a positive emission reduction at 0 \$/tC (Figure 5.3) as fuel switching to new gas plants (the least-cost technology path) lowers CO_2 output even in the absence of a price on emissions (see Figures 5.2 and 5.4a). This dynamic is a more pronounced demonstration of the free lunch effect. In contrast, the zero-abatement position of the high gas price scenario nearly coincides with that of the standard run as coal and nuclear currently fill the lower levels of the dispatch order (Figure 5.4b). The higher gas price affects the cost of providing shorter-duration peak demand, but does not significantly impact overall CO_2 emissions (Figure 5.2).

The reversal in ordering of the gas price scenario mitigation cost curves at higher levels of CO_2 abatement may seem counterintuitive; basic economic considerations, however, provide an explanation. All other things being equal, a decrease in the price of natural gas necessarily lowers generating costs for a given level of CO_2 abatement. The costs of electricity generation (not including the price of CO_2 emissions) under all gas price scenarios, however, must converge as emissions approach zero and the generating mix shifts toward near-zero emission coal, (existing) nuclear, and renewable technologies. Plotted against CO_2 reduction, the total cost curve under a low gas price scenario will therefore rise more steeply at high levels of emission abatement, and mitigation costs – the derivative of the total cost curve – will be correspondingly greater.

Figure 5.3 illustrates this phenomenon. For moderate levels of abatement, low gas prices yield less expensive CO_2 reductions as fuel switching and displacement of coal by gas plants lower overall emissions at favorable cost. The ordering of the supply curves flips for CO_2 reductions above 50 percent, with the lowest mitigation costs corresponding to the high gas price scenario. Total generating costs, however, remain uniformly lower for the 2.5 \$/GJ gas price scenario as the reduction in capital and O&M expenses is greater than the increase in CO_2 control costs.

From a social cost standpoint, the consequences of gas price uncertainty increase when constraints on future carbon emissions are also unknown. A return to the moderate and relatively stable gas prices of the 1990s would sustain the decade's preference for gas

[4] Note that gas prices increase at the baseline 4 percent per-period rate under all scenarios.

over coal plants. Should significant reductions in CO_2 output be required, this alternative could represent an expensive sunk investment and lock-in to a high-cost technology path. In the face of high gas prices, a coal-based CCS infrastructure could provide lower-cost abatement for greater levels of CO_2 mitigation. While the results behind this analysis are, of course, highly dependent on modeling assumptions, such possibilities highlight the need to consider how investment decisions made today might restrict mitigation options in an uncertain future.

5.3 Carbon Capture Retrofits of Vintage Coal Plants

Section 5.2 examined the "existing capacity versus new plant" dynamic as a driver of electric sector CO_2 mitigation costs. There is reason, however, to think that coal plant retrofits – an intermediate approach – could be an important route to early adoption of CCS. Flue gas separation of CO_2 using an amine absorption process, for instance, is a mature technology and is similar in concept to "add-on" controls for sulfur dioxide (SO_2) emissions; construction expertise and management experience would likely transfer from one control system to the other. More fundamentally, a cost-effective retrofit option would extend the useful life of existing coal plants in a world with constraints on carbon emissions. This compatibility with the economics and timing of infrastructure turn-over could lower electric sector CO_2 abatement costs. Tempering this optimism are the energy requirements of the capture process and subsequent derating of plant output, as well as land constraints at existing coal plants (Herzog, Drake, and Adams, 1997), licensing and regulatory issues, and the need to modify (or design) separation technologies for a new operating environment. Issues related to CO_2 sequestration, of course, pose an additional challenge, though one that is not unique to CCS retrofits.

Data on retrofit costs and performance, however, are generally unavailable. Although utility managers are known to be exploring the option, most engineering studies remain private. Simbeck and McDonald (2001) provide one of the few thorough retrofit assessments in the public domain, and carbon capture retrofits have recently been incorporated into the Carnegie Mellon University / US Department of Energy *Integrated Environmental Control Model* (IECM, 2001; Rubin, Rao, and Berkenpas, 2001). These sources furnished the retrofit specifications detailed in Chapter 3. As noted in the baseline model discussion (Chapter 4), CCS retrofits of pre-existing coal plants remain uncompetitive under this set of assumptions and do not contribute to the reduction of MAAC region CO_2 emissions.

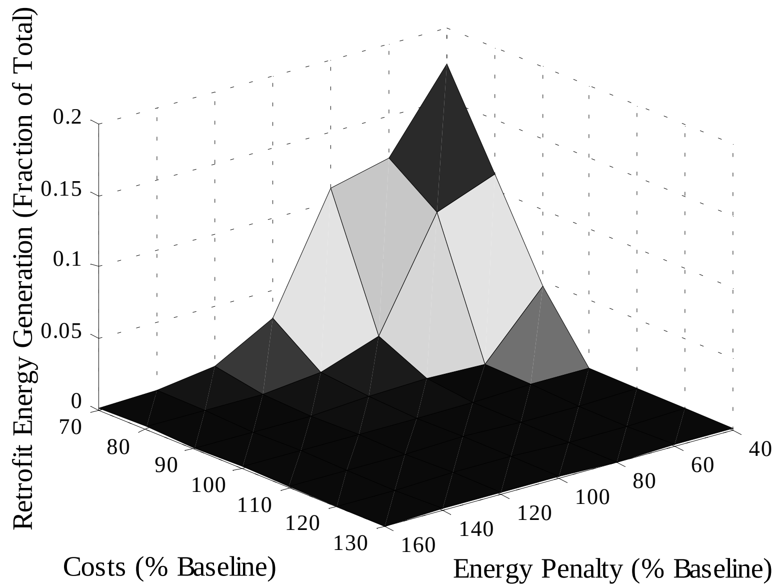
It is therefore worth estimating the range of retrofit cost and performance specifications over which the option (as modeled) makes economic sense. Four parameters determine the attractiveness of retrofitting the existing coal-fired generating infrastructure for CO_2 capture: the initial conversion capital cost, the associated increase in marginal operating costs, the energy penalty of the control technologies, and – related in its effects to this last factor – the efficiencies of the original coal plants.[5] Figures 5.5 through 5.7 present results from a combined parametric analysis of these model inputs.

The first point to note from these figures is that even radical improvements in the baseline retrofit energy penalty (i.e., halving the penalty to 10 percent) alone do not increase the share of electricity generated by modified coal plants to more than 10 percent. Only when the energy penalty and retrofit costs both decrease (Figures 5.5a and 5.6a), or base coal plant efficiencies can be increased (Figure 5.7a), do retrofits play a role in CO_2 abatement. Retrofit capacity contributes slightly less than a quarter of generated electricity in the most favorable retrofit scenarios examined; for more modest improvements in base case parameters retrofits typically account for 10 percent of total generation.

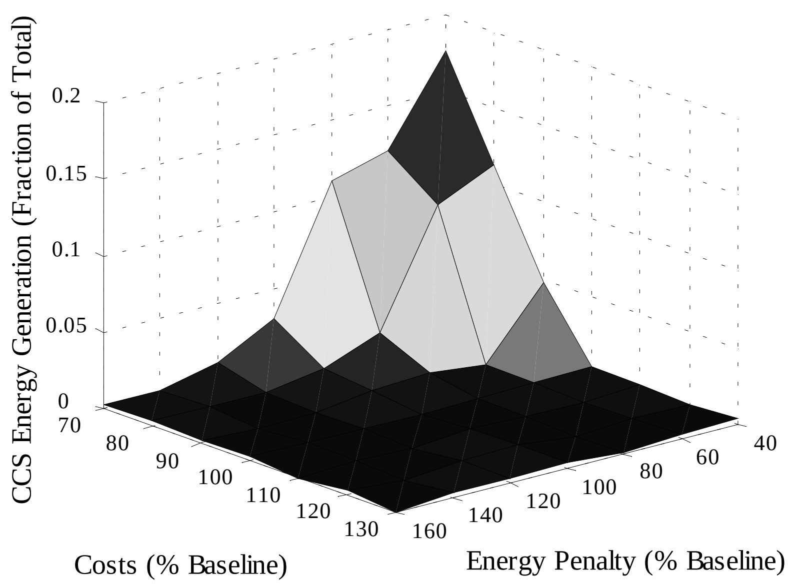
The cost of carbon emissions does not alter this conclusion (compare, for example Figures 5.5a and 5.6a).[6] In addition, note that the ability to retrofit coal plants for post-combustion CO_2 capture does not significantly affect the overall share of CCS units in the generating mix at higher carbon prices (Figures 5.5b and 5.6b). Halving the retrofit energy penalty and achieving significant cost reductions, for instance, doubles retrofit electricity production, but does not substantially increase the approximately 40 percent CCS share of power generation (IGCC capture units simply play a diminished role). As a result, retrofit improvements have little effect on overall mitigation costs (Figure 5.8). CCS in general is limited to reducing baseload CO_2 emissions until further abatement

[5] Recall from Chapter 3 that retrofit capital costs in $/kW net output depend on the retrofit capital cost in $/kW thermal input as well as the retrofit energy penalty and the base coal plant efficiency. These parameters are therefore not independent.

[6] The same effect holds for the Figure 5.7 analysis

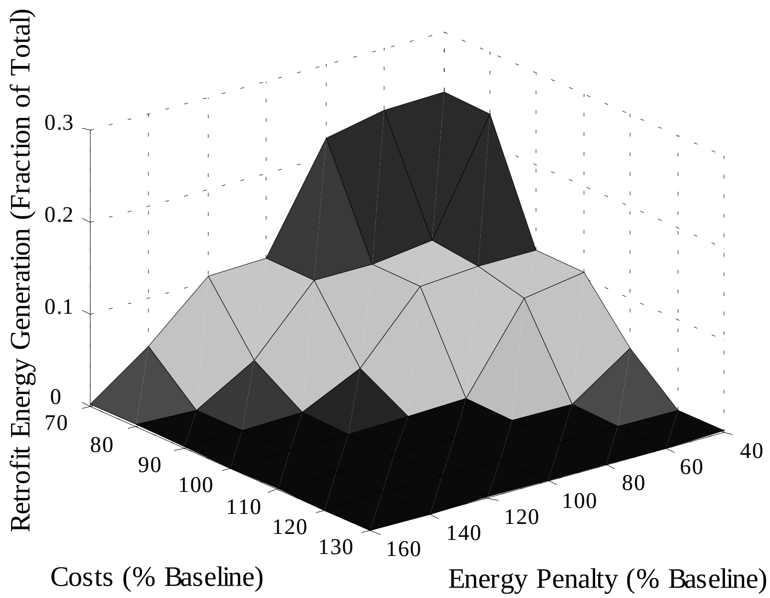


(a)

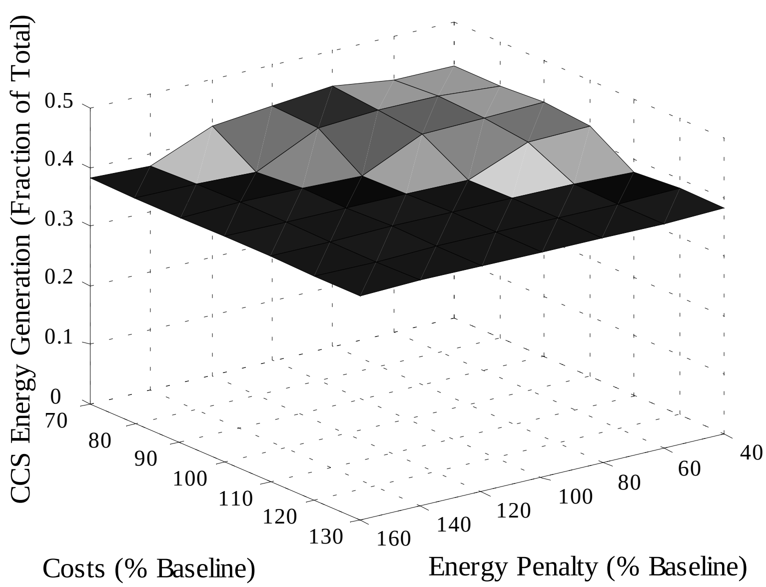


(b)

Figure 5.5 – Fraction of electricity produced in period 6 (2026-2030) by retrofit coal plants (a) and all CCS generating units (b) as a function of retrofit costs and energy penalty under a 75 $/tC emissions price. Costs include capital plus fixed and variable O&M, and both sets of model parameters are shown as a percentage of their baseline specifications (see Chapter 3).



(a)



(b)

Figure 5.6 – Fraction of electricity produced in period 6 (2026-2030) by retrofit coal plants (a) and all CCS generating units (b) as a function of retrofit costs and energy penalty under a 150 $/tC emissions price. Costs include capital plus fixed and variable O&M, and both sets of model parameters are shown as a percentage of their baseline specifications (see Chapter 3).

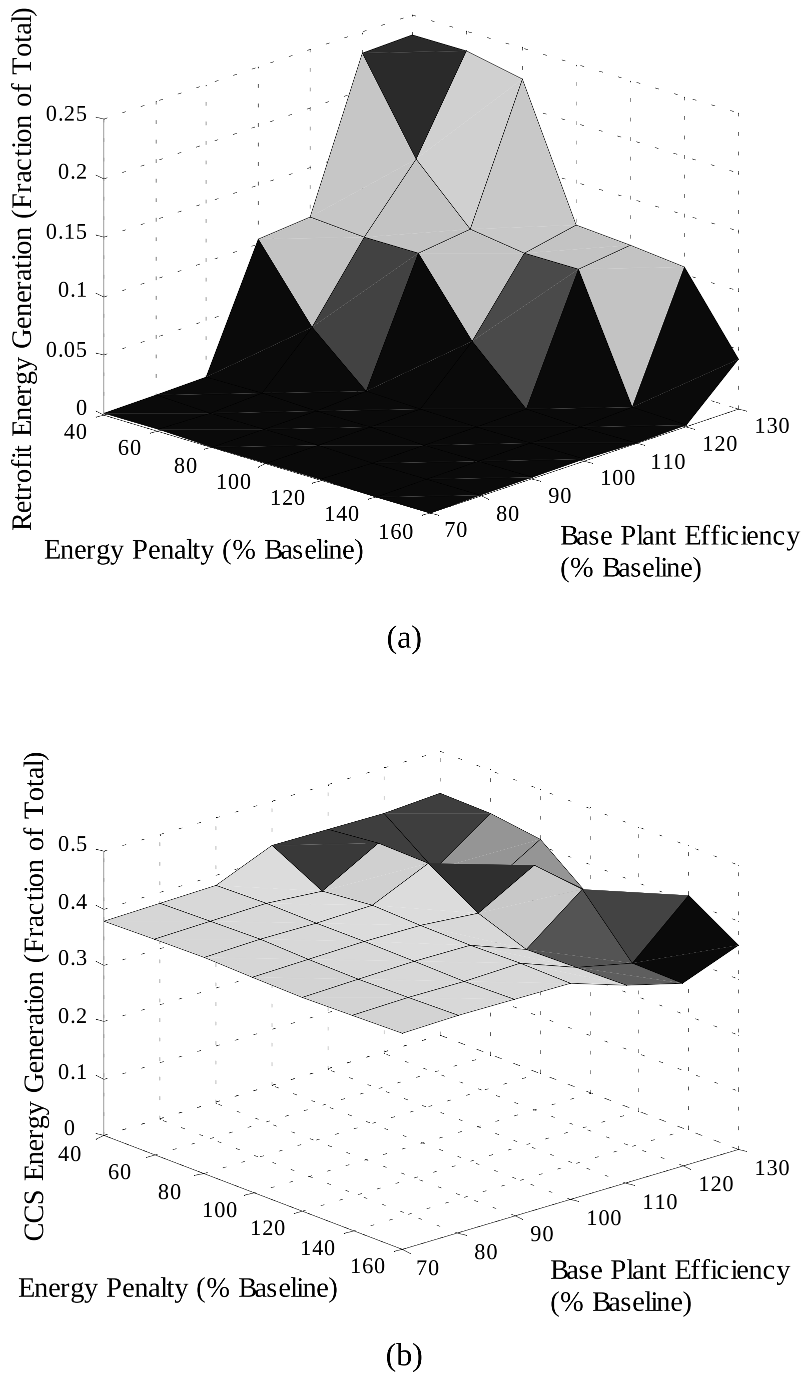


Figure 5.7 – Fraction of electricity produced in period 6 (2026-2030) by retrofit coal plants (a) and all CCS generating units (b) as a function of base coal plant efficiency and energy penalty under a 150 \$/tC emissions price. Both sets of model parameters are shown as a percentage of their baseline specifications (see Chapter 3).

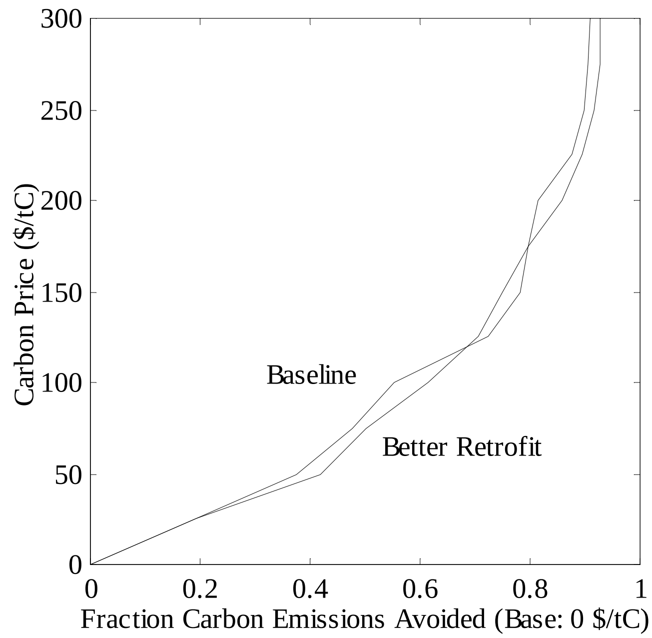


Figure 5.8 – CO_2 mitigation supply curves for a more optimistic retrofit specification. The "Better Retrofit" reflects a 20 percent reduction in all retrofit costs combined with a 50 percent reduction in the retrofit energy penalty, relative to the baseline scenario. See Figure 4.12 for details concerning figure calculations.

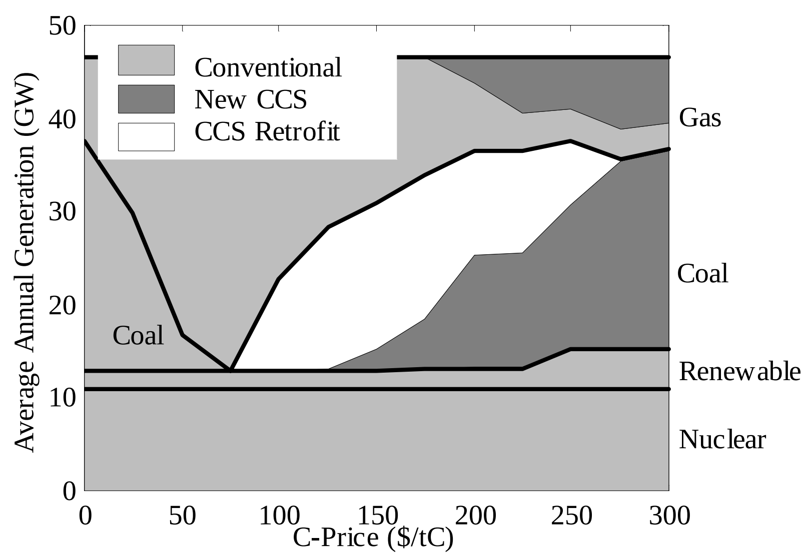


Figure 5.9 – Average annual generation in period 6 (2026-2030) as a function of carbon price for the H_2-CGCC coal plant retrofit option. Compare to figure 4.6 and note that the increased retrofit generation does not significantly increase the overall share of electricity produced by CCS technologies.

requires cuts in the emissions of plants supplying peak loads. The lower utilization of units supplying electricity at higher levels of the dispatch order, however, makes it more difficult to recover capital investment, increasing the average cost of electricity as well as the cost of CO_2 control.

Post-combustion CO_2 capture via flue gas scrubbing, however, is not the only near-term CCS-retrofit option available to coal plant operators. Conversion to a hydrogen-fired coal gasification combined cycle plant (H_2-CGCC) – that leaves intact only the original coal-handling and substation equipment – provides a second alternative (Simbeck, 2001b).[7] This repowering option, which would incur estimated capital costs on the order of 1500 $/kW (net) as industry experience with gasification technology increases, does not share the capacity derating that is a primary disadvantage of flue-gas scrubbing retrofits.[8] In addition, a repowered H_2-CGCC plant would have a smaller footprint than the original boiler and steam turbine, thus avoiding the space constraint problems of "add-on" retrofits. Unfamiliarity with gasification technologies in the utility industry appears to be the major hurdle confronting this alternative (an argument, of course, to which MEA flue-gas scrubbing is not immune; see Simbeck [2001b]).

As modeled here, the improved economic performance of the H_2-CGCC option increases dependence on coal plant conversion. Coal plant retrofits now become competitive as a mitigation option at 75 $/tC and comprise a substantially larger share of the generating mix at higher carbon prices (Figure 5.9). This difference highlights the extent to which the amine retrofit plant derating discourages coal plant conversion – a disadvantage that decreases with improvement in the associated energy penalty. But like post-combustion retrofit schemes, adoption of the H_2-CGCC alternative does not significantly affect the combined share of new and retrofit CCS units. Once again, CCS is limited to base-load electricity generation for all but the highest levels of CO_2 mitigation.

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[7] "Oxyfuel" coal plant retrofits are an additional possibility, but are not considered here; see the discussion in Chapter 1.

[8] Apart from the 1500 $/kW capital cost, the model treats H_2-CGCC retrofits like IGCC plants with carbon capture, with an efficiency of 36 percent, and variable and fixed O&M costs of 0.35 cents/kWh and 55 $/kW, respectively.

5.4 CCS in a Multipollutant Framework

5.4.1 The Control of Multipollutants and its Interaction with CCS

Tighter controls on electric sector emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), toxics such as mercury, and fine particulates would impose cost and performance penalties that, in turn, influence technology choices. Stricter regulation of conventional pollutants, for instance, could accelerate retirement of existing coal plants and favor investment in new gas units and renewable energy sources. The introduction of control requirements for CO_2 could have similar effects. Important interactions between the reduction of criteria pollutants and CO_2, however, may lead to the opposite outcome – especially if the latter is achieved via CCS.

While proposed CCS technologies would increase capital and operating costs, they also decrease conventional pollutant emissions.[9] As a result, the costs of CCS technologies are likely to be less for electric power plants that must meet stronger criteria pollutant control standards than for those that do not, and plausible scenarios of more stringent environmental regulation could accelerate the adoption of CCS technologies. An assessment of how specific CCS generating technologies would be used in an actual electric power system under different conventional pollutant constraints is therefore needed.

This section extends the baseline capacity planning and dispatch model to examine CCS in a multipollutant framework, once again focusing on a regional electricity market (the MAAC NERC region). It is important, however, to note that this first-order analysis seeks only to illustrate how synergies between the control of conventional pollutants – in this case, SO_2 and NO_X – and CO_2 affect CO_2 mitigation costs and the role of CCS. The aim is not to estimate SO_2 or NO_X control costs, nor is it to examine a particular multipollutant regulatory initiative. In addition, the analysis does not consider mercury or fine particulates, though mandated reductions in both are on the regulatory agenda. Finally, the emphasis is on coal-fired generating units which – by virtue of the chemical composition of coal as well as the fact that these plants operate at

[9] Post-combustion amine coal plant retrofits are perhaps the sole exception, with higher NO_X emissions on a per-kWh (net output) basis.

high capacity factors to meet base-load electricity demand – dominate both criteria pollutant and CO_2 emissions.

5.4.2 Incorporating Multipollutant Controls in the Baseline Model

Owners of existing coal-fired generating units would have some flexibility in responding to stricter limits on criteria pollutants. Reducing plant utilization (i.e., dispatch), of course, would lower pollutant emissions. Likewise, fuel-switching to natural gas would cut NO_X emissions and virtually eliminate SO_2. Coal plant retrofits are a further option. Low NO_X burners and other pre-combustion controls, for instance, would provide modest decreases in NO_X, while advanced technologies like post-combustion selective catalytic and non-catalytic reduction (SCR and SNCR, respectively) could cut emissions more than 80 percent, though at much higher cost. Similarly, the use of low-sulfur coal would yield modest reductions in SO_2, with near elimination requiring flue gas desulfurization (FGD) retrofits.

A thorough analysis of multipollutant-CO_2 interactions therefore requires knowledge of existing plant configurations, including identification of which control technologies are in place and which might be incompatible with current plant design.[10] In addition, the emission limits a given plant must meet today are, in part, a function of its age and location, as well as the season; NO_X emissions will depend further on the plant's actual load factor. Finally, a more elaborate coal market model is also required – one stratified by quality (i.e., sulfur content and heating value), as well as price.

Incorporating this level of detail in an extension of the Chapter 3 capacity planning and dispatch model presents a challenge and would exceed the goals of this analysis. The difficulty of reducing a diverse mix of coal-fired units into a few generic categories, however, remains. A look at the relationships between key parameters for MAAC region coal plants provides a starting point. Figures 5.10 and 5.11, for instance, plot NO_X and SO_2 emission rates (both on an input basis) against net plant heat rate, while Figures 5.12 to 5.14 focus on the sulfur content of coal; Table 5.1 provides a breakdown of existing control technologies. Note that a strong correlation does not exist between heat rate and either NO_X or SO_2 emissions. The variation in SO_2 emission rates,

[10] Not all boilers, for instance, can accommodate low-NO_X burners.

however, increases with the coal sulfur content (Figure 5.12), which has a bi-modal distribution (Figure 5.13). Low-NO_X burners are the primary means of controlling NO_X emissions, and there is little correlation between the presence of advanced control technologies for NO_X and SO_2 (Table 5.1).

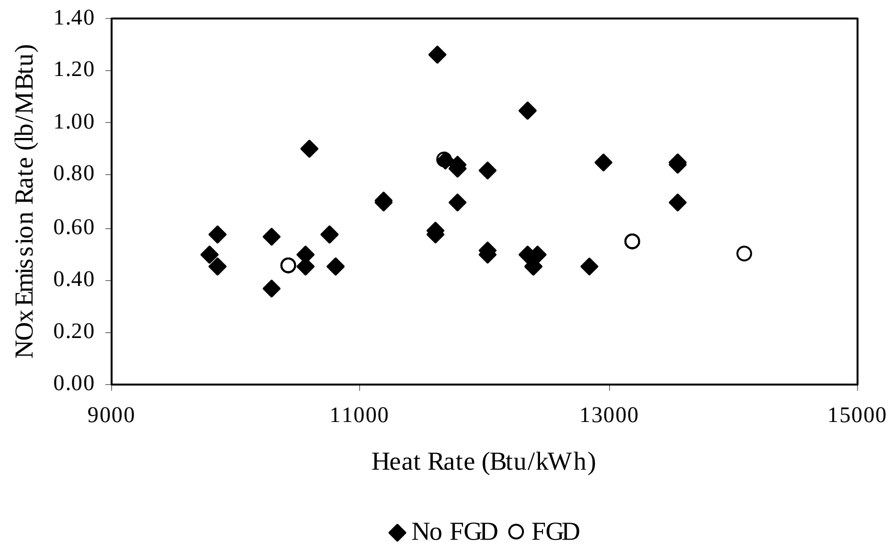


Figure 5.10 – NO_X emission rate versus heat rate for MAAC region coal-fired electric power plants. Plants with flue gas desulfurization (FGD) for SO_2 control are indicated. Note that the emissions rate is on a heat input basis. (Source: EIA, 1999; EPA, 2001.)

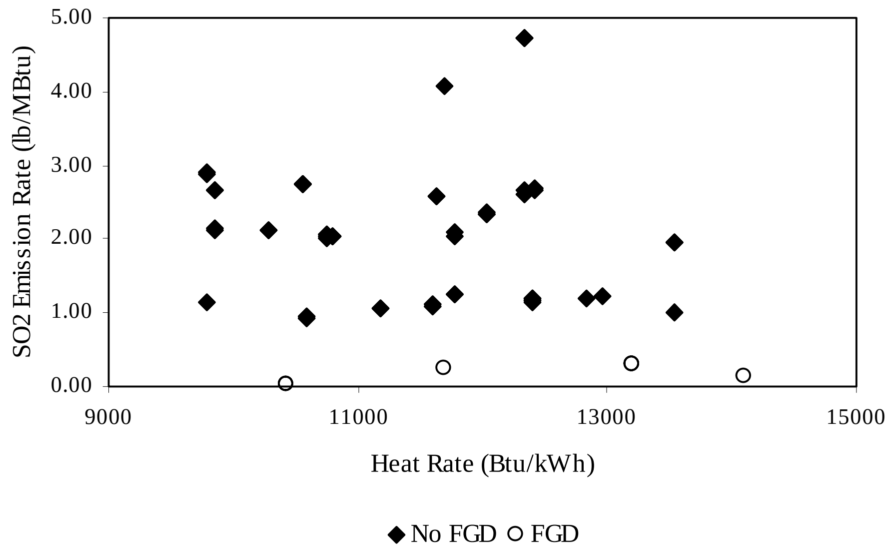


Figure 5.11 – SO_2 emission rate versus heat rate for MAAC region coal-fired electric power plants. Plants with flue gas desulfurization (FGD) for SO_2 control are indicated. Note that the emissions rate is on a heat input basis. (Source: EIA, 1999; EPA, 2001.)

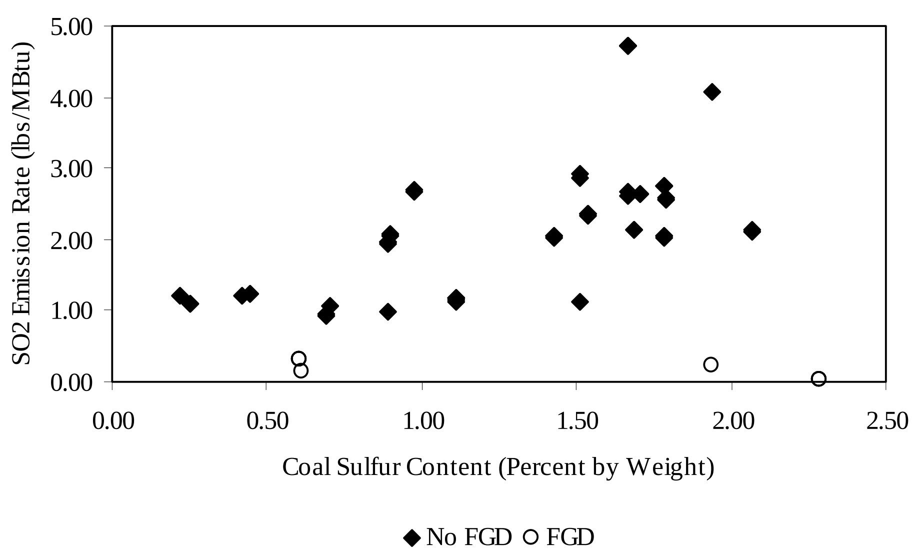


Figure 5.12 – SO_2 emission rate versus median monthly coal sulfur content for MAAC region coal-fired electric power plants. Plants with flue gas desulfurization (FGD) for SO_2 control are indicated. Note that the emissions rate is on a heat input basis. (Source: EIA, 1999; EPA, 2001.)

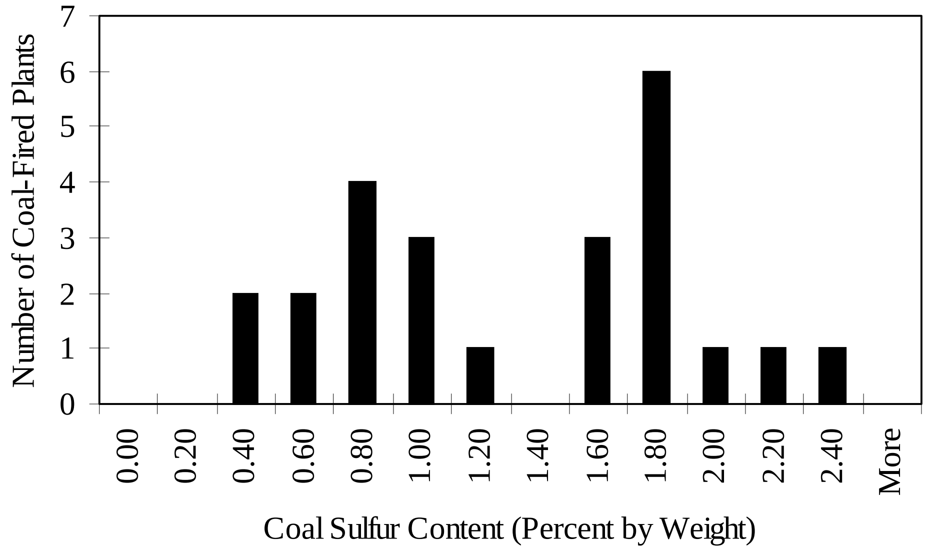


Figure 5.13 – Distribution of the median monthly coal sulfur content for MAAC region coal-fired electric power plants. (Source: EIA, 1999; EPA, 2001.)

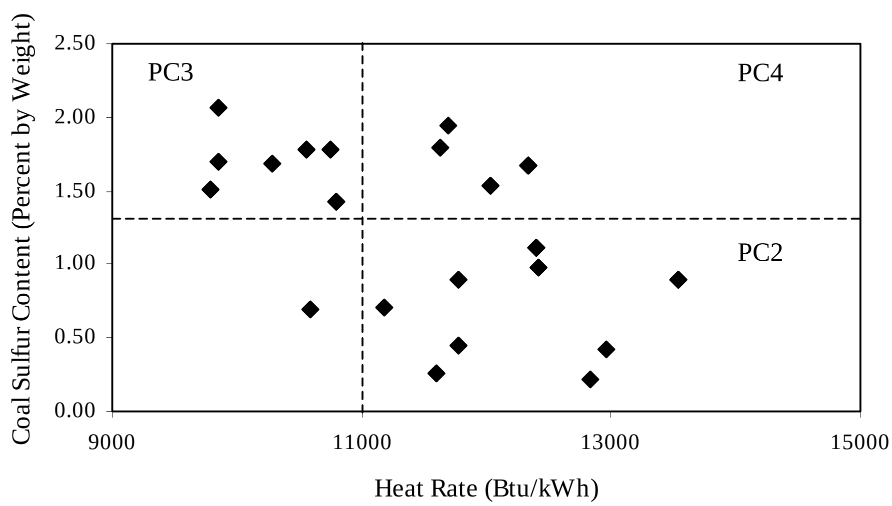


Figure 5.14 – Median monthly coal sulfur content versus heat rate for MAAC region coal-fired electric power plants without flue gas desulfurization (FGD). The classification scheme for existing non-FGD coal plants is indicated (Source: EIA, 1999; EPA, 2001.)

Table 5.1 – Fraction of boiler capacity stratified by NO_X and SO_2 control device. Data are for MAAC region coal-fired electric power plants (source: EIA, 1999; EPA, 2001). (FGD = flue gas desulfurization; SNCR = selective non-catalytic reduction.)

	NO_X Control					
SO_2 Control	*Low Excess Air*	*Low NO_X Burners*	*Not Applicable*	*Overfire Air*	*SNCR*	*All NO_X*
FGD	0.00	0.10	0.03	0.00	0.01	0.14
None	0.03	0.58	0.09	0.12	0.05	0.86
All SO_2	0.03	0.68	0.12	0.12	0.06	1.00

Table 5.2 – Multipollutant model categorization of existing MAAC region coal-fired electric power plants (source: EIA, 1999; EPA, 2001).

Coal Plant	*Fuel*	*FGD*	*NO_X (lb/MBtu input)*	*Non-Fuel VOM (cents/kWh)*	*FOM (\$/kWnet)*	*Thermal Efficiency*	*Existing Capacity (GW)*
PC1	High-S	Yes	0.56	0.50	30.0	0.28	4.2
PC2	Low-S	No	0.65	0.45	30.0	0.28	8.0
PC3	High-S	No	0.50	0.45	30.0	0.33	10.6
PC4	High-S	No	0.87	0.45	30.0	0.28	2.0

The modeling strategy adopted here employs four existing coal plant classes (Table 5.2), and adds a second coal to the available fuels (Table 5.3).[11] Advanced NO_X controls (roughly 6 percent of installed boiler capacity) are ignored, though all plants are assumed to have the equivalent of low-NO_X burners. One plant group is reserved for FGD and assigned a high-sulfur coal.[12] The remaining three existing coal plant categories differ by heat rate (below or above than 11000 Btu/kWh) and fuel sulfur

[11] This stratification of existing coal-fired generation accounts for all but 4 percent of available boiler capacity.

[12] 70 percent of the installed MAAC region FGD capacity uses a coal with a sulfur content above 1.3 percent by weight (EIA, 1999; EPA, 2001).

content (below or above 1.3 percent by weight) (see Figure 5.14 and Table 5.2).[13] Finally, new coal plants with and without CO_2 capture are also available; both are the equivalent of the IGCC plants described in Chapter 3, and are further differentiated here by conventional pollutant emissions (see Table 3.3).[14, 15]

Table 5.3 – Fuel property specifications for the multipollutant model. Fuel costs remain constant, except for the price of natural gas which increases 4 percent per five-year period.

Fuel	*2001-2005 Cost ($/GJ)*	*E-intensity (kg fuel/GJ)*	*C-intensity (kgC/kg fuel)*	*S-intensity (kgS/kg fuel)*
High-S Coal	1.00	35.21	0.67	0.018
Low-S Coal	1.15	51.55	0.48	0.008
Nat Gas	3.20	18.38	0.74	0.000
Oil	4.10	22.4	0.850	0.003
Uranium	0.10	0.0005	0.000	0.000

Four retrofit schemes may be applied to each existing coal plant category: the equivalent of an SCR unit for NO_X control; FGD for SO_2; combined SCR and FGD; plus SCR and FGD coupled with post-combustion CO_2 capture (Table 5.4).[16] Like the CO_2 retrofits described in Chapter 3 (and examined in the previous section of this Chapter), only existing capacity is available for conversion and retrofit capacity cannot be modified in subsequent time periods. The multipollutant retrofits are characterized by seven

[13] There is a rough correspondence between heat rate, NO_X emissions rate and plant age; see Table 5.2. The average year on line of the first boiler for each existing plant category is as follows: 1963 (PC1), 1962 (PC2 and PC3), and 1954 (PC4).

[14] The IGCC plant with CO_2 capture approximates a "zero-emission" coal-fired plant. The SO_2 removal efficiency for both IGCC plants is 99 percent, while the capture version also cuts CO_2 emissions by 99 percent. The NO_X emission rate for the non-CO_2 capture plant is 0.10 lbs. NO_X/MBtu, while that for the capture equivalent is effectively zero.

[15] While the focus here is on coal-fired units, gas and oil plants contribute pollutants of their own. Table 5.3 specifies the carbon and sulfur content of these fuels; the model uses the average NO_X emission rates for existing MAAC region gas and oil plants (0.20 and 0.30 lbs. NO_X/MBtu, respectively), while new gas plants are assumed to meet current emission standards (0.02 lbs. NO_X/MBtu for combined-cycle plants, and 0.08 lbs. NO_X/MBtu for single-cycle turbines; EIA [2001b]).

[16] Note that the retrofit options with FGD do not provide a further SO_2 reduction for the FGD coal plant category.

parameters: a capital expense (in \$/kW gross input), non-fuel variable and fixed O&M cost increases (in cents/kWh and \$/kW, respectively), a retrofit energy penalty, a NO_X emission rate, and removal efficiencies for SO_2 and CO_2 (derived from IECM [2001] and Simbeck and McDonald [2001]). Note that capital costs are once again specified in terms of kW thermal (gross); as described in Chapter 3, the base plant efficiency and retrofit energy penalty combine with this figure to provide a retrofit capital cost on an output (kW net) basis.[17] The multipollutant retrofit constraints in the linear programming model are also analogous to the CO_2 retrofit constraints described in the Appendix to Chapter 3 (Section 3.7).[18]

5.4.3 Multipollutant Reductions and the Cost of CO_2 Control

Average annual emissions in period 1 (2001-2005) of the baseline multipollutant model are 1.43 Mt SO_2, 0.28 Mt NO_X, and 40 MtC (147 Mt CO_2).[19] Figure 5.15 shows the time course for SO_2 and NO_X emissions, while Figure 5.16 illustrates how CO_2 control costs decrease when conventional pollutant emissions are constrained.[20] Note that SO_2 and NO_X emissions are capped on a per-period basis, expressed in Figure 5.16 as a percentage reduction in the unconstrained baseline's period 1 output (i.e., all periods in a particular scenario must meet the same SO_2 and NO_X constraints). Compared to CO_2, anthropogenic SO_2 and NO_X emissions have relatively short atmospheric residence times. A concern with per-period criteria pollutant emissions is therefore appropriate as

[17] Division of the retrofit capital cost in \$/kW (gross) by an existing coal plant's thermal efficiency and one minus the retrofit energy penalty yields the plant-specific retrofit capital cost on a \$/kWnet basis. Likewise, the thermal efficiency of the retrofitted plant is decreased by a factor of one minus the retrofit energy penalty.

[18] There are two classes of retrofit technology constraints. In words, no more than the existing capacity of a particular coal plant category may be retrofitted, though this capacity can be divided in any manner among the retrofit options (retrofit capacity is derated by the corresponding energy penalty). Second, the original capacity remaining for dispatch in each period can be no more that what remains unmodified. Appendix 2 contains a copy of the multipollutant *MATLAB* constraint generation subroutine. Note that multipollutant SO_2 emission calculations are completely analogous to their CO_2 counterparts in the baseline model; see the Chapter 3 Appendix (Section 3.7). The multipollutant model specifies NO_X emissions rates directly (as lbs. NO_X/MBtu gross); division by the base plant efficiency (with appropriate conversion units) yields NO_X emissions per unit of electricity generated (i.e., kg NO_X/kWh net).

[19] 2000 and projected 2005 MAAC region emissions are as follows: 1.04 and 0.91 Mt SO_2; 0.23 and 0.20 Mt NO_X; and 33 and 38 MtC (EIA, 2001a).

[20] Note that the unconstrained multipollutant baseline does not take existing criteria pollutant limits into account; SO_2 and NO_X emissions are therefore higher in future years than current regulations will allow.

their direct effects will be more immediate. The long atmospheric lifetime of CO_2, in contrast, warrants a focus on aggregate (2001-2040) emissions.

Table 5.4 – Multipollutant model retrofit parameters. Data are derived from IECM (2001) and Simbeck and McDonald (2001) for a 500 MW (gross) coal-fired electric power plant operating with a 75 percent load factor and in-furnace controls for NO_X. (FGD = flue gas desulfurization; SCR = selective catalytic reduction; Amine = post-combustion CO_2 capture using an amine absorption process.)

	Retrofit Scheme			
	FGD (SO_2)	*SCR (NO_X)*	*FGD + SCR*	*FGD + SCR + Amine (CO_2)*
Capital Cost ($/kW thermal)	50	20	70	150
VOM Increase (cents/kWh)	0.15	0.08	0.23	0.30
FOM Increase ($/kW net)	11	1	12	35
Energy Penalty (%)	3	1	4	20
NO_X Intensity (lbs/MBtu input)	(Base Plant Values)	0.10	0.10	0.10
CO_2 Removal Efficiency	0.00	0.00	0.00	0.90
SO_2 Removal Efficiency	0.95	0.00	0.95	0.99

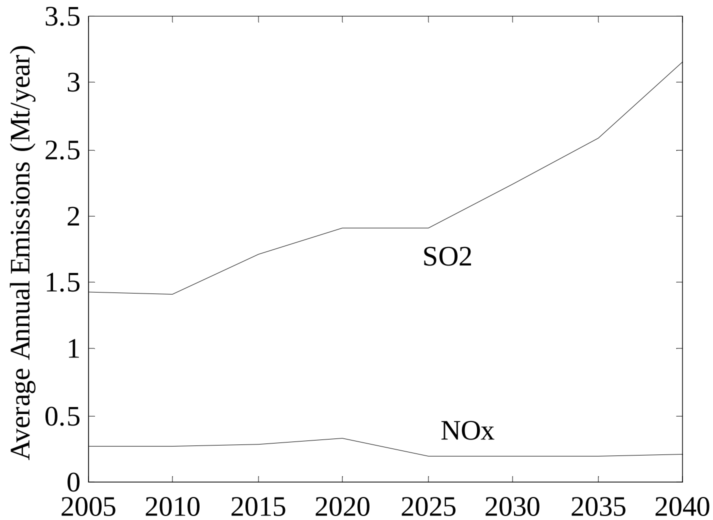


Figure 5.15 – Average annual SO_2 and NO_X emissions by time period for the unconstrained baseline multipollutant model.

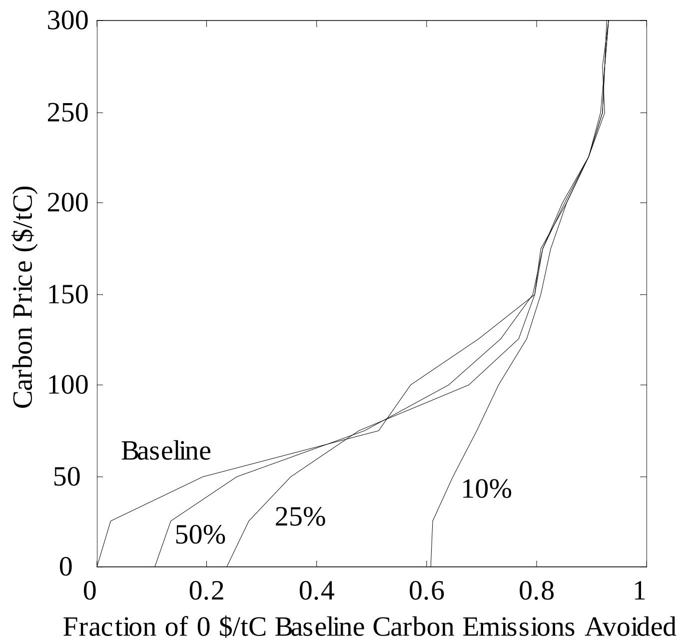
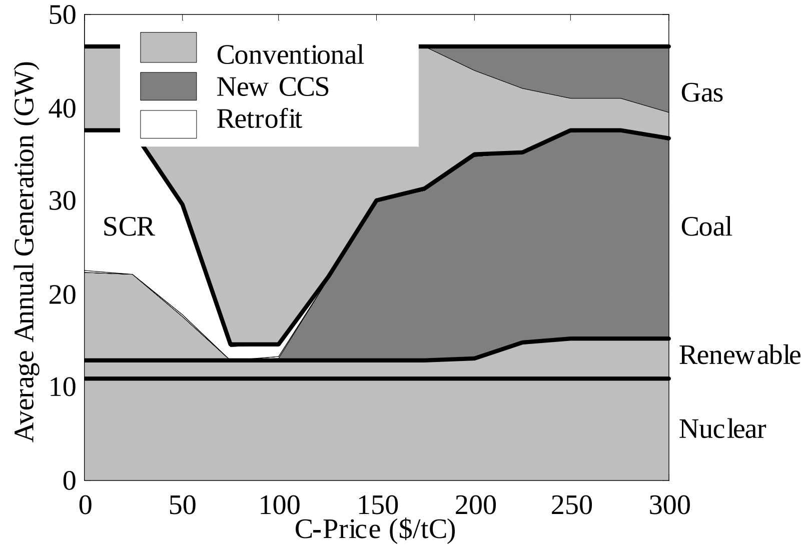


Figure 5.16 – The cost of carbon mitigation as a function of SO_2 and NO_X emission reductions. Per-period emissions are constrained as indicated to a percentage of the multipollutant baseline's period 1 (2001-2005) output (1.43 Mt SO_2 and 0.28 Mt NO_X). Note that the 0 $/tC aggregate (i.e., 2001-2040) CO_2 emissions level of the baseline run (2.4 GtC, or 8.6 $GtCO_2$) is used to calculate the fraction of CO_2 avoided for all scenarios.

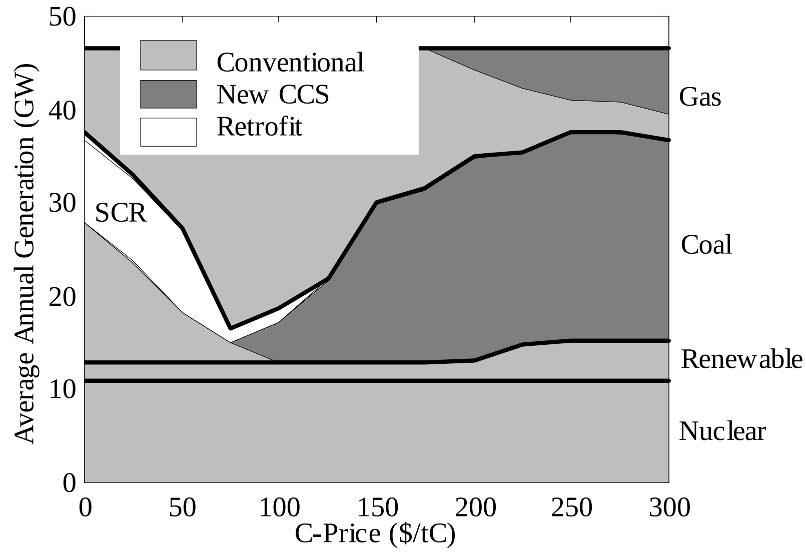
Two features of Figure 5.16 deserve special attention. The first to note is that the horizontal distance between the baseline and constrained-emission cost curves at the 0 $/tC level reflects the "free" reduction in CO_2 emissions that accompanies the progressively tighter SO_2 and NO_X limits. The cost of CO_2 control decreases with increasing stringency of criteria pollutant regulation, though primarily for moderate levels of CO_2 abatement – the second feature to note. SO_2 and NO_X emission constraints affect the least-cost generating mix only when the price of carbon is below 75 $/tC (compare panels a through d of Figure 5.17).[21] The cost curves converge under all multipollutant control scenarios as the need to make significant cuts in CO_2 emissions dominates the optimal technology choice.

One could therefore reverse perspective and argue that stringent CO_2 controls would lower the cost of SO_2 and NO_X reduction. Figure 5.18, for instance, illustrates how the severity of criteria pollutant constraints affects (undiscounted) total costs as the price of carbon emissions increases. In the absence of CO_2 control, tighter SO_2 and NO_X emission limits produce significant cost increases, while aggregate costs converge on unconstrained levels at higher carbon prices. The focus on CO_2 control costs, however, is motivated by the larger assessment of CCS, as well as the fact that mandatory reductions in electric sector carbon emissions are more controversial – and are a more recent part of environmental policy initiatives – than increased regulation of criteria pollutants. Either way, the important point to note is that base-case assumptions about emission regulation can matter in multipollutant assessments.

[21] Note that SCR retrofits enter the baseline (unconstrained) model as a means of extending the lifetime of existing coal plants – a modeling artifact (see Figure 5.17a). In addition, new coal CCS plants serve as a "zero emission" technology and therefore enter without a CO_2 incentive (i.e., at 0 $/tC) under the most severe SO_2 and NO_X constraints (Figure 5.17d).

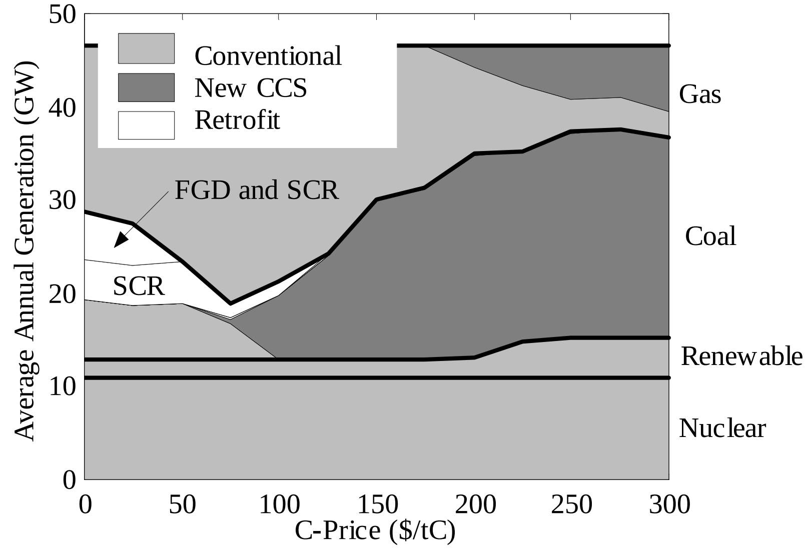


(a) Multipollutant baseline (no SO_2 and NO_X constraint)

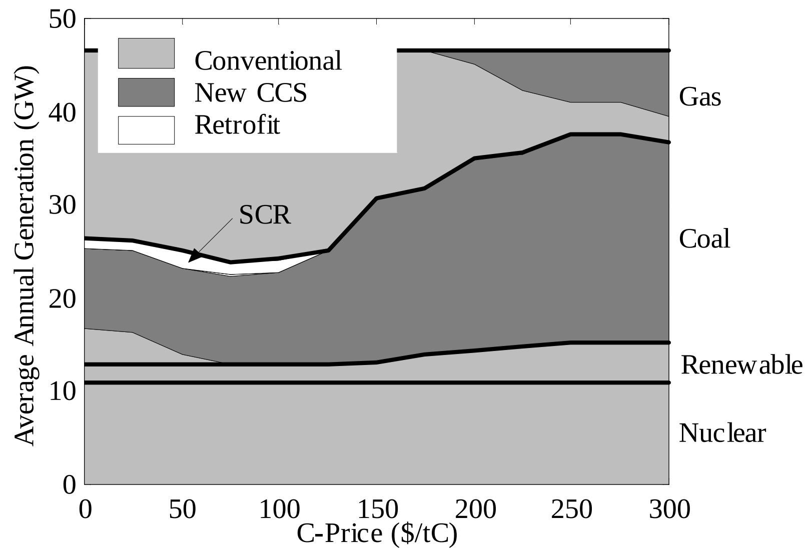


(b) SO_2 and NO_X constraint at 50 below baseline

Figure 5.17 – Average annual generation in period 6 (2026-2030) as a function of carbon price and multipollutant emission constraint. Per-period emissions are constrained as indicated in panels b through d to a percentage of the multipollutant model's baseline (panel a) period 1 (2001-2005) output (1.43 Mt SO_2 and 0.28 Mt NO_X). Note that new coal CCS plants prevent CO_2 as well as SO_2 and NO_X emissions, and are therefore competitive for the most stringent levels of criteria pollutant abatement at 0 $/tC.



(c) SO_2 and NO_X constraint at 75 below baseline



(d) SO_2 and NO_X constraint at 90 below baseline

Figure 5.17 (Continued)

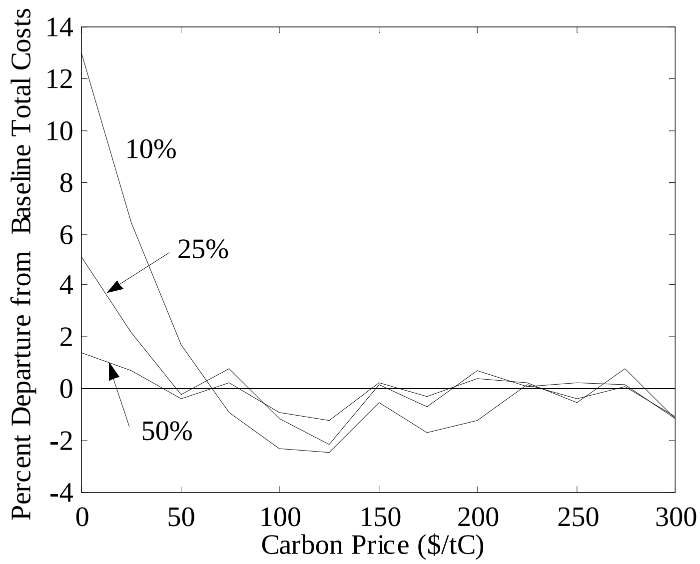


Figure 5.18 – Percent departure from *undiscounted* multipollutant baseline total costs as a function of carbon price and criteria pollutant emission constraint. Per-period emissions are constrained as indicated to a percentage of the multipollutant baseline's period 1 (2001-2005) output (1.43 Mt SO_2 and 0.28 Mt NO_X). Total costs are the sum of nominal capital and operating expenses over the model time horizon (2001-2040).

Finally, the timing and integration of criteria pollutant and CO_2 regulations could affect the extent to which technological synergies lower control costs. More stringent reductions in SO_2 and NO_X, for instance, if required in the near future, might lead the electric power industry onto a technology path that would be suboptimal should higher-than-anticipated reductions in CO_2 emissions be necessary, say, a decade or two later. The Figure 5.16 mitigation curves correspond to the least-cost generating mix, assuming that knowledge of all costs (CO_2) and constraints (SO_2 and NO_X) is complete. Technology choices made on this basis ("lock-in") could yield higher emission control costs should assumptions about either be in error and stranded costs become significant. Path dependencies and the costs of regulatory uncertainty therefore deserve further analysis.

5.5 References to Chapter 5

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Chapter 6: Carbon Sequestration in the US Outer Continental Shelf – Capacity and Regulation of Offshore Injection Sites

6.1 Chapter Overview

This chapter examines in greater detail an issue that the analysis to this point has represented in a single cost term: the long-term sequestration of CO_2 from the atmosphere. As discussed in Chapter 1, the literature contains numerous studies assessing the suitability of terrestrial formations as well as the waters of the deep ocean as CO_2 disposal sites. A range of capacity estimates for these sites is also available, especially as they coincide with industrial – and high CO_2 emission – nations such as Canada and the US.[1] Less attention has been paid to the regulatory issues surrounding sequestration and how CO_2 injection might fit within existing domestic and international legal frameworks. This chapter illustrates the complexities surrounding both the estimation of sequestration capacities and the regulation of CO_2 disposal by focusing on a particular disposal site that has received less attention: the sub-seabed of the Outer Continental Shelf (OCS) in US territorial waters.

Statoil's seabed injection of CO_2 separated from its Sleipner West gas recovery operations in the North Sea has provided the world's first experience with carbon sequestration for the deliberate avoidance of atmospheric CO_2 emissions – onshore or off. As such, the project has become the focus of technical and geological studies (see, e.g., the papers in Williams, et al., 2000, as well as Gale, et al., 2001), and has come under the scrutiny of the environmental community (e.g., Johnston, et al., 1999). Apart from this attention, however, few studies have assessed the near-term feasibility of linking sub-seabed sequestration with the large onshore point sources of CO_2 common, for instance, throughout the electric sector.[2]

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[1] See, for instance, Bachu (2000, 2001, 2002); Herzog, Caldeira, and Adams (2001); Gunter, et al., (1998); Hitchon, et al., (1999); Holloway (2001); Stevens and Gale (2000); and Wong, et al., (2000).

[2] This is not to claim that separate aspects of OCS sequestration have been ignored. Several studies, for instance, have examined the conditions for CO_2 sequestration in sub-seabed aquifers (see, e.g., Koide, et al., 1995; Koide, Shindo, et al., 1997; Koide and Yamazaki, 2001; and Sasaki and Kibayashi, 2000). In addition, Murray, et al., (1999) examined CO_2 sequestration via mineral reaction with sedimentary layers of the ocean floor, while Guevel, et al., (1996) and Murray, et al., (1996) suggested dropping solid, torpedo-shaped CO_2 "penetrators" into the seabed – a concept similar to one-time proposals for nuclear waste disposal. Finally, Koide, et al., (1995) and Koide, Tazaki, et al., (1997) looked at the role hydrates might play as a seabed CO_2 sequestration mechanism. Note that Stevens, et al., (1999) and Stevens and Gale

This chapter begins to remedy this deficiency by scoping out the technical and regulatory issues surrounding CO_2 injection into US submerged lands under Federal jurisdiction. Section 6.2 discusses the advantages and disadvantages of OCS sequestration. A lower-bound assessment of the sequestration capacity of the US seabed follows (Section 6.3). Section 6.4 then presents a detailed look at how OCS sequestration of CO_2 would fit into the current domestic and international regulatory regimes, and Section 6.5 offers concluding remarks. While the analysis aims only to frame the technical and legal issues surrounding sub-seabed CO_2 sequestration, its conclusions question the treatment of sequestration as an afterthought to CO_2 capture – a view encouraged by early claims that CO_2 transport and injection might account for no more than one-fourth of total CO_2 capture and sequestration costs (DOE, 1999).

6.2 Advantages and Disadvantages of OCS Sequestration

Given the sensitivities surrounding ocean disposal of industrial wastes and the strong international support for protecting marine ecosystems, and considering the added technical complexities of transporting and injecting CO_2 into sub-seabed formations, one might question why submerged lands would be thought of as a potential CO_2 sequestration site. Before turning to an assessment of OCS sequestration capacities and legal issues, this section briefly reviews the advantages and disadvantages of offshore CO_2 disposal relative to land-based alternatives. The distance between OCS sequestration sites and areas of human habitat, as well as the buffer provided by the ocean itself, provide arguments both for and against sequestration in submerged lands.

Sub-seabed sequestration offers three fundamental advantages over the injection of CO_2 into terrestrial formations. Perhaps the most immediate benefit is a reduction in *human* health and safety risks.[3] While estimates of the sequestration capacity of

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(2000) include offshore reservoirs in their assessment of the sequestration capacity of depleted oil and gas formations.

[3] Note that there are two general categories of risk associated with CO_2 sequestration. The first concerns the human and ecological effects of a CO_2 leak: CO_2 is denser than air and at moderate concentrations is an asphyxiant. Note, however, that the greater hazard in this regard is from a ruptured pipeline or a well blow-out; except in, say, a salt dome, the permeability of most geological formations would prevent the rapid release of CO_2. The second category of risks, however, is less dependent on the rate of escape. As CO_2 capture requires energy, and as this additional energy is likely to come from the combustion of fossil fuels, a widespread failure to sequester CO_2 permanently would lead to a higher atmospheric CO_2 concentration than would otherwise have been the case.

terrestrial formations are large,[4] the possible need to avoid sequestration under even mid-sized communities, as well as low-lying basins, may limit what is feasible in practice. In contrast, the distance between an offshore injection site and the nearest (permanent) population center would be great enough that even a catastrophic release of CO_2 would disperse before reaching land – eliminating the risk of (human) asphyxiation.[5] Seabed sequestration would also reduce the chance of CO_2 migration into fresh-water aquifers tapped as sources of drinking water (Holloway, 2001).

The second advantage of OCS sequestration results from the ocean's ability to provide a buffer between sequestered CO_2 and the atmosphere. Whereas any leak from a terrestrial reservoir will enter the atmosphere, relatively slow releases of CO_2 from sub-seabed sequestration sites will first mix with seawater. The residence time of CO_2 in the ocean would then be a function of the depth of release as well as the leak rate. Simulations and experiments with ocean injection of CO_2, however, suggest that isolation from the atmosphere could be significant. While approximately 65 percent of a direct CO_2 release would remain in the atmosphere after 100 years, basic ocean models indicate that only 30 percent of the CO_2 injected at 1000 m would enter the atmosphere on this timescale – a fraction that drops to 5 percent for injection depths approaching 2000 m (Herzog, et al., 2001).[6] The extent to which CO_2 would mix with seawater (and, for instance, form hydrates) or bubble to the surface is the subject of continuing research (e.g., see Brewer, et al. [1999] and Herzog, et al. [2000]).

Finally, depending on its depth at release, CO_2 escaping from the seafloor could have a density greater than that of seawater (i.e., slightly greater than 1000 kg/m^3), and would therefore be negatively buoyant. The important difference between the seafloor and land is temperature: below the thermocline (a depth near 500 m), for instance, water temperatures remain near 5 °C; on land, in contrast, surface temperatures can vary from the single digits Celsius in temperate zones to 25-30 °C in tropical regions (Bachu, 2001). The colder "starting point" and higher static pressure of the ocean bottom may therefore

[4] See the discussion in Chapter 1.
[5] An asphyxiation risk, of course, would remain for individuals located on nearby oil and gas drilling platforms, or even on nearby ocean vessels, although the flat ocean terrain would allow rapid dispersal of CO_2 not trapped within the structure (or vessel) itself (Koide, et al., 1997).

be sufficient to achieve a water-like density over a range of sequestration depths – an effect that higher land temperatures generally preclude.

A few calculations using the equation of state for CO_2 illustrate this effect. Assuming that pressure increases hydrostatically at 10 MPa per kilometer and that ocean water temperatures below the thermocline do not vary significantly from 5 °C, CO_2 on the ocean bottom will have a density greater than 1000 kg/m^3 at the point of injection for seafloor depths below 2 km.[7] The impact of a sub-seabed formation's failure to contain CO_2 would therefore be limited at these depths as liquid or supercritical CO_2 would remain in the formation or rest on the ocean bottom. It is also conceivable that reservoirs into which CO_2 had been injected would not necessarily require a cap. But while the density of CO_2 increases with pressure and decreases with temperature, sedimentary basin temperatures increase roughly 25 °C per kilometer from the surface.[8] Hence, the range of reservoir depths (i.e., below the seafloor) at which sequestered CO_2 would be negatively buoyant is not wide – on the order of a few hundred meters for a 2 km injection depth to a kilometer for injection sites below 3 km.

Like the advantages OCS sequestration offers over its terrestrial counterparts, its primary disadvantages involve the distance between CO_2 sources and offshore sinks. While isolation from human habitat is a significant benefit, for instance, use of the sub-seabed limits public access to injection wells and increases the challenge of monitoring site integrity. This distance could be a source of difficulty in gaining public support and environmental community trust, and would complicate the long-term verification efforts on which credit for sequestration would rest. In addition, by lowering the pH of the surrounding seawater, a slow CO_2 leak could substantially harm the ocean biotic community (Haugan, 1997; Caldeira, et al., 2001; Seibel and Walsh, 2001).[9]

Beyond these concerns lies a more immediate disadvantage of OCS sequestration: all other things being equal, disposal of CO_2 captured onshore beneath submerged lands

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[6] A related study comparing one- and three-dimensional models examined the oceans' ability to sequester CO_2 injected at 1 PgC/yr for 100 years. The mean retention across all sites was 20 percent for injection at 800 m, near 50 percent at 1500 m, and around 75 percent at 3000 m (Caldeira, et al., 2001).
[7] See Bachu (2001) and Lemmon, McLinden, and Friend (2001) for CO_2 properties
[8] This gradient is subject to the significant effects of local geological conditions; see Bachu (2001).
[9] A massive offshore discharge, by contrast, would be more likely than a small but steady escape of CO_2 to bubble out of the water and dissipate in the atmosphere.

would cost more than injection into terrestrial formations.[10] Consider drilling costs alone. The average cost of a well sunk in the continental US varies between $700k and $800k, with oil wells somewhat cheaper to drill than those associated with gas production; OCS production wells, in contrast, vary from $5M to $6M, with those in deep water running upwards of $10M (LMOGA, 1999).[11] How much greater offshore sequestration costs in general would be, however, is partly a function of the scale of related OCS activities.

6.3 The US OCS as a CO_2 Sequestration Site and a Lower-bound Estimate of its Capacity

Like CO_2 capture, the process of sequestering CO_2 below the earth's surface is similar in concept to established industrial practices, with OCS drilling and gas injection providing the closest seabed analogues. Offshore oil recovery in US waters began in 1896 near Summerland, CA, while discovery wells were first drilled in the Gulf of Mexico in the late 1930s, and the initial leases for sites off the Alaska coast were signed in 1976 (MMS, 2001d). Nearly 18500 offshore wells exist in US waters, with over 7000 currently providing a quarter of the nation's domestically-produced oil and natural gas (MMS, 2001a). In addition, gas and water injection for seabed reservoir pressure maintenance and secondary hydrocarbon recovery is routine, as is the reinjection of formation waters, drill cuttings, and the natural gas that often accompanies oil production.

Reasons therefore exist for believing that OCS sequestration might be feasible in the near-term at a favorable cost, even though the OCS is generally not thought of as a likely site for CO_2 disposal. This section presents these reasons by first reviewing OCS-related activities that are analogous to sub-seabed CO_2 injection, and then working through a first-order assessment of sequestration capacities. Note that the intent is to provide a lower-bound estimate of what might be economically and technically feasible over the next fifteen to twenty years; the section concludes with a look at the prospects for longer-term and higher-capacity offshore sequestration.

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[10] An exception would be the reinjection of acid gasses such as CO_2 and hydrogen sulfide (H_2S) stripped from natural gas at offshore production and processing facilities.

[11] Though the difference in costs is substantial, its magnitude on a "CO_2 sequestered per kWh" basis may be minor.

6.3.1 Industrial Operations on the US Outer Continental Shelf

The scale of current OCS activities provides an indication of the near-term feasibility of using submerged lands for CO_2 sequestration. Like their terrestrial counterparts, sub-seabed aquifers, hydrocarbon reservoirs, and salt caverns offer possible OCS sequestration sites. Although US submerged lands are of interest for their sulfur and salt deposits, oil and gas production dominate offshore activity and also furnish the closest analogues to the processes required for OCS CO_2 sequestration.[12] Experience with offshore drilling and fluid injection, as well as pipeline operations, for instance, would apply directly to CO_2 disposal. Producing hydrocarbon reservoirs are also relatively well-characterized compared to sub-seabed aquifers, and much of the needed infrastructure and requisite experience associated with these formations is either in place or available (Bachu, 2000). A lower bound on the near-term sequestration capacity of OCS lands can therefore reasonably focus on oil and gas reservoirs.

Table 6.1 presents a snapshot of existing OCS activities in the Gulf of Mexico and Pacific regions, while Table 6.2 gives a more comprehensive look at past oil and gas production as well as current reserve estimates. Note that exploration off the Alaska coast started in 1975, and that while 83 wells had been drilled as of October 2001, only 11 out of the 30 wells located in the Beaufort Sea are producible (there are also 2 active leases in the Cook Inlet) (MMS Alaska, 2001a and 2001b). This analysis is therefore concerned primarily with the OCS off the mainland US.

Although the term OCS often refers to all submerged lands within US jurisdiction, the true geological OCS makes up approximately 15 percent of this region. It is in the latter, where water depths are less than 200 m, that hydrocarbon exploration and recovery have historically occurred. Deep water operations, however, are becoming more common, with wells recently drilled along the Continental Slope in water depths exceeding 2000m (MMS, 1999). Production from all Federal OCS lands in 2000

[12] The OCS is also viewed as a potential source of sand and gravel, as well as minerals such as tin, gold, titanium, phosphorite, manganese, and platinum (MMS, 2001a).

Table 6.1 – US OCS oil and gas production statistics for year 2000 (Sources: Cranswick, 2001; MMS 2001b; MMS Gulf of Mexico, 2001b, 2001c, and 2001d; MMS Pacific, 2001a and 2001b).

	Gulf of Mexico	*Pacific Region*
Production volumes		
Oil (million Bbl)	522	36
Gas (Tcf)	4.95	0.08
Water (million Bbl)	635	78
Infrastructure		
Platforms	4043	23
Active Wells	6455[a]	890
Kilometers of Pipeline	44220[b]	290
Injection volumes		
Gas Injection (Bcf)	28.5	30.2
Water Injection (million Bbl)	17.8	16.1
Water Disposal (million Bbl)	2.4	3.4

Notes to Table 6.1:
a. October 2001
b. June 2001

Table 6.2 – Cumulative OCS oil and gas production plus current reserve estimates (Sources: Crawford, et al., 2000; MMS, 2001c; Sorensen, et al., 2000).

	Gulf of Mexico	*Pacific Region*	*Total*
Cumulative production through 31 December 1998			
Oil (Bbbl)	10.91	0.92	12
Gas (Tcf)	133	0.87	134
Proven reserves as of 31 December 1998			
Oil (Bbbl)	3.36	0.41	3.77
Gas (Tcf)	30	1.29	31.29
Unproven reserves as of 31 December 1998			
Oil (Bbbl)	1.0	1.32	2.32
Gas (Tcf)	5.1	0.92	6.02
Mean estimate of undiscovered, economically recoverable resources (Total includes Atlantic and Alaska Regions; figures vary with the assumed price of oil and gas.)			
Oil (Bbbl)	18-28	5-7	27-47
Gas (Tcf)	100-141	8-12	117-168

included nearly 600 million barrels (bbl) of oil – or 27 percent of domestic production. Similarly, a quarter of US natural gas production took place offshore, with 5 Tcf recovered from submerged lands in 2000. Compared to over 95600 onshore oil and gas wells, nearly 18500 were in service throughout the OCS (MMS, 2001b). A quick glance at Table 6.1 shows the dominance of the Gulf of Mexico as a source for this activity.

6.3.2 CO_2 Sequestration in Gulf of Mexico Hydrocarbon Reservoirs

An exclusive focus on Gulf of Mexico hydrocarbon basins as OCS CO_2 disposal sites can be justified by considering the conditions under which sequestration in depleted reservoirs would be most favorable. The first, and perhaps most intuitive, is simply the scale of oil and gas recovery operations. Three issues are particularly important in this regard – beyond the sequestration capacities of actual hydrocarbon reservoirs (Bachu, 2001). First, knowledge of the geology and hydrology of producing reservoirs is reasonably thorough; this is not necessarily the case, for instance, in the Alaska OCS region or off the Atlantic coast, where few exploratory wells have been producible. Second, nearly 200 hydrocarbon fields in the Gulf of Mexico are now depleted, avoiding the potential for contamination associated with CO_2 injection into active reservoirs (Crawford, et al., 2000; Bachu, 2000). Finally, decades of Gulf of Mexico activity have yielded an extensive transportation and processing infrastructure, through which the material flow would essentially be reversed for CO_2 sequestration. This infrastructure includes not only offshore pipelines and injection platforms, but also the land and legal right-of-way associated with onshore processing facilities.

Its proximity to large onshore point sources of CO_2 emissions is a second consideration that favors the Gulf of Mexico over other US OCS sequestration sites. The Gulf states from Texas to Florida dominate electric sector CO_2 emissions, for instance, producing approximately 138 million tC in 1998 – a quarter of the industry's output for that year (EIA, 2000, 2001a and 2001c).[13] The West Coast states of Washington, Oregon, and California, by contrast, released only 18 million tC, with electricity producers in Alaska generating slightly less than one million tC. This advantage is

[13] Texas, in fact, ranked first in US electric sector CO_2 emissions (67 million tC), while Florida was third (33 million tC) (EIA, 2001c).

supported further by the fact that OCS operations in the Gulf are dispersed along the coast, while oil and gas operations in the Pacific are centered on a relatively small region off the California shoreline near Santa Barbara.

Finally, geological considerations that discourage use of the Pacific OCS as a CO_2 disposal site favor hydrocarbon basins beneath the Gulf of Mexico seafloor. Convergent basins, like those along the West Coast, are prone to seismic hazards and therefore carry the risk of a relatively sudden release of CO_2 during an earthquake or along a pathway opened by more gradual faulting mechanisms. In contrast, the compacting basins along the Gulf (and Atlantic) OCS are relatively stable, although the downward force of sedimentary compression results in the flow of fluids – including CO_2 – out from the basin on geological timescales (Bachu, 2000).

A conservative estimate of the CO_2 sequestration capacity of the US OCS might therefore focus on the Gulf of Mexico region, where the economic and technical hurdles are lowest. Estimation of a near-term lower bound might also consider depleted natural gas and oil reservoirs separately. Justification for this treatment involves a fundamental difference in the nature of gas and oil recovery.[14] "Depleted" natural gas reservoirs are typically just that: nearly exhausted of their original gas content. Oil reservoirs, in contrast, are often abandoned with oil left in place – "depletion" in this case referring to resources that are recoverable under current economic conditions. Commercial considerations may therefore discourage CO_2 sequestration in presently abandoned oil reservoirs that, with improved technology, may once again provide an economically recoverable source of oil (Bachu, 2000).[15]

Focusing first on the sequestration capacity of offshore natural gas reservoirs, a conservative estimate would equate the volume of CO_2 a reservoir can sequester with the volume of natural gas it can produce, where both figures are taken at standard temperature and pressure (STP) (Gunter, et al., 1998; Holloway, 2001). This equation assumes that the flow of water into the depleted reservoir is insignificant, and that the

[14] In addition, gas reservoirs are generally larger and deeper than oil fields and therefore have a greater CO_2 storage capacity (Stevens and Gale, 2000).
[15] Indeed, the Federal regulations governing well abandonment stipulate that "no production well shall be abandoned until its lack of capacity for further profitable production of oil, gas, or sulfur has been demonstrated" (30 CFR §250.700). Permanent CO_2 sequestration would require the abandonment not only

formation's structural integrity is intact. With that caveat, an aggregation of past production with both proved and unproved reserves (see Table 6.2) suggests that natural gas reservoirs in the Gulf of Mexico could sequester nearly 170 Tcf of CO_2 (9 Gt CO_2, or 2.4 Gt C). Inclusion of undiscovered Gulf of Mexico gas reserves provides an OCS sequestration capacity of 270 to 310 Tcf CO_2 (3.9 to 4.5 Gt C), with the range driven primarily by the price at which gas recovery becomes economically feasible.

Depending on reservoir-specific properties, however, the mass of CO_2 sequestered in natural gas reservoirs may be significantly greater than this estimate suggests. In general, the ideal sequestration site would be a formation that could support CO_2 either as a high-density liquid or a supercritical fluid, where the form of CO_2 (i.e., its phase) depends on the reservoir temperature and pressure.[16] CO_2 is a supercritical fluid – with the expansive properties of a gas but a density that can exceed that of water (1000 kg/m^3) – above 31.1 °C and 7.38 MPa; below this critical point, CO_2 would be sequestered either as a gas or a liquid.[17] Reservoir pressure, however, is dependent on fluid flow and formation permeability, and temperatures vary with local geological conditions (Bachu, 2001). As Bachu (2000) points out, generalizations about the location of the 31.1 °C isotherm and 7.38 MPa isobar based solely on sub-surface depth may therefore lead to overestimation of a formation's sequestration capacity. Hence, it is not a trivial task to provide a more precise estimate of gas field sequestration capacity, and the figures given above (which assume CO_2 sequestration as a low-density gas) are likely to be quite conservative.

Keeping in mind the earlier discussion regarding the commercial value of remaining reserves, a similar line of reasoning applies to assessing the sequestration capacity of economically depleted oil reservoirs. Unlike gas formations, however, a first-order estimate of oil reservoir capacity would equate the volume of *liquid* CO_2 to barrels of oil recovered. Hence, an assumption about the density of liquid CO_2 is required. A minimum, and therefore conservative, value would be the density at which CO_2 is either a

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of individual wells, but the reservoir into which they are drilled; see the discussion in the following section on domestic regulation of OCS sequestration.

[16] Note that this is distinct from *injection* pressure, which is largely determined by the stress tolerance of the formation rock, as well as the porisity and amount of water in the reservoir (Bachu, 2000; Holloway, 2001).

liquid or a supercritical fluid. For realistic reservoir temperatures (i.e., greater than 10 °C), this density corresponds to a formation pressure of at least 8 MPa, and ranges between 200 and 900 kg/m^3 CO_2 (Bachu, 2001).[18] The result is that, at STP, between 600 to 2700 scf of (gaseous) CO_2 could be injected for every barrel of recovered oil.[19] Based on past oil production as well as estimates of proven and unproven reserves (see Table 6.2), the Gulf of Mexico OCS could therefore sequester 9 to 42 Tcf of CO_2 (0.13 to 0.60 Gt C) in oil reservoirs. Inclusion of undiscovered oil reserves increases the sequestration capacity by 11 to 76 Tcf CO_2 (0.16 to 1.10 Gt C).

6.3.3 Enhanced Oil Recovery in the OCS

As an alternative to permanent geological sequestration, CO_2 may be isolated from the atmosphere in productive activity. Enhanced oil recovery (EOR) via CO_2 injection ("tertiary recovery"), for instance, is not currently practiced in OCS oil and gas operations but may offer an early and important niche market for anthropogenic sources of CO_2.[20] Requiring four to eight mcf of CO_2 per additional barrel of oil produced, for instance, EOR offers the ability to recover as much as 40 percent of a field's remaining oil reserves (Bachu, 2000; Holloway, 2001).[21] A considerable fraction of the CO_2 injected for EOR, however, returns to the surface (with recovered oil) in a matter of years and would therefore have to be reinjected. Hence, while offshore EOR may provide a valuable commercial use for captured electric sector CO_2, the previous argument about "depleted" oil reservoirs applies and it may be best to consider CO_2 injected for tertiary recovery apart from other estimates of sequestration capacity (Gunter, et al., 1998; Bachu, 2000).

Four factors parameterize a simplified assessment of EOR "sequestration" potential: the efficiency of primary oil recovery (i.e., the fraction extracted without

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[17] Solid CO_2 hydrates are a further possibility, though not enough is known to explore even a first-order estimate here; see Koide, et al., (1995) and Koide, Tazaki, et al., (1997).

[18] The density of CO_2 at 8 MPa drops dramatically from 900 kg/m^3 at 10 °C to a plateau of 200 kg/m^3 for temperatures greater than 40 °C (see Bachu, 2001).

[19] One barrel is equivalent to 0.16 m^3, yielding a mass of CO_2 between 32 and 144 kg per barrel for the given densities. Conversion back to gaseous CO_2 at STP assumes a density of 19 scf/kg CO_2.

[20] EOR via water flooding is practiced in the Gulf of Mexico (personal communication, Joe Gordon, MMS Gulf of Mexico Region Safety Office, New Orleans, LA, 10 October 2001).

[21] Enhanced recovery of natural gas, less common than tertiary oil recovery, is not considered here.

EOR); the share of remaining oil that can be recovered with EOR; the amount of CO_2 that must be injected to extract an additional barrel of oil; and the fraction of injected CO_2 that remains in the reservoir when tertiary recovery is complete. Table 6.3 illustrates how both pessimistic and optimistic assumptions about these factors affect total EOR CO_2 requirements as well as long-term CO_2 disposal. The amount of CO_2 permanently sequestered via EOR in each case is small relative to the reservoir capacities estimated above. Consideration of EOR for undiscovered resources increases the sequestration potential by 1 to 22 Tcf CO_2 (15 to 310 MtC).

Table 6.3 – Parametric analysis of EOR CO_2 sequestration potential for proven and unproven Gulf of Mexico oil reserves. Note that "pessimistic" and "optimistic" refer to CO_2 sequestration, not hydrocarbon recovery.

	Pessimistic					*Optimistic*
Assumptions:						
CO_2 required for EOR (Mcf CO_2 per bbl Oil)	4	6	6	6	6	8
Fraction of primary oil recovered without EOR	0.6	0.6	0.6	0.4	0.4	0.4
Fraction of remaining oil recovered via EOR	0.2	0.3	0.4	0.3	0.4	0.4
Fraction of injected CO_2 remaining in reservoir	0.2	0.3	0.3	0.3	0.3	0.4
Results:						
Oil recovered with EOR (billion bbl)	0.3	0.5	0.6	0.7	1.0	1.0
CO_2 required for EOR (Tcf CO_2)	1.3	2.9	3.8	4.3	5.8	7.7
CO_2 sequestered (Tcf CO_2)	0.3	0.9	1.2	1.3	1.7	3.1
CO_2 sequestered (MtC)	3.7	12.4	16.6	18.7	24.9	44.2

6.3.4 OCS Sequestration Capacity: Summary and Prospects

Table 6.4 summarizes these lower-bound estimates for Gulf of Mexico hydrocarbon reservoir sequestration capacities. A few comparisons may put these numbers in perspective. The US electric sector currently releases approximately 600 Mt C per year (42 Tcf CO_2), or 25 percent of the total capacity of *known* Gulf of Mexico oil and gas reserves and economically depleted formations (EIA, 2000 and 2001a). If consideration is restricted to the CO_2 output of electricity generators in the Gulf Coast states from Texas to Florida,[22] a little over 17 years worth of current annual emissions could be sequestered.[23] Including optimistic estimates of undiscovered resources doubles the capacity. The figures for depleted offshore reservoirs are on the order of those given for abandoned oil and gas reservoirs elsewhere in the US, but are substantially less than the 25 GtC that all terrestrial hydrocarbon-bearing formations in the US might sequester (see Herzog, et al., 1997). Note for reference that a "typical" 500 MW coal plant generates the equivalent of 1.2 Mt C per year (Holloway, 2001).

It is also instructive to compare sequestration volumes with current Gulf of Mexico OCS activities (see Table 6.1). On an annual basis, for instance, injection amounts are much smaller than yearly production. Even if injected water is converted to a corresponding volume of liquid CO_2 (at 900 kg/m^3, slightly less than the density of water), total injection volumes in the Gulf of Mexico amount to an equivalent of 0.09 Tcf CO_2 (1.3 Mt C) per year – a fraction of the 5 Tcf of natural gas recovered from Gulf of Mexico reservoirs in 2000, and much less than annual Gulf state electric sector CO_2 emissions.[24]

[22] Roughly 140 MtC or 10 Tcf CO_2 per year (EIA 2000, 2001a, and 2001c).
[23] All other things being equal, of course, CO_2 emissions will increase over this timeframe. Sequestration, however, would not occur without a significant carbon constraint (in the form of a tax or regulatory equivalent), which – on its own – would also lower emissions. The estimate is therefore conservative.
[24] As a final comparison, Norway's Statoil is injecting approximately 19 billion scf CO_2 (0.27 Mt C) per year separated from its Sleipner West offshore gas production facilities into aquifers of the Utsira Sand reservoir, 800 to 1000 m beneath the North Sea (Holloway, 2001).

Table 6.4 – Lower-bound CO_2 sequestration capacity estimates for Gulf of Mexico OCS geological formations.

	Gulf of Mexico OCS Sequestration Capacity (in GtC) Associated With:		
	Short-Term		*Long-Term*
	Depleted formations	Proven and unproven reserves	Undiscovered resources[a]
Gas reservoirs	1.90	0.50	1.50 – 2
Oil reservoirs[b]	0.10	0.03	0.16 – 0.24
EOR	0.01 – 0.04		0.02 – 0.31
Aquifers			40 – 50

Notes to Table 6.4:
a. The given range reflects different assumptions about oil and gas prices.
b. These numbers correspond to the lower liquid CO_2 density.

Finally, consideration of OCS hydrocarbon reserves provides a first-order estimate of the near-term OCS sequestration capacity – what might be economically and technically feasible given current experience, infrastructure, and knowledge of seabed geological formations. Salt caverns and aquifers, however, provide two additional OCS sequestration sites. In the near term, neither is likely to compete with depleted hydrocarbon reservoirs in the OCS as a CO_2 sequestration site. Caverns must be opened in salt domes, for instance, leading to environmental problems with brine disposal (Gunter, et al., 1998; Bachu, 2001).

As with terrestrial sequestration, however, aquifers could provide a significant sink for anthropogenic CO_2. Sequestration in oil and natural gas reservoirs may be viewed as a more specific case of aquifer disposal, since hydrocarbon-bearing formations are generally that part of an aquifer in which some trapping mechanism has constrained oil or gas migration. A "zeroth-order" assessment of the sequestration capacity of OCS aquifers might therefore compare similar estimates for terrestrial hydrocarbon reservoirs and aquifers, and assume that the ratio of sequestration capacities for these land-based formations generalizes to the seabed. Gunter, et al., (1998) and Holloway (2001) cite studies suggesting that aquifers worldwide might be able to sequester between 100 and 10000 Gt C; global estimates for depleted oil and gas reservoirs range between 100 and 500 Gt C. This spread reflects considerable uncertainty, but even a 1:10 hydrocarbon reservoir to aquifer ratio suggests that Gulf of Mexico seabed aquifers could sequester an additional 40 to 50 Gt C.

Like oil and gas reservoirs, a more accurate assessment of seabed aquifer CO_2 sequestration capacities would require extensive study of specific formations (e.g., characterization of their pore geometry, the salinity of formation water, and in situ stress conditions). Bachu (2001) also points out that at seabed depths approaching 2000 m in the Gulf of Mexico, the technological and safety challenges of high formation pressures would hinder aquifer sequestration. Serious consideration of these factors would likely follow the exhaustion of depleted hydrocarbon reservoirs as potential sites for CO_2 disposal.

6.4 Regulation of CO_2 Sequestration in the OCS

Sub-seabed sequestration of CO_2 may therefore be technically feasible. Such practicality, however, says nothing about the legality of using submerged lands for CO_2 disposal. This chapter concludes by addressing this issue. In short, neither US law nor international agreements *explicitly* forbid injection of CO_2 beneath the seafloor. Hence, one is led to ask if the existing domestic and international regulatory regimes provide the necessary legal framework for dealing with sub-seabed CO_2 sequestration and, if so, whether use of the OCS for CO_2 disposal would be allowed.[25] This section examines these questions as they pertain to sequestration in submerged lands under US jurisdiction. Domestic regulation of offshore activity is first discussed; a look at how OCS CO_2 sequestration would fit into the regime of international environmental agreements follows.

[25] Note that "allowed" in this sense is not synonymous with "politically feasible" or "socially acceptable." Even if OCS sequestration is allowable under existing law, legitimate sensitivity about using the oceans for industrial purposes as well as public concern with a novel approach to the mitigation of climate change could require explicit legislative attention.

6.4.1 US Regulation of Submerged Lands[26]

National sovereignty over OCS lands and their natural resources is derived from the 1982 United Nations Convention on the Law of the Sea (UNCLOS), which established for coastal nations a 200 nautical mile (370 km, as measured from the shoreline) "Exclusive Economic Zone" (EEZ). Though the US Senate has not ratified the UNCLOS, US law incorporated this definition in 1983,[27] building on the earlier Submerged Lands Act and Outer Continental Shelf Lands Act (OCSLA) which delineated State and Federal jurisdiction in 1953.[28] State mineral rights under these acts extend three nautical miles (5.6 km) from shore, with the Federal Government, through the Department of the Interior (DOI), having regulatory authority seaward of states' coastal waters. Western Florida and Texas are the exceptions, with state coastal waters extending three marine leagues (16.65 km) from shore.[29] In 1982 the Minerals Management Service (MMS) was established within the DOI to oversee mineral resource recovery, environmental protection, leasing, and associated revenue collection in that part of the OCS lying beyond the states' jurisdiction. The MMS, in turn, is divided into three administrative regions covering submerged lands in the Gulf of Mexico and Atlantic Ocean, the Pacific Ocean off the West Coast of the US, and the waters surrounding Alaska (Figure 6.1).

The MMS would oversee CO_2 injection into the US OCS, although, as with offshore oil and gas operations more generally, its regulatory authority would overlap with that of other Federal agencies. The key to understanding how sub-seabed CO_2 *sequestration* might be regulated, however, lies in recognizing that all CO_2 is not alike. The distinction turns on source and purpose: CO_2 injected to enhance offshore oil or gas

[26] Note that the focus here is on activities affecting submerged lands beneath Federal waters. A careful look at individual State regulations is beyond the scope of this chapter. A more thorough justification, however, might appeal to the Underground Injection Control program, which governs waste disposal through land-based wells but also includes seabed injection wells in State waters (40 CFR §144.1(g)(1)(i)). Offshore CO_2 sequestration in submerged lands under State jurisdiction might therefore be treated in a manner similar to terrestrial injection.
[27] Presidential Proclamation 5030 (3 CFR 22).
[28] 43 USC §1301-1315 and 43 USC §1331-1356, respectively.
[29] The US Exclusive Economic Zone also applies to its overseas territories. This chapter, however, considers only those portions of the OCS adjacent to the continental US and Alaska.

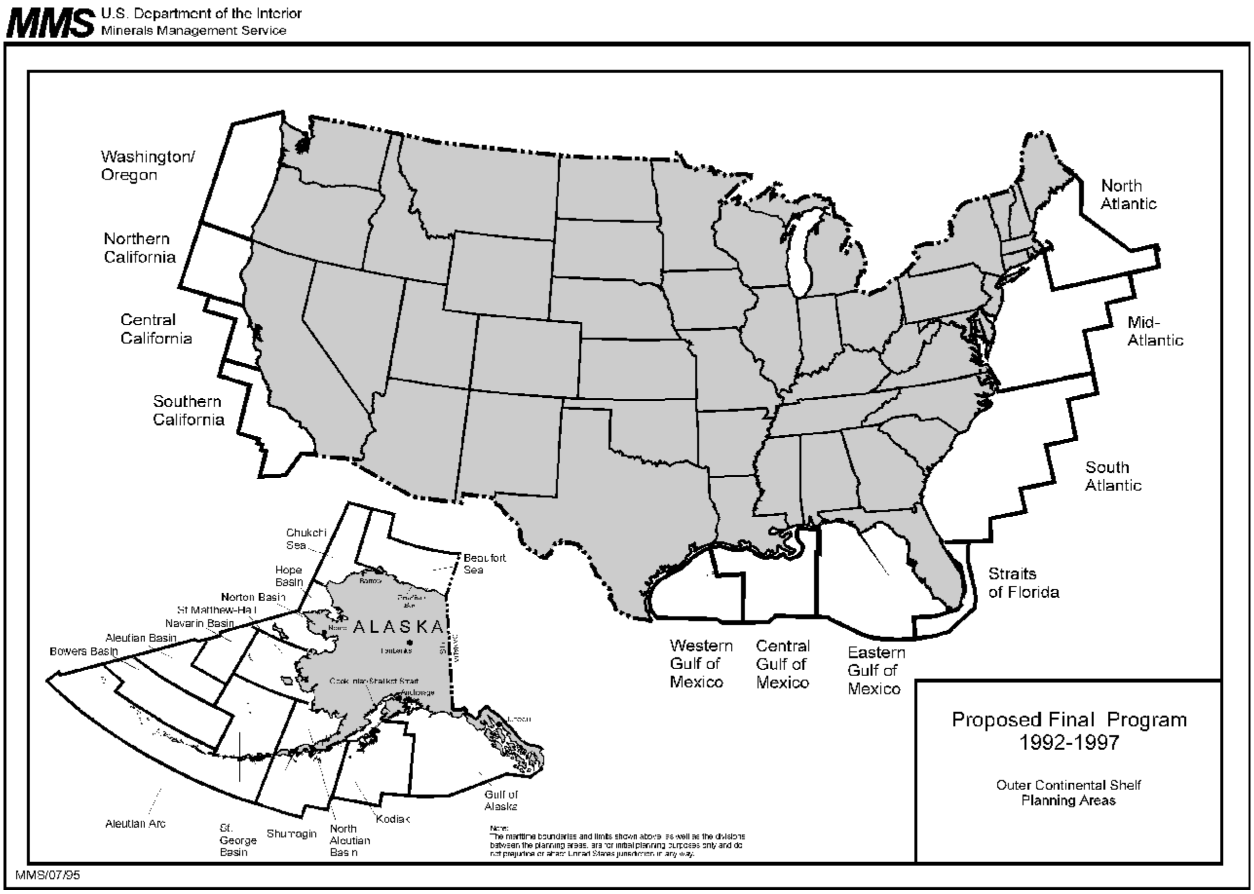

Figure 6.1 – Minerals Management Service Outer Continental Shelf planning areas. US offshore lands fall into three administrative regions: the Gulf of Mexico and Atlantic, the Pacific Coast, and Alaska (map source: MMS, 2002).

recovery, for instance, is legal under current administrative law.[30] Disposal of CO_2 from sources and for purposes unrelated to OCS oil and gas operations, in contrast, would require an extension of MMS authority.[31] In order to understand the legal framework into which OCS sequestration would fit, it is therefore necessary to take a look at the regulation of offshore activities similar in nature to sub-seabed CO_2 disposal.

The OSCLA is the major piece of legislation governing mineral recovery from submerged lands.[32] The MMS, as administrator of the OCSLA, prepares five year comprehensive programs for prospective oil and gas activities, and solicits the input of industry and other interested parties regarding specific leases. Lessees then submit applications for exploration activities or development and production operations to the regional MMS administrators; separate drilling permits are also required. The MMS has primary responsibility for enforcing safety standards, specifying platform and drilling equipment requirements, inspecting offshore facilities, collecting and processing both environmental and production data, and managing revenue through site clearance and the abandonment of each lease. Within the bounds of relevant legislation and administrative law, approval of most routine mineral recovery activities in the OCS rests with the regional MMS administrators.

Consider sub-seabed injection and waste disposal, the closest analogues to OCS CO_2 sequestration.[33] In the Gulf of Mexico, for instance, operators must obtain approval of the regional administrator, per the terms of DOI regulations, prior to the offshore disposal or storage of drilling cuttings, produced waters, naturally occurring radioactive materials that are above background levels, and other wastes associated with offshore oil and gas production.[34] Disposal wells, however, cannot be drilled into commercially viable reservoirs, need to be capped by a shale barrier, and must be below aquifers

[30] 33 USC §1362(6)(B), 30 CFR §250.118 and 30 CFR §250.1107, for instance, cover offshore EOR.
[31] Personal communication, Elmer Peter Danenberger III, Chief, Engineering and Operations Division, Minerals Management Service, Herndon, VA, 22 August 2001.
[32] Much of the administrative law pertaining to the OSCLA is contained in 30 CFR §§200-299.
[33] The EPA estimates that 80% of OCS drilling wastes are moved to shore for disposal, while the remaining 20% are reinjected; see 66(14) FR 6849-6919 ("Effluent limitations guidelines and new source performance standards for the oil and gas extraction point source category," published 22 January 2001).
[34] See 30 CFR §250.300(b)(2) for DOI waste disposal regulations, as well as MMS Gulf of Mexico Region Notice to Lessees No. 99-G22, "Guidelines for the Sub-Seabed Disposal and Offshore Storage of Solid Wastes," September 24, 1999. Note that reinjection of naturally occurring radioactive materials that are below background levels is approved more generally.

containing potable water; encapsulated wastes must also be sunk at least 300 m beneath the seafloor. Likewise, offshore EOR and gas storage require regional approval. While seabed natural gas storage is not currently practiced, the MMS encourages gas injection to: "(1) Enhance [oil and gas] recovery; (2) Prevent flaring of casinghead gas; or (3) Implement other conservation measures approved by the Regional Supervisor."[35] Indeed, injection of the natural gas that often accompanies oil production – the second of these motivations – has become routine.[36]

Finally, it is interesting to note that the MMS regulations governing well abandonment address closure and site clearance, but do not require extended monitoring of the closure integrity.[37] Monitoring and verification of reservoir fluid containment, of course, would play an important role in any CO_2 sequestration scheme – on shore or off. A well cannot be abandoned, however, "until its lack of capacity for further profitable production of oil, gas, or sulfur has been demonstrated to the satisfaction of the [MMS] District Supervisor," further supporting the earlier exclusion of oil wells from a lower bound estimate of OCS CO_2 sequestration capacities.[38]

The MMS also acts as an intermediary between offshore operators and other Federal agencies. As with any Federal action that may significantly affect the human environment, for instance, an environmental impact statement (EIS) must be generated for all proposed offshore activities. The MMS therefore prepares the necessary documents per the National Environmental Policy Act (NEPA), as administered through the Environmental Protection Agency (EPA).[39] The EPA, under the Federal Water Pollution Control Act (FWPCA) and the Clean Water Act (CWA),[40] also regulates the

[35] Personal communication, Joe Gordon, MMS Gulf of Mexico Region Safety Office, New Orleans, LA, 10 October 2001), and 30 CFR §§250.118-119. 30 CFR §250.1107 encourages injection for secondary oil and gas recovery. Note that gas storage is assumed to be temporary ("for later commercial benefit," 30 CFR §250.119), and that storage on unleased OCS lands requires special approval (30 CFR §250.123).

[36] As much as 25 percent of the gas produced in the Pacific region, for instance, is reinjected (Sorensen, et al., 2000).

[37] See 30 CFR §§250.700-704.

[38] 30 CFR §250.700

[39] For NEPA, which was passed in 1969, see 42 USC §4321, et seq. Individual Federal actions do not necessarily require an EIS; depending on the situation, a Categorical Exclusion Review (CER) or Environmental Assessment (EA) may suffice if the environmental impact of a proposed action is minor or if a more inclusive EIS exists.

[40] For the FWPCA see 33 USC §1251, et seq.; for CWA see Public Law 95-217. The relevant administrative law is contained in 40 CFR §§221, 222, and 435. As defined by this legislation, "pollutant" does not include gas or water injected for EOR (33 USC 1362(6)(B)).

discharge of drilling fluids and produced waters from platforms and related vessels in the OCS. Five year National Pollution Discharge Elimination System (NPDES) permits are issued to offshore operators, although the EPA explicitly favors a zero-discharge policy – implying a preference for reinjection or, if necessary, onshore disposal.[41] Finally, the EPA sets standards for offshore air emissions as specified by the Clean Air Act and its amendments.[42] Note, however, that the Underground Injection Control program (UIC), which the EPA administers under the Safe Drinking Water Act (SWDA), does *not* apply to OCS lands beyond state waters.[43]

Several other pieces of Federal legislation govern OCS activities and, to the extent that sub-seabed CO_2 sequestration would affect the coastal and marine environments, deserve mention here. Most significant is the Coastal Zone Management Act (CZMA), which is overseen by the National Oceanic and Atmospheric Administration and allows individual coastal states to review any Federal offshore action impacting either the land or waters within their jurisdiction.[44] Other relevant pieces of legislation include the Marine Mammal Protection Act, the Endangered Species Act, and the Fishery Conservation and Management Act, all safeguarding marine species, as well the National Historic Preservation Act, protecting submerged archaeological sites and shipwrecks.[45]

Finally, the Departments of Transportation (DOT) and the Interior (through the MMS) jointly regulate pipeline transport of oil and gas recovered offshore. A Memorandum of Understanding between the departments divides responsibility between pipelines serving production operations (MMS) and those used exclusively to move hydrocarbons to shore (DOT).[46] While neither this agreement nor the departments'

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[41] See 40 CFR §122 for NPDES. 66(14) FR 6849-6919 ("Effluent limitations guidelines and new source performance standards for the oil and gas extraction point source category," published 22 January 2001) details the EPA's position on ocean discharge of drilling (and other) fluids.

[42] 42 USC. §7401 et seq. The EPA has responsibility for enforcing air quality standards for all OCS regions outside of the western Gulf of Mexico, which the DOI (MMS) oversees.

[43] See 42 USC §300f et seq. for the SWDA and part C of the SWDA for the UIC. The UIC also specifically excludes underground storage of hydrocarbons that are gaseous at STP; see 40 CFR §144.1(g)(2).

[44] See 16 USC §1451 et seq.

[45] See 16 USC §1361, et seq. and 16 USC §1531, et seq., 16 USC §1801, et seq., and 16 USC §470-470t, respectively.

[46] "Memorandum of understanding between the Department of Transportation and the Department of the Interior regarding Outer Continental Shelf pipelines," signed 10 December 1996. See 49 CFR §§191-3,

respective regulations address pipeline transfer of substances generated on land *to* offshore facilities, transport of CO_2 generated onshore for sub-seabed disposal (i.e., independent of oil and gas production) would not fit the current jurisdictional framework. A modification of the relevant legal arrangements would likely be necessary.

As submerged lands have traditionally been thought of as a source of oil, gas, sulfur, and other mineral resources, the legislation cited here either specifically addresses OCS mineral recovery, or has found application through its interpretation in administrative law. The use of the OCS for purposes other than mineral exploration and recovery – especially the transport of materials generated *onshore* to the OCS for disposal – would therefore require a clarification of MMS authority. Given the novelty and sensitivity of using submerged lands for CO_2 sequestration, an administrative ruling by the DOI may not be sufficient for seabed disposal, and Congressional legislation specifically addressing the issue may be necessary.

A look at US legislation and administrative law *from a purely domestic point of view* therefore provides an indefinite answer to questions regarding the legal status of OCS sequestration. In contrast, international environmental agreements, though no more explicit about CO_2, at least provide greater clarity regarding ocean disposal of human-generated substances.

6.4.2 International Regulation of Submerged Lands

Several international agreements either address protection of the ocean environment specifically or, in regulating the transboundary movement of pollutants, limit ocean waste disposal. Of these, the 1972 London Convention (more formally, the "Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter") – especially in its more recent guise as the1996 London Protocol – is the most definite.[47] And as the London Convention is also one of the few international treaties

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and 195 as well as 30 CFR §§1007-1010. Note that 49 CFR §195, which covers pipeline transportation of hazardous liquids and CO_2, excludes OCS pipelines carrying CO_2 for production purposes only (as opposed to transportation to or from the shore). See also the Hazardous Liquid Pipeline Safety Act at 49 USC §60101, et seq., as well as 49 USC §5101, et seq., for legislation covering the transportation of hazardous materials. The US Coast Guard and the Army Corp of Engineers are also involved in the regulation of offshore pipelines, especially as they impact navigation of ocean traffic.

[47] The London Convention is probably better known as the London Dumping Convention; "dumping" was dropped from the shorthand title in the 1990s to reflect efforts that broadened the Convention's

relevant to sub-seabed CO_2 sequestration to have entered US law, it deserves detailed consideration here.[48] This section therefore concentrates on the London Convention, while concluding with a brief look at other international agreements.

Negotiated in 1972 and in force since 1975, the London Convention originally sought to prevent marine pollution by limiting the discharge – or "dumping" – of human-generated materials into the oceans. Subsequent amendments banned ocean disposal of industrial and radioactive wastes, as well as offshore waste incineration. These amendments were brought together in a more comprehensive – and restrictive – revision as the 1996 Protocol. Though the 1996 Protocol is not in force, it will replace the earlier 1972 Convention when it receives the requisite number of state signatures.

The fundamental difference between the original Convention and the later Protocol concerns the manner in which they limit dumping. The 1972 Convention delineates which substances may not be discharged into the oceans, thus allowing – subject to a permit process – disposal of other matter; the 1996 Protocol, in contrast, simply prohibits ocean disposal of any substances beyond a narrow list of relatively harmless materials, which are nevertheless subject to a strict review.[49] In addition, the 1996 Protocol requires that a "precautionary approach" be taken when the discharge of a given substance may result in environmental damage, even though the scientific knowledge is incomplete; the Protocol, in other words, errors on the side of protecting the marine environment.[50] Note that while the London Convention and Protocol cover dumping of wastes from ships, aircraft, and offshore platforms, the MARPOL 73/78 Convention regulates pollution associated with the regular operation of ocean vessels.[51]

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prohibitions. The full title of the 1996 Protocol reads: "1996 Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, 1972."

[48] The London Convention is implemented under Title I of the Marine Protection, Research and Sanctuaries Act
33 USC §§1401-1445 (as Ch. 27 "Ocean Dumping"). The US, however, is not a party to the 1996 Protocol.

[49] See Annex I of the 1972 London Convention for a list of banned substances, Annex II for a list of materials requiring "special care," and Annex III for guidelines governing the disposal of all other wastes. Annex 1 of the 1996 Protocol lists those substances that may be disposed of in the oceans, subject to the assessment process detailed in Annex 2.

[50] Article 3(1).

[51] "The International Convention for the Prevention of Marine Pollution from Ships, 1973 as modified by the Protocol of 1978 relating thereto" (MARPOL 73/78) entered into force October 1983.

Neither the London Convention's classification of banned substances nor the 1996 Protocol's list of allowed materials include CO_2. The "wastes or other matter" which both seek to regulate refer to "material[s] and substance[s] of any kind, form or description."[52] A more specific distinction, however, rests on the definition of "industrial waste." By amendment, the 1972 Convention bans the discharge of such matter, defined as "waste materials generated by manufacturing or processing operations."[53] According to the Convention's Scientific Group, CO_2 resulting from the use of fossil fuels is an industrial waste and its disposal into the oceans (including the sub-seabed) would therefore violate the London Convention.[54] Participants at a subsequent Consultative Meeting questioned this interpretation, however, and requested that the Scientific Group monitor proposals for ocean disposal of CO_2 pending further discussion.[55] Hence, the legality of ocean sequestration of anthropogenic CO_2 under the London Convention remains officially unresolved, though consideration of CO_2 in other terms might help. The 1996 Protocol, for instance, prohibits the discharge of wastes producing a biological response in marine life above an acute (or chronic) threshold, and in all cases where "adequate information is not available to determine the likely effects of [a] proposed disposal option."[56] CO_2 would likely fall under this restriction.

Further speculation about the legal status of sub-seabed CO_2 sequestration, however, must consider other aspects of offshore CO_2 disposal. Start, for instance, with the status of submerged lands under the London Convention. Whereas the 1972 Convention defines "sea" as "all marine waters other than the internal waters of States,"[57]

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[52] Article III(4) and Article 1(8), respectively.
[53] The resolution banning industrial waste (LDC.43(13)) passed on 1990 and took effect 1 January 1996; see Annex I(11) of the 1972 London Convention.
[54] Report of the Twenty-Second Meeting of the Scientific Group, 10 to 14 May 1999, LC/SG 22/13, §§11.12 to 11.16. (10 June 1999).
[55] Report of the Twenty-First Consultative Meeting of Contracting Parties to the Convention on the Prevention of Marine Pollution By Dumping of Wastes and Other Matter, 4 to 8 October 1999, LC 21/13, §§5.18 to 5.27 (1 November 1999). Later meetings of the Scientific Group recalled the issue, through subsequent Consultative Meetings have not addressed offshore CO_2 sequestration. The 2001 Consultative Meeting, for instance, only notes that "a review of emerging practices i.e., regarding ocean disposal of CO_2 from fossil fuel production and use" is being planned (Report of the Twenty-Third Consultative Meeting of Contracting Parties to the Convention on the Prevention of Marine Pollution By Dumping of Wastes and Other Matter, 22 to 26 October 2001, LC 23/16, Annex 8, §3.3.5 (10 December 2001).)
[56] Annex 2(10.1) and Annex 2(14), respectively
[57] Article III(3); note that in 1990 the Thirteenth Consultative Meeting of Contracting Parties to the Convention on the Prevention of Marine Pollution By Dumping of Wastes and Other Matter adopted

the 1996 Protocol extends this definition by explicitly including “the seabed and the subsoil thereof,” though “it does not include sub-seabed repositories accessed only from land.”[58] Furthermore, the 1996 Protocol considers dumping to be “any storage of wastes or other matter in the seabed and the subsoil thereof from vessels, aircraft, platforms or other man-made structures at sea.”[59] In addition, while the 1972 and 1996 agreements allow disposal of wastes resulting from “the normal operations of vessels, aircraft, platforms or other man-made structures at sea and their equipment,” such discharges are illegal when the vessels or structures exist solely for disposal, or when the waste itself is a by-product of the offshore treatment of other wastes.[60] Both agreements, however, specifically allow “[t]he disposal or storage of wastes or other matter directly arising from, or related to the exploration, exploitation and associated off-shore processing of seabed mineral resources.”[61]

If “other man-made structures at sea” is taken to include pipelines extending from the land to offshore wells, and CO_2 is found to be an industrial waste, then sequestration in submerged lands beneath the OCS of CO_2 from fossil-electric power plants would be illegal under the 1996 Protocol to the London Convention. Coupled with the Protocol’s precautionary stance, its admonition not to “transfer, directly or indirectly, damage or likelihood of damage from one part of the environment to another or transform one type of pollution into another,” further supports this conclusion.[62] In general, the 1996 Protocol favours the prevention or reduction of pollution at its source, with local disposal encouraged even for those land-based wastes that may be discharged at sea.[63]

The 1996 London Protocol, however, is not in force. Absent a ruling that anthropogenic CO_2 is an “industrial waste,” OCS sequestration is not currently banned. Pending this decision, or until the US becomes a contracting party to the more limiting 1996 Protocol, CO_2 sequestration in submerged lands beneath US territorial waters would not be prohibited as “ocean dumping” under the 1972 London Convention.

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resolution LDC.41(13) clarifying that the London Convention *does* include sub-seabed waste disposal (Johnston, et al., 1999).

[58] Article 1(7); This restriction presumably excludes pipelines residing on, or just beneath, the ocean floor.

[59] Article 1(4.1.3)

[60] Article III(1)(b)(i) and Article 1(4.2.1), respectively

[61] Article III(1)(c) and Article 1(4.3), respectively

[62] Article 3(3)

[63] See the guidelines in Annex 2.

Finally, two other international agreements are worth mentioning, although the US has ratified neither. The first of these is the 1989 Basel Convention, which governs the transboundary movement of hazardous (and other) wastes. While the Convention seeks to prevent the export of wastes for disposal in developing nations, it does pertain to the "[r]elease [of designated substances] into seas/oceans including sea-bed insertion."[64] Whether CO_2 "exported" for disposal falls within the Basel Convention's list of controlled substances requires an interpretation of its classification scheme. For instance, "[w]astes from industrial pollution control devices for cleaning of industrial off-gases" are included, as – more generally – are those deemed toxic.[65] The Convention also stresses the need to dispose of waste near its source whenever reduction is not possible.

More specific, perhaps, is the 1982 United Nations Convention on the Law of the Sea (UNCLOS). By specifying that "[n]ational laws, regulations and measures shall be no less effective in preventing, reducing and controlling such pollution [by ocean dumping] than the global rules and standards," and by explicitly considering the seabed to be part of the marine environment, the UNCLOS binds its signatories to the London Convention.[66] Moreover, the UNCLOS bans the "transfer, directly or indirectly, [of] damage or hazards from one area to another or [the transformation of] one type of pollution into another."[67] In addition, "the release of toxic, harmful or noxious substances" from land-based sources is singled out.[68] Determining whether CO_2 falls under these restrictions requires, once again, further clarification.

6.5 Chapter Conclusions

As a geological sequestration site, the US Outer Continental Shelf offers both advantages and disadvantages over terrestrial alternatives. The source of the most significant advantage – the physical separation between OCS reservoirs and land-based areas of human habitation – is also a weakness. While distance and the cover of ocean waters reduces health, safety, and even environmental risks, it also reduces access, increasing both sequestration costs and the difficulties of monitoring injection sites.

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[64] Annex IV(D7)
[65] Annex VIII(A4100) and Annex III(9 H11), respectively
[66] Articles 210.6 and 194.3(c), respectively
[67] Article 195
[68] Article 207.5

Extensive experience with offshore oil and gas operations, however, suggests that the technical uncertainties associated with OCS sequestration are not large. Seabed hydrocarbon reservoirs in the Gulf of Mexico, for instance, are well-characterized, and both drilling and pipeline operations have become routine even in deep waters. A conservative estimate indicates that at least 15 to 20 years worth of Gulf state electric sector CO_2 emissions could be sequestered in adjacent offshore reservoirs.

The question, therefore, is not whether OCS sequestration is technically feasible; rather, the major uncertainties are political and perceptual. The legality of seabed CO_2 sequestration under both US domestic regulations and international environmental agreements is ambiguous; clarification is needed and explicit legislation may be necessary on each level, which may conflict. The success of any future efforts will depend on the support for CO_2 capture and sequestration more generally – the momentum of which will turn on how regulators, the environmental community, and – not least – the public perceive the issue. Would offshore CO_2 sequestration, for instance, be seen as "storage" or "disposal"? Would the focus be on use of the "oceans" or "submerged lands"? Is CO_2 from fossil-fuels an "industrial waste" or a naturally occurring substance?[69]

Witness, for instance, the fate of proposals to store radioactive wastes beneath the seafloor. Despite the continuing support of some in the scientific community, use of the seabed as a repository for spent nuclear materials never gained political (or even industry) support; although Congress allocated funds for research in the mid-1980s, the appropriation was effectively frozen at the start and government efforts to coordinate related activities stalled before ending less than a decade later (Nadis, 1996). Though the public is likely to be more ambivalent about CO_2 than radioactive waste, the place of the oceans in the public mind could render OCS sequestration politically difficult. Opposition to, and the consequent postponement of, planned CO_2 injection experiments off the coast of Hawaii may provide an indication of the public's reaction and subsequent political response should ocean CO_2 sequestration be pursued more generally.

[69] Greenpeace, for instance, is firmly behind the "industrial waste" interpretation; see Johnston, et al. (1999).

On the other hand, the submerged lands in which upstream fossil energy producers have a presence may provide an attractive sequestration site should the industry throw its support (and lobbying clout) behind CO_2 capture and sequestration. And, so far as use of the OCS would put distance between sequestered CO_2 and people, injection of CO_2 beneath the seafloor would reduce the ever-present and legitimate objections to putting a potentially harmful substance in the public's "backyard." The politics – and regulatory approval – of OCS sequestration would likely turn on these dynamics.

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Chapter 7: Thesis Conclusions

7.1 Chapter Overview

Stabilization of atmospheric greenhouse gas concentrations will likely require significant cuts in electric sector CO_2 emissions. The ability to capture and sequester CO_2 in a manner compatible with today's fossil-fuel based power generating infrastructure offers a potentially low-cost contribution to a larger climate change mitigation strategy. This thesis has explored that potential by both assessing the extent to which CCS might lower near-term electric sector mitigation costs and examining the key factors driving these estimates. The analysis highlights how generating unit dispatch, the retirement of vintage capacity, competition from abatement alternatives such as coal-to-gas fuel-switching and non-fossil renewables, the performance of CCS technologies, and various electric sector trends affect the attractiveness of CCS in particular, and the cost of CO_2 mitigation more generally. A look at seabed CO_2 sequestration complements this assessment by considering issues of risk, storage capacity, and regulation. By way of summary, the following section revisits the motivating questions posed in Chapter 1. Section 7.3 then concludes with a discussion of useful extensions to the analysis.

7.2 Discussion: CCS and Electric Sector CO_2 Mitigation

Chapter 1 provided an overview of the thesis by examining four questions that motivate its analysis. A return to these questions offers a convenient means of summarizing significant conclusions.

(1) Given CCS cost and performance specifications, by how much does the availability of CCS reduce the cost of electric-sector CO_2 control in a particular electric market? At what mitigation cost (in, e.g., \$/tC) does CCS become competitive with other abatement options?

This analysis demonstrates that even under conservative assumptions regarding its costs and performance, CCS can significantly lower the cost of mitigating CO_2 emissions in a centrally dispatched electric market. Moreover, the analysis points to the ways in which the cost of CO_2 control depends on more general electric sector dynamics. CCS units, for instance, enter the generating mix at an emissions price around 75 \$/tC, after fuel switching and dispatch reordering have cut emissions nearly in half. New coal CCS plants then dominate gas CCS units under most scenarios, with the latter becoming important only when gas prices fall to 2.5 $/GJ, or when very high levels of CO_2 abatement (i.e., greater than 80 percent) force significant cuts in emissions from plants dispatched to meet short-duration peak loads.

While differing assumptions about the timing and magnitude of CO_2 reductions, as well as variations in economic and temporal perspectives, complicate direct comparisons between other models and this assessment, it is worth noting that these mitigation cost estimates are typically lower than those resulting from either plant-level or general equilibrium analyses that include CCS technologies.[1] This difference points to the value of considering unit dispatch in assessing the cost of electric sector CO_2 control. When plants with carbon capture are introduced into the generating mix, for instance, they will be dispatched to the limits of their availability, while conventional units will be displaced higher up the load-duration curve. As Chapter 2 discusses, and Chapter 4 illustrates, this shift in dispatch lowers the effective cost of CO_2 control via CCS.

Chapters 4 and 5 examine how various factors affect these baseline conclusions. Improvements in wind generation, for instance, lower mitigation cost estimates only when CCS technologies are unavailable. In addition, mitigation costs and the share of CCS-generated electricity are seen to be more sensitive to over-optimism regarding CCS performance and cost assumptions than excessive pessimism. And in a related assessment, the analysis points to how CCS retrofit energy requirements and the economic restriction of CCS to baseload electricity generation limit conversion of vintage coal plants. Retrofits do not enter the baseline model below 300 $/tC, and for all but radical improvements in cost and performance do not account for more than 10 percent of electricity generation.

[1] Macroeconomic assessments, which are generally *not* limited to the electric sector, estimate mitigation costs on the order of several hundred $/tC. Differences in baseline assumptions about the timing and level of CO_2 mitigation, however, make comparisons difficult; see, for example, Edmonds, Dooley, and Kim, (1999) and McFarland, et al., (2001), plus the studies reviewed in Weyant (2000). Plant level assessments typically show CCS becoming competitive at a mitigation cost above 100 $/tC; see, for instance, David and Herzog (2000) and Simbeck (2001a and 2001b), as well as the other studies summarized in Table 1.2 from Chapter 1.

(2) How does the composition of existing generating capacity affect CO_2 mitigation costs? How do assumptions about natural gas prices influence these estimates?

The cost of CO_2 mitigation is influenced by the initial distribution of plant technologies – for the MAAC region, a market dominated by vintage coal plants. At moderate natural gas prices, such a distribution is significantly out of equilibrium: given current prices for fuel and the operating characteristics of new plants, the generating mix would move from coal to gas – and therefore to lower CO_2 emissions – in the absence of a CO_2 constraint. Chapter 5 illustrates how estimated CO_2 control costs are therefore lower than they would be in a system that began in economic equilibrium, with installed capacity optimized for current costs and technology standards. The analysis, for instance, finds mitigation cost estimates to be as much as 50 $/tC lower for CO_2 reductions between 50 and 80 percent than they would be without this "free lunch."

More generally, the manner in which CO_2 abatement is achieved and the carbon price at which CCS becomes competitive depend on the cost of natural gas. For gas prices around the baseline 3.2 $/GJ, coal-to-gas fuel-switching and carbon-ordered dispatch reduce emissions up to 40 percent, and CCS does not enter the generating mix until carbon prices exceed 75 $/tC. Higher gas prices produce different behavior. Coal plants with CO_2 capture, for example, enter at an emissions reduction close to 30 percent when gas is near 4.2 $/GJ. At gas prices within the range prevailing throughout much of the 1990s (i.e., around 2.5 $/GJ), however, conventional and CCS gas units provide the dominant means of controlling CO_2 emissions. While this sensitivity to gas prices is partially an artifact of the simple optimization framework described in Chapter 3, the real world can show an equally strong sensitivity as demonstrated by the by the recent reemergence of interest in coal-fired capacity after a decade-long absence of significant new coal plant construction. The challenge for future analyses is to choose optimally between coal and gas when both gas and carbon prices are uncertain.

(3) How might stricter limits on criteria pollutants (e.g., sulfur dioxide, nitrogen oxides) affect CCS economics?

Chapter 5 takes an initial look at interactions between the control of criteria pollutants and the cost of CO_2 mitigation, and examines how constraints on SO_2 and NO_X

emissions reduce CO_2 output independent of the need to control the latter. A 75 percent cut in SO_2 and NO_X, for instance, decreases baseline CO_2 emissions by nearly one-fourth. This free lunch lowers the estimated cost of CO_2 mitigation up to the point where the need to make very high reductions in carbon emissions (i.e., greater then 75 percent) overwhelms criteria pollutant abatement. While preliminary, this analysis has important implications for the timing and comprehensiveness of emission regulation. Stringent reductions in criteria pollutants, for instance, may favor increased reliance on natural gas-fired electric power generation. Results from Chapters 4 and 5, however, indicate that coal plants with carbon capture are preferred to gas when CO_2 emission reductions greater than 50 percent are required. Further fuel-switching could therefore result in a suboptimal technology path – and higher mitigation costs – should the electric sector face a greater-than-anticipated carbon constraint in the coming decades. In short, the costs of regulatory uncertainty could be significant.

(4) How do the near-term prospects of CO_2 sequestration compare to those of carbon capture?

The storage potential, cost, regulation, and public acceptance of geological carbon sequestration are uncertain. Chapter 6 examines two of these uncertainties in the context of a region that has received comparatively little attention: the seabed beneath the US Outer Continental Shelf (OCS). The distance between injection sites and areas of human habitation, the buffer that ocean waters would provide between off-shore geological reservoirs and the atmosphere should CO_2 escape, and the fact that at sufficient injection depths CO_2 would be negatively buoyant in seawater are the primary advantages the OCS offers relative to more familiar land-based alternatives. This physical separation, of course, would also reduce access and complicate monitoring and verification.

A look at analogous offshore activities, however, suggests that the technical uncertainties associated with near-term OCS sequestration are not large. A number of well-characterized hydrocarbon reservoirs in the Gulf of Mexico, for instance, are now economically depleted, and both drilling and pipeline operations are becoming routine even in deep waters. Relying on very conservative assumptions, Chapter 6 concludes that at least 15 to 20 years worth of Gulf state electric sector CO_2 emissions could be sequestered in adjacent offshore natural gas and oil reservoirs.

In contrast, the legality of seabed CO_2 sequestration is more ambiguous than its technical feasibility. Neither US law nor international environmental agreements have specifically addressed the issue. US regulations, for instance, concern mineral recovery and the movement of materials to shore. Specific approval would therefore be needed and a more general clarification of administrative authority would likely be required before seabed sequestration could proceed. US law, however, recognizes the 1972 London Convention and its prohibition of offshore waste disposal. Should CO_2 be deemed an "industrial waste" under the Convention's framework, seabed disposal would be banned in submerged lands beneath US territorial waters. In addition, the 1996 Protocol to the Convention, though not yet in force, is more restrictive and would proscribe seabed CO_2 sequestration without a separate ruling; the US, however, is not a party to this update of the original agreement. The OCS may therefore be the first region where US and international regulatory regimes clash over CO_2 sequestration.

Finally, previous chapters of the thesis touch on the economics of CO_2 sequestration. The ability to sell CO_2 for enhanced oil or coal-bed methane recovery, for instance, could provide an early niche market for fossil-electric CO_2, launching a beneficial cycle in which experience lowers CCS technology costs and encourages further industry adoption. Chapter 4 captures part of this dynamic: mitigation costs decline with sequestration expenses, but the entry of CCS technologies into the generating mix (relative, for instance, to fuel-switching) does not change appreciably until CO_2 has a positive market value. The costs of long-term monitoring and verification, however, may significantly inflate what now appear to be reasonable transportation- and injection-related expenses. How the industry might deal with liability for accidental CO_2 releases also requires further investigation.

7.3 Future Work: Extensions to the Thesis

The success of any attempt to capture and sequester fossil-electric CO_2 will depend as much on public perception and its impact on the politics of climate change as it will on technology and economics. The level of public support for serious action to mitigate the risks of climate change and the nature of the resulting policy response are significant sources of uncertainty (Herzog, Drake, and Adams, 1997). Advocates within the fossil-energy industry and from environmental non-governmental organizations can be counted on to press their respective cases and attempt to influence public opinion should a significant carbon constraint make CCS attractive. But beyond an understanding of the benefits and hazards of CCS, public acceptance would hinge on its trust in the processes and institutions set up to manage long-term sequestration risks (Keith and Morgan, 2001). The history of nuclear waste management in the US provides an unfavorable analogue, while experience with underground hazardous waste injection suggests that CO_2 sequestration may not provoke insurmountable objections (Herbert, 1996).

Missing from the analysis is therefore a point of view that asks not whether CCS *could* provide an economic means of electric sector CO_2 control, but whether it *should*. Issues related to the opportunity costs of resources diverted to CCS research, continued dependence on fossil fuels, environmental justice, transboundary pollution, and more general social values regarding consumption merit attention (see, for example, Jamieson [1996], Socolow [1997], and Keith and Morgan [2001]). On the other hand, CCS could provide a low-cost route to substantial CO_2 reductions without large increases in the cost of electricity – a resource for which demand is relatively inelastic. That CCS could moderate the impact of climate-related energy price increases on those consumers least able to afford it deserves consideration. Likewise, an analysis of the secondary benefits of CO_2 reduction would complement this control-cost assessment (see, for instance, Burtraw, et al. [1999] and Wang and Smith [1999]).

The analysis, however, would also benefit from consideration of several factors directly related to its technical and economic focus that would be relevant in any actual implementation of CCS. This section discusses four of these issues. While their combined impact on the attractiveness of CCS as an abatement strategy – as well as on mitigation costs more generally – is difficult to predict, there is reason to be optimistic that the effects of these factors could accelerate electric sector CCS adoption.

7.3.1 Technological Change and Experience Effects

The cost of CCS technologies would likely decline with time should widespread adoption of CCS create additional cost reductions trough learning-by-doing and the attainment of economies of scale (Grubler, et al., 1999). As several authors have noted (see, e.g., Azar and Dowlatabadi, 1999; Grubler, et al., 1999), interactions between climate policy and technological development can yield non-marginal improvements in technology costs and performance. The estimated costs of mitigating climate change can therefore be much higher in analyses – such as this – that ignore this dynamic and treat technological change exogenously.

At least three factors, however, complicate the modeling of technological change: first, cost and performance improvements will apply to conventional generation technologies and non-fossil renewables as well as CCS; second, the inclusion of endogenous change would require a (computationally-intensive) non-linear model; and, third, there is no demonstrated ability to predict technological evolution. As described in Chapter 3, the CCS cost estimates employed here are intended to represent plants that would be operational by 2015 as part of a cumulative installed capacity of at least 5 GW in the MAAC region. CCS plants, however, are added later in most of the modeled scenarios and worldwide installed capacity would presumably be much larger. The abatement cost estimates provided here are therefore likely to be conservative.

Estimating learning-curve parameters for carbon capture and sequestration technologies would be a particularly challenging task. The constituent technologies of an integrated CCS system, for instance, are currently at different points on their individual learning curves. While some component technologies are relatively mature, others have yet to be applied on an industrial scale. In addition, the success of CCS will depend on enhancing synergies between these components – on developing the system, the level at which experience will be most valuable. More generally, experience-related cost reductions will depend on how the interactions between CCS and the current fossil-electric infrastructure – so-called “network effects” – either encourage or retard adoption of the new technology (Grubler, et al., 1999).

Lieberman’s (1984) analysis of learning in the chemical industry would provide a useful model for assessing the effects of experience with CCS technologies.

Understanding the extent to which industry concentration facilitates technological learning, for instance, would be particularly relevant. In addition, the approach pursued by the Christiansson (1995) and Neij (1997) studies – asking, in this case, what rate of learning is required for CCS to become cost-competitive and achieve a given market penetration – would be applicable. Identification of obstacles to the accumulation and transfer of industry experience would also be valuable, and may point to a role for government-sponsored research. Loiter and Norberg-Bohm (1999), for instance, discuss how public funding for information gathering can reduce private risks and transaction costs in technology development. Relevant to CCS, the same study examines the early development of wind turbines for power generation and concludes that adapting component technologies from other applications (e.g., aviation) both reduced turbine costs and improved system reliability.

7.3.2 Policy Scenarios, Time Dynamics, and Technology Lock-In

This analysis has not considered policy design, nor has it examined the consequences of unanticipated changes in assumptions.[2] Mitigation costs, for instance, are calculated under a flat CO_2 emissions price, and factor prices – though subject to change – are known with "perfect foresight." Neither feature of the analysis, of course, is realistic. The timing and extent of future CO_2 regulation are significant sources of uncertainty, and predictions about the level and stability of natural gas prices in, say, twenty years are subject to a large margin of error. Electric sector planning, however, cannot escape the need think several decades out, and the risk that investment decisions made today will lock electricity generators into an undesirable technology path cannot be eliminated.

The need to identify which policy scenarios minimize global carbon mitigation costs must therefore be coupled with an understanding of how "surprises" increase the cost of CO_2 control. A straightforward extension of the Chapter 3 modeling framework

[2] Grubb (1997), for instance, discusses how the timing of CO_2 regulation would affect mitigation costs. Applied to this analysis of CCS, deferral of emission reductions – should significant cuts eventually be required – would reduce the cost benefits of industry experience (more gradual "learning-by-doing") and could lead to the economic losses of stranded investment (particularly in conventional gas-fired generating units). Grubler (1998), however, notes that regulation without a time lag between announcement and enactment may result in risk-averse research and subsequent lock-in to a suboptimal technology path.

would serve this purpose. Consider, for instance, the imposition of a higher than anticipated carbon tax (or regulatory equivalent) starting in 2020. Mitigation costs could be compared for two scenarios: one with full knowledge of the higher emissions price (say, 150 $/tC), and a second in which new capacity additions for the first two decades are constrained to that of, for instance, a 50 $/tC model run. The cost of CO_2 control will be greater under the second scenario as (the initial) fuel-switching to natural gas (and abandonment of coal plants) would be suboptimal under the higher emissions price, which would favor coal units with carbon capture. A similar dynamic would hold for unexpected changes in gas price assumptions. Such an analysis would illustrate how path dependencies and technology lock-in affect the cost of electric sector CO_2 mitigation.

7.3.3 Demand Growth and Plant Retirement

Assumptions about future electricity consumption and the generating capacity required to meet this demand interact to influence model results. Increasing demand, for instance, requires investment in new generating units beyond that necessary for replacement of retiring capacity. An increase in the price of CO_2 emissions will likewise require investment by raising the operating costs of existing carbon-intensive units enough to force their retirement and replacement with new capacity.

The cost of electricity, and therefore the economics of CO_2 mitigation, depend on the interaction between these drivers of new capacity investment. In a world with a constraint on CO_2 emissions but little increase in electricity consumption, for instance, low- or zero-emission generating units would replace existing capacity. Conversely, capacity must be added regardless of the price of carbon emissions when demand growth is high – the only difference being the choice of conventional units when the cost of emissions is low versus renewables and CCS when CO_2 output is penalized. The increase in the average cost of electricity generation will therefore be lower under the latter scenario, though the magnitude of this decrease merits assessment.

Obscuring this dynamic effect, however, is the fact that the existing generating mix is out of economic equilibrium. As discussed in Chapter 5, fuel switching from coal to gas can be attractive for purely economic reasons when gas prices are moderate. The impact of the resulting "free lunch" emissions reduction on CO_2 mitigation costs depends, in turn, on demand growth. Under high growth conditions, initial installed capacity is roughly two-thirds of that required to meet period 8 demand; hence, the free lunch of fuel switching will have less of an impact on mitigation costs. Conversely, when demand is flat and little new capacity is required, the free lunch reduction in mitigation costs will be more prominent. The free lunch dynamic therefore runs counter to the effects of demand growth, and a complete analysis must tease out this interaction.

7.3.4 Electric Sector Trends and Their Impact on CCS

The Chapter 5 multipollutant analysis illustrates how the stringency of broader environmental regulations could impact CO_2 control costs. Further attention should be given to how the technology and market trends currently reshaping the US electric sector might affect CCS adoption. A movement to distributed power generation, for instance, would increase the difficulty of CO_2 capture. The use of hydrogen in microturbines or fuel cells, on the other hand, could create a new niche for CCS if the hydrogen was produced from fossil fuels at centrally-located facilities. While full development of a hydrogen infrastructure lies beyond the thirty-year timeframe of this analysis, significant growth of distributed generation does not.

A more complete assessment of CCS would therefore include distributed generation and other emerging technologies. The compatibility between biomass and CCS, for instance, could increase experience with CCS and further decrease the cost of electric sector CO_2 control. In addition, the continuing development of wind turbines and increasing industry experience with coal gasification technologies deserve greater attention in this context – the former for its ability to compete with CCS, the latter because of its synergies.

Finally, broader use of emission permit trading regimes as well as further market restructuring would increase the capacity planning and dispatch model's realism – particularly from a social cost perspective. As opposed to control technology requirements, for instance, permit trading allows generators to seek out the lowest-cost means of reducing emissions – much as the model identifies the least-cost mix of generating technologies for a given carbon price. Similarly, the creation of additional (region-wide) independent system operators – with centralized control over the dispatch of privately-owned power plants – would move the industry closer to the model's global optimization framework. Moreover, the eventual resolution of uncertainties related to market restructuring could produce a "boom" in new plant investment and retirement of aging units. Such turnover in the generating infrastructure would reduce the transition costs to CCS (and alternative means of CO_2 control) should the electric power industry also face the need to make serious cutbacks in its CO_2 emissions.[3] The extent to which these issues might impact the control of electric sector CO_2 emissions – and therefore CCS – deserves further attention.

In summary, this thesis fills an important niche between economy-wide assessments of carbon capture and sequestration and plant-level studies of CO_2 control costs. The analysis highlights the manner in which plant dispatch, the initial distribution of generating capacity, trends in fuel prices, and the feasibility of CO_2 sequestration would influence the attractiveness of CCS should significant reductions in electric sector CO_2 emissions be required. A balanced consideration of these factors provides support for CCS and lends credence to the conclusion of top-down analyses that the availability of CCS significantly reduces overall CO_2 abatement costs (see, e.g., Edmonds, Dooley, and Kim, 1999). CCS, however, would be a disruptive technology, forcing reevaluation of the assumptions on which regulation, institutional arrangements, technology choices, and even environmental goals are based. Rigorous prediction of these broader impacts lies beyond the reach of this analysis.

7.4 References to Chapter 7

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[3] Hadi Dowlatabadi of the University of British Columbia and Carnegie Mellon University deserves credit for this suggestion.

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Appendix 1: *EXCEL-MATLAB* Implementation and Numerics of the CCS Capacity Planning and Dispatch Model

A1.1 Overview of the Model Structure

This appendix provides an overview of the baseline CCS capacity planning and dispatch model's structure and numerical implementation. Section A1.2 first describes the baseline model indices, input variables and parameters, and outputs. Discussions of the model's implementation in Microsoft *Excel* and Mathworks *MATLAB* follow (Sections A1.3 and A1.4, respectively). A schematic of the model is given below (Figure A1.1); the corresponding (and significant) Microsoft *Excel* and Mathworks *MATLAB* file names are given in parentheses. Note that *Excel* serves as a "front-end" for parameter and input variable specification, while *MATLAB* subroutines perform the actual optimization and post-processing. (See Appendix 2 for the *Excel* worksheet and *MATLAB* programming code.)

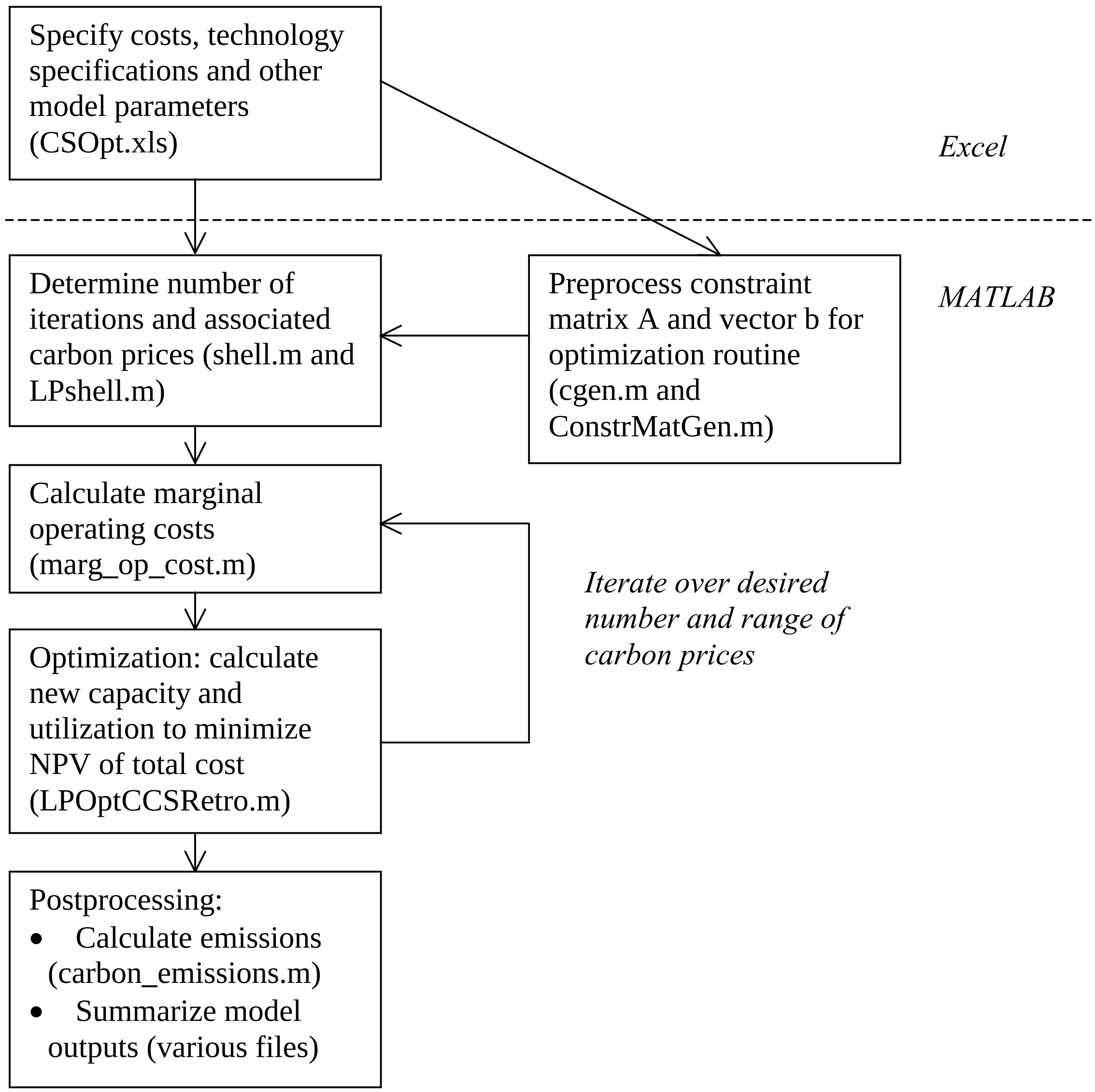

Figure A1.1 – Schematic of the baseline CCS capacity planning and dispatch model (primary Microsoft *Excel* and Mathworks *MATLAB* subroutines are noted in parentheses).

A1.2 Model Indices, Variables, and Outputs

Tables A1.1 to A1.3 describe indices, input variables and parameters, and outputs for the capacity planning and dispatch model. All variable names are as used in the actual computer code.

Table A1.1 – Capacity planning and dispatch model indices.

Index	*Maximum*	*Interpretation*
t	8	Number of time periods (t = 1 is the period beginning in year 2001)
p	6	Number of segments in the discretized load-duration curve (p = 1 is always peak demand; p = $pmax$ = 6 always reflects base load)
j	16	Number of power generation technologies
v	9	Number of technology vintages (= number of pre-existing vintages + $tmax$); v = 1 corresponds to plants built prior to 2001; beginning t = 1 vintages correspond to $v = t + vtdiff$
$vtdiff$	1	Number of pre-existing vintages (= $vmax$ – $tmax$ = 1)
f	4	Number of fuel types
$iter$	(variable)	Number of carbon price iterations (and, hence, model runs)

Table A1.2 – Capacity planning and dispatch model cost and technology parameter inputs passed from *Excel* to *MATLAB*. See Table A1.1 for a description of model indices.

Variable	*Units*	*Indices*	*Interpretation*
Time Related			
discount_rate	(fraction)	(scalar)	Annual (NOT per-period) discount rate
period_length	years/period	(scalar)	Length of time period *t*
D	MW/year	*p, t*	Yearly demand
Q	hours/year	*p*	Length of load-duration segment *p*
fuel_price	$/GJ (HHV)	*f, t*	Fuel price
dNCdt	MW/period	*j,t*	Maximum new generating capacity allowed per period for each technology
growthrate	MW/period	(3 classes)	Rate of new capacity growth for gas, CCS, and wind generating technologies
Cost Related			
capital_cost	$/MW	*j, t*	Discounted cost of new capital
var_OM	cents/kWh	*v, j*	Non-fuel marginal O&M
fix_OM	$/kW-year	*v, j*	Annual fixed O&M
fixOM_infl	(fraction/period)	*v, j*	Non-fuel O&M Escalation Rate
C_price and C_tax	$/tC	*t*	CO_2 emissions price
C_seq_cost	$/tC	*t*	Cost of carbon sequestration (including transportation and injection)

(Table A1.2 continues on the following page.)

Table A1.2 (continued)

Variable	*Units*	*Indices*	*Interpretation*
		Technology Related	
techname	(text)	*j*	Cell array with technology names
tech	(index and fractions)	*j, 7*	Technology parameters: fuel type (*f*), CO_2 separation efficiency, SO_2 separation efficiency, NO_X intensity, and retrofit energy penalty
fuel	kg fuel/GJ, kgC/GJ, kgS/GJ	*f, 3*	Fuel parameters: E-intensity, C-intensity and S-intensity by fuel type (*f*)
EC	MW	*j, v*	Existing installed capacity at time $t = 1$
thermal_eff	(fraction)	*j,v*	Thermal efficiency (note that there are actually three matrices, corresponding to successive paired layers of the load-duration curve)
availability	(fraction)	*j,v*	Per period dispatch availability

Table A1.3 – Capacity planning and dispatch model outputs.

Variable	*Units*	*Indices*	*Interpretation*
NewCapacity	MW	*j, t, iter*	New capacity installed per period
Utilization	MW	*j, t, v, p, iter*	Utilization per period stratified by layer of the load-duration curve
TotalCost	base year $	*iter*	NPV of total cost (the objective function minimum)
AverageCOE	cents/kWh	*t*	Average per-period cost of electricity
Cemissions	tC/period	*j, t, iter*	Carbon emissions per period
Semissions	tS/period	*j, t, iter*	Sulfur emissions per period
Nemissions	tNO_X/period	*j, t, iter*	NO_X emissions per period

A1.3 Preprocessing in Excel

Microsoft *Excel* (2000) provides a "front end" for parameter and input specification. The *Excel Link* add-in (version 1.0.8) automatically passes these variables to the *MATLAB* workspace. Within *Excel*, demand (*D*) and fuel price (*fuel_price*) are specified by their period 1 values and per-period growth rates; values for subsequent periods are determined before being sent to *MATLAB*. Other pre-processing steps include CCS coal plant retrofit calculations (capital, variable, and fixed O&M costs, plus thermal efficiencies), as well as the reduction in coal and nuclear capacity thermal efficiencies for higher levels of the load-duration curve (for successive pairs of layers, shoulder efficiencies are 30 percent of baseload, while peak load values are effectively zero). In addition, *Excel* calculates the end-effect capital cost correction (reducing capital costs by 20 percent, starting in period 5). Chapter 3 describes the purpose of these computations. Note that the input variable dimensions implicitly determine values for the model indices in *MATLAB* (Table A.1.1).

A1.4 *MATLAB* Implementation

A1.4.1 Optimization algorithm

The CCS Capacity Planning and Dispatch model uses the *MATLAB Student Edition* (version 5.3), and incorporates the "linprog.m" linear programming (LP) algorithm from the *MATLAB Optimization Toolbox* (version 2). The "linprog.m" algorithm has the following general form; Table A1.4 defines the variables.

minimize $objfn * dv$

subject to
$$A * dv \le b$$
$$Aeq * dv \le beq$$
$$lb \le dv \le ub$$

Table A1.4 – Definition of variables used by the "linprog.m" *MATLAB* optimization subroutine in the capacity planning and dispatch model.

Term	*Description*
dv	vector of decision variables
objfn	vector of objective function coefficients on the decision variables
A	matrix of decision variable coefficients for the left side of the inequality constraints
b	vector of values corresponding to the right side of the inequality constraints
Aeq	matrix of decision variable coefficients for the left side of the equality constraints
beq	vector of values corresponding to the right side of the equality constraints
lb	lower bounds on the decision variables
ub	upper bounds on the decision variables

Notes:

1. The corresponding *MATLAB* function call is: [*dv, TC*] = linprog(*objfn, A, b, Aeq, beq, lb, ub, x0, options*).
2. The objective function value (NPV of total costs) is: $TC = objfn' * dv$.
3. The model does not require equality constraints; all elements of *Aeq* and *beq* are therefore empty.
4. The "large scale" version of *MATLAB*'s linprog (the default) is used; an initial value (*x0*) of *dv* is therefore not specified.
5. The termination tolerance of the objective function is set through the statement: options = optimset('TolFun', 0.01).

A1.4.2 Decision Variable Structure

The decision variable vector (*dv*) concatenates two variables: new capacity added (in MW), $NC(j,t)$, and utilization (in MW), $U(j,t,v,p)$ (i.e., $dv = [NC(:)\ U(:)]$ in *MATLAB* code). The first $jmax * tmax$ elements of *dv* correspond to *NC*, with sequential blocks of *jmax* elements given for successive periods *t*. The next $jmax * tmax * vmax * pmax$ elements correspond to *U*, with the first *pmax* elements referring to $j = 1$, $t = 1$, $v = 1$, $p = 1$ the second set of *pmax* elements to $j = 1$, $t = 1$, $v = 2$, $p = 1$, etc. Hence, the length of *dv* is: $(jmax * tmax) + (jmax * tmax * vmax * pmax)$, or a total of 7040 decision variables in the baseline model.

A1.4.3 Model Scaling and Sparse Matrix Implementation

From above, the number of decision variables (the length of *dv*) is: $(jmax * tmax) + (jmax * tmax * vmax * pmax) = 7040$.

Table A1.5 describes the total number of constraint equations, and therefore the length of the right-hand side constraint vector (*b*).

Table A1.5 – Number of constraints in the capacity planning and dispatch model. (See the appendix to Chapter 3 for a full listing and explanation of model constraints.)

Constraint Category	*Number of Constraints*	*Baseline Model Value*
Demand	*tmax* * *pmax*	48
Dispatch	*jmax* * *tmax* * *vmax*	1152
New Capacity Growthrate	3 * *tmax*	24
CCS Retrofit	4 + 4 * *tmax*	36
	Total	1260

The coefficient matrix (*A*) is length(*b*) by length(*dv*) in size (1260 rows by 7040 columns). The *MATLAB* implementation, however, takes advantage of the fact that most elements of *A* are zero, the remainder being either 1 or –1. *A* is therefore a "sparse" matrix.

Note that $v = t + vtdiff$ for $v > vtdiff$; hence, most structures in the model actually scale with the square of *tmax*, while scaling proportionally with *jmax* and *pmax*. Table A1.6 summarizes these calculations.

Table A1.6 – Dimensions of key vectors and matrices in the capacity planning and dispatch model.

Structure	*Dimensions*
dv	$(jmax * tmax) + (jmax * tmax * vmax * pmax) = 7040$
A	$(tmax * pmax) + (jmax * tmax * vmax) + (7 * tmax) + 4$ by
	$(jmax * tmax) + (jmax * tmax * vmax * pmax) = 1260$ by 7040
b	$(tmax * pmax) + (jmax * tmax * vmax) + (7 * tmax) + 4 = 1260$
lb	$(jmax * tmax) + (jmax * tmax * vmax * pmax) = 7040$
ub	$(jmax * tmax) + (jmax * tmax * vmax * pmax) = 7040$

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Appendix 2: Microsoft *Excel* "Front-End" and Mathworks *MATLAB* Subroutines for the Baseline Capacity Planning and Dispatch Model

This appendix contains paper equivalents of the computer files that lie at the heart of the baseline capacity planning and dispatch model described in Chapter 3 and Appendix 1. The Microsoft *Excel* worksheet that serves as a "front-end" for parameter and input variable specification is first; the individual Mathworks *MATLAB* subroutines ("*.m" scripts and functions) follow. Figure A1.1 of Appendix 1 illustrates the relationships between these files/routines, which are presented in the order listed below. Note that the header for each *MATLAB* subroutine describes its purpose.

File Order:

"Front-End" (*Excel*) Worksheet

shell.m

cgen.m

ConstrMatGen.m

MPConstrMatGen.m (Multipollutant version of ConstrMatGen.m)[1]

LPshell.m

marg_op_cost.m

LPoptCCSRetro.m

COEvsPeriod.m

carbon_emissions.m

[1] Except for MPConstrMatGen.m, the multipollutant subroutines do not vary significantly from their baseline counterparts. See Chapter 5 (Section 5.4) for details.

Carbon Management Power Plant Optimization Model Scenario Builder
With Vintage PC Retrofits

Written by Timothy Lawrence Johnson
Version of 07 May 2002

Note that named variables appear in **bold**; these names are maintained in MATLAB.

DATA ARE FOR THE MAAC NERC REGION -- PJM ISO

Border indicates data sent to MATLAB.

All cost figures are in year 2001 $.

MATLAB FUNCTIONS

11	
11	Put techname (hardwired)
11	Put EC
11	Put D
11	Put Q
11	Put dNCdt
11	Put cap_cost
11	Put per_length
11	Put fuel_price
11	Put C_seq_cost
11	Put var_OM
11	Put fix_OM
11	Put thermal_eff1
11	Put thermal_eff2
11	Put thermal_eff3
11	Put availability
11	Put disc_rate
11	Put fuel
11	Put tech
11	Put lifetime
11	Put varOM_infl
11	Put fixOM_infl

Time-Related Parameters

Period Length **(per_length)** *(years)* 5

Discount Rate **(disc_rate)** *(annual)* 0.075

Demand Forecast

p		Duration **(Q)** *(hrs/yr)*	Growth Rate *(per period)*	*Annual* Demand **(D)** in Period t *(MW)* *1* *(2001-05)*	*2* *(2005-10)*	*3* *(2010-15)*	*4* *(2015-20)*	*5* *(2020-25)*	*6* *(2025-30)*	*7* *(2030-35)*	*8* *(2035-40)*
1	*Peak*	200	0.08	52000	56160	60653	65505	70745	76405	82517	89119
2	*Shoulder*	1000	0.08	41700	45036	48639	52530	56732	61271	66173	71466
3	*Shoulder*	3100	0.08	36500	39420	42574	45979	49658	53630	57921	62555
4	*Shoulder*	5800	0.08	31300	33804	36508	39429	42583	45990	49669	53643
5	*Shoulder*	7900	0.08	26100	28188	30443	32878	35509	38349	41417	44731
6	*Base*	8760	0.08	20900	22572	24378	26328	28434	30709	33166	35819
			Energy (TWh/yr)	278	300	324	350	378	408	441	476
			% Increase		0.08	0.17	0.26	0.36	0.47	0.59	0.71

Fuel Prices per Period *($)*

Fuel (f)	Fuel Parameters **(fuel)** E-intensity *(kg fuel/GJ)*	C-intensity *(kgC/kg fuel)*	Growth Rate *(per period)*	Fuel Price **(fuel_price)** in Period t *($/GJ)* *1* *(2001-05)*	*2* *(2005-10)*	*3* *(2010-15)*	*4* *(2015-20)*	*5* *(2020-25)*	*6* *(2025-30)*	*7* *(2030-35)*	*8* *(2035-40)*
Coal (1)	34.1	0.707	0.00	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
Nat Gas (2)	18.9	0.723	0.04	3.20	3.33	3.46	3.60	3.74	3.89	4.05	4.21
Oil (3)	22.4	0.850	0.00	4.10	4.10	4.10	4.10	4.10	4.10	4.10	4.10
Ur (4)	0.0005	0.000	0.00	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renew (5)	0.0	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

(All figures are HHV)

Retrofit Parameters *(See also tech immediately below)*

Capital Cost *($/kW thermal)* 150

Incremental variable O&M increase *(cents/kWh)* 0.3

Incremental fixed O&M increase *($/kW)* 35

Existing Capacity *(MW)*

j	Technology (techname)	Technology Parameters (tech) Fuel Type (f)	Carbon Separation Efficiency	Energy Penalty	Existing Capacity (EC) (MW)
1	*PC1*	1	0.00	0.00	7550
2	*PC2*	1	0.00	0.00	9300
3	*PC3*	1	0.00	0.00	8000
4	*PC4*	1	0.00	0.00	0
5	*IGCC*	1	0.00	0.00	0
6	*IGCC+CS*	1	0.99	0.00	0
7	*GT*	2	0.00	0.00	6500
8	*NGCC*	2	0.00	0.00	1700
9	*NGCC+CS*	2	0.95	0.00	0
10	*Oil*	3	0.00	0.00	6400
11	*NUC*	4	0.00	0.00	13700
12	*Hydro-Wind*	5	1.00	0.00	2300
13	*PC1-Retro*	1	0.90	0.20	0
14	*PC2-Retro*	1	0.90	0.20	0
15	*PC3-Retro*	1	0.90	0.20	0
16	*PC4-Retro*	1	0.90	0.20	0

Cost of New Capacity *($/kWe)*

			Cost of New Capacity **(cap_cost)** by Period t *($/kWe)*							
		Growth Rate	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*
j	Technology	*(per period)*	*(2001-05)*	*(2005-10)*	*(2010-15)*	*(2015-20)*	*(2020-25)*	*(2025-30)*	*(2030-35)*	*(2035-40)*
1	*PC1*	0.00	10000000	10000000	10000000	10000000	10000000	10000000	10000000	10000000
2	*PC2*	0.00	10000000	10000000	10000000	10000000	10000000	10000000	10000000	10000000
3	*PC3*	0.00	10000000	10000000	10000000	10000000	10000000	10000000	10000000	10000000
4	*PC4*	0.00	1200	1200	1200	1200	960	720	480	240
5	*IGCC*	0.00	1400	1400	1400	1400	1120	840	560	280
6	*IGCC+CS*	0.00	1900	1900	1900	1900	1520	1140	760	380
7	*GT*	0.00	300	300	300	300	240	180	120	60
8	*NGCC*	0.00	450	450	450	450	360	270	180	90
9	*NGCC+CS*	0.00	900	900	900	900	720	540	360	180
10	*Oil*	0.00	10000000	10000000	10000000	10000000	10000000	10000000	10000000	10000000
11	*NUC*	0.00	10000000	10000000	10000000	10000000	10000000	10000000	10000000	10000000
12	*Hydro-Wind*	0.00	1500	1500	1500	1500	1200	900	600	300
13	*PC1-Retro*	0.00	694	694	694	694	556	417	278	139
14	*PC2-Retro*	0.00	625	625	625	625	500	375	250	125
15	*PC3-Retro*	0.00	551	551	551	551	441	331	221	110
16	*PC4-Retro*	0.00	493	493	493	493	395	296	197	99
							0.80	0.60	0.40	0.20

Constraints on New Capacity *(GW per period)* and Expected Lifetime (for capital write-off in *years*)

j	Technology	Maximum Increase **(dNCdt)** *(MW per period)*	Expected Life **(lifetime)** *(years)*
1	*PC1*	100	25
2	*PC2*	100	25
3	*PC3*	100	25
4	*PC4*	15000	25
5	*IGCC*	15000	25
6	*IGCC+CS*	1000000	25
7	*GT*	1000000	25
8	*NGCC*	1000000	25
9	*NGCC+CS*	1000000	25
10	*Oil*	100	25
11	*NUC*	100	25
12	*Hydro-Wind*	1000000	25
13	*PC1-Retro*	1000000	25
14	*PC2-Retro*	1000000	25
15	*PC3-Retro*	1000000	25
16	*PC4-Retro*	1000000	25

Note that as implemented in MATLAB, ***aggregate*** *new CCS capacity (the sum of IGCC+CS and NGCC+CS) is limited to dNCdt(IGCC+CS) MW per period.*

Carbon Sequestration Cost *($/tC)*

Cost of Carbon Sequestration Cost **(C_seq_cost)** *($/tC)* 30 8.18 *$/tCO2*

Base Year Variable O&M Costs -- NOT Including Fuel or Emissions Tax *(cents/kWh)*

Variable O&M Cost **(var_OM)** by Technology j *(cents/kWh)*

		Existing	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*
j	Technology	*Vintage*	*(2001-05)*	*(2005-10)*	*(2010-15)*	*(2015-20)*	*(2020-25)*	*(2025-30)*	*(2030-35)*	*(2035-40)*
1	*PC1*	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
2	*PC2*	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
3	*PC3*	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
4	*PC4*	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
5	*IGCC*	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
6	*IGCC+CS*	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
7	*GT*	0.05	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
8	*NGCC*	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
9	*NGCC+CS*	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
10	*Oil*	0.05	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
11	*NUC*	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
12	*Hydro-Wind*	0.00	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
13	*PC1-Retro*	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
14	*PC2-Retro*	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
15	*PC3-Retro*	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
16	*PC4-Retro*	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70

Per-Period Variable O&M Growth Rate **(varOM_infl)**

		Existing	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*
j	Technology	*Vintage*	*(2001-05)*	*(2005-10)*	*(2010-15)*	*(2015-20)*	*(2020-25)*	*(2025-30)*	*(2030-35)*	*(2035-40)*
1	*PC1*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	*PC2*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	*PC3*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	*PC4*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	*IGCC*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	*IGCC+CS*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	*GT*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	*NGCC*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	*NGCC+CS*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	*Oil*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	*NUC*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	*Hydro-Wind*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	*PC1-Retro*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	*PC2-Retro*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	*PC3-Retro*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	*PC4-Retro*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Thermal Efficiency (HHV)

BASE Thermal Efficiency **(thermal_eff3)** by Technology j

j	Technology	*Existing Vintage*	*1 (2001-05)*	*2 (2005-10)*	*3 (2010-15)*	*4 (2015-20)*	*5 (2020-25)*	*6 (2025-30)*	*7 (2030-35)*	*8 (2035-40)*
1	*PC1*	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
2	*PC2*	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
3	*PC3*	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
4	*PC4*	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
5	*IGCC*	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42
6	*IGCC+CS*	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
7	*GT*	0.23	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
8	*NGCC*	0.50	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
9	*NGCC+CS*	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
10	*Oil*	0.20	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
11	*NUC*	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
12	*Hydro-Wind*	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	*PC1-Retro*	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
14	*PC2-Retro*	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
15	*PC3-Retro*	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
16	*PC4-Retro*	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30

SHOULDER Thermal Efficiency **(thermal_eff2)** by Technology j — *Coal Shoulder Penalty* *0.3*

j	Technology	*Existing Vintage*	*1 (2001-05)*	*2 (2005-10)*	*3 (2010-15)*	*4 (2015-20)*	*5 (2020-25)*	*6 (2025-30)*	*7 (2030-35)*	*8 (2035-40)*
1	*PC1*	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
2	*PC2*	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
3	*PC3*	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
4	*PC4*	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
5	*IGCC*	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
6	*IGCC+CS*	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
7	*GT*	0.23	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
8	*NGCC*	0.50	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
9	*NGCC+CS*	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
10	*Oil*	0.20	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
11	*NUC*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	*Hydro-Wind*	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	*PC1-Retro*	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
14	*PC2-Retro*	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
15	*PC3-Retro*	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
16	*PC4-Retro*	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09

PEAK Thermal Efficiency **(thermal_eff1)** by Technology j — *Coal Peak Penalty* *0.001*

j	Technology	*Existing Vintage*	*1 (2001-05)*	*2 (2005-10)*	*3 (2010-15)*	*4 (2015-20)*	*5 (2020-25)*	*6 (2025-30)*	*7 (2030-35)*	*8 (2035-40)*
1	*PC1*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	*PC2*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	*PC3*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	*PC4*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	*IGCC*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	*IGCC+CS*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	*GT*	0.23	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
8	*NGCC*	0.50	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55
9	*NGCC+CS*	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
10	*Oil*	0.20	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
11	*NUC*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	*Hydro-Wind*	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	*PC1-Retro*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	*PC2-Retro*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	*PC3-Retro*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	*PC4-Retro*	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Availability

Availability **(availability)** by Technology j

j	Technology	Existing Vintage	1 (2001-05)	2 (2005-10)	3 (2010-15)	4 (2015-20)	5 (2020-25)	6 (2025-30)	7 (2030-35)	8 (2035-40)
1	PC1	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
2	PC2	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
3	PC3	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
4	PC4	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
5	IGCC	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
6	IGCC+CS	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
7	GT	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
8	NGCC	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
9	NGCC+CS	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
10	Oil	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
11	NUC	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
12	Hydro-Wind	0.80	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
13	PC1-Retro	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
14	PC2-Retro	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
15	PC3-Retro	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
16	PC4-Retro	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80

Base Year Fixed O&M Costs *($/kW)*

Fixed O&M Cost **(fix_OM)** by Technology j *($/kW)*

j	Technology	Existing Vintage	1 (2001-05)	2 (2005-10)	3 (2010-15)	4 (2015-20)	5 (2020-25)	6 (2025-30)	7 (2030-35)	8 (2035-40)
1	PC1	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
2	PC2	30.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
3	PC3	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
4	PC4	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
5	IGCC	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
6	IGCC+CS	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0
7	GT	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
8	NGCC	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
9	NGCC+CS	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
10	Oil	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
11	NUC	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0	57.0
12	Hydro-Wind	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
13	PC1-Retro	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
14	PC2-Retro	65.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
15	PC3-Retro	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
16	PC4-Retro	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0

Per-Period Fixed O&M Growth Rate **(fixOM_infl)**

j	Technology	Existing Vintage	1 (2001-05)	2 (2005-10)	3 (2010-15)	4 (2015-20)	5 (2020-25)	6 (2025-30)	7 (2030-35)	8 (2035-40)
1	PC1	0.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	PC2	0.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	PC3	0.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	PC4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	IGCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	IGCC+CS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	GT	0.90	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
8	NGCC	0.50	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
9	NGCC+CS	0.00	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
10	Oil	0.75	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
11	NUC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	Hydro-Wind	0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
13	PC1-Retro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	PC2-Retro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	PC3-Retro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	PC4-Retro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

shell.m

```
%   shell.m script file to run LP Power Plant Optimization Routine
%
%   Written by Timothy Lawrence Johnson
%   Version of 01 April 2002
%

%   Subscript notes:
%   t   Time period (t=1 is period beginning in year 2000)
%   p   Segment of Load-Duration curve (p=1 is always peak demand; p=pmax
%       always reflects base load.)
%   v   Vintage (v=1 corresponds to plants built from 1940 to 1959;
%       and v=5 those from 1990 to 1999; beginning t=1 vintages correspond
%       to v = t+vtdiff)
%   j   Technology (see the "techname" cell array)
%   f   Fuel type (1=coal, 2=natural gas, 3=Uranium)


clear all;
load temp;


%   Note need to transpose matrices to maintain consistency with older MATLAB routines
var_OM = var_OM';
varOM_infl = varOM_infl';
thermal_eff1 = thermal_eff1';
thermal_eff2 = thermal_eff2';
thermal_eff3 = thermal_eff3';
availability = availability';


%   Enter C-price increment and number of iterations in batch run
C_tax_step = input('Enter carbon tax step ($/tC): ');
maxiter = input('Enter number of C-tax iterations: ');


%   Some parameter calculations:
    tmax = size(D,2);            %   No. of time periods (t)
    jmax = size(EC,1);       %   No. of plant technologies (j)
    fmax = size(fuel,1);         %   No. of fuel types (f)
    pmax = size(Q,1);            %   No. of L-D curve divisions (p)
    vmax = size(EC,2) + tmax; %   No. of plant vintages (v)
    vtdiff = size(EC,2);         %   Correction to sync v and t indicies

    params = {tmax jmax fmax pmax vmax vtdiff maxiter};


%   Generate FLAT C_price(iter,t) profile (nominal $/metric tC per period for each
iteration)
    for iter = 1:maxiter,
        for t = 1:tmax,
            C_price(iter,t) = C_tax_step * (iter - 1);
        end
    end


%   Call function LPshell.m
[TotalCost,TCOE,VarCost,CapCost,NewCapacity,Utilization,Cemissions,Costs,techindex] ...
= LPshell(C_price,params);


%   The following is required to maintain consistency with eariler MATLAB routines
%   that assume Utilization is aggregated over all LDC segments (p).
U = Utilization;
clear Utilization;
Utilization = reshape(sum(U,3),jmax,tmax,pmax,maxiter);
```

cgen.m

```
function cgen
%   cgen.m script file to generate constraint matrix A and vector b for
%   LP Power Plant Optimization Routine WITH PC CCS RETROFITS ONLY
%
%   Written by Timothy Lawrence Johnson
%   Version of 09 May 2002
%


clear all;
load temp;


%   Note need to transpose matrices to maintain consistency with older MATLAB routines
var_OM = var_OM';
varOM_infl = varOM_infl';
thermal_eff1 = thermal_eff1';
thermal_eff2 = thermal_eff2';
thermal_eff3 = thermal_eff3';
availability = availability';


%   Assign thermal efficiencies to L-D curve layers
thermal_eff(:,:,1) = thermal_eff1;
thermal_eff(:,:,2) = thermal_eff1;
thermal_eff(:,:,3) = thermal_eff2;
thermal_eff(:,:,4) = thermal_eff2;
thermal_eff(:,:,5) = thermal_eff3;
thermal_eff(:,:,6) = thermal_eff3;


%   Set parameters:
    tmax = size(D,2);             %   No. of time periods (t)
    jmax = size(EC,1);        %   No. of plant technologies (j)
    fmax = size(fuel,1);          %   No. of fuel types (f)
    pmax = size(Q,1);             %   No. of L-D curve divisions (p)
    vmax = size(EC,2) + tmax;     %   No. of plant vintages (v)
    vtdiff = size(EC,2);          %   Correction to sync v and t indicies
    maxiter = 1;              %   Number of iterations in batch run

    params = {tmax jmax fmax pmax vmax vtdiff maxiter};



%   Modify EXCEL inputs to correspond to MATLAB model requirements
    %   Break demand (D) down by L-D curve layer
        Dtemp(pmax,:) = D(pmax,:);
        for p = (pmax-1):-1:1,
            Dtemp(p,:) = D(p,:) - D((p+1),:);
        end
        D = Dtemp;
        clear Dtemp;


%   Generate constraint coefficient matrix A and vector b (function ConstrMatGen.m)
    [A,b] = ConstrMatGen(EC, dNCdt, availability, D, Q, per_length, tech, params);


%   Write A and b to file constmats.mat
    save constmats A b;
```

ConstrMatGen.m

```
function [A,b] = ConstrMatGen(EC, dNCdt, availability, D, Q, per_length, tech, params)
%   ConstrMatGen.m linear programming (LP) optimization function for LINEAR
%   Power Plant Optimization Model WITH PC CCS RETROFITS ONLY
%
%   This function generates the sparse constraint matrix A and (nonsparse) vector b for
%   the MATLAB linprog.m routine:
%       minimize objfn
%       subject to: A*DV <= b
%                   lb <= DV <= ub
%
%   Written by Timothy Lawrence Johnson
%   Version of 08 May 2002
%


disp(sprintf('Begin constraint generation.'))
tic;
flops(0);


%   Some MATLAB parameters:
tmax = params{1};         %   No. of time periods (t)
jmax = params{2};         %   No. of plant technologies (j)
fmax = params{3};         %   No. of fuel types (f)
pmax = params{4};         %   No. of L-D curve divisions (p)
vmax = params{5};         %   No. of plant vintages (v)
vtdiff = params{6};       %   Correction to sync v and t indicies
maxiter = params{7};      %   Number of iterations in batch run


Epenalty(1:jmax) = tech(:,3); %   Extract energy penalty data (j)


%   Calculate constraint matrices:
%   A: Left side inequality constraint matrix
%   b: Right side inequality constraint vector

    %   Create index vector Uidx for U(j,t,v,p) (length jmax*tmax*vmax*pmax);
    %   Index runs from 1+(jmax*tmax) to (jmax*tmax) + (jmax*tmax*vmax*pmax)
    %   as first (jmax*tmax) values of DV correspond to NC.
    Uidx = ((1+(jmax*tmax)):((jmax*tmax) + (jmax*tmax*vmax*pmax)));


    %   Convert Uidx into matrix form
    Uidx = reshape(Uidx,jmax,tmax,vmax,pmax);


    %   Demand constraints:
    %   sum over j=1 to jmax and v=1 to t+vtdiff of Ujtvp >= D(p,t)
    Aidx = 0;
    bidx = 0;
    for p = 1:pmax,
        for t= 1:tmax,
            bidx = bidx + 1;                      %   Index vector for b
            btmp(bidx) = -1 * D(p,t);             %   Value of right side of constraint
            Uidxtmp = Uidx(:,t,(1:(t+vtdiff)),p); %   Retrieve relevant indicies of U
            V = reshape(Uidxtmp,1,(t+vtdiff)*jmax);
            m = size(V,2);
            for n = 1:m,
                Aidx = Aidx + 1;      %   Index of nonzero elements of A
                I(Aidx) = bidx;       %   Row index for sparse form of A
                J(Aidx) = V(n);       %   Column index for sparse form of A
                Avector(Aidx) = -1;   %   Vector of nonzero elements of A
            end
        end
    end
```

```
%   Capacity utilization constraints (in general: U - NC <= EC)
    for j = 1:jmax,
        for t = 1:tmax,

            %   v = 1 to vtdiff (EC only, no NC)
            %   U(j,t,v,p) <= EC(j,v)
            for v = 1:(vtdiff),

                bidx = bidx + 1;
                btmp(bidx) = EC(j,v) * availability(v,j);

                for p = 1:pmax,
                    Aidx = Aidx + 1;
                    I(Aidx) = bidx;
                    J(Aidx) = Uidx(j,t,v,p);
                    Avector(Aidx) = 1;
                end

            end

            %   v = (vtdiff + 1) to (vtdiff + t) (NC only, no EC)
            %   U(j,t,v,p) - NC(j,1:t) <= 0
            for v = (vtdiff + 1):(vtdiff + t),

                bidx = bidx + 1;
                btmp(bidx) = 0;

                for p = 1:pmax,
                    Aidx = Aidx + 1;              %   This block for U(j,t,v,p)
                    I(Aidx) = bidx;
                    J(Aidx) = Uidx(j,t,v,p);
                    Avector(Aidx) = 1;
                end

                Aidx = Aidx + 1;                  %   This block for NC
                I(Aidx) = bidx;
                J(Aidx) = j + (jmax * (v - vtdiff - 1));
                Avector(Aidx) = -1 * (1 - Epenalty(j)) * availability(v,j);
                % Retrofit capacity derating

            end

            %   v = (t + vtdiff + 1) to vmax (No EC or NC)
            %   U(j,t,v,p) <= 0
            if t <= (tmax - 1),
                for v = (vtdiff + t + 1):vmax;

                    bidx = bidx + 1;
                    btmp(bidx) = 0;

                    for p = 1:pmax,
                        Aidx = Aidx + 1;
                        I(Aidx) = bidx;
                        J(Aidx) = Uidx(j,t,v,p);
                        Avector(Aidx) = 1;
                    end

                end
            end

        end
    end


%   Constraints to ensure that NC(6,t) + NC(9,t) <= dNCdt(j) for IGCC+CS and
%   NGCC+CS (j = 6 and 9).

    for t = 1:tmax,

        bidx = bidx + 1;
        btmp(bidx) = dNCdt(6);    %   Assume that dNCdt(9) = dNCdt(6)
```

```
        Aidx = Aidx + 1;          %   IGCC+CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 6;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;          %   NGCC+CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 9;
        Avector(Aidx) = 1;

    end


%   Constraints to ensure that NC(j,t) <= growthrate(j) * sum over t' = 0 to t-1 of
%   NC(j,t') for:
%   (1) all gas (j = 7, 8, 9; including NGCC+CS);
%   (2) all CCS (j = 6, 9, 13:16; including coal retrofits);
%   (3) wind (j = 12);
%   where NC(j,0) = EC(j).  Note that for CCS and wind there is no existing, "period
%   0", capacity value. An assumed EC value (per0TECH) is therefore used to
%   calculate their period 1 constraints.

    %   Gas
        per0GAS = (EC(7) + EC(8) + EC(9)) + 91950;   %   Pseudo existing capacity (MW)
        growthrateGAS = 0.15;                        %   Per-period growth rate

        t = 1;
            bidx = bidx + 1;
            btmp(bidx) = per0GAS * growthrateGAS;

            Aidx = Aidx + 1;                         %   GT
            I(Aidx) = bidx;
            J(Aidx) = ((t-1)*jmax) + 7;
            Avector(Aidx) = 1;

            Aidx = Aidx + 1;                         %   NGCC
            I(Aidx) = bidx;
            J(Aidx) = ((t-1)*jmax) + 8;
            Avector(Aidx) = 1;

            Aidx = Aidx + 1;                         %   NGCC + CS
            I(Aidx) = bidx;
            J(Aidx) = ((t-1)*jmax) + 9;
            Avector(Aidx) = 1;

        for t = 2:tmax,
            bidx = bidx + 1;
            btmp(bidx) = per0GAS * growthrateGAS;

            %   Period t
            Aidx = Aidx + 1;                         %   GT
            I(Aidx) = bidx;
            J(Aidx) = ((t-1)*jmax) + 7;
            Avector(Aidx) = 1;

            Aidx = Aidx + 1;                         %   NGCC
            I(Aidx) = bidx;
            J(Aidx) = ((t-1)*jmax) + 8;
            Avector(Aidx) = 1;

            Aidx = Aidx + 1;                         %   NGCC + CS
            I(Aidx) = bidx;
            J(Aidx) = ((t-1)*jmax) + 9;
            Avector(Aidx) = 1;

            %   Periods t-1 to 1 (Total installed capacity)
            for tt = (t-1):-1:1,
                Aidx = Aidx + 1;                         %   GT
                I(Aidx) = bidx;
                J(Aidx) = ((tt-1)*jmax) + 7;
```

```
            Avector(Aidx) = -1 * growthrateGAS;

            Aidx = Aidx + 1;                        %   NGCC
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 8;
            Avector(Aidx) = -1 * growthrateGAS;

            Aidx = Aidx + 1;                        %   NGCC + CS
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 9;
            Avector(Aidx) = -1 * growthrateGAS;
        end

    end

%   CCS
    per0CCS = 50000;          %   Pseudo existing capacity (MW)
    growthrateCCS = 0.30;     %   Per-period growth rate

    t = 1;
        bidx = bidx + 1;
        btmp(bidx) = per0CCS * growthrateCCS;

        Aidx = Aidx + 1;                        %   IGCC + CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 6;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                        %   NGCC + CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 9;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                        %   Retro PC1
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 13;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                        %   Retro PC2
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 14;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                        %   Retro PC3
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 15;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                        %   Retro PC4
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 16;
        Avector(Aidx) = 1;

    for t = 2:tmax,
        bidx = bidx + 1;
        btmp(bidx) = per0CCS * growthrateCCS;

        %   Period t
        Aidx = Aidx + 1;                        %   IGCC + CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 6;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                        %   NGCC + CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 9;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                        %   Retro PC1
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 13;
```

```
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                            %   Retro PC2
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 14;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                            %   Retro PC3
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 15;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                            %   Retro PC4
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 16;
        Avector(Aidx) = 1;

        %   Periods t-1 to 1 (Total installed capacity)
        for tt = (t-1):-1:1,
            Aidx = Aidx + 1;                            %   IGCC + CS
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 6;
            Avector(Aidx) = -1 * growthrateCCS;

            Aidx = Aidx + 1;                            %   NGCC + CS
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 9;
            Avector(Aidx) = -1 * growthrateCCS;

            Aidx = Aidx + 1;                            %   Retro PC1
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 13;
            Avector(Aidx) = -1 * growthrateCCS;

            Aidx = Aidx + 1;                            %   Retro PC2
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 14;
            Avector(Aidx) = -1 * growthrateCCS;

            Aidx = Aidx + 1;                            %   Retro PC3
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 15;
            Avector(Aidx) = -1 * growthrateCCS;

            Aidx = Aidx + 1;                            %   Retro PC4
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 16;
            Avector(Aidx) = -1 * growthrateCCS;
        end

    end

%   Wind
    per0WIND = 10000;         %   Pseudo existing capacity (MW)
    growthrateWIND = 0.25;    %   Per-period growth rate

    t = 1;
        bidx = bidx + 1;
        btmp(bidx) = (1/availability(t+1,12)) * per0WIND * growthrateWIND;

        Aidx = Aidx + 1;
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 12;
        Avector(Aidx) = 1;

    for t = 2:tmax,
        bidx = bidx + 1;
        btmp(bidx) = (1/availability(t+1,12)) * per0WIND * growthrateWIND;

        %   Period t
        Aidx = Aidx + 1;
```

```
            I(Aidx) = bidx;
            J(Aidx) = ((t-1)*jmax) + 12;
            Avector(Aidx) = 1;

            %   Periods t-1 to 1 (Total installed capacity)
            for tt = (t-1):-1:1,
                Aidx = Aidx + 1;
                I(Aidx) = bidx;
                J(Aidx) = ((tt-1)*jmax) + 12;
                Avector(Aidx) = -1 * growthrateWIND;
            end

        end


    %   Retrofit Constraints -- In all that follows, I assume: (1) only coal (j=1:4) is
    %   converted to C capture; (2) only pre-existing vintages (v=1) are converted; and
    %   (3) that the retrofits corresponding to EC(j=1:4,v=1) are NC(j=13:16,t=1:tmax),
    %   respectively.

    %   "Cannot retrofit more than existing installed capacity."
    %   sum over t=1:tmax NC(j+12,t) < EC(j,1) for j = 1:4
    for j = 1:4,

        bidx = bidx + 1;
        btmp(bidx) = EC(j,1);  %   Original PC capacity

        %   Total retrofit (over all t) corresponding to j: NC(j+12, all t)
        for t = 1:tmax,
            Aidx = Aidx + 1;
            I(Aidx) = bidx;
            J(Aidx) = (j+12) + (jmax * (t - 1));
            Avector(Aidx) = 1;
        end

    end

    %   "Cannot dispatch more existing capacity than was installed - retrofit."
    %   U(j,t,v=1,p=1:pmax) < (EC(j,1) - sum tt=1:t  NC(j + 12, tt)) for j = 1:4, t=1:tmax
    for j = 1:4,
        for t = 1:tmax,

            bidx = bidx + 1;
            btmp(bidx) = EC(j,1) * availability(v,j);

            for p = 1:pmax,                %   This block for U(j,t,1,p)
                Aidx = Aidx + 1;
                I(Aidx) = bidx;
                J(Aidx) = Uidx(j,t,1,p);
                Avector(Aidx) = 1;
            end

            for tt = 1:t,                  %   This block for NC(j + 12, tt) from tt=1:t
                Aidx = Aidx + 1;
                I(Aidx) = bidx;
                J(Aidx) = (j+12) + (jmax * (tt - 1));
                Avector(Aidx) = 1 * availability(v,j);
            end

        end
    end


    A = sparse(I,J,Avector);
    b = btmp';


disp(sprintf('Constraint gen. run time (sec.): %4.0f, mflops: %5.1f',toc,flops/1E6));
disp(sprintf('Constraints: %5.0f, Decision Variables: %5.0f',size(A)));
```

MPConstrMatGen.m (Multipollutant version of ConstrMatGen.m)

```
function [A,b] = MPConstrMatGen(EC, dNCdt, availability, D, Q, per_length, ...
tech, Slimit, Nlimit, Sintensity, Nintensity, params)
%	ConstrMatGen.m linear programming (LP) optimization function for LINEAR
%	Power Plant Optimization Model WITH PC MULTIPOLLUTANT RETROFITS
%
%	This function generates the sparse constraint matrix A and (nonsparse) vector b for the
%	MATLAB linprog.m routine:
%		minimize objfn
%		subject to: A*DV <= b
%				lb <= DV <= ub
%
%	Written by Timothy Lawrence Johnson
%	Version of 08 May 2002
%


disp(sprintf('Begin constraint generation.'))
tic;
flops(0);


%	Some MATLAB parameters:
tmax = params{1};		%	No. of time periods (t)
jmax = params{2};		%	No. of plant technologies (j)
fmax = params{3};		%	No. of fuel types (f)
pmax = params{4};		%	No. of L-D curve divisions (p)
vmax = params{5};		%	No. of plant vintages (v)
vtdiff = params{6};	%	Correction to sync v and t indicies
maxiter = params{7};	%	Number of iterations in batch run


Epenalty(1:jmax) = tech(:,7);	%	Extract energy penalty data (j)


%	Calculate constraint matrices:
%	A: Left side inequality constraint matrix
%	b: Right side inequality constraint vector

	%	Create index vector Uidx for U(j,t,v,p) (length jmax*tmax*vmax*pmax);
	%	Index runs from 1+(jmax*tmax) to (jmax*tmax) + (jmax*tmax*vmax*pmax)
	%	as first (jmax*tmax) values of DV correspond to NC.
	Uidx = ((1+(jmax*tmax)):((jmax*tmax) + (jmax*tmax*vmax*pmax)));

	%	Convert Uidx into matrix form
	Uidx = reshape(Uidx,jmax,tmax,vmax,pmax);

	%	Demand constraints:
	%	sum over j=1 to jmax and v=1 to t+vtdiff of Ujtvp >= D(p,t)
	Aidx = 0;
	bidx = 0;
	for p = 1:pmax,
		for t= 1:tmax,
			bidx = bidx + 1;					%	Index vector for b
			btmp(bidx) = -1 * D(p,t);				%	Value of right side of constraint
			Uidxtmp = Uidx(:,t,(1:(t+vtdiff)),p);	%	Retrieve relevant indicies of U
			V = reshape(Uidxtmp,1,(t+vtdiff)*jmax);
			m = size(V,2);
			for n = 1:m,
				Aidx = Aidx + 1;		%	Index of nonzero elements of A
				I(Aidx) = bidx;		%	Row index for sparse form of A
				J(Aidx) = V(n);		%	Column index for sparse form of A
				Avector(Aidx) = -1;	%	Vector of nonzero elements of A
			end
		end
	end
```

```
%	Capacity utilization constraints (in general: U - NC <= EC)
	for j = 1:jmax,
		for t = 1:tmax,

			%	v = 1 to vtdiff (EC only, no NC)
			%	U(j,t,v,p) <= EC(j,v)
			for v = 1:(vtdiff),

				bidx = bidx + 1;
				btmp(bidx) = EC(j,v) * availability(v,j);

				for p = 1:pmax,
					Aidx = Aidx + 1;
					I(Aidx) = bidx;
					J(Aidx) = Uidx(j,t,v,p);
					Avector(Aidx) = 1;
				end

			end

			%	v = (vtdiff + 1) to (vtdiff + t) (NC only, no EC)
			%	U(j,t,v,p) - NC(j,1:t) <= 0
			for v = (vtdiff + 1):(vtdiff + t),

				bidx = bidx + 1;
				btmp(bidx) = 0;

				for p = 1:pmax,
					Aidx = Aidx + 1;			%	This block for U(j,t,v,p)
					I(Aidx) = bidx;
					J(Aidx) = Uidx(j,t,v,p);
					Avector(Aidx) = 1;
				end

				Aidx = Aidx + 1;				%	This block for NC
				I(Aidx) = bidx;
				J(Aidx) = j + (jmax * (v - vtdiff - 1));
				Avector(Aidx) = -1 * (1 - Epenalty(j)) * availability(v,j);	% Retrofit capacity derating

			end

			%	v = (t + vtdiff + 1) to vmax (No EC or NC)
			%	U(j,t,v,p) <= 0
			if t <= (tmax - 1),
				for v = (vtdiff + t + 1):vmax;

					bidx = bidx + 1;
					btmp(bidx) = 0;

					for p = 1:pmax,
						Aidx = Aidx + 1;
						I(Aidx) = bidx;
						J(Aidx) = Uidx(j,t,v,p);
						Avector(Aidx) = 1;
					end

				end
			end

		end
	end


%	Constraints to ensure that NC(6,t) + NC(9,t) <= dNCdt(j) for IGCC+CS and
%	NGCC+CS (j = 6 and 9).

	for t = 1:tmax,

		bidx = bidx + 1;
```

```
		btmp(bidx) = dNCdt(6);	%	Assume that dNCdt(9) = dNCdt(6)

		Aidx = Aidx + 1;		%	IGCC+CS
		I(Aidx) = bidx;
		J(Aidx) = ((t-1)*jmax) + 6;
		Avector(Aidx) = 1;

		Aidx = Aidx + 1;		%	NGCC+CS
		I(Aidx) = bidx;
		J(Aidx) = ((t-1)*jmax) + 9;
		Avector(Aidx) = 1;

	end


%	Constraints to ensure that NC(j,t) <= growthrate(j) * sum over t' = 0 to t-1 of NC(j,t') for:
%	(1) all gas (j = 7, 8, 9; including NGCC+CS);
%	(2) all CCS (j = 6, 9, 13:16; including coal retrofits);
%	(3) wind (j = 12);
%	where NC(j,0) = EC(j).  Note that for CCS and wind there is no existing, "period 0", capacity
%	value. An assumed EC value (per0TECH) is therefore used to calculate their period 1 constraints.

	%	Gas
		per0GAS = (EC(7) + EC(8) + EC(9)) + 91950;	%	Pseudo existing capacity (MW)
		growthrateGAS = 0.15;				%	Per-period growth rate

		t = 1;
			bidx = bidx + 1;
			btmp(bidx) = per0GAS * growthrateGAS;

			Aidx = Aidx + 1;				%	GT
			I(Aidx) = bidx;
			J(Aidx) = ((t-1)*jmax) + 7;
			Avector(Aidx) = 1;

			Aidx = Aidx + 1;				%	NGCC
			I(Aidx) = bidx;
			J(Aidx) = ((t-1)*jmax) + 8;
			Avector(Aidx) = 1;

			Aidx = Aidx + 1;				%	NGCC + CS
			I(Aidx) = bidx;
			J(Aidx) = ((t-1)*jmax) + 9;
			Avector(Aidx) = 1;

		for t = 2:tmax,
			bidx = bidx + 1;
			btmp(bidx) = per0GAS * growthrateGAS;

			%	Period t
			Aidx = Aidx + 1;				%	GT
			I(Aidx) = bidx;
			J(Aidx) = ((t-1)*jmax) + 7;
			Avector(Aidx) = 1;

			Aidx = Aidx + 1;				%	NGCC
			I(Aidx) = bidx;
			J(Aidx) = ((t-1)*jmax) + 8;
			Avector(Aidx) = 1;

			Aidx = Aidx + 1;				%	NGCC + CS
			I(Aidx) = bidx;
			J(Aidx) = ((t-1)*jmax) + 9;
			Avector(Aidx) = 1;

			%	Periods t-1 to 1 (Total installed capacity)
			for tt = (t-1):-1:1,
				Aidx = Aidx + 1;			%	GT
				I(Aidx) = bidx;
				J(Aidx) = ((tt-1)*jmax) + 7;
```

```
            Avector(Aidx) = -1 * growthrateGAS;

            Aidx = Aidx + 1;                          %   NGCC
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 8;
            Avector(Aidx) = -1 * growthrateGAS;

            Aidx = Aidx + 1;                          %   NGCC + CS
            I(Aidx) = bidx;
            J(Aidx) = ((tt-1)*jmax) + 9;
            Avector(Aidx) = -1 * growthrateGAS;
        end

    end

%   CCS
    per0CCS = 50000;        %   Pseudo existing capacity (MW)
    growthrateCCS = 0.30;   %   Per-period growth rate

    t = 1;
        bidx = bidx + 1;
        btmp(bidx) = per0CCS * growthrateCCS;

        Aidx = Aidx + 1;                          %   IGCC + CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 6;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                          %   NGCC + CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 9;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                          %   Retro PC1
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 13;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                          %   Retro PC2
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 14;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                          %   Retro PC3
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 15;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                          %   Retro PC4
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 16;
        Avector(Aidx) = 1;

    for t = 2:tmax,
        bidx = bidx + 1;
        btmp(bidx) = per0CCS * growthrateCCS;

        %   Period t
        Aidx = Aidx + 1;                          %   IGCC + CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 6;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                          %   NGCC + CS
        I(Aidx) = bidx;
        J(Aidx) = ((t-1)*jmax) + 9;
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;                          %   Retro PC1
        I(Aidx) = bidx;
```

```
		J(Aidx) = ((t-1)*jmax) + 13;
		Avector(Aidx) = 1;

		Aidx = Aidx + 1;				%	Retro PC2
		I(Aidx) = bidx;
		J(Aidx) = ((t-1)*jmax) + 14;
		Avector(Aidx) = 1;

		Aidx = Aidx + 1;				%	Retro PC3
		I(Aidx) = bidx;
		J(Aidx) = ((t-1)*jmax) + 15;
		Avector(Aidx) = 1;

		Aidx = Aidx + 1;				%	Retro PC4
		I(Aidx) = bidx;
		J(Aidx) = ((t-1)*jmax) + 16;
		Avector(Aidx) = 1;

		%	Periods t-1 to 1 (Total installed capacity)
		for tt = (t-1):-1:1,
			Aidx = Aidx + 1;			%	IGCC + CS
			I(Aidx) = bidx;
			J(Aidx) = ((tt-1)*jmax) + 6;
			Avector(Aidx) = -1 * growthrateCCS;

			Aidx = Aidx + 1;			%	NGCC + CS
			I(Aidx) = bidx;
			J(Aidx) = ((tt-1)*jmax) + 9;
			Avector(Aidx) = -1 * growthrateCCS;

			Aidx = Aidx + 1;			%	Retro PC1
			I(Aidx) = bidx;
			J(Aidx) = ((tt-1)*jmax) + 13;
			Avector(Aidx) = -1 * growthrateCCS;

			Aidx = Aidx + 1;			%	Retro PC2
			I(Aidx) = bidx;
			J(Aidx) = ((tt-1)*jmax) + 14;
			Avector(Aidx) = -1 * growthrateCCS;

			Aidx = Aidx + 1;			%	Retro PC3
			I(Aidx) = bidx;
			J(Aidx) = ((tt-1)*jmax) + 15;
			Avector(Aidx) = -1 * growthrateCCS;

			Aidx = Aidx + 1;			%	Retro PC4
			I(Aidx) = bidx;
			J(Aidx) = ((tt-1)*jmax) + 16;
			Avector(Aidx) = -1 * growthrateCCS;
		end

	end

%	Wind
	per0WIND = 10000;		%	Pseudo existing capacity (MW)
	growthrateWIND = 0.25;		%	Per-period growth rate

	t = 1;
		bidx = bidx + 1;
		btmp(bidx) = (1/availability(t+1,12)) * per0WIND * growthrateWIND;

		Aidx = Aidx + 1;
		I(Aidx) = bidx;
		J(Aidx) = ((t-1)*jmax) + 12;
		Avector(Aidx) = 1;

	for t = 2:tmax,
		bidx = bidx + 1;
		btmp(bidx) = (1/availability(t+1,12)) * per0WIND * growthrateWIND;
```

```
            %     Period t
            Aidx = Aidx + 1;
            I(Aidx) = bidx;
            J(Aidx) = ((t-1)*jmax) + 12;
            Avector(Aidx) = 1;

            %     Periods t-1 to 1 (Total installed capacity)
            for tt = (t-1):-1:1,
                Aidx = Aidx + 1;
                I(Aidx) = bidx;
                J(Aidx) = ((tt-1)*jmax) + 12;
                Avector(Aidx) = -1 * growthrateWIND;
            end

        end


%     Retrofit Constraints -- In all that follows, I assume: (1) only coal (j=1:4) is
%     converted; (2) only pre-existing vintages (v=1) are converted; and (3) that
%     the retrofits corresponding to EC(j=1:4,v=1) are NC(j=13:16,t=1:tmax) for SNC,
%     NC(j=17:20,t=1:tmax) for S, NC(j=21:24,t=1:tmax) for N, and NC(j=25:28,t=1:tmax) for SN.

%     "Cannot retrofit more than existing installed capacity."
%     sum over t=1:tmax {NC(j+12,t) + NC(j+16,t) + NC(j+20,t) + NC(j+24,t)} < EC(j,1) for j = 1:4
for j = 1:4,

    bidx = bidx + 1;
    btmp(bidx) = EC(j,1);%     Original PC capacity for technology j

    for t = 1:tmax,    %     Total retrofit (over all t and retofit types) corresponding to technology j

        Aidx = Aidx + 1;            %     SNC Retrofit
        I(Aidx) = bidx;
        J(Aidx) = (j+12) + (jmax * (t - 1));
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;            %     S Retrofit
        I(Aidx) = bidx;
        J(Aidx) = (j+16) + (jmax * (t - 1));
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;            %     N Retrofit
        I(Aidx) = bidx;
        J(Aidx) = (j+20) + (jmax * (t - 1));
        Avector(Aidx) = 1;

        Aidx = Aidx + 1;            %     SN Retrofit
        I(Aidx) = bidx;
        J(Aidx) = (j+24) + (jmax * (t - 1));
        Avector(Aidx) = 1;

    end

end

%     "Cannot dispatch more existing capacity than was installed - retrofit."
%     U(j,t,v=1,p=1:pmax) < {EC(j,1) - sum tt=1:t (NC(j + 12, tt) + NC(j + 16, tt) +
%     NC(j + 20, tt) + NC(j + 24, tt)} for j = 1:4, t=1:tmax
for j = 1:4,
    for t = 1:tmax,

        bidx = bidx + 1;
        btmp(bidx) = EC(j,1) * availability(v,j);

        for p = 1:pmax,                  %     This block for U(j,t,1,p)
            Aidx = Aidx + 1;
            I(Aidx) = bidx;
            J(Aidx) = Uidx(j,t,1,p);
            Avector(Aidx) = 1;
        end
```

```
		for tt = 1:t,				%	This block for NC(j + 12, tt) from tt=1:t

			Aidx = Aidx + 1;		%	SNC Retrofit
			I(Aidx) = bidx;
			J(Aidx) = (j+12) + (jmax * (tt - 1));
			Avector(Aidx) = 1 * availability(v,j);

			Aidx = Aidx + 1;		%	S Retrofit
			I(Aidx) = bidx;
			J(Aidx) = (j+16) + (jmax * (tt - 1));
			Avector(Aidx) = 1 * availability(v,j);

			Aidx = Aidx + 1;		%	N Retrofit
			I(Aidx) = bidx;
			J(Aidx) = (j+20) + (jmax * (tt - 1));
			Avector(Aidx) = 1 * availability(v,j);

			Aidx = Aidx + 1;		%	SN Retrofit
			I(Aidx) = bidx;
			J(Aidx) = (j+24) + (jmax * (tt - 1));
			Avector(Aidx) = 1 * availability(v,j);

		end

	end
end


%	S and NOx emission constraints -- For each time period t, these are of the form:
%	{sum over all j, v, and p of U(j,t,v,p) * Q(p) * Sintensity(v,j,p)} < Slimit(t),
%	where Sintensity is in kgS/kWh and Slimit is in tS/yr.

	%	S
	for t = 1:tmax,
		bidx = bidx+1;
		btmp(bidx) = Slimit(t);

		for p = 1:pmax,
			Uidxtmp = Uidx(:,t,(1:t+vtdiff),p);
			V = reshape(Uidxtmp,1,(t+vtdiff)*jmax);

			for j = 1:jmax,
				for v = 1:(vtdiff+t),
					Aidx = Aidx + 1;
					I(Aidx) = bidx;
					J(Aidx) = V(jmax*(v-1) + j);
					Avector(Aidx) = Q(p) * per_length * Sintensity(v,j,p);
					%	Note that conversion units in above cancel:
					%	hrs/yr * yrs./period * kgS/kWh * 1000kW/MW * tS/1000kgS
					%	when multiplied by U (in MW) gives tS/period
				end
			end

		end

	end

	%	NOx
	for t = 1:tmax,
		bidx = bidx+1;
		btmp(bidx) = Nlimit(t);

		for p = 1:pmax,
			Uidxtmp = Uidx(:,t,(1:t+vtdiff),p);
			V = reshape(Uidxtmp,1,(t+vtdiff)*jmax);

			for j = 1:jmax,
				for v = 1:(vtdiff+t),
					Aidx = Aidx + 1;
```

```
                    I(Aidx) = bidx;
                    J(Aidx) = V(jmax*(v-1) + j);
                    Avector(Aidx) = Q(p) * per_length * Nintensity(v,j,p);
                    %     Note that conversion units in above cancel:
                    %     hrs/yr * yrs./period * kgNOx/kWh * 1000kW/MW * tN/1000kgNOx
                    %     when multiplied by U (in MW) gives tNOx/period
                end
            end

        end

    end


  A = sparse(I,J,Avector);
  clear I J Avector;

  b = btmp';
  clear btmp;


disp(sprintf('Constraint gen. run time (sec.): %4.0f, mflops: %5.1f',toc,flops/1E6));
disp(sprintf('Constraints: %5.0f, Decision Variables: %5.0f',size(A)));
```

LPshell.m

```
function [TotalCost,TCOE,VarCost,CapCost,NewCapacity,Utilization,Cemissions, ...
Costs,techindex] = LPshell(C_price,params)
%
%   LPshell.m function for LINEAR Power Plant Optimization Model
%   The function executes a batch run for a given C_tax, where each iteration loads the
%   temp.mat file, calls the LPopt.m function (the optimization routine),
%   and processes the results.
%
%   OUTPUTS ("iter" indexes batch run iteration, from 1 to "maxiter"):
%   Costs          Fuel prices and carbon tax (Nominal $/GJ and $/tC) (f+1,t,iter)
%   TotalCost      Minimum value (NPV) of objective function (base year $) (iter)
%   TCOE           Total cost of electricity under specified conditions ($) (iter)
%   NewCapacity    Final matrix of new capacity added (MW) (j,t,iter)
%   Utilization    Final matrix of capacity utilized (MW) (j,t,p,v,iter)
%   Cemissions     Total carbon emissions by t (metric tC/period) (iter,t)
%   techindex      Index vector of technologies in order of increasing marginal operating
%                  costs (j,t,iter)
%
%   Written by Timothy Lawrence Johnson
%   Version of 06 May 2002
%


%   INPUTS (The following are loaded for each batch run iteration
%   from the temp.mat file.):
%   D                  Yearly demand load(MW/year) (p,t)
%   Q                  Length of load-duration segment p (hours/year) (by index p)
%   per_length         Length of time step t (years)
%   disc_rate          Annual (NOT per-period) discount rate
%   tech               Technology parameters: fuel type (f), carbon separation
%                      efficiency, and energy penalty (j,3)
%   life               Expected lifetime of technology for capital write-off (years) (j)
%   techname           Cell array with technology names (j)
%   EC                 Existing installed capacity at time t=1 (MW) (j,v)
%   cap_cost           Cost of new capacity (nominal $/kW) (j,t)
%   dNCdt              Maximum new capacity installed per period (MW/period) (j)
%   var_OM             Base year variable O&M -- excluding fuel, carbon emission
%                      fee and capital charge (nominal cents/kWh) (v,j)
%   fix_OM             Base year fixed O&M (nominal $/kW-year) (v,j)
%   fixOM_infl         Per-period growth rate of fix_OM (v, j)
%   C_seq_cost         Cost of carbon sequestration (nominal $/tC)
%   thermal_eff<p>     Thermal efficiency (%) (v,j)
%   availability       Availability per period (%) (v,j)
%   fuel               Fuel parameters: E-intensity (kg fuel/GJ) and C-intensity
%                      (kgC/GJ fuel) by fuel type (f,2)
%   fuel_price         Fuel price (nominal $/GJ HHV) (f,t)
%   C_price            Carbon price (nominal $/metric tC per period for each iteration)
%                      (iter,t)


%   Some MATLAB parameters:
tmax = params{1};         %   No. of time periods (t)
jmax = params{2};         %   No. of plant technologies (j)
fmax = params{3};         %   No. of fuel types (f)
pmax = params{4};         %   No. of L-D curve divisions (p)
vmax = params{5};         %   No. of plant vintages (v)
vtdiff = params{6};       %   Correction to sync v and t indicies
maxiter = params{7};      %   Number of iterations in batch run


%   Load constraint matrix A and vector b from file constmats.mat
    load constmats


%   Load temp.mat and modify EXCEL inputs to correspond to MATLAB model requirements

    load temp;
```

```
    %   Break demand (D) down by L-D curve layer
        Dtemp(pmax,:) = D(pmax,:);
        for p = (pmax-1):-1:1,
            Dtemp(p,:) = D(p,:) - D((p+1),:);
        end
        D = Dtemp;
        clear Dtemp;

    %   Transpose matrices
        var_OM = var_OM';
        varOM_infl = varOM_infl';
        thermal_eff1 = thermal_eff1';
        thermal_eff2 = thermal_eff2';
        thermal_eff3 = thermal_eff3';
        availability = availability';

    %   Assign thermal efficiencies to L-D curve layers
        thermal_eff(:,:,1) = thermal_eff1;
        thermal_eff(:,:,2) = thermal_eff1;
        thermal_eff(:,:,3) = thermal_eff2;
        thermal_eff(:,:,4) = thermal_eff2;
        thermal_eff(:,:,5) = thermal_eff3;
        thermal_eff(:,:,6) = thermal_eff3;


%   Execute batch run of optimizations (number of iterations = maxiter)
for iter = 1:maxiter,


    disp(sprintf('Iteration:%4.0f',iter))


    %   Determine C_tax for specific iteration based on iteration and C_price
    for t = 1:tmax,
        C_tax(t) = C_price(iter,t);
    end


    %   Calculate OC(j,v,t,p) (cents/kWh) and C_output (v,j,p) (kgC/kWh)
    %   matrices (function marg_op_cost.m)
    [OC, C_output] = marg_op_cost(tech, fuel, fuel_price, C_tax, C_seq_cost, ...
    var_OM, thermal_eff, disc_rate, varOM_infl, per_length, params);

        %   Save some cost data
        Costs(1:fmax,1:tmax,iter) = fuel_price(1:fmax,1:tmax);
        Costs(fmax+1,1:tmax,iter) = C_tax(1:tmax);

        %   Average(over v and p) and sort (over j) OC matrix to obtain
        %   index vector (I) of technologies (j) in order of increasing
        %   marginal operating costs.
        [Y,I] = sort(sum(sum(OC,4),2),1);
        techindex(1:jmax,1:tmax,iter) = I;


    %   Call LP optimization routine (function LPoptCCSRetro.m)
    [NC,U,TC] = LPoptCCSRetro(EC, OC, cap_cost, fix_OM, fixOM_infl, ...
    dNCdt, Q, per_length, disc_rate, A, b, params);


    %   Save desired optimization results
    NewCapacity(1:jmax,1:tmax,iter) = NC;
    Utilization(1:jmax,1:tmax,1:vmax,1:pmax,iter) = U;
    TotalCost(iter) = TC;


    %   Calculate undiscounted per period costs ($) (function COEvsPeriod.m)
    [TotalCOE, Vcost, Ccost] = COEvsPeriod(NC, U, tech, fuel, fuel_price, C_tax, ...
    C_seq_cost, var_OM, varOM_infl, fix_OM, fixOM_infl, cap_cost, ...
    thermal_eff, 0, Q, per_length, params);
    TCOE(iter,1:tmax) = TotalCOE;
    VarCost(iter,1:tmax) = Vcost;
```

```
    CapCost(iter,1:tmax) = Ccost;


    %   Call function carbon_emissions.m (metric tC/period) (j,t)
    Cemissions(iter,1:tmax) = sum(carbon_emissions(U,C_output,Q,per_length, params),1);


    %   Clear remaining unneeded variables from memory
    clear OC C_tax Y I NC U TC C_output;


end %   End of batch run ("iter") loop
```

marg_op_cost.m

```
function [OC, C_output] = marg_op_cost(tech, fuel, fuel_price, C_tax, C_seq_cost, ...
var_OM, thermal_eff, disc_rate, varOM_infl, per_length, params)
%   marg_op_cost.m function calculates marginal operating cost OC (j,v,t,p)
%   (cents/kWh) and C_output (v,j,p) (kgC/kWh) matrices for LINEAR Power Plant
%   Optimization Model.
%
%   Written by Timothy Lawrence Johnson
%   Version of 31 August 2001
%


%   Some MATLAB parameters:
tmax = params{1};         %   No. of time periods (t)
jmax = params{2};         %   No. of plant technologies (j)
fmax = params{3};         %   No. of fuel types (f)
pmax = params{4};         %   No. of L-D curve divisions (p)
vmax = params{5};         %   No. of plant vintages (v)
vtdiff = params{6};       %   Correction to sync v and t indicies
maxiter = params{7};      %   Number of iterations in batch run


%   Extract fuel parameters E_int(f) and C_int(f) from Fuel: inverse
%   energy intensity (kg fuel/GJ) and carbon intensity (kgC/kg fuel)
    for f = 1:fmax,
        E_int(f) = fuel(f,1);
        C_int(f) = fuel(f,2);
    end


%   fuel_cons(v,j,p)   Fuel consumption calculations (kg fuel/kWh)
%   = (1/thermal_eff) * E_int * GJ/1000MJ * 3.6MJ/kWh
    for p = 1:pmax,
        for j = 1:jmax,
            for v = 1:vmax,
                fuel_cons(v,j,p) = E_int(tech(j,1)) * (3.6/1000) / thermal_eff(v,j,p);
            end
        end
    end


%   var_fuel (v,j,t,p) Variable fuel costs (cents/kWh)
%   = (1/thermal_eff) * fuel_price * 100cents/$ * 3.6MJ/kWh * GJ/1000MJ
    for p = 1:pmax,
        for t = 1:tmax,
            for j = 1:jmax,
                for v = 1:vmax,
                    var_fuel(v,j,t,p) = fuel_price(tech(j,1),t) * (3.6/10) / ...
                    thermal_eff(v,j,p);
                end
            end
        end
    end


%   C_output(v,j,p)    Carbon emissions calculations (kgC/kWh)
%   = fuel_cons * C_int * (1 - carbon separation efficiency)
%   C_captured(v,j,p) = fuel_cons * C_int * carbon separation efficiency (kgC/kWh)
    for p = 1:pmax,
        for j = 1:jmax,
            for v = 1:vmax,
                C_emiss(v,j,p) = fuel_cons(v,j,p) * C_int(tech(j,1)) * (1 - tech(j,2));
                C_captured(v,j,p) = fuel_cons(v,j,p) * C_int(tech(j,1)) * tech(j,2);
            end
        end
    end
    C_output = C_emiss;
```

```
%   var_Cseq(v,j,p)    Variable cost of carbon sequestration (cents/kWh)
%   = C_captured * C_seq_cost * tC/1000kg * 100cents/$
    var_Cseq = C_captured * C_seq_cost / 10;


%   var_Ctax(v,j,t,p)  Variable carbon emission tax costs (cents/kWh)
%   = C_output * C_tax * 100cents/$ * t/1000kg
    for p = 1:pmax,
        for t = 1:tmax,
            for j = 1:jmax,
                for v = 1:vmax,
                    var_Ctax(v,j,t,p) = C_output(v,j,p) * C_tax(t) / 10;
                end
            end
        end
    end


    %   Note below that the discount rate is on an annual basis while varOM_infl
    %   is per period.
    for p = 1:pmax,
        for t = 1:tmax,
            for j = 1:jmax,
                for v = 1:(vtdiff + t),
                    OM(j,v,t,p) = (var_OM(v,j)*((1 + varOM_infl(v,j))^(t-1)) + ...
                    var_Cseq(v,j,p) + var_fuel(v,j,t,p) + var_Ctax(v,j,t,p)) / ...
                    ((1 + disc_rate)^(per_length*(t-1)));
                end
            end
        end
    end
    OC = OM;
```

LPoptCCSRetro.m

```
function [NC,U,TC] = LPoptCCSRetro(EC, OC, cap_cost, fix_OM, fixOM_infl, ...
dNCdt, Q, per_length, disc_rate, A, b, params);
%   LPoptCCSRetro.m linear programming (LP) optimization function for LINEAR
%   Power Plant Optimization Model WITH PC CCS RETROFITS ONLY
%
%   This function uses the MATLAB linprog.m routine:
%       minimize objfn
%       subject to: A*DV <= b
%                       lb <= DV <= ub
%
%   Written by Timothy Lawrence Johnson
%   Version of 02 May 2002
%


%   Output results:
%   NC          Final matrix of new capacity added (MW) (j,t)
%   U           Final matrix of capacity utilized (MW) (j,t,v,p)
%   TC          Minimum value of objective function: NPV of total cost (base year $)


disp(sprintf('Begin optimization routine.'))
tic;
flops(0);


%   Some MATLAB parameters:
tmax = params{1};         %   No. of time periods (t)
jmax = params{2};         %   No. of plant technologies (j)
fmax = params{3};         %   No. of fuel types (f)
pmax = params{4};         %   No. of L-D curve divisions (p)
vmax = params{5};         %   No. of plant vintages (v)
vtdiff = params{6};       %   Correction to sync v and t indicies
maxiter = params{7};      %   Number of iterations in batch run


%   DV: Vector of decision variables (length jmax*tmax + jmax*tmax*vmax*pmax).
%   The first jmax*tmax elements correspond to NC or new capacity added (MW),
%   with sequential blocks of jmax elements given for a specific t.  The next
%   jmax*tmax*vmax*pmax elements correspond to U or actual usage (MW) of each
%   category of potential capacity, with the first pmax elements referring
%   to j=1, t=1, v=1, the second set of pmax elements to j=1, t=1, v=2, etc.


%   Initialize decision variable vector DV (MW)
    for n = 1:((jmax*tmax) + (jmax*tmax*vmax*pmax)),
        DVtmp(n) = 0;
    end
    DV = DVtmp';
    clear DVtmp;


%   Upper and lower bounds for decision variable vector DV (MW)
    %   Bounds on NC (MW)
    for t = 1:tmax,
        for j = 1:jmax,
            lbtmp(((t-1)*jmax) + j) = 0;
            ubtmp(((t-1)*jmax) + j) = dNCdt(j);   %   Upper limit set by dNCdt
        end
    end


    %   Bounds on U (MW)
    for k = ((jmax*tmax) + 1):((jmax*tmax) + (jmax*tmax*vmax*pmax)),
        lbtmp(k) = 0;
        ubtmp(k) = 10000000;   %   Somewhat arbitrary upper limit
    end
```

```
    lb = lbtmp';
    ub = ubtmp';
    clear lbtmp ubtmp;


%   Define objective function (base year $)

    %   Cost of new capital (base year $/MW)
        %   Convert cap_cost from nominal to base year $/kW
        for t = 1:tmax;
            for j = 1:jmax;
            disc_cap_cost(j,t) = cap_cost(j,t)/((1+disc_rate)^(per_length*(t-1)));
            end
        end

        NCcost = 1000 * disc_cap_cost(:); %   (note 1000 = 1000kW/MW)

    %   Marginal operating cost calculations: combine variable and fixed O&M (base year
    %   $/MW) (Note 10 = 1000 kW/MW * $/100 cents, 1000 = 1000 kW/MW,
    %   and that OC is already discounted.)
    n = 0;
    for p = 1:pmax,
        for v = 1:vmax,
            for t = 1:tmax,
                for j = 1:jmax,
                    n = n + 1;
                    MARGcost(n) = [(OC(j,v,t,p) * Q(p) * 10 * per_length) + ...
                    ((fix_OM(j,v) * per_length * ((1+fixOM_infl(j,v))^(t-1)) * 1000) / ...
                    ((1+disc_rate)^(per_length*(t-1))))];
                end
            end
        end
    end


    objfntmp = [NCcost', MARGcost];
    objfn = objfntmp';
    clear objfntmp;


%   Minimization using linear programming
    options = optimset('TolFun', 0.01);
    [DV,TC] = linprog(objfn,A,b,[],[],lb,ub,[],options);


%   Build matrices NC(j,t) and U(j,t,v,p) from vector DV (both in MW)
    NC = reshape(DV(1:(jmax*tmax)),jmax,tmax);
    U = reshape(DV(((jmax*tmax)+1):end),jmax,tmax,vmax,pmax);


%   Clear unneeded variables from memory
    clear A b lb ub DV;


disp(sprintf('Optimization run time (sec.): %4.0f, mflops: %5.1f',toc,flops/1E6));
```

COEvsPeriod.m

```
function [TotalCOE, Vcost, Ccost] = COEvsPeriod(NC, U, tech, fuel, fuel_price, ...
C_tax, C_seq_cost, var_OM, varOM_infl, fix_OM, fixOM_infl, cap_cost, ...
thermal_eff, disc_rate, Q, per_length, params)
%   COEvsPeriod.m function calculates total cost of electricity, as well as separate
%   variable and capital cost components (all in discounted $), versus time period for
%   a given carbon tax and discount rate.
%
%   Written by Timothy Lawrence Johnson
%   Version of 06 May 2002
%


%   Some MATLAB parameters:
tmax = params{1};         %   No. of time periods (t)
jmax = params{2};         %   No. of plant technologies (j)
fmax = params{3};         %   No. of fuel types (f)
pmax = params{4};         %   No. of L-D curve divisions (p)
vmax = params{5};         %   No. of plant vintages (v)
vtdiff = params{6};       %   Correction to sync v and t indicies
maxiter = params{7};      %   Number of iterations in batch run


%   Cost of new capital (base year $)
    for t = 1:tmax;
        for j = 1:jmax;
            %   Convert cap_cost from nominal to base year $/kW
            disc_cap_cost(j,t) = cap_cost(j,t)/((1+disc_rate)^(per_length*(t-1)));

            %   Note that 1000 = 1000kW/MW.
            Total_cap_cost(j,t) = disc_cap_cost(j,t) * NC(j,t) * 1000;
        end
    end

    cap_cost_period = reshape(sum(Total_cap_cost,1),1,tmax);


%   Call marg_op_cost to find OC(j,v,t,p) (base year cents/kWh)
    [OC, C_output] = marg_op_cost(tech, fuel, fuel_price, C_tax, C_seq_cost, ...
    var_OM, thermal_eff, disc_rate, varOM_infl, per_length, params);


%   Total marginal operating costs: combine variable and fixed O&M (base year $)
    for p = 1:pmax,
        for v = 1:vmax,
            for t = 1:tmax,
                for j = 1:jmax,
                    %   Index order reversed to match marg_cost and U.  Note that 10 = 1000
                    %   kW/MW * $/100 cents, 1000 = 1000 kW/MW, and that OC is already
                    %   discounted.
                    marg_cost(j,t,v,p) = [(OC(j,v,t,p) * Q(p) * 10 * per_length) + ...
                    ((fix_OM(j,v) * per_length * ((1+fixOM_infl(j,v))^(t-1)) * 1000) / ...
                    ((1+disc_rate)^(per_length*(t-1))))];

                    Total_marg_cost(j,t,v,p) = marg_cost(j,t,v,p) * U(j,t,v,p);
                end
            end
        end
    end

    marg_cost_period = reshape(sum(sum(sum(Total_marg_cost,4),3),1),1,tmax);


TotalCOE = cap_cost_period + marg_cost_period;
Vcost = marg_cost_period;
Ccost = cap_cost_period;
```

carbon_emissions.m

```
function emissions = carbon_emissions(U,C_output,Q,per_length,params)
%   carbon_emissions.m function for Linear Power Plant Optimization Model.
%
%   The function returns the carbon emissions matrix (in metric tC/period;
%   by technology j and period t) for given utilization (U(j,t,v,p); in MW)
%   and technology-vintage specific carbon output (C_output(v,j);
%   in kgC/kWh) matrices.
%
%   Written by Timothy Lawrence Johnson
%   Version of 13 June 2001
%


%   Some MATLAB parameters:
tmax = params{1};         %   No. of time periods (t)
jmax = params{2};         %   No. of plant technologies (j)
fmax = params{3};         %   No. of fuel types (f)
pmax = params{4};         %   No. of L-D curve divisions (p)
vmax = params{5};         %   No. of plant vintages (v)
vtdiff = params{6};       %   Correction to sync v and t indicies
maxiter = params(7);      %   Number of iterations in batch run


emissions = zeros(jmax,tmax);


%   Note that conversion units below cancel out: Utilization is in MW while
%   C_output is in kgC/kWh; hence, MW * kgC/kWh * hrs/yrs * yrs/period *
%   1000kW/MW * ton/1000kg gives tons/period.
for j = 1:jmax,
    for t = 1:tmax,
        for v = 1:(t+vtdiff),
            for p = 1:pmax,
            emissions(j,t)=emissions(j,t)+(U(j,t,v,p)*C_output(v,j,p)*Q(p)*per_length);
            end
        end
    end
end
```