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Carbon Capture by Fossil Fuel Power Plants: An Economic Analysis

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For fossil fuel power plants to be built in the future, carbon capture and storage (CCS) technologies offer the potential for significant reductions in carbon dioxide (CO_2) emissions. We examine the break-even value for CCS adoptions, that is, the critical value in the charge for CO_2 emissions that would justify investment in CCS capabilities. Our analysis takes explicitly into account that the supply of electricity at the wholesale level (generation) is organized competitively in some U.S. jurisdictions, whereas in others a regulated utility provides integrated generation and distribution services. For either market structure, we find that emissions charges near \$30 per tonne of CO_2 would be the break-even value for adopting CCS capabilities at new coal-fired power plants. The corresponding break-even values for natural gas plants are substantially higher, near \$60 per tonne. Our break-even estimates serve as a basis for projecting the change in electricity prices once carbon emissions become costly. CCS capabilities effectively put an upper bound on the increase in electricity prices resulting from carbon regulations, and we estimate this bound to be near 30% at the retail level for both coal and natural gas plants. In contrast to the competitive power supply scenario, however, these price increases materialize only gradually for a regulated utility. The delay in price adjustments reflects that for regulated firms the basis for setting product prices is historical cost, rather than current cost.

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1. Introduction

Several of the world's largest economies are currently formulating or tightening their regulations of domestic carbon dioxide (CO_2) emissions. For most of these countries, a cap-and-trade system appears to be the leading regulatory mechanism. A crucial question mark for policy makers, however, remains the market price per tonne of CO_2 that would emerge for alternative emission limits (caps). Fossil fuel power plants are destined to play a central role in this context not only because they are currently a major source of CO_2 emissions, but also because they face a range of technological opportunities for reducing their emissions.[1] Among these abatement technologies, geologic carbon capture and storage (CCS) has received particular attention. Demonstration projects have shown the feasibility of capturing CO_2 either before or after burning the fossil fuel. Thereafter, the CO_2 gas is transported via pipelines to underground formations for permanent storage.[2]

This paper examines the economics of several currently known CCS technology options. We address two related questions. First, how far would the price of CO_2 emission permits have to rise for investments in CCS technology to be cost effective? Second, to what extent does the adoption of CCS capabilities mitigate the rise in electricity prices resulting from carbon emission charges? To address these questions, we develop an economic framework that should also be applicable beyond the context of geologic CCS for fossil fuel power plants. In particular, our economic framework should prove useful in evaluating the cost effectiveness of other carbon capture technologies or even other power generation technologies, including renewable energy sources.[3]

[1] For the United States alone, coal-fired and natural gas power plants contributed more than 40% of the economy's total 6 gigatonnes (Gt) of CO_2 emissions in 2008 (U.S. Environmental Protection Agency 2010). On a global scale, coal-fired power plants alone contributed nearly 8 out of 28 Gt of CO_2 emissions in 2008 (Winning 2008). Finally, according to the International Energy Agency (2004), fossil fuels will remain a significant part of the energy mix up to 2030, comprising roughly 72% of the global electricity generation.

[2] A study by the Massachusetts Institute of Technology (MIT 2007) provides a detailed description of different CCS technologies. There are still significant open questions regarding the certification of these technologies for plants on a commercial scale. We discuss some of these issues and related prior literature in more detail below.

[3] Although we focus on geologic CCS, there has been recent progress in demonstrating the feasibility of carbon mineralization

Our analysis of how power producers are likely to respond to carbon emission charges distinguishes between alternative scenarios in the market structure for electricity generation. In the United States, electricity has traditionally been provided by a vertically integrated utility, with product prices determined according to a rate-of-return (RoR) regulation scheme. Prices are then set in each period so as to reimburse the regulated firm for all applicable costs, including a target return on its invested capital. For this traditional market structure, we presume that a consumer-oriented utility regulator will allow the utility to make investments in CCS technology provided such investments are justified from the perspective of future discounted consumer surpluses.

Currently, some 15 states in the United States have deregulated the supply of power generation, as opposed to transmission and distribution, whereas in 8 other states deregulation has been suspended (U.S. Energy Information Administration (EIA) 2009). We therefore consider an alternative scenario in which utilities procure electric power in a competitive wholesale market and then distribute it to consumers at the retail level. We argue that in this competitive scenario, the break-even value for CCS adoption is determined by the need to minimize the so-called levelized cost of electricity (LCOE). This cost concept, which is familiar from the energy literature, seeks to capture the average cost of output over the plant's entire life cycle by aggregating upfront capital expenditures and subsequent periodic operating costs.[4] Although the levelized cost of electricity represents a long-run average cost, we nonetheless argue that this cost is also the appropriate benchmark for the short-term equilibrium price in a market with many competing power suppliers.

For a scenario of competing power generators, we find that \$31 per tonne of CO_2 emitted is the *break-even* price for the adoption of CCS capabilities by coal-fired power plants. Thus power generators would attain a lower levelized cost of electricity by investing in CCS capabilities rather than paying for CO_2 emissions permits, provided these permits trade for at least \$31 per tonne. Concurrent with the investment in CCS capabilities, firms will switch from pulverized coal (PC) plants to so-called integrated gasification combined cycle (IGCC) plants. Furthermore, we estimate that the competitive wholesale price of electricity would increase by about 52%. Because electricity generation amounts to roughly 60% of the retail price of electricity (the remainder comprising the cost of transmission and distribution), the projected increase in electricity retail prices would be about 31% (60% · 52%).[5] We emphasize that these estimates apply to *new* coal-fired power plants to be built in the future rather than to retrofitting existing plants.

We obtain an alternative set of cost and price estimates for the scenario of a regulated utility whose product prices are determined according to a rate-of-return regulation scheme. In contrast to the competitive power supply scenario, prices are then no longer driven by the forward-looking cost of power generation, but instead by the utility's historical cost basis, a large component of which are the depreciation charges associated with past capacity investments. For coal-fired power plants we find that a consumer-oriented regulator would instruct the utility to invest in CCS capabilities provided emission permits trade for at least \$30 per tonne.[6] Although this break-even value is close to that obtained in the competitive scenario, the resulting adjustment in electricity prices is likely to be much slower. Because regulated prices are set to cover the firm's historical accounting cost, product price increases will be phased in gradually under rate-of-return regulation. For instance, if utilities receive emission allowances for CO_2 emitted from older power plants constructed prior to the regulation of CO_2 emissions (100% "grandfathering"), then electricity prices are projected to rise linearly over a 30 year time window to a new equilibrium level that would be about 25%–30% above the status quo level.

For power plants running on natural gas, we find that in the competitive scenario a substantially higher carbon tax of \$60 (\$57 in the regulation scenario) would be required to make CCS investments financially attractive. These higher break-even prices emerge because (i) traditional natural gas plants emit only about half as much CO_2 as traditional coal-fired plants per kilowatt hour, and (ii) the increase in plant construction costs associated with CCS technology is comparatively high for a natural gas plant. It is generally accepted that, absent any CO_2 emission charges, coal-fired power plants generate electricity more cheaply than natural gas plants. In a carbon-constrained environment, we find that coal-fired plants retain their cost advantage if CO_2 emission permits trade either below \$20 per tonne or

processes, which seek to absorb the flue gases of fossil fuel power plants in bicarbonate solids; see, for instance, Kolstad and Young (2010) and Lassiter et al. (2009).

[4] See, for instance, MIT (2007) or Kammen and Pacca (2004) for discussions of this concept.

[5] This projection stands in contrast to some forecasts that have raised the specter of a doubling of electricity prices in response to CO_2 regulations (MIT 2007, Table 3.1; Warner 2009).

[6] Our findings here are based on the assumption that a consumer-oriented regulator adopts the same discount rate as the regulated firm. The choice of the discount rate in evaluating future welfare levels has been contentious in the well-publicized report by Stern (2007), which seeks to forecast the social costs associated with various levels of CO_2 concentrations in the atmosphere; see also Arrow (2007).

above \$50 per tonne. In the high price range, the advantage of coal depends crucially on CCS technology becoming available on the currently projected cost terms. In contrast, because natural gas plants emit substantially less CO_2 per kilowatt hour to begin with, they generate electricity more cheaply if emission permits trade in the intermediate range of \$20 to \$50. These findings are consistent with the apparent reluctance in the power generation community to finance new coal-fired plants at this stage (Ball 2008).

From a policy perspective, the break-even calculations for investment in CCS technology provide significant data points in forecasting the *effective carbon tax*, that is, the market price for CO_2 emission permits under a cap-and-trade system.[7] Because CCS capabilities are projected to cut CO_2 emissions by 85%–90% and fossil fuel plants contribute more than one third of the overall worldwide emissions, the break-even price for investment in CCS technology provides an upper bound for the marginal cost of reducing CO_2 emissions over a substantial emissions range. One recurring suggestion in the current policy debate is the introduction of "safety valves" that would commit the government to issuing additional permits once the effective carbon tax exceeds a certain threshold level. Our calculations for coal and gas plants speak to the likelihood that such valves would ever need to be activated if the price threshold were to be set above \$60 per tonne.[8]

There are significant investments in CCS pilot plants and development programs currently underway. These efforts make it plausible that CCS technology will be fully established for commercial power plants (at least 500 megawatts) within the next few years. In this context, the FutureGen project in Illinois, which is currently under construction, is arguably the most prominent demonstration project showcasing a new IGCC plant on a commercial scale with CCS capabilities (Galbraith 2009). In addition, a number of power-generating companies have recently started initiatives aimed at retrofitting existing fossil fuel plants.[9]

Several prior studies have examined the cost effectiveness of CO_2 abatement by means of CCS technology; see, for instance, McKinsey (2008), Sekar et al. (2007), MIT (2007), and Intergovernmental Panel on Climate Change (IPCC 2006). The reported cost estimates range anywhere between \$25 and \$90 per tonne for coal-fired power plants. The wide range of these forecasts is attributable to a number of factors. First, the estimates refer to different types of plants, e.g., pulverized coal rather than integrated gasification plants. In addition, some cost estimates apply to new power plants, whereas others refer to retrofits of existing plants. Second, there are substantial differences in the engineering cost estimates regarding the upfront construction and ongoing operating costs of different types of plants.[10] These discrepancies reflect in part that CCS technology has yet to be operated on a commercial scale. Finally, it appears that the existing studies have not employed a consistent economic cost methodology. Some studies, like McKinsey (2008), make reference to "full-cost" concepts without providing the requisite details. In assessing the cost per tonne of CO_2 avoided, the MIT (2007) coal study makes reference to the levelized cost of electricity, yet, as argued below, their implementation of this concept is not fully transparent.

Sekar et al. (2007) also conduct a break-even calculation for CCS adoption. They obtain critical values of \$45 per tonne for a pulverized coal plant and \$20 per tonne for IGCC plants. In contrast to our study, Sekar et al. (2007) examine a setting in which an *existing* power plant without CCS capabilities seeks to minimize its future cash outlays by choosing between the adoption of CCS technology and buying CO_2 emission permits. Accordingly, the initial construction cost of the plant is a sunk cost, while the concept of the LCOE does not apply. The analysis in Sekar et al. (2007) effectively speaks to the economics of retrofitting an existing plant with CCS capabilities.[11]

The remainder of this paper is organized as follows. Section 2 focuses on the scenario of competitive power suppliers. We present the economic framework and the engineering cost data in §§2.1 and 2.2. Our

[7] The well-known study by McKinsey (2007) seeks to rank the cost of different abatement strategies including energy saving measures, CCS, biofuels, and afforestation. The overall marginal cost of achieving a particular level of emission reductions is then obtained by rank ordering the costs of the different abatement strategies.

[8] Predictions about the role of safety valves are obviously sensitive to the time table for progressively lower emission caps. In general, CCS will become a more effective abatement strategy as the schedule for emission reductions is "backloaded" over time.

[9] For instance, American Electric Power Corporation plans to install technology at its Mountaineer coal plant in West Virginia that uses chilled ammonia to trap CO_2 (Warner 2009). Japan's Toshiba Corporation intends to accelerate the development of its CCS technology by building a retrofit pilot CCS plant at its Mikawa Power Plant (Young 2009). Finally, five North American utility companies are partnering with the Electric Power Research Institute (EPRI) to explore postcombustion CO_2 at existing coal-fired plants (ClimateBiz 2009).

[10] Appendix B provides a summary of the engineering cost estimates emerging from prior studies. One issue that we do not explore in this study is learning by doing. See Al-Juaied and Witmore (2009) on this point.

[11] MIT (2007) questions whether the engineering cost estimates that apply to new power plants with CCS capabilities are also applicable on an incremental basis to retrofitting existing plants. The demonstration projects currently underway will provide clarification on this issue.

main results on break-even values, projected increases in electricity prices, and a cost comparison of coal versus natural gas plants are presented in §2.3. Section 3 focuses on the scenario of a price-regulated utility. To study the dynamics of prices under rate-of-return regulation, we first derive the concept of a price equilibrium in §3.1. Our numerical results for the regulation scenario are presented in §3.2. We conclude in §4.

2. Competitive Power Generation

2.1. Levelized Cost of Electricity

Some 15 states in the United States have deregulated the supply of power generation. The distributors of electricity (utilities) then purchase electric power at the wholesale level from competing power suppliers. For modeling purposes, we take this framework to an idealized extreme by supposing that wholesale electricity prices are fully competitive in the sense that firms earn zero economic profits over the entire life cycle of their capital investments.

A standard life cycle cost concept in the energy literature is the so-called *levelized cost of electricity*. This cost figure is intended to capture the long-run unit cost per kilowatt hour of electricity by aggregating upfront capital expenditures and periodic operating costs including fuel, labor, and maintenance (Kammen and Pacca 2004). The principal advantage of such an average cost calculation is that it permits a comparison of alternative technologies that may differ substantially in terms of upfront investments, useful lives, and ongoing periodic expenditures. Because the LCOE is viewed as a break-even value in terms of the firm's output, it should be fundamentally compatible with corporate finance precepts, including discounting, firm leverage, and tax effects.

Despite widespread references to the concept of LCOE, there does not seem to be a commonly accepted formula for calculating this average cost. The MIT (2007, p. 127) coal study, for instance, states that "the levelized cost of electricity is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors." However, the MIT (2007) study operationalizes the capital cost component of the LCOE by simply "applying a 15% carrying charge factor to the total plant cost" (p. 127).[12] Our parameter specifications, shown below, lead us to apply a substantially smaller carrying charge.

To derive the LCOE formally, consider a single investment in a new power-generating facility. Suppose this new investment comes "online" with a lag of one period, initially generates production capacity for K units of output, and has a useful life of T years. Productive capacity may diminish to K_t over time. In connection with solar power panels, for instance, it is commonly assumed that the electricity yield is subject to a constant "systems degradation rate," which is modeled as a pattern of geometrically declining capacity levels (Campbell 2008). Accordingly, we assume that $K_t = x_t \cdot K$, with $x_1 = 1 \geq x_2, \cdots \geq x_T > 0$. Two important special cases are (i) the "one-hoss shay" scenario of undiminished capacity, where $x_t = 1$ for all t, and (ii) the geometric decline pattern, where $x_t = x^{t-1}$ for some $x \leq 1$.[13]

Suppose the acquisition expenditure for the asset is $v \cdot K$, so that v is the cost per unit of capacity available initially. Suppose also that the applicable cost of capital is r. We adopt the assumption that that the firm seeks to maintain a constant debt/equity ratio throughout the duration of the project. It is well known that the applicable discount rate is then given by the weighted average of the equity and debt cost of capital (WACC). If one supposes for simplicity that there are no variable production costs and no corporate income taxes, the LCOE would simply be given by

$$c = \frac{v}{\sum_{t=1}^{T} x_t \cdot \gamma^t}, \qquad (1)$$

where $\gamma \equiv 1/(1+r)$. Because the cost v represents a joint cost of acquiring one unit of capacity for T periods, this joint cost is divided by the present value term $\sum_{t=1}^{T} x_t \cdot \gamma^t$ in Equation (1) to obtain the cost of capacity for a *single unit of output*. Accordingly, we refer to c as the *unit cost of capacity*. If the firm were to receive the amount c as revenue for its output, then total revenue in year i would be

$$\frac{v}{\sum_{t=1}^{T} x_t \cdot \gamma^t} \cdot x_i \cdot K,$$

and therefore the firm would exactly break even on its initial investment of $v \cdot K$ over the T-year horizon.

In addition to capacity-related costs, a power generating plant incurs variable production costs for inputs such as fuel, transportation, labor, and maintenance. Consistent with earlier studies, these costs are assumed to vary proportionately with output, and the corresponding unit cost is denoted by w. Finally,

[12] Short et al. (1995), Kammen and Pacca (2004), Campbell (2008), and Kolstad and Young (2010) all provide their own derivations of the LCOE. Their formulas differ from each other in part because of varying assumptions, e.g., ignoring income taxes (possibly because the investor is a nonprofit organization) or differing assumptions regarding the decay of productive capacity over the useful life of the asset.

[13] The term "one-hoss shay" is commonly used in the regulation literature. Arrow (1964) also refers to this productivity pattern as "sudden death."

let $0 \leq \alpha < 1$ denote firms' marginal income tax rate. Taxes affect the LCOE through both the depreciation tax shield and the debt tax shield. The latter shield is usually accounted for through the calculation of the WACC (see Appendix A for details). Suppose that for each dollar of investment undertaken at date 0, the depreciation charge at date t is d_t^o for $1 \leq t \leq T^o$, where T^o is the asset's useful life for tax purposes. It will be convenient to define the following *tax factor*:

$$\Delta(\alpha) \equiv \frac{1 - \alpha \cdot \sum_{t=1}^{T^o} d_t^o \cdot \gamma^t}{1 - \alpha}. \tag{2}$$

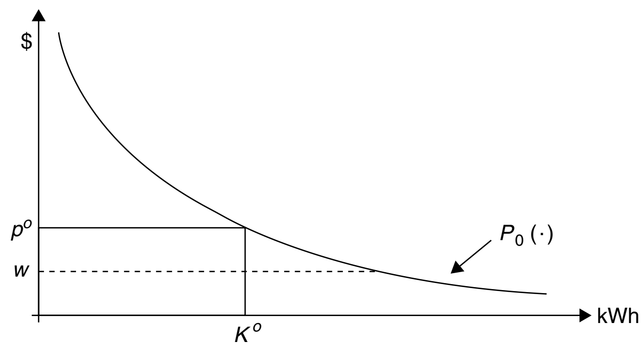
A depreciation schedule has the property that $\sum_{t=1}^{T} d_t^o = 1$, i.e., the full historic cost of the investment is amortized over time. Because $\gamma < 1$, the tax factor $\Delta(\alpha)$ will be bounded by 1 and $1/(1-\alpha)$. It is readily verified that $\Delta(\alpha)$ is increasing and convex in α. On the other hand, a more accelerated tax depreciation schedule tends to lower $\Delta(\alpha)$ closer to 1. Combining the preceding elements, we obtain the following expression for the LCOE:[14]

$$p^o = w + c \cdot \Delta(\alpha). \tag{3}$$

Appendix A demonstrates that the LCOE, as given in (3), is indeed the critical output price that ensures that capacity investments are zero net present value (NPV) projects. Furthermore, the price p^o can also be viewed as the short-run competitive equilibrium price, provided market demand expands over time such that $P_{t+1}(q) > P_t(q)$ for all t. Given the initial investments at date 0, the variable cost of producing one more kilowatt hour is only $w < p^o$. Yet, at the equilibrium investment levels, the constraints on capacity prevent producers from delivering a quantity that drives the market price down to the short-run marginal cost of w. Figure 1 illustrates a competitive equilibrium in which producers invest an aggregate level of capacity level K^o, such that consumers' willingness to pay for that level of output is exactly p^o, that is, $P_0(K^o) = p^o$. In subsequent periods, there will be additional investments as the initial capacity declines and/or consumer demand expands. In equilibrium, these capacity levels will again be determined by the condition that $P_t(K_t^o) = p^o$. In the short-run, firms cannot do better than to sell their entire capacity at the market clearing price of p^o. At the same time, firms earn exactly zero economic profits (zero NPV) on their investments. Thus, $K \leq K^o$ in equilibrium.

It is instructive to relate the preceding discussion to the earlier literature on capital accumulation; see, for

Figure 1 **Levelized Cost of Electricity, p^o, as the Equilibrium Price**



instance, Arrow (1964). In these models, firms undertake a sequence of overlapping investments. Given a path of new capacity investments, the joint cost of acquiring one unit of capacity for T periods can in fact be allocated unambiguously to individual time periods. Ignoring income taxes, the marginal cost of acquiring one unit of capacity *for one period of time* is given by c in (1). Arrow (1964) shows that one can construct a variation of the sequence of future investments so as to provide the firm with one additional unit of capacity in the next period, but leave all subsequent capacity levels unchanged. The net present value cost of such a variation in the future investment levels is exactly given by c. Including variable production costs and income taxes, we conclude that the LCOE in (3) can also be interpreted as a long-run marginal cost. Furthermore, because firms are capacity constrained in the short term, LCOE also emerges as the equilibrium market price in a setting with many competing suppliers.[15]

Our development of the levelized cost of electricity has thus far omitted the issue of CO_2 emission charges and the possibility of adopting alternative production technologies that result in lower CO_2 emissions. Suppose that for the status quo technology the power plant emits m tonnes of CO_2 per unit of output. If there is a carbon emissions charge of $\$q$ per ton, the resulting LCOE under the status quo technology becomes $p^o(q) = p^o + m \cdot q$.

Suppose now an alternative technology is available for power plants to be newly constructed. The alternative technology would have the effect of reducing emissions to $\widehat{m}$ tonnes of CO_2 per unit of electricity output. This alternative technology presumably would entail a higher unit cost of capacity $\widehat{v}$ and/or a higher unit variable cost of production $\widehat{w}$. The corresponding LCOE is given by $\widehat{p}^o(q) = \widehat{p}^o + \widehat{m} \cdot q$, where $\widehat{p}^o$

[14] The formula for the LCOE shows that taxes have no effect on p^o if $\Delta(\alpha) = 1$. This will happen if new investments can be written off immediately for tax purposes, that is, $d_0^o = 1$ and $d_t^o = 0$ for $t \geq 1$. In that case, the NPV of all after-tax cash flows is just $(1-\alpha)$ times the NPV of all pretax cash flows, and thus the tax rate α does not affect the break-even price p^o.

[15] Borenstein (2000) makes the related point that despite the combination of high upfront fixed costs and relatively low unit variable costs in the electric power industry, no supplier needs to have market power to be in a position to earn normal economic profits.

is given by (3) after substituting $\hat{v}$ and $\hat{w}$ for v and w, respectively.

The point to note is that an increase in the effective carbon tax will result in an optimized LCOE that is given by the minimum of the two straight lines $p^o(q)$ and $\hat{p}^o(q)$. The *break-even* point for switching to the lower emission technology is given by

$$q^* = \frac{\hat{p}^o - p^o}{m - \hat{m}}. \qquad (4)$$

In particular, the LCOE increases at the rate m for values of $q \le q^*$, but only at the rate $\hat{m}$ for $q \ge q^*$. The following two subsections will calibrate the parameters (v, w, m) and $(\hat{v}, \hat{w}, \hat{m})$ for fossil fuel power plants with and without CCS capabilities. These estimates are then plugged into (4) to calculate both the break-even estimate for CCS adoption and the projected price increases in electricity for the competitive scenario.

2.2. Data Calibration

The key cost parameters in the model described above are v and w. The upfront fixed cost v represents the capacity investment expenditure required per unit of capacity (per kWh). In the context of power plants, this parameter is calculated as

$$v = TPC/(365 \cdot 24 \cdot CF),$$

where TPC stands for total plant cost in cents per kilowatt, CF is a capacity utilization factor (percentage), and $365 \cdot 24$ represents the number of hours per year.

Consistent with most other studies, we assume that capacity is undiminished over the entire useful life of the plant, that is, $x_t = 1$. As a consequence, the term $\sum_{t=1}^{T} x_t \cdot \gamma^t$ in the denominator of (3) reduces to the value of an annuity corresponding to one dollar paid over T years at a discount rate of r. In addition, we assume that the coal-fired plants under consideration are base-load plants that are operated 85% of the time. Accordingly, we set $CF = 0.85$. The operating cost w comprises fuel cost, operating and maintenance expenses, as well as a periodic charge for insurance and property taxes.

The following table provides a summary of the engineering estimates we rely on with regard to v and w for different fossil fuel plants. Specifically, we seek to compare cost estimates for the following types of fossil fuel plants: (i) PC plants, (ii) IGCC coal-fired plants, and (iii) natural gas combined cycle (NGCC) plants. All three types of plants can be outfitted with carbon capture capabilities. Table 1 reports the corresponding higher cost parameters as $\hat{v}$ and $\hat{w}$, respectively. Finally, Table 1 also shows the amount of CO_2 emitted per megawatt hour of electricity, both with and without carbon capture capabilities.

Table 1 Construction and Operating Costs per Kilowatt Hour and CO_2 Emissions per Megawatt Hour

	No CCS			CCS		
	v (¢/kWh)	w (¢/kWh)	CO_2 emitted (t/MWh)	$\hat{v}$ (¢/kWh)	$\hat{w}$ (¢/kWh)	CO_2 emitted (t/MWh)
PC plant	21.31	2.4	0.804	38.85	3.72	0.115
IGCC plant	24.53	2.76	0.796	32.36	3.38	0.093
NGCC plant	7.89	4.80	0.361	16.27	5.77	0.042

The "point estimates" shown in Table 1 are based on a study by the National Energy Technology Laboratory (NETL 2007). As shown in Appendix B, the NETL engineering cost data tend to be more conservative for CCS capabilities than other studies. As a consequence, our estimates are likely to exhibit an upward bias in projecting the impact of carbon regulations on electricity prices. The increase in variable operating costs, i.e., the increase from w to $\hat{w}$ in Table 1 resulting from the adoption of carbon capture technology, reflects two factors. First, this cost now includes the transportation and storage of captured CO_2.[16] Second, the capture of CO_2 itself requires substantial electricity, and, as a consequence, the annual operating cost per kilowatt hour delivered also increases. For future reference, we note that natural gas plants emit less than *one-half* of the CO_2 emissions of coal-fired power plants. Carbon capture capabilities would reduce CO_2 emissions by about 85% for both types of fossil fuel plants.

In the numerical analysis below, the remaining model parameters are assessed as follows:

- The useful life of new power plants, i.e., the parameter T, is assumed to be 30 years.
- Productive capacity conforms to the one-hoss shay pattern, where $x_t = 1$ for all $1 \le t \le T$.
- The depreciation rules used for tax purposes, $\{d_i^o\}$, conform to the current IRS rules requiring that steam-generating power plants are depreciated according to the 150% declining balance method with a recovery period of 20 years.[17]
- The marginal tax rate α is set equal to 35%.

[16] Consistent with Sekar et al. (2007) and the IPCC (2006), our variable operating costs include a charge of \$5 per tonne of CO_2 for transportation and storage. This transportation cost will depend on several factors including the proximity of the plant to a suitable underground saline formation and the possibility of enhanced oil recovery; see, for example, Leach et al. (2009).

[17] These rules are based on the modified accelerated cost recovery system. Under straight-line depreciation, the annual depreciation charge would be 5% of the invested amount if the asset recovery period is 20 years. Under the 150% declining balance method, the depreciation charge is 7.5% (or 1.5 times 5%) of the remaining book value of the asset.

• Firms impute a weighted average cost of capital of $r = 8\%$.[18]

As a first validation of the above parameter choices, we note that absent any CO_2 emission charges and without CCS capabilities, our parameter choices yield an LCOE at the wholesale level of 4.78¢/kWh for PC plants. Similarly, for an NGCC plant, the projected unit cost is 5.68¢/kWh.[19] These forecast values are reasonably close to observed prices in some regions of the United States (EIA 2010a). However, because there is considerable variation in the wholesale electricity prices across different regions of the United States, our price projections will not focus on absolute values, but rather on the *percentage increase* in electricity prices due to CO_2 regulations.

2.3. Results

Suppose first that power generators are confined to coal-fired power plants. For low emission charges, firms will continue to use PC plants and simply purchase the required number of CO_2 permits. On the other hand, Table 1 shows that once emission permits become sufficiently expensive, coal-fired plants will have an incentive to make two simultaneous changes: switch to IGCC plants and adopt CCS technology. The following baseline result identifies the *break-even price* for CO_2 emission permits, at which it would be cost effective to adopt CCS capabilities. The result also shows the increase in wholesale electricity prices as a function of the effective carbon tax.

Result 1. *For coal-fired power plants, an investment in CCS technology becomes advantageous once emission charges for CO_2 exceed the break-even price of $q^* = \$31.16$ per tonne. For an emission charge of \$q per tonne of CO_2, the competitive wholesale price of electricity is projected to increase by the following percentage changes, Δp^o:*

$$\Delta p^o = \begin{cases} 1.68 \cdot q & \text{for } q \leq 31.16, \\ 52.38 + 0.19 \cdot (q - 31.16) & \text{for } q > 31.16. \end{cases}$$

Our findings in Result 1 are predicated on the parameter choices in Table 1. Absent any CCS capabilities and absent any CO_2 emission charges, a LCOE of 4.78¢/kWh for power generation can be achieved by a PC plant, but not an IGCC plant. Beyond the break-even point of \$31 per tonne, firms would find it advantageous to adopt CCS technology and at the same time switch to IGCC plants. The cost parameters $\hat{v} = 32.36$ and $\hat{w} = 3.38$ correspond to an IGCC plant with CCS capabilities. For an effective carbon tax of $q^* = \$31$ per tonne, the levelized cost of electricity would increase to about 7.29¢/kWh.

The presence of CCS technology implies that the wholesale price for electricity is a piecewise linear function of the effective carbon tax, with a sharp kink at the break-even point of \$31 per tonne. Because traditional coal-fired plants emit large amounts of CO_2 (0.8 tonnes per megawatt hour), wholesale electricity prices increase at a rate of 16.8% for every additional \$10 in the effective carbon tax up to the break-even point of \$31. With CCS capabilities, in contrast, further price increases are limited to a rate of 1.9% for every additional \$10 in the carbon tax. Thus, an investment in CCS capabilities effectively insulates electricity prices from further increases in the carbon tax, because power generators have to buy permits only for the remaining 15% of their previous emissions. The sharp kink in the projected wholesale price of electricity can be interpreted as a "put option" associated with CCS capabilities: operators of coal-fired power plants and consumers are protected from further increases in the market price of emission permits.

The preceding observation suggests that new power plants without CCS capabilities would be inherently riskier in a world of uncertain emission charges. To illustrate, suppose a representative firm views the emissions charge for CO_2 in future periods as a random variable, $\tilde{q}$, such that the expected value of this random variable is equal to the break-even price of $q^* = \$31$. Suppose furthermore that the firm anticipates that the wholesale price of electricity will vary with $\tilde{q}$. We denote this function by $p(\tilde{q})$; its functional form is of no importance for the following argument. If the firm opts for a traditional PC plant without CCS capabilities, then for any realization of $\tilde{q}$, the net present value of its discounted after-tax cash flows can be expressed as

$$h_0 + h_1 \cdot p(\tilde{q}) - h_2 \cdot \tilde{q}, \tag{5}$$

where the coefficients (h_0, h_1, h_2) are functions of the underlying parameters specified in the previous subsection.[20] In contrast, if the firm were to build an IGCC plant with CCS capabilities, then for any

[18] One refinement of our analysis would be to use state-of-the-art techniques for estimating the weighted average cost of capital of electricity producers. We expect such refinements to point to a weighted average cost capital somewhere in the range of 7%–9%.

[19] As a further calibration, we recall that the MIT (2007) study operationalizes the LCOE concept by applying a 15% carrying charge to the original total plant cost. For the above parameter choices we obtain a corresponding charge of 11%, that is, $\Delta(\alpha)/(\sum_{t=1}^{T} x_t \cdot \gamma^t) = 0.11$. Thus, our component of the LCOE attributable to the cost of installed capacity is approximately 36% lower than that in the MIT (2007) study.

[20] In particular, h_0 depends on all of the underlying parameters, whereas h_1 only capitalizes future sales revenues, and h_2 reflects the CO_2 emission rate per kilowatt hour. Step 2 in Appendix A provides the explicit expression for the firm's after-tax cash flows.

given $\tilde{q}$, the expected value of its discounted after-tax cash flows can be expressed as

$$\hat{h}_0 + \hat{h}_1 \cdot p(\tilde{q}) - \hat{h}_2 \cdot \tilde{q}, \tag{6}$$

with $h_2 > \hat{h}_2$. By construction of our break-even calculation, the expected values of (5) and (6) are the same provided $E[\tilde{q}] = q^* = \$31$. Thus, a risk-neutral decision maker would be indifferent between the two technologies because the unit cost associated with higher emission charges is linear in $\tilde{q}$ under either alternative.[21] In contrast, a risk-averse decision maker would prefer the investment in CCS technology under the same circumstances. Because the lottery in (5) is a mean-preserving spread of the one in (6), it is well known that for any concave utility function the expected utility associated with (6) is greater than the expected utility associated with the lottery in (5) (Mas-Colell et al. 1995, Proposition 6.D.2).

The public discussion about the economic consequences of a cap-and-trade system has included some dire predictions for the economy's most energy intensive sectors. In particular, commentators in the popular press have suggested that electricity prices may *double*; see, for instance, Warner (2009).[22] Our numbers in Result 1 suggest a far more modest impact. The 52.5% increase in the price of electricity generation corresponding to an emission permit price of \$31 per tonne would roughly translate into a 30% increase in the retail price of electricity. This calculation assumes that power generation constitutes about 60% of the overall retail price of electricity, whereas transmission and distribution services account for the remainder. Furthermore, because of the option embedded in CCS capabilities, retail electricity prices would increase by no more than 36%, even if the effective carbon tax were to reach \$70 per tonne of CO_2.

The break-even value of \$31 per tonne for coal-fired plants also provides a significant data point in forecasting the effective carbon tax under a cap-and-trade system. Reliable predictions regarding the emerging market price for emission permits are notoriously difficult because they ultimately depend on the incentives for different industries to embrace measures and technologies that reduce CO_2 emissions. The study by McKinsey (2007) seeks to combine a range of alternative CO_2 abatement strategies, including energy-saving measures, biofuels, and reforestation. The effective carbon tax under a cap-and-trade system is principally the overall marginal cost that is obtained by rank-ordering alternative abatement strategies in terms of their incremental costs. Coal-fired power plants have the potential to be a major segment of this cost curve. On a worldwide scale, coal accounted for roughly 8 Gt of the approximately 28 Gt of CO_2 emitted globally in 2008. Our analysis indicates that over the course of the next 30 years CCS technology offers the potential for an 85%–90% abatement of these emissions at a marginal cost of \$31 per tonne.

If the supply of electric power is indeed competitive, equilibrium prices should not be affected by any "grandfathering" rules that the government may adopt with regard to emission permits. Although the exact policy of issuing emission allowances for incumbent power plants has significant effects on the profitability of firms' existing assets, it should be of no consequence to the long-run marginal cost of production and therefore the competitive equilibrium price. As a caveat, however, we note that our cost and price projections do not address the dynamics of the price adjustment that results once firms have to buy emission permits. The precise dynamics here will depend on the expectations that firms have regarding the price of CO_2 emission permits. In the short run, capacity-related costs are obviously sunk, and electricity prices are determined by both variable operating costs and consumers' willingness to pay for the quantity corresponding to the aggregate industry capacity.

To conclude our analysis of CCS for coal-fired power plants in the competitive scenario, we conduct several robustness checks on our finding in Result 1. Because CCS technology has yet to be "certified" for power plants on a commercial scale, it is essential to examine how sensitive the projected break-even value is to variations in the underlying cost parameters. Figure 1 considers alternative parameter values for $\hat{v}$, the construction cost of a new plant with CCS capabilities per kilowatt, and for $\widehat{w}$, the unit variable cost. The lines in Figure 1 depict isoquants that correspond to the same break-even price for alternative combinations of $\hat{v}$ and $\widehat{w}$. Consistent with our baseline calculations, the parameter values $\hat{v} = 32.36$ and $\widehat{w} = 3.38$ will lead to a break-even value of \$31 per tonne.[23]

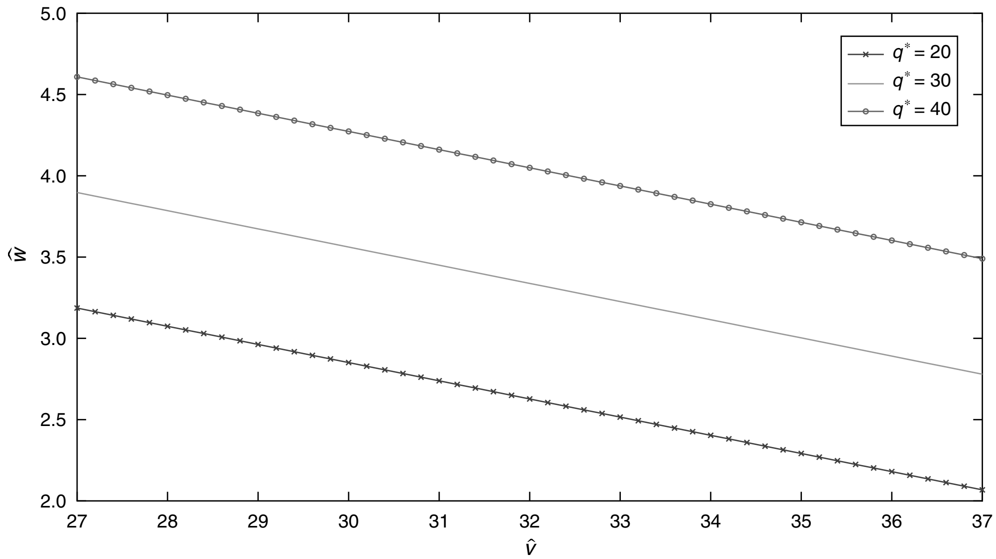
As further robustness checks on the finding in Result 1, we also consider variations in the discount rate, r, and the useful life of the plant, T. Figures 2–4 show that for "reasonable" parameter values, the price curve identified in Result 1 is relatively insensitive to changes in these two parameters.

[21] The value of both (5) and (6) would be zero if, hypothetically, $\tilde{q} \equiv q^*$.

[22] Without the possibility of investing in CCS capabilities, our model also predicts that an effective carbon tax of \$60 per tonne would lead to a doubling of the *wholesale* cost of electricity.

[23] Appendix B summarizes the engineering cost projections from other studies regarding the parameters $\hat{v}$ and $\widehat{w}$. We note that the NETL numbers, which are the basis of our calculations, are conservative in the sense that they result in the highest break-even values.

Figure 2 **Cost Parameters Resulting in the Same Break-Even Permit Price q^***



We now turn to an analysis of natural gas plants. Consistent with the preceding calculations for coal-fired plants, we seek to project both the break-even price in terms of CO_2 emission permits and the change in electricity prices if operators of natural gas plants face a choice between purchasing emission permits and adopting costly CCS technology. As before, the relevant cost inputs are based on Table 1, and the determination of the LCOE is based on Equation (3).

Result 2. *For NGCC plants, an investment in CCS technology becomes advantageous once the charge for CO_2 emissions exceeds the break-even price of $q^* = \$59.78$ per tonne. For an emission charge of $\$q$ per tonne of CO_2, the competitive wholesale price of electricity is projected to rise by the following percentage increases, Δp^o:*

$$\Delta p^o = \begin{cases} 0.64 \cdot q & \text{for } q \le 59.78, \\ 37.98 + 0.07 \cdot (q - 59.78) & \text{for } q > 59.78. \end{cases}$$

At \$60 per tonne of CO_2, the break-even charge for investing in CCS technology for natural gas plants is almost exactly twice that of coal-fired plants. This stark discrepancy reflects that (i) natural gas plants emit less than half of the CO_2 of their coal-fired counterparts, and (ii) the percentage increase in plant construction costs (the difference between v and $\hat{v}$)

Figure 3 **Percentage Increase in the Competitive Wholesale Price of Electricity as a Function of the Price for CO_2 Emission Permits for Alternative Discount Rates r**

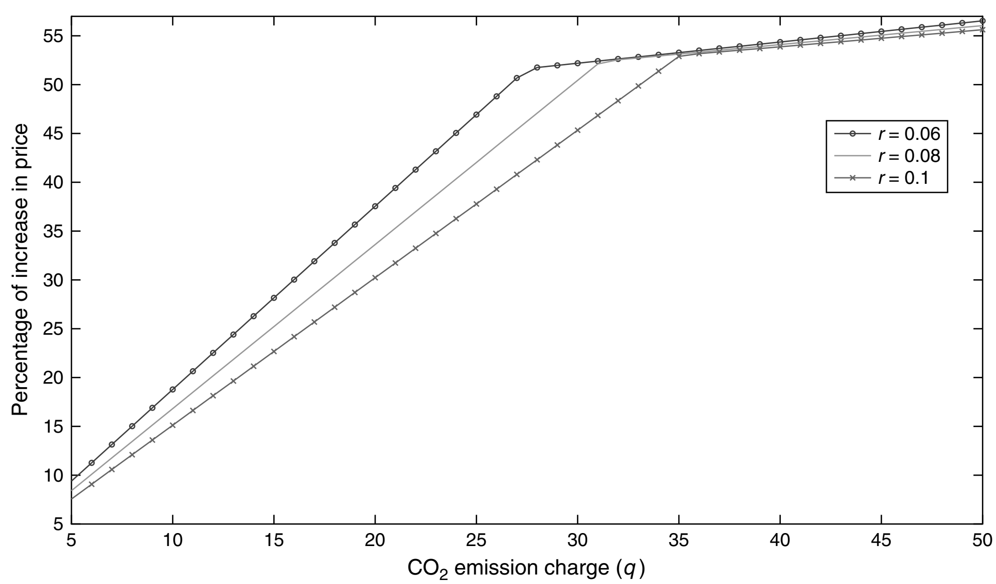
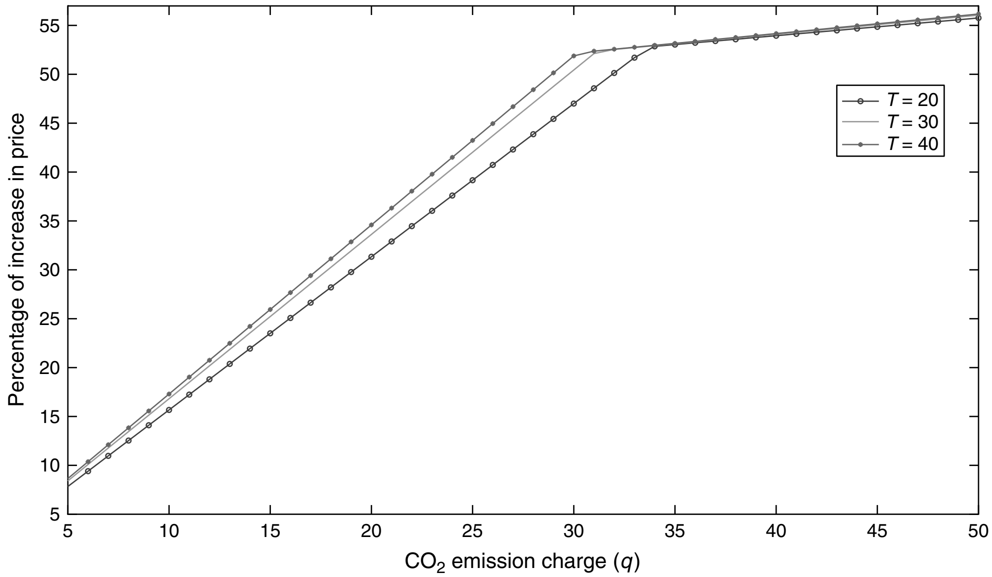


Figure 4 Percentage Increase in the Competitive Wholesale Price as a Function of the Price for CO_2 Emission Permits for Alternative Levels of the Useful Life *T*



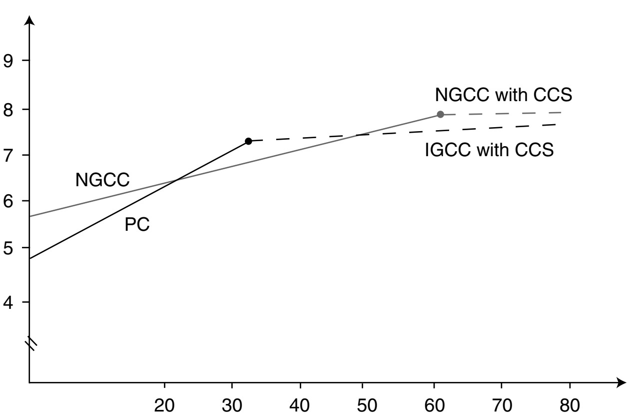
required for CCS capabilities is substantially higher for NGCC plants. Both of these factors make it more attractive for operators of natural gas plants to pay the carbon tax up to much higher values of q rather than incur the upfront investment cost associated with CCS technology. Although natural gas plants will seek to invest in CCS capabilities only for a much higher carbon tax, the wholesale electricity price increases are nonetheless no more than those predicted for coal, even for a relatively high tax in the range of $q > \$70$.

One recurring suggestion in connection with a cap-and-trade system is to introduce so-called safety valves that would commit the government to issuing additional emission allowances once the market price for permits reaches a certain threshold. Because in the United States fossil fuel power plants account for slightly more than 40% of the overall CO_2 emissions (at a total of roughly 6 Gt), the availability of CCS speaks directly to the likelihood that safety valves would in fact have to be activated if the price threshold were to be set above \$60 per tonne. Of course, the chances of the effective carbon tax reaching this level ultimately depend on the timetable for ratcheting down the emission caps. The legislative proposals currently in front of Congress envision a sharp acceleration in CO_2 reductions for the period post-2020. Such "backloading" of the overall reduction levels significantly enhances the prospects for CCS to become a significant abatement strategy. At the same time, backloading of the emissions reduction schedule makes it more likely that safety valves in the range of \$60 per tonne will not be activated.

Our analysis thus far has compared the impact of emissions charges for each type of power plant separately. We conclude this section by comparing the production costs of coal- and gas-fired power plants if both fossil fuel sources are available in a particular location and therefore power suppliers can freely choose between them. Figure 5 below plots the two piecewise linear functions derived in Results 1 and 2 in absolute price terms: the LCOE measured in cents per kilowatt hour as a function of the effective carbon tax.

We conclude that among the four technology options (traditional versus CCS and PC versus IGCC plants), NGCC plants with CCS capabilities are never cost competitive for any carbon tax rate $q \leq 100$. In contrast, NGCC plants without CCS capabilities achieve a lower levelized cost electricity once the

Figure 5 Cost Comparison of Coal-Fired and Natural Gas Power Plants



effective carbon tax reaches around \$20 per tonne.[24] This cost advantage starts to diminish once coal-fired plants adopt CCS capabilities (at \$31 per tonne), and it reverses to an advantage for coal only after the effective carbon tax reaches \$50 per tonne. These findings are consistent with the reservations that have recently been expressed by investors in connection with new coal-fired power plants (Ball 2008, Warner 2009).[25]

3. Regulated Power Supply

3.1. Rate-of-Return Regulation

The most common industrial structure for electric power services in the United States remains a vertically-integrated monopoly that is subject to price regulation. Product prices are then based on the firm's historical cost. Specifically, the regulated firm must meet consumer demand at a price that satisfies the constraint that the firm's accounting rate of return does not exceed an allowable rate of return set by the regulator. This RoR regulation constraint is usually represented by the requirement that in each period the firm's return on assets does not exceed some allowable rate. Our analysis takes the perspective that the RoR regulation rules have been in effect for a "long time," and therefore the process has reached its long-run equilibrium. For a baseline reading, we identify the long-run equilibrium price under RoR regulation that emerges absent any CCS technology and absent any CO_2 emission charges.

Because prices are calculated so as to reimburse the firm for its historical cost, it is essential to keep track of the relevant history of past capacity investments. At date t, this history is given by $\mathbf{I}_t = (I_{t-T}, \ldots, I_{t-1})$. The total capacity available at date t then is $K_t(\mathbf{I}_t) = I_{t-T} + \cdots + I_{t-1}$. New assets are capitalized in their acquisition period and then amortized according to some depreciation schedule $\mathbf{d} = (d_1, \ldots, d_T)$. In contrast to the accelerated depreciation rules used for tax purposes, regulatory agencies usually rely on straight-line depreciation to determine the regulated firm's income and assets. Given an investment history $\mathbf{I}_t$, the total depreciation charge in period t is given by

$$D_t(\mathbf{I}_t) = v \cdot (d_T \cdot I_{t-T} + \cdots + d_1 \cdot I_{t-1}).$$

Pretax income is calculated as revenues less variable operating costs and depreciation charges:

$$Inc_t(\mathbf{I}_t) = P_t(K(\mathbf{I}_t)) \cdot K_t(\mathbf{I}_t) - w \cdot K_t(\mathbf{I}_t) - D_t(\mathbf{I}_t),$$

where, as before, $P_t(K_t)$ denotes the price that consumers are willing to pay in period t if K_t units of output are supplied.

The regulated firm's taxable income is then given by

$$Inc_t^o(\mathbf{I}_t) = P_t(K(\mathbf{I}_t) \cdot K_t(\mathbf{I}_t) - w \cdot K_t(\mathbf{I}_t) - D_t^o(\mathbf{I}_t),$$

where, by definition, the total depreciation for tax purposes is calculated as $D_t^o(\mathbf{I}_t) = v \cdot (d_T^o \cdot I_{t-T} + \cdots + d_1^o \cdot I_{t-1})$. Finally, after-tax income is given by

$$NInc_t(\mathbf{I}_t) \equiv Inc_t(\mathbf{I}_t) - \alpha \cdot Inc_t^o(\mathbf{I}_t).$$

To complete the description of the RoR regulation scheme, we note that the remaining book value of a new asset acquired at date t, originally recorded at its cost v, and then amortized according to the depreciation schedule, $\mathbf{d}$, is

$$bv_\tau = \left(1 - \sum_{i=1}^{\tau} d_i\right) \cdot v$$

at date $t + \tau$, where $0 \le \tau \le T$. Given the investment history, $\mathbf{I}_t$, the firm's aggregate value of capacity assets at date $t-1$ is given by

$$AV_{t-1}(\mathbf{I}_t) = bv_{T-1} \cdot I_{t-T} + \cdots + bv_0 \cdot I_{t-1}.$$

In summary, the RoR regulation constraint can be represented as[26]

$$\frac{NInc_t}{AV_{t-1}} \le r. \tag{7}$$

The regulated firm is allowed to set product prices to recover both variable operating costs and capital costs, that is, depreciation charges plus an imputed capital charge on the book value of the firm's capacity assets.

The regulated firm is in effect instructed to choose new capacity investments and output prices such that

[24] The best-case scenario for natural gas occurs at $q^* = \$31$, and at that point the LCOE cost of natural gas is 0.5¢/kWh lower than that of an IGCC coal-fired plant.

[25] It should be kept in mind, though, that historically the price of natural gas has been far more volatile than that of coal. Our cost figures in Table 1 are based on a price for natural gas of approximately \$6.50 per thousand cubic feet for electric power producers (NETL 2007). This figure is roughly consistent with the overall mean value over the past seven years. However, market prices for natural gas have fluctuated widely over that time period, oscillating between \$4 and \$12 per thousand cubic feet.

[26] Alternatively, the RoR constraint can be represented in terms of a zero residual income constraint. Specifically, residual income at time t is given by $RI_t \equiv NInc_t - r \cdot AV_{t-1}$. It has long been recognized in both the regulation and the accounting literature that a firm operating consistently under the constraint imposed by (7) will not make any positive economic profits in the sense that the present value of all cash flows is nonpositive. This follows from the *conservation property of residual income*, which states that for a firm with no assets at its inception, the present value of cash flows is equal to the present value of all residual incomes, regardless of the applicable depreciation rules (Schmalensee 1989). Conversely, the firm will break even over its entire lifetime in terms of discounted cash flows if the inequality constraint in (7) is met as an equality in *every* period.

the resulting consumer demand is consistent with the available capacity and the return constraint in (7) is met in each period. Nezlobin et al. (2010) show that when consumer demand grows at a constant rate over time, there is a generally a unique price which can emerge as an equilibrium under the RoR regulation process. This price depends on the cost of capital, the useful life of assets, the depreciation rules used in the computation of income and asset values as well as the growth in consumer demand. We extend the findings of Nezlobin et al. (2010) in Appendix C to show that that the long-run equilibrium price under RoR regulation can be expressed as

$$\bar{p} = w + c \cdot \Delta(\alpha) \cdot \Gamma. \tag{8}$$

The equilibrium price $\bar{p}$ coincides with the expression derived for the levelized cost of electricity, p^o in (3), except for the factor Γ. Therefore, Γ will be referred to as the *accounting bias* factor. It would be equal to 1 if for regulatory purposes assets are depreciated in a manner that reflects the productivity of the asset over time. In particular, for the "one-hoss shay" scenario of an asset that has identical productivity over its entire useful life, unbiased depreciation would amount to the so-called annuity depreciation method (Rogerson 2008, Rajan and Reichelstein 2009).[27] The magnitude of the bias Γ depends jointly on the growth rate in the size of the product market, the tax rate, and the depreciation rules that are used for both regulation and taxation purposes; see Appendix C for details. Our numerical analysis adopts the following parameter assessments:

- For regulatory purposes, the useful life of new power plants is assumed to be 30 years. All assets are depreciated according to the straight-line method, and therefore $d_i = 0.033$.
- The allowable rate of return, r, for RoR regulation purposes is equal to the firm's cost of capital, which is set equal to 8%.
- For any given price of electricity, consumer demand exhibits a constant price elasticity, which we set equal to 0.32.[28]
- Finally, for any given price, the constant elasticity demand is assumed to grow annually at a rate of 3%.[29]

As before, the firm's income tax rate is assumed to be $\alpha = 0.35$, and for tax purposes, assets are depreciated according the 150% declining balance method with a recovery period of 20 years. For these parameter choices, the accounting bias turns out to be near $\Gamma = 0.91$. At first glance, it may seem implausible that the long-run equilibrium price emerging under RoR regulation can be below the LCOE, p^o. After all, the regulated firm achieves zero economic profits over its entire infinite lifetime; i.e., the present value of all cash flows, discounted at the cost of capital r, is zero. The explanation for this seeming "subsidy" is that prices will exceed the LCOE in early time periods before approaching their equilibrium values below p^o.[30]

3.2. Results

We take as our starting point the long-run equilibrium price $\bar{p}$ in (8). The adoption of CCS technologies and/or the imposition of CO_2 emission charges will cause prices to rise gradually to their new long-run equilibrium level. However, as will become clear, it will take a long time to reach the new equilibrium. For that reason, it is essential to map out the resulting trajectory of wholesale electricity prices in real time.

Once CO_2 emissions are costly, regulatory commissions will confront the following intertemporal tradeoff. If the utility buys emission permits on the open market, operating costs and prices will increase in the short run. An investment in CCS technology, on the other hand, will increase depreciation charges now and in future periods. In balancing this tradeoff, the regulatory commission is assumed to take a consumer-oriented approach: CCS technology is adopted once the effective carbon tax is sufficiently high so that future discounted consumer surpluses will be higher if new power plants have CCS capabilities. For simplicity, we employ the same discount rate of 8% in these calculations.

Suppose first that power generators are confined to coal-fired power plants. The following result presumes that the utility has to purchase permits only for the emissions associated with new capacity investments. In effect, this amounts to a policy of "100%

[27] This result stands in contrast to the economic logic articulated in many microeconomics textbooks regarding the inherent inefficiency of rate-of-return regulation, e.g., Nicholson (2005) and Schotter (2008). The argument here is that for the firm to break even, prices must cover average cost, which includes the (historical) fixed cost associated with capacity investments. Yet, as demonstrated by Rogerson (2010), for suitably chosen depreciation rules the historical cost of past capacity expenditures will align precisely with the long-run marginal cost of capacity, i.e., with the LCOE p^o identified in §2. Of course, these arguments ignore the concerns that are central to large parts of the literature on incentives and regulation, which has argued that a regulated monopolist will be inclined to admit slack in its operations whenever operating expenses are fully reimbursed (Laffont and Tirole 1993).

[28] The 0.32 estimate is based on Bernstein and Griffin (2005).

[29] The assumption of constant growth in consumer demand is reasonable in the case of electricity demand. The projections in the Annual Energy Outlook 2010 suggest that the growth rate for electricity demand will be almost flat through 2035 (EIA 2010b).

[30] Nezlobin et al. (2010) illustrate the dynamics and global stability of the price process that emerges under RoR regulation for the case where the firm starts out initially with no assets and capacity decays geometrically over time. Prices then converge monotonically to the equilibrium price $\bar{p}$ in (8).

Table 2 Coal-Fired Power Plants: Percentage Increase in the Regulated Wholesale Price of Electricity as a Function of Time and the CO_2 Emission Charge, Assuming 100% Grandfathering

	Emission Charges: $q									
Years	5	10	15	20	25	30	35	40	45	50
1	0.4	0.8	1.2	1.5	1.8	2.4	2.4	2.5	2.5	2.5
5	1.9	3.8	5.6	7.3	8.9	11.7	11.9	12.0	12.2	12.4
10	3.6	7.1	10.6	13.9	17.2	22.3	22.7	23.0	23.4	23.7
15	5.1	10.2	15.1	20.0	24.8	31.6	32.1	32.7	33.2	33.7
20	6.5	12.9	19.3	25.6	31.9	39.4	40.1	40.8	41.6	42.3
25	7.7	15.3	23.0	30.6	38.1	46.5	47.3	48.2	49.1	50.0
30	8.7	17.5	26.3	35.0	43.8	52.4	53.4	54.4	55.4	56.4
35	8.7	17.5	26.2	35.0	43.7	52.2	53.2	54.2	55.2	56.3
40	8.7	17.5	26.2	35.0	43.7	52.1	53.1	54.1	55.1	56.2

grandfathering" for incumbent plants that were built prior to the legislation requiring CO_2 emission permits. The following result identifies the *break-even price* for CO_2 emission permits at which a consumer-oriented regulator would instruct the utility to adopt CCS capabilities.

Result 3. *For coal-fired power plants, a consumer-oriented regulator will instruct the regulated firm to adopt CCS capabilities, provided CO_2 emission permits trade at a price of at least* \$30.0. *Given a policy of "100% grandfathering," the regulated wholesale price of electricity is projected to increase by the percentages shown in Table* 2 *as a function of time and the CO_2 emission charge q.*

Result 3 also identifies the percentage price increases, $\Delta\bar{p}$, that will emerge over time for alternative levels of the effective carbon tax. The percentage increases are calculated with reference to the baseline level of $\bar{p} = 4.6$¢/kWh, which is the RoR equilibrium price (Equation (8)) for a PC plant in the absence of any CO_2 emission charges. Direct comparison of Results 1 and 3 shows certain parallels but also some striking differences between the competitive and the regulation scenarios. First, the break-even point of \$30 per tonne in the RoR regulation scenario is remarkably close to that identified in Proposition 1.[31] The rough intuition is that a decision maker who seeks to maximize future consumer surpluses will adopt CCS capabilities under similar conditions as a decision maker concerned with minimizing the LCOE. This is plausible because the long-run equilibrium price under RoR differs from the LCOE only in the application of the accounting bias factor, and this factor is invariant to the inclusion of emission charges.

A second parallel between the regulated and the competitive scenarios is that the ultimate percentage price increases for electricity at the wholesale level are again in the range of 52% for an effective carbon tax of \$30, and near 56% for an effective carbon tax of \$50 per tonne. In sharp contrast to the competitive power supply scenario, however, the price increases for electricity are phased in gradually for a regulated firm. For any emissions charge q (i.e., for any column in Table 2), it takes about 30 years to reach the new equilibrium price levels. This gradual phase-in reflects that the capital costs (depreciation and interest charges) of old plants without CCS capabilities dominate the historical costs in early years, and product prices are calculated to reimburse the firm for its historical cost. After 30 years (the assumed useful life of a power plant), prices settle down to their new equilibrium levels.

In the political discussion over a cap-and-trade system, one major point of contention continues to be the rules for issuing emission allowances to parties that have had high CO_2 emissions in the past. Wholesale electricity prices should not be affected by the specific grandfathering rules if power generation is organized competitively. In contrast, product prices will be sensitive to the number of emission permits given to a regulated firm. Permits issued by the government now effectively become a source of revenue for the firm. Because prices are calculated to meet the RoR regulation constraint, a more generous grandfathering policy will have the effect of slowing down the increases in electricity prices. The following result presents a variant of Result 3 by considering the other extreme grandfathering policy in which the regulated firm receives no emission permits for free.

Result 3′. *For coal-fired power plants, a consumer-oriented regulator will instruct the regulated firm to adopt CCS capabilities, provided CO_2 emission permits trade at a price of at least* \$30.0. *Given a policy of "0% grandfathering," the regulated wholesale price of electricity is projected to increase by the percentages shown in Table* 3 *as a function of time and the CO_2 emission charge q.*

The price increases shown in Table 3 reflect that without any emission allowances, the regulated firm has essentially no short-run choices for mitigating the

[31] Once CO_2 emission charges exceed the break-even value of \$30 per tonne, the regulated firm stops investing in pulverized coal plants and instead switches to IGCC plants with CCS capabilities. The values in Table 2 were obtained in Matlab by a numerical search process that seeks in each period a product price that meets the two conditions: (i) there exists a nonnegative level of investment for the current period such that consumer demand at the candidate price is compatible with the currently available capacity, and (ii) at this price and quantity, the RoR constraint is satisfied with equality (in case there are several such candidate prices, the lowest one is implemented). The iterative search process starts from a steady-state solution in which the firm charges the equilibrium price level $\bar{p} = 4.6$¢/kWh, and investments have been growing at the constant rate $\mu = 0.03$ over the past $T = 30$ years.

Table 3 Coal-Fired Power Plants: Percentage Increase in the Regulated Wholesale Price of Electricity as a Function of Time and the CO_2 Emission Charge, Assuming No Grandfathering

	Emission Charges: $q									
Years	5	10	15	20	25	30	35	40	45	50
1	8.4	16.8	26.7	36.6	46.5	56.3	66.0	75.8	85.4	95.1
5	8.4	16.9	25.3	33.8	42.3	51.6	59.1	66.9	74.9	83.1
10	8.5	17.1	25.6	34.2	42.7	53.3	59.3	65.3	71.5	77.8
15	8.8	17.5	26.3	35.0	43.7	55.0	59.6	64.2	68.9	73.6
20	8.9	17.8	26.7	35.6	44.4	55.3	58.7	62.2	65.6	69.1
25	8.9	17.7	26.6	35.4	44.2	54.3	56.5	58.6	60.8	63.0
30	9.0	18.0	26.9	35.8	44.8	54.1	55.3	56.5	57.8	59.0
35	8.6	17.3	25.9	34.5	43.2	51.2	52.1	53.0	53.8	54.7
40	8.7	17.3	26.0	34.7	43.4	51.5	52.4	53.3	54.2	55.1

effects of a high carbon tax.[32] The percentage increases for the column corresponding to $q = \$50$ are quite dramatic, at least at the wholesale level. To cover the cost of high CO_2 emission charges, the firm must raise prices, which in turn will drive down demand and slow new capacity investments. In fact, the firm may have to increase the price up to a point where its available capacity is no longer fully utilized.[33] After a few years, however, the retirement of old plants and growth in the demand for electricity will ensure that capacity will again be fully utilized and new investments with CCS capabilities will be undertaken. As a consequence, wholesale electricity prices start to decline until they converge to the new steady-state level which is again about 52% higher than the status quo.[34]

Alternative grandfathering policies do not seem to affect the break-even value of $30 for the adoption of CCS at coal-fired plants. Because this finding is consistent with that obtained in Result 1, we obtain yet another confirmation for the value $30 as the (long-run) marginal cost of CO_2 abatement via CCS technology. Given the sheer magnitude of emissions from coal-fired power plants, this estimate should be a major data point in predicting the range of the effective carbon tax that is likely to emerge for particular emission caps.

We finally turn to the scenario of a regulated utility that generates power by burning natural gas. We recall from §2 that to minimize the long-run marginal cost of power generation, a new natural gas plant would be outfitted with CCS capabilities once the effective carbon tax passes the break-even value of $60 per tonne. As explained above, this relatively high value results from the fact that natural gas plants emit only one-half of the carbon dioxide that coal-fired plants emit per kilowatt hour. In addition, the increase in construction costs associated with CCS capabilities is much higher in relative terms for an NGCC plant. The following calculations are based on an initial RoR equilibrium price of $\bar{p} = 5.6$¢/kWh for NGCC plants.

Result 4. *For NGCC plants, a consumer-oriented regulator will instruct the regulated firm to adopt CCS capabilities, provided CO_2 emission permits trade at a price of at least \$57.5. Given a policy of "100% grandfathering," the regulated wholesale price of electricity is projected to increase by the percentages shown in Table 4 as a function of time and the CO_2 emission charge q.*

The values in Table 4 are consistent with the general pattern established in Results 1–3. In terms of the break-even price, the competitive and regulated scenarios lead to approximately the same critical value for emission charges, that is, about $60 per tonne, that would make it advantageous to endow new NGCC plants with carbon capture capabilities. The ultimate percentage price increases are also comparable across the two market structure scenarios. In particular, we find an effective upper bound of about 40% at the wholesale level (25% at the retail level) even if the effective carbon tax were to reach a level of $70 per tonne of CO_2. These price increases are again phased in almost linearly over 30 years provided older installations are fully grandfathered. Our findings in Result 3′ suggests that such a gradual monotonic increase would probably not be obtained for partial grandfathering policies.

Table 4 Natural Gas Power Plants: Percentage Increase in the Regulated Wholesale Price of Electricity as a Function of Time and Alternative CO_2 Emission Charges, Assuming 100% Grandfathering

	Emission Charges: $q							
Years	10	20	30	40	50	57.5	70	80
1	0.3	0.6	0.9	1.2	1.4	1.8	1.8	1.9
5	1.5	2.9	4.3	5.6	6.9	8.7	8.9	9.0
10	2.7	5.4	8.0	10.6	13.1	16.4	16.7	17.0
15	3.9	7.7	11.4	15.1	18.7	22.9	23.4	23.8
20	4.8	9.6	14.4	19.1	23.8	28.2	28.9	29.4
25	5.7	11.4	17.0	22.6	28.2	33.1	33.9	34.5
30	6.4	12.9	19.3	25.7	32.2	37.0	38.0	38.7
35	6.4	12.9	19.3	25.7	32.2	37.0	37.9	38.7
40	6.4	12.9	19.3	25.7	32.2	36.9	37.9	38.6

[32] This finding must of course be qualified by recalling that our analysis does not consider the possibility of retrofitting existing plants with CCS capabilites.

[33] Our numerical search allowed for the possibility that the firm could leave old plants with high CO_2 emissions idle and accelerate the investment in new plants with CCS capabilities. However, that alternative did not emerge as a viable option for carbon taxes in the range $q \leq \$50$.

[34] In contrast to the values obtained for 100% grandfathering, Table 3 shows that prices keep changing even past the first 30 years if the firm receives no emission permits for free. However, beyond the 40 year mark, prices are essentially stable with any further increases limited to less than 2/10 of 1%.

4. Concluding Remarks

Coal and natural gas are the dominant energy sources for electricity generation in many parts of the world. For countries like the United States and China, CO_2 emissions from fossil fuel power plants constitute more than 40% of the overall "emissions pie." CCS technologies offer considerable potential as a CO_2 abatement strategy because CCS is projected to reduce emissions from fossil fuel power plants by 85%–90%. Our analysis indicates that investors and regulators would have incentives to include CCS capabilities in new coal-fired power plants once the market price for CO_2 emission permits moves beyond the range of \$25–30 per tonne. This estimate is obtained consistently for the two scenarios of competitive and regulated power generation. Given the sheer magnitude of emissions from coal, the break-even value for CCS adoption should prove a significant factor in limiting the effective carbon tax that will emerge under a cap-and-trade system.

An important option value associated with CCS capabilities is that electricity prices are essentially shielded from increases in the carbon tax beyond the break-even value. In contrast to some of the dire predictions reported in the popular press, we find that a 30% increase in the retail price of electricity constitutes an upper bound, even if the carbon tax were to reach \$70 per tonne. This upper bound applies to both coal-fired and natural gas power plants. Furthermore, if electricity is provided by a price regulated utility, the resulting price increases will be phased in gradually over a 30 year time span. The specific price path will depend on the government's policy of issuing free emission allowances. If firms receive emission allowances for their existing plants (100% grandfathering), we find that electricity prices would rise in an almost linear fashion to their new equilibrium levels.

Our economic analysis has been anchored to two constructs: the LCOE for independent power producers and the long-run price equilibrium for electricity providers that are subject to rate-of-return regulation. This economic framework should also be applicable for a range of issues that are closely related to the ones examined in this paper. For instance, as mentioned in the introduction, carbon capture technologies other than geologic CCS have recently emerged as technological alternatives. In particular, carbon mineralization processes have the principal advantage that existing fossil fuel power plants would not need to be retrofitted, because carbon mineralization processes can absorb the entire flue gas of a coal or natural gas plant. Provided these alternative processes prove to be technologically and economically viable on a commercial scale, they could add significant CO_2 abatement potential even within the next decade.

From a policy perspective, it would be useful to obtain a more complete set of predictions regarding the effects of alternative grandfathering policies. In particular, one would like to know how fast electricity prices would rise in the short run if a regulated firm is given emission allowances for existing plants, yet these allowances are either limited to a certain number of years or they diminish over time. Such policies would fall in between the two extreme scenarios of 0% and 100% grandfathering considered in this paper.

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Appendix A

This appendix provides a formal proof of the fact that the price p^o, identified in Equation (3) in §2.1, is indeed the LCOE. Specifically, we show that p^o satisfies the criterion in the MIT (2007, p. 127) coal study: "the levelized cost of electricity is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors."

Consider a single investment for an electricity-generating facility. Let r_d denote the cost of debt, that is, the interest rate required by the firm's bond holders. In contrast, r_e denotes the equity cost of capital, that is, the required rate of return for equity investors.[35] The firm's leverage ratio, β, is given by the ratio of the book value of its debt, D_t relative to the sum of the book value of debt and equity, $D_t + E_t$.

Lemma 1. *With a constant leverage ratio of β, the LCOE is given by*

$$p^o = w + c \cdot \Delta(\alpha),$$

where $\gamma = 1/(1+r)$ and $r \equiv (1-\beta)\cdot r_e + \beta \cdot r_d \cdot (1-\alpha)$.

Proof of Lemma 1.

Step 1. Let $(CF_0^*, CF_1^*, \ldots, CF_T^*)$ denote a sequence of after-tax cash flows. These cash flows take into consideration the depreciation tax shield, but ignore the tax shield related to debt. If this sequence of cash flows satisfies

$$\sum_{t=0}^{T} CF_t^* \cdot \gamma^t = 0, \tag{A1}$$

where $\gamma = 1/(1+r)$ and $r = (1-\beta)\cdot r_e + \beta \cdot r_d \cdot (1-\alpha)$, then there exist repayment schedules $(y_1^e, \ldots, y_T^e)$ and $(y_1^d, \ldots, y_T^d)$ such that

(i) $E_t = E_{t-1}\cdot(1+r_e) - y_t^e$,
(ii) $D_t = D_{t-1}\cdot(1+r_d) - y_t^d$,

[35] In inflation environments, these rates should be interpreted as nominal rather than real interest rates.

(iii) $D_t/(E_t + D_t) = \beta$ for $0 \leq t \leq T$,
(iv) $E_0 = (1-\beta) \cdot CF_0^*$,
(v) $D_0 = \beta \cdot CF_0^*$,
(vi) $E_T = D_T = 0$,
(vii) $y_t^e + y_t^d = CF_t^* + \alpha \cdot r_d \cdot D_t$.

This approach is standard in the corporate finance literature; see, for instance, Ross et al. (2005). Conditions (i), (iv), and (vi) ensure that the firms's equity holders earn the required return r_e over the entire horizon of the project, whereas (ii), (v), and (vi) ensure the same for debt holders. Condition (iii) says that the firm's leverage is unchanged over the life of the project, and finally, condition (vii) says that the total cash flow available for distribution to shareholders and creditors is the overall after-tax cash flow, including the debt tax shield at date t, given by $\alpha \cdot r_d \cdot D_t$. In sum, the tax shield related to debt is reflected appropriately by discounting the project's after-tax cash flows at the WACC given by $r \equiv (1-\beta) \cdot r_e + \beta \cdot r_d \cdot (1-\alpha)$.

Step 2. Given an investment in K units of capacity at date 0 and a product price equal to p, the firm's after-tax operating cash flow (excluding the debt tax shield) in period t is

$$CF_0^* = -v \cdot K,$$

and

$$CF_t^* = x_t \cdot K \cdot (p-w) - \alpha \cdot [x_t \cdot K \cdot (p-w) - v \cdot K \cdot d_t^o].$$

By Step 1, it suffices to show that

$$\sum_{t=0}^{T} CF_t^* \cdot \gamma^t = 0$$

holds at $p = p^o$. Direct substitution yields

$$\sum_{t=1}^{T} \gamma^t \cdot [x_t \cdot (p-w) - \alpha \cdot [x_t \cdot (p-w) - v \cdot d_t^o]] = v. \qquad \text{(A2)}$$

Solving this linear equation for p yields exactly the price p^o in (3). This completes the proof of Lemma 1.

Appendix B

The fundamental cost parameters for our study are the plant construction cost v and the unit variable cost w, both with and without CCS capabilities. This appendix shows how the engineering cost estimates we rely on compare to those obtained in earlier studies.[36] We also provide more details regarding the varying technology assumptions that have been used in earlier studies. Tables B.1 and B.2 summarize the parameter estimates for PC and IGCC power plants, respectively. In particular, v and w refer to the traditional plant structure without CCS capabilities, whereas the parameters $\hat{v}$ and $\hat{w}$ reflect CCS capabilities.

To illustrate the calculation of the parameter, v = 21.31¢/kWh for a PC plant without CCS technology according to the NETL (2007), we note that they assess the total plant cost for a 550 MW plant to be \$866 million. In addition, they include initial fuel costs and initial operating and maintenance costs to arrive at a total initial capital expenditure of \$873 million (NETL 2007, pp. 417–421). Therefore,

$$v = \$873 \text{ million}/550 \text{ MW} \cdot 365 \cdot 24 \text{ h} \cdot 0.85 = \$0.2132/\text{kWh}.$$

For a second illustration, the parameter $\hat{w}$ = 3.38¢/kWh for IGCC plants with CCS capabilities is obtained from NETL (2007, pp. 174–178) in the following manner: fuel costs, variable operating costs and annual fixed operating costs add up to about \$130 million. Dividing these annual costs by the total annual output yields

$$\$130 \text{ million}/555 \text{ MW} \cdot 365 \cdot 24 \text{ h} \cdot 0.8 = \$0.033/\text{kWh}.$$

Assuming a 5\$ per tonne of CO_2 charge for transportation and storage, we add an additional 0.047¢/kWh, leading to an overall $\hat{w} = 3.38$.

The variation in estimates obtained from these earlier studies are partly attributable to the following specifications:

- Sekar et al. (2007) compare a subcritical air-fired PC plant to an IGCC plant. Carbon in the PC plant is captured by flue gas scrubbing using the monoethanolamine (MEA) process, whereas carbon in the IGCC plant is captured by scrubbing the shifted syngas using the Selexol process. The costs are in 2004 U.S. dollars.
- The parameters in Parsons Infrastructure and Technology Group (2002) and Simbeck (2002) are consistent with those provided in the MIT (2007) coal study. The EPRI/Parsons Infrastructure and Technology Group (2002) study compares a supercritical PC plant to an e-gas IGCC plant. The PC plant uses the MEA process to capture carbon. Simbeck (2002) compares an ultra-supercritical PC plant to a Texaco IGCC plant. The PC plant captures carbon by the MEA process. The costs are in 2005 U.S. dollars.
- The NETL (2008) reports parameters for air-fired supercritical PC plant with and without Econamine carbon capture technology. All costs are in January 2007 U.S. dollars. The NETL (2007) reports parameters for a General Electric Energy IGCC plant that can capture CO_2 with the Selexol process. All costs are in 2006 U.S. dollars.
- The National Regulatory Research Institute (NRRI 2007) data are consistent with the Electric Power Research Institute (2006), the costs are in 2006 U.S. dollars. The CO_2 emission parameters of the PC plant are specific to supercritical PC plants.

For natural power plants, Table B.3 summarizes some parameters estimated in Rubin et al. (2007) and NETL (2007).

Specific technological assumptions employed in these studies include the following:

- Rubin et al. (2007) provide parameters of an NGCC plant that includes two General Electric 7FA gas turbines and 3-pressure reheat recovery steam generators (HRSGs). Carbon capture is based on amine absorber technology. All costs are in 2005 U.S. dollars.
- The NETL (2007) reports parameters for a General Electric Energy IGCC plant that can capture CO_2 via the Selexol process and for an NGCC plant that includes two advanced F-class combustion turbines and HRSGs. Again, CO_2 is captured by an amine absorber. All costs are in 2006 U.S. dollars.

[36] Hamilton et al. (2009) seek to update the cost inputs of the MIT (2007) study and argue that, as a general trend, plant construction costs appear to have increased significantly.

Table B.1 Parameter Estimates for PC Power Plants With and Without CCS

	PC power plants					
	No CCS			CCS		
	v (¢/kWh)	w (¢/kWh)	CO_2 emitted (t/MWh)	$\hat{v}$ (¢/kWh)	$\hat{w}$ (¢/kWh)	CO_2 emitted (t/MWh)
Sekar et al. (2007)	19.5	1.93	0.774	33.79	3.39	0.108
Parsons Infrastructure and Technology Group (2002)	17.04	2.37		29.5	3.67	
Simbeck (2002)	19.2	2.01		33.5	2.93	
NETL (2007)	21.31	2.4	0.804	38.85	3.72	0.115
NRRI (2007)	18.1		0.800	30.4		0.052

Table B.2 Parameter Estimates for IGCC Power Plants With and Without CCS

	IGCC power plants					
	No CCS			CCS		
	v (¢/kWh)	w (¢/kWh)	CO_2 emitted (t/MWh)	$\hat{v}$ (¢/kWh)	$\hat{w}$ (¢/kWh)	CO_2 emitted (t/MWh)
Sekar et al. (2007)	20.39	2.06	0.769	26.27	2.79	0.089
Parsons Infrastructure and Technology Group (2002)	16.6	2.03		24.5	2.45	
Simbeck (2002)	19.3	2.01		26.8	2.5	
NETL (2007)	24.53	2.76	0.796	32.36	3.38	0.093
NRRI (2007)	20.0		0.86	25.8		0.156

Table B.3 Parameter Estimates for Natural Gas Power Plants With and Without CCS

	NG power plants					
	No CCS			CCS		
	v (¢/kWh)	w (¢/kWh)	CO_2 emitted (t/MWh)	$\hat{v}$ (¢/kWh)	$\hat{w}$ (¢/kWh)	CO_2 emitted (t/MWh)
Rubin et al. (2007)	9.01		0.367	14.65		0.043
NETL (2007)	7.89	4.80	0.361	16.27	5.77	0.042

Appendix C

This appendix demonstrates that the price $\bar{p}$, identified in Equation (8), is indeed an equilibrium price under rate-of-return regulation. The following derivations extend the analysis in Nezlobin et al. (2010) by considering income taxes and the possibility that tax depreciation rules will generally differ from the depreciation rules used for regulatory purposes.

An equilibrium price of the RoR regulation process, say p, must be supported by a sequence of past investments such that (i) the resulting capacity levels satisfy demand at the price p, and (ii) the RoR constraint in (7) is satisfied in each period. The prices and quantities that emerge from the RoR regulation process clearly depend on the choice of depreciation schedule $\mathbf{d} = (d_1, \dots, d_T)$. Although our analysis assumes that assets are depreciated according to the straight-line rule for regulatory purposes, it will nonetheless be useful to consider a form of *unbiased* depreciation which ensures that the RoR process results in a price equal to the LCOE, that is, $p = p^o$. Such an unbiased depreciation schedule indeed exists. To see this, define the date t *capital cost* per unit of investment undertaken at date $t - i$ as the sum of depreciation and imputed interest charges:

$$z_i \equiv v \cdot d_i + r \cdot bv_{i-1}. \tag{C1}$$

Thus, $z_i \cdot I_{t-i}$ is the capital cost charged in period t for investment I_{t-i} undertaken at date $t - i$. Suppose now the regulator were to choose a depreciation schedule $\mathbf{d}^*$ such that the corresponding capital costs satisfy[37]

$$z_i^* = (1 - \alpha) \cdot c \cdot \Delta(\alpha) + \alpha \cdot v \cdot d_i^o. \tag{C2}$$

It is a matter of straightforward algebra to check that if the depreciation schedule used for regulatory purposes and

[37] It is well known from earlier studies of the residual income metric that there is a one-to-one relation between depreciation schedules $\mathbf{d} = (d_1, \dots, d_T)$ and the historical cost charges $(z_1, \dots, z_T)$; see, for example, Rogerson (1997). Formally, the linear mapping defined by (C1) is one to one: for any intertemporal cost charges $(z_1, \dots, z_T)$, with the property that $\sum_{\tau=1}^{T} z_\tau \cdot \gamma^\tau = v$, there exists a unique depreciation schedule $\mathbf{d}$ such that (C1) is satisfied.

the corresponding capital costs satisfy (C2), then for any sequence of investment levels $\mathbf{I}_t = (I_{t-T}, \ldots, I_{t-1})$, the RoR constraint in (7) will be met if the product price is set equal to $p^o = w + c \cdot \Delta(\alpha)$. This follows from the observation that for each generation of investments $I_{t-\tau}$ the corresponding contribution to residual income is exactly zero at date t.

Lemma 2. *Suppose that for any given price p, market demand grows at the constant rate μ. Then,*

$$\bar{p} = w + c \cdot \Delta(\alpha) \cdot \frac{\sum_{i=1}^{T} (1+\mu)^{T-i} \cdot [z_i(\mathbf{d}) - \alpha \cdot v \cdot d_i^o]}{\sum_{i=1}^{T} (1+\mu)^{T-i} \cdot [z_i^* - \alpha \cdot v \cdot d_i^o]} \qquad \text{(C3)}$$

is an equilibrium price of the rate-of-return regulation process. This price is supported by a sequence of constant growth investments of the form $I_{t+1} = I_t \cdot (1+\mu)$.

Proof of Lemma 2. It suffices to show that for a constant growth trajectory of the form $I_{t-T} = I$ and $I_{t-\tau} = (1+\mu)^{T-\tau} \cdot I$, the RoR regulation constraint:

$$RI_t(\mathbf{I}_t) = NInc_t(\mathbf{I}_t) - r \cdot AV_{t-1}(\mathbf{I}_t) = 0 \qquad \text{(C4)}$$

will be met provided the product price is set equal to $\bar{p}$, as given in the statement of Lemma 2. The expression for residual income in (C4) can be rewritten as

$$(\bar{p} - w) \cdot K_t(\mathbf{I}_t) - Z_t(\mathbf{I}_t) - \alpha \cdot \left[(\bar{p} - w) \cdot K_t(\mathbf{I}_t) - \sum_{i=1}^{T} (1+\mu)^{T-i} \cdot d_i^o \cdot v \cdot I \right], \qquad \text{(C5)}$$

where, by definition,

$$Z_t(\mathbf{I}_t) \equiv D_t(\mathbf{I}_t) + r \cdot AV_{t-1}(\mathbf{I}_t).$$

The expression for capital costs is also equal to

$$Z_t(\mathbf{I}_t) = \sum_{i=1}^{T} (1+\mu)^{T-i} \cdot z_i(\mathbf{d}) \cdot I.$$

The constraint in (C4) is therefore equivalent to

$$(1-\alpha) \cdot c \cdot \Delta(\alpha) \cdot \Gamma \cdot K_t(\mathbf{I}_t) = Z_t(\mathbf{I}_t) - \alpha \cdot \sum_{i=1}^{T} (1+\mu)^{T-i} \cdot d_i^o \cdot v \cdot I,$$

where

$$\Gamma \equiv \frac{\sum_{i=1}^{T} (1+\mu)^{T-i} [z_i(\mathbf{d}) - \alpha \cdot v \cdot d_i^o]}{\sum_{i=1}^{T} (1+\mu)^{T-i} [z_i^* - \alpha \cdot v \cdot d_i^o]}. \qquad \text{(C6)}$$

To complete the proof, it therefore suffices to show that

$$(1-\alpha) \cdot c \cdot \Delta(\alpha) \cdot K_t(\mathbf{I}_t) = I \sum_{i=1}^{T} (1+\mu)^{T-i} [z_i^* - \alpha \cdot v \cdot d_i^o].$$

This step follows from the following two observations. First,

$$K_t(\mathbf{I}_t) = \sum_{i=1}^{T} (1+\mu)^{T-i} \cdot I,$$

and second,

$$z_i^* = (1-\alpha) \cdot c \cdot \Delta(\alpha) + \alpha \cdot v \cdot d_i^o,$$

as shown in Equation (C2). This completes the proof of Lemma 2.

The price in (C3) is the only candidate for an asymptotic outcome of the RoR regulation process. More specifically, if the product prices that emerge from the RoR process converge at all, they must converge to (8). Nezlobin et al. (2010) prove this result in a model without income taxes ($\alpha = 0$), though their uniqueness result carries over to the present setting with taxes. The accounting bias, Γ, will differ from 1 only to the extent that the depreciation rules for regulatory purposes differ from the unbiased rule identified in (C2). For the choice of parameters identified in §3.1, including straight-line depreciation for regulatory purposes, the accounting bias is close to $\Gamma = 0.91$, provided the growth parameter μ is equal to 3%.

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