

# Carbon Capture Retrofits and the Cost of Regulatory Uncertainty

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*Power generation firms confront impending replacement of an aging coal-fired fleet in a business environment characterized by volatile natural gas prices and uncertain carbon regulation. We develop a stochastic dynamic programming model of firm investment decisions that minimizes the expected present value of future power generation costs under uncertain natural gas and carbon prices. We explore the implications of regulatory uncertainty on generation technology choice and the optimal timing of investment, and assess the implications of these choices for regulators. We find that interaction of regulatory uncertainty with irreversible investment always raises the social cost of carbon abatement. Further, the social cost of regulatory uncertainty is strongly dependent on the relative competitiveness of IGCC plants, for which the cost of later carbon capture retrofits is comparatively small, and on the firm's ability to use investments in natural gas generation as a transitional strategy to manage carbon regulation uncertainty. Without highly competitive IGCC or low gas prices, regulatory uncertainty can increase the expected social cost of reducing emissions by 40 to 60%.*

## 1. INTRODUCTION

The timing and stringency of future regulations on carbon dioxide (CO<sub>2</sub>) emissions from electric power generation remain deeply uncertain. In the E.U., the long-run carbon price faced by power generators is highly uncertain due to

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political uncertainty about the allocation of permits, while in the U.S., national regulation is widely anticipated<sup>1</sup> and state-level regulation already exists. In both regions, significant investment in new capacity to replace aging generation facilities and to meet growing demand is likely to occur prior to long-term resolution of regulatory uncertainty. Given the long lifetimes of power plants, technology commitments can have large implications for both electricity firms and regulators. This paper investigates factors that can ameliorate or exacerbate the private and social costs of regulatory uncertainty.

In the coming two to three decades, generation capacity constructed for replacement of retired plants is likely to be significantly greater than capacity added for demand growth, in the U.S. a factor of two greater. Demand growth is projected to increase industry generating capacity approximately 15% in OECD Europe and 20% in the U.S. by 2030 (EIA 2006). By 2030, more than 80% of coal capacity and 40% of natural gas capacity in the U.S. will reach the average recent retirement age for each technology (EIA 2005). If this pattern persists, more than 40% of overall U.S. capacity will be retired and replaced by 2030 from these two generation technologies, which alone account for 70% of existing capacity.

Of particular interest is the baseload application of coal, the most carbon-intensive fuel, in aging low efficiency coal plants. Coal-fired plants account for approximately 25% of generation capacity in Europe and 35% in the U.S., yet supply slightly more than 30% and 50% of demand, respectively (EIA 2006). In the E.U., 50% of coal-fired plants are greater than 30 years old, and nearly 80% are greater than 20 years (Kjarstad and Johnsson 2007). In the U.S., increasing operating costs as plants age combined with increasingly stringent regulation of conventional pollutants will likely drive the replacement or refurbishment of much of the coal-fired generation fleet, which now has a capacity-weighted mean age of 34 years, within the next two decades even without constraints on CO<sub>2</sub> emissions. In both regions, retirement of older, lower efficiency coal-fired plants can have an outsized impact on carbon emissions.

Switching to natural gas fired generation offers the most readily available means to reduce CO<sub>2</sub> emissions. It provides a cleaner, low-capital-cost alternative to coal-fired generation, yet conversion to natural gas is inhibited by high and volatile gas prices and expectations of continued volatility and increasing prices (EIA 2005). Beyond natural gas, options for carbon-constrained electricity supply fall into two broad classes: centralized electricity production, such as nuclear or CO<sub>2</sub> capture and storage (CCS), and more decentralized alternatives, such as wind power or natural gas cogeneration. Decentralized technologies may offer cost-effective CO<sub>2</sub> mitigation as well as other diversity and security related benefits, but widespread implementation of these technologies is contingent on changes in transmission infrastructure, electricity markets, and associated regula-

1. For example, in 2002 and 2003 Granger Morgan of Carnegie Mellon has asked large audiences which included many CEOs and other senior officials in the power industry, "How many of you believe that there will not be Federal controls on CO<sub>2</sub> emissions from U.S. power plants within the next 20 years?" In both cases less than 2% of the people in the room raised their hands.



tions (McGowan and Connors 2000; Farrell, Zerriffi et al. 2004; DeCarolus and Keith 2005).

Although nuclear power and CCS are technologically unrelated, they have important similarities from the perspective of electric-sector decision makers. Both could replace existing coal-fired generation providing dispatchable baseload power without requiring significant alteration of existing transmission infrastructures and markets. Both have high capital costs and very low CO<sub>2</sub> emissions. Finally, both involve uncertainties related to siting, regulation, and public acceptance (Morgan 1993; Palmgren, Morgan et al. 2004).

Unlike nuclear power, however, CCS technologies (which capture CO<sub>2</sub> gases prior to emitting to the atmosphere for long-term geologic storage) can be retrofitted to existing coal-fired power plants. For new coal-fired power plants there is a choice of two technologies: pulverized coal the currently dominant technology and integrated gasification combined cycle (IGCC). Absent restrictions on CO<sub>2</sub> emissions, the two technologies have very roughly similar cost and performance characteristics, but IGCC is more technically risky and thus carries an uncertain cost risk premium, so absent any other incentive, operators will prefer pulverized coal (Sekar, Parsons et al. 2006). However, the possibility of future restrictions on CO<sub>2</sub> emissions can alter this choice because the cost of retrofitting an IGCC plant for CO<sub>2</sub> capture is significantly lower than the cost of retrofitting a pulverized coal plant (IPCC 2005; Sekar, Parsons et al. 2006). The cost premium for an IGCC plant can be viewed as the purchase price of a real option to reduce CO<sub>2</sub> emissions compliance costs in the event of stringent regulations.

We analyze the impacts of uncertainty in the timing and stringency of CO<sub>2</sub>-emission regulations on coal-fired plant replacement investment decisions made by deregulated private firms providing centralized electricity supply and the implications of these decisions on regulatory policy using stochastic-dynamic programming methods. From the firm's perspective, regulatory uncertainty is one of many uncertain factors under which the firm aims to maximize profits. We restrict our decision model to cost minimization, a necessary condition of profit maximization, since the firm's cost expectations for producing electricity with its aging plant relative to a replacement drives both the timing of investment and technology choice. From the regulator's perspective, the timing and stringency of regulations are chosen to maximize net public benefits which we compress into two dimensions: cost of electricity generation and amount of carbon emissions.

We treat uncertainty about carbon policy and natural gas prices explicitly. These are not, of course, the only uncertainties faced by electricity generators and regulators. Among the most important uncertainties that we treat implicitly or ignore are market structure, the regulation of conventional pollutants, and technological change. We simplify the analysis by assuming a proxy increase in operating costs to capture the effects of a more detailed treatment of future conventional air pollution regulations. The basis of this assumption and a sensitivity analysis on its value are discussed in later sections.



Despite these limitations, our model provides insight into several interrelated questions relevant to both capital investment decisions by electricity generation firms and carbon/climate policy-making decisions by regulators over the next few decades. How does the threat of future restrictions on carbon emissions affect current private investment decisions? Does regulatory uncertainty combined with irreversible investment create an incentive to delay retirement of existing coal plants with associated power generation cost and pollution consequences? How valuable is the flexibility that arises from building IGCC plants for which the cost of later CCS retrofits is comparatively small? What is the social cost of delaying policy decisions about carbon constraints? How is the cost effectiveness of CO<sub>2</sub> reductions influenced by regulatory uncertainty and the flexibility provided by CCS retrofits?

The body of paper uses costs and prices chosen to represent average conditions expected in the U.S. electric power market. We discuss the model's application to European conditions and the insights for the sector level capacity expansion issue that can be gleaned from this firm level model in the concluding section.

The paper proceeds as follows: Section 2 presents the model and specific modeling assumptions, Section 3 examines model results and capabilities, Section 4 contains concluding remarks, and the Appendix presents the mathematical details of the stochastic dynamic programming model and discusses model solution methodologies.

## **2. THE MODEL**

We model the aging pulverized coal (PC) plant replacement decision of a deregulated private power generation firm. The firm seeks to minimize the expected present value cost of continuing to supply the amount of power generated by its aging PC plant over a specified time horizon by deciding on the timing and technology type of power plant investment under market uncertainty in future natural gas prices and regulatory uncertainty over future CO<sub>2</sub> emissions.

The problem is formulated as a discrete time stochastic dynamic programming problem and solved based on Bellman's Principle of Optimality: "An optimal policy has the property that whatever the initial state and initial decision are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision (Bellman 1957)." Stochastic dynamic programming implicitly models all of the multiple, interacting, sequential real options that characterize the timing and technological choice of irreversible investments under uncertainty (Dixit and Pindyck 1994).

Investment decisions are made each period over a finite time horizon based on the information available to the firm at that time: the age and technology of the firm's existing generation facility, as well as, the current prices of natural gas and carbon emissions. The firm chooses the optimal current action by analyzing the expected present value cost over the complete time horizon of all avail-

able investment decisions, including the option to delay investment, the option to invest in any technology, the option to purchase a later option for cost-effective carbon capture retrofit, the option to retrofit a technology, and the option to abandon one technology and replace it with another.

In a finite time horizon problem, Bellman's principle is recursively implemented by backward induction beginning with the final period decision. The stochastic nature of the problem renders the optimal investment policy a contingent policy, contingent on the realized history of the stochastic natural gas price and CO<sub>2</sub> regulation variables at the time investment decisions are undertaken. Mathematical details are provided in the appendix.

## 2.1 Technology Choices and their Rationale

The power generation technologies considered here are summarized in Table 1. In all cases, we assume the firm begins with a pre-existing pulverized coal (PC) plant with characteristics that reflect typical values for large plants constructed three or four decades ago. In both the U.S. and Europe, the increasing stringency of SO<sub>x</sub>, NO<sub>x</sub>, and "air toxics" emission control regulations combined with rising operating costs will necessitate a choice between retirement and expensive refurbishment of many older coal plants in the coming two to three decades.

In U.S., for example, the combined effects of New Source Review (Dewitt and Lee 2003), the Clean Air Mercury Rule, and the Clean Air Interstate Rule will accelerate the retirement of the aging coal fleet. Rather than modeling these regulations explicitly, we raise the growth rate of fixed operations and maintenance cost (FOM) for pre-existing PC relative to other technologies by an amount that roughly reflects the cost of advanced post-combustion emission controls amortized over a 15-year time horizon. This parameterization essentially forces the retirement of the initial PC plant within two decades.

**Table 1. Technology Parameters**

	Pre-existing PC	Advanced PC	NGCC	IGCC	IGCC+ CCS
Capital investment cost (\$/kW)	n/a	1200	450	1200+C <sub>rp</sub>	1550+C <sub>rp</sub>
Thermal efficiency (%)	30	38	55	38	32
Initial fixed operating cost (\$/kW capacity)	30	22	15	22	26
Annual fixed cost growth rate (%)	15	2	2	2	2
Variable operating cost (\$/MWhr)	5	3.6	0.5	3.6	4.3
Carbon emission rate (kg-C/MWhr)	289	228	89	228	27
Carbon storage cost (\$/MWhr)	0	0	0	0	6.1
Cost of Electricity over 20 years (\$/MWhr)	34.40	47.70	44.90	48.90	67.00

PC = Pulverized Coal, NGCC = Natural Gas Combined Cycle, IGCC = Integrated Gasification Combined Cycle, CCS = Carbon Capture and Storage, C<sub>rp</sub> = IGCC cost risk premium



In addition to natural gas combined cycle (NGCC), the type of natural gas-fired power plant that would compete against coal for baseload power generation, we consider three kinds of new coal-fired power plants: advanced pulverized coal (APC); integrated gasification combined cycle (IGCC); and IGCC with installed CO<sub>2</sub> capture and storage (IGCC+CCS).

There is surprisingly little difference between the cost and performance of IGCC and advanced pulverized coal plants with super- or ultra-super-critical steam cycles and the full complement of post-combustion emissions controls. Both kinds of power plants offer similar efficiencies (37-43% HHV) and similar levels of emissions. Moreover, if we ignore use of low-rank coals and consider plants designed with identical efficiencies and emissions rates, they offer similar costs. While the projected costs and performance are similar, only a handful of IGCC plants have been operated to date whereas thousands of PC plants are in use worldwide and more than 10 GW of APC plants have been constructed in Europe within the last decade. Despite the projected similarity in performance, firms have therefore overwhelmingly chosen APC over IGCC because (i) IGCC is an unfamiliar technology; (ii) there are significant risks that IGCC plants will have technical problems that result in lower availabilities; and (iii) firms have not had to comply with stringent controls on air pollutants lowering the effective cost of APC.

To simplify the interpretation of results, the operating parameters of APC and IGCC plants are assumed to be identical and all differences are incorporated into an adjustable "IGCC cost risk premium" that is added to the capital cost of IGCC. This cost risk premium is intended to reflect the higher perceived risk level associated with commercial adoption of IGCC technology relative to the other commercially proven technologies. We consider a range of values for this cost risk premium to explore how technological competitiveness of IGCC affects model results.

In our model, IGCC's sole advantage is that it may be cost-effectively retrofitted to capture CO<sub>2</sub> pre-combustion. Although PC plants can also be retrofitted for capture of CO<sub>2</sub> post-combustion at several times the cost for IGCC plants, we ignore that possibility here because its inclusion would add complexity without significantly altering any of our conclusions. Despite the labels given to the various technologies, one may regard the "IGCC cost risk premium" as a retrofit flexibility premium: the price to purchase a real option to lower retrofit and compliance costs if stringent CO<sub>2</sub> emissions regulations are implemented.

Costs and performance data for the IGCC and IGCC+CCS plants with Texaco gasifier technology are based on an IPCC (2005) review of previous studies and an EPRI (2003) engineering economic study on the phasing of construction of IGCC plants with CO<sub>2</sub> capture. The latter study examines two sequences of plant construction: IGCC plants with pre-investment for eventual carbon capture retrofit and IGCC plants without pre-investment.

Pre-investment will be preferred if the additional cost of pre-investment is more than compensated by the expected discounted savings of later lower cost



retrofit, taking into account both the probability that the stringency of the carbon regulation will induce retrofit and the uncertain timing of regulation implementation. Given the carbon price scenario used here (Section 2.2), IGCC plants without pre-investment for eventual carbon capture retrofit always have lower expected cost than IGCC plants with pre-investment. Therefore, the IGCC plant parameters without carbon capture used in the model are based on a design without pre-investment for capture. Carbon storage/sequestration costs for IGCC plants with CCS are not included in the plant design and are estimated at \$25/tC stored (~\$7/tCO<sub>2</sub>). (IEA 2004; IPCC 2005)

The only natural gas power plant considered is a high-efficiency combined cycle design with a 55% (HHV) efficiency that roughly corresponds to General Electric's new "H"-class system.

All plants are assumed to operate at a fixed capacity factor of 70%. Ignoring the load-demand curve and the heterogeneity of plant dispatch is an enormous simplification which enables us to treat uncertainties in gas prices and carbon taxes explicitly. One may view the model as simulating one segment of the load curve in a real electric power system. The 70% capacity factor is slightly higher than the current U.S. average. These assumptions are supported by results from (Johnson and Keith 2004) who investigated the economics of CCS in a model that included the dynamics of plant dispatch and found that CCS or other high-capital and low-operating-cost technologies introduced in response to a carbon tax will be operated as base load plants with a higher dispatch factor than the plants they replace.

We ignore the continuing uncertainty about the structure of electric markets and the interaction of electric markets with transmission services. That is, we assume that an operator aims to minimize the cost of generation which operates in a fixed segment of the load/dispatch curve.

In each period, the cost function is composed of six elements: new capital investment in plant construction or retrofit, fixed operating cost, variable operating cost, fuel cost, carbon emissions taxes, and carbon storage costs. The explicit functional dependence of each cost component on technology type, plant age, natural gas price, and carbon price is detailed in the appendix. Annual carbon emissions taxes are the product of the tax rate per ton,  $P^C$ , and the annual tons of carbon emitted. Each possible investment decision yields a future cost stream that evolves with the stochastic parameters for natural gas prices and CO<sub>2</sub> regulation. Parameter values for the range of technologies considered are presented in Table 1. Future costs are discounted at 14% to reflect the high real discount rates typically used for investment decisions by deregulated private power generation firms.<sup>2</sup>

2. Economic analysis of electric generation industry investment typically calculates a levelized cost of electricity by levelizing capital related carrying charges with a levelized carrying charge factor (CCF) based on capital cost flows over an abbreviated plant lifetime (or capital recovery period). An industry common 15% CCF over a 20-year lifetime is equivalent to a 14% real discount rate (see, for example, EPRI 2003 and EIA 2006).

## 2.2 Regulatory Assumptions

The timing, stringency, and policy instrument of future CO<sub>2</sub> emissions regulations are uncertain. We model future carbon regulation uncertainty as a carbon tax with uncertain implementation date and magnitude. For simplicity, we use a formulation that produces a linear increase in the expected carbon tax from \$0/tC in 2005 to \$100/tC in 2030 with constant value thereafter. The model specifies a 20% probability for implementation of CO<sub>2</sub> regulations in model periods 1 to 5, corresponding to 5-year time steps from 2010 to 2030. We assume a higher 2/3 probability that a lower \$50/tC tax will be implemented and a lower 1/3 probability that a stringent \$200/tC tax will occur. Once taxes appear they do not change in the remainder of the 40-year horizon focus of our model. The model can be readily modified to incorporate other parameter values and delay of the uncertain onset of the tax.

## 2.3 Natural Gas Price Assumptions

Natural gas price is assumed to evolve by Brownian motion with constant drift.<sup>3</sup> This assumption yields a continuous probability distribution for the price of natural gas ( $P^{NG}$ ) with both the mean price and the variance of price increasing linearly over time. For our base case, we assume an initial natural gas price of \$4/GJ, annual drift of \$0.1/GJ, and a standard deviation of \$0.2/GJ. While there is a wide divergence in forecasts from different sources, these values approximate the long-term trend forecast in the Annual Energy Outlook (EIA 2005) and the recent volatility in natural gas prices. Mathematical details are provided in the appendix.

## 2.4 Expected Value of Perfect Regulatory Information

To understand the impact of regulatory uncertainty on private investment decisions and private costs, and in turn the social cost consequences of these private decisions, we calculate the expected value of perfect regulatory information (EVPRI). This close analog to the expected value of perfect information (EVPI) compares the expected present value cost of optimal investment decisions under both market and regulatory uncertainty to the lower expected present value cost deriving from investment decisions made under perfect information about future CO<sub>2</sub> regulations while maintaining irresolvable stochastic natural gas prices.

For each possible perfect information regulatory time path, we calculate the optimal investment policy contingent on stochastic natural gas prices. We then calculate the overall expected minimum cost under perfect regulatory information

3. Since carbon prices are realized during the time period based on the stochastic specification, this assumption implies that natural gas prices are statistically independent of carbon prices. The ramifications of this simplifying assumption, in light of model results indicating the dynamic probability of observing natural gas power generation, are discussed in the conclusion.



by weighting the minimum cost of optimal decision making along each regulatory time path by the probability of that path in the stochastic carbon price specification. Subtracting this value, from the higher expected minimum cost under the full stochastic model, results in the EVPRI measure of the private cost of regulatory uncertainty. Mathematical details are provided in the appendix.

## **2.5 Social Cost of Private Decisions**

Since evaluating the benefits of reducing climate change damages through CO<sub>2</sub> emissions abatement is far beyond the scope of this study, we seek to develop a measure to assess the tradeoffs between higher electricity production costs and lower emissions, a measure that expresses the social cost effectiveness of abatement policy in dollars per ton carbon (\$/tC) abated. To establish a model comparison benchmark, we define baseline emissions and costs as what would have happened in the certain absence of any future CO<sub>2</sub> emissions regulation. The expected baseline emissions and cost time paths are calculated with the model by specifying a certain future of zero carbon taxes, while maintaining irresolvable natural gas price uncertainty, thereby establishing the stochastic evolution of generation technologies and emissions, including the timing of pre-existing PC plant retirement, in the absence of future regulations.

In a dynamic setting, a single measure must somehow aggregate costs and emissions across time. While discounting costs across time is commonly accepted practice, an emerging consensus from the forest sequestration literature also discounts future emissions abatement (Stavins 1999; Richards and Stokes 2004).

While there exists a long and largely unresolved debate in the literature over the divergence of private and social discount rates (Lind, Arrow et al. 1982), no one analyzing the social costs and benefits of climate change policy in a dynamic setting uses a discount rate anywhere near the 14% rate commonly used in private investment decisions in the deregulated power generation industry<sup>4</sup>. The benefits to society of CO<sub>2</sub> abatement and eventual reductions in damages from climate change are more commonly discounted at social discount rates in the range of 0% to 6% (Metz, Davidson et al. 2001). Since our goal is to analyze the societal consequences of regulatory policy uncertainty on private decision making, we retain private industry discount rates while modeling investment decision making but evaluate the corresponding social costs resulting from these private decisions at a social discount rate of 4%.

We calculate the expected present value social cost of electricity generation by evaluating the costs resulting from private decision making at the social

4. Capital asset pricing model theory indicates that the private discount rate should only exceed the risk-free discount rate for non-diversifiable shareholder risk, however, as suggested by Arrow and Lind (1970), an agency problem exists since managers may discount for shareholder diversifiable risk (contrary to shareholder interests) because the manager's income and career depend on firm specific success. Further investigation of these issues is beyond the scope of this paper.



discount rate over the model time horizon for both the baseline no regulation and uncertain regulation cases. The social cost of emissions abatement is simply the difference between the two. These social costs include all the terms in the cost function (Equation A1, Appendix) except the emissions tax cost since these are just transfer payments.

An analogous calculation, comparing emissions time paths between the no regulation baseline and uncertain regulation cases, is made to calculate the expected present value quantity of emissions abatement discounted at the social discount rate. Dividing the expected present value social cost of emissions abatement by the expected present value quantity of emissions abatement yields a measure of abatement policy cost effectiveness. While discounting emissions reductions is an inexact surrogate for ameliorating future climate change damages, since it is equivalent to assuming that the marginal damage of all future emissions remains constant (Stavins 1999; Richards and Stokes 2004), it serves as reasonable benchmark. Furthermore, summation of undiscounted emissions abatement coupled with discounted abatement costs results in a cost-effectiveness measure highly sensitive to the model time horizon length, as smaller and smaller future present value abatement costs are divided by future undiscounted abatement quantities.

Finally, placing our analysis in the broader context of differing approaches, this cost-effectiveness measure is based on a bottom-up engineering analysis which is necessarily a supply-side, partial equilibrium measure because it does not capture any demand side adjustment to rising electricity prices due to CO<sub>2</sub> regulations or any other indirect impacts on the economy at large through changing prices in other sectors characteristic of general equilibrium modeling (Rose and Oladosu 2002). The measure also does not consider any potential tax revenue recycling advantages from replacing distortionary taxes with an externality tax (Parry, Williams et al. 1999). Finally, this measure does not consider any secondary environmental benefits such as reduction of other types of pollution.

### **3. MODEL RESULTS**

The backward induction model (Equation A3, Appendix) calculates the minimum expected present value cost of electricity generation as well as the optimal contingent investment policy. Forward calculations, combining this optimal investment policy with the inter-period transition probabilities of the state vector, yield the future utilization probability distributions of different power generation technologies. Close study of the evolution of these distributions demonstrates the operation of the model and provides insight into the economic incentives that drive firm technology choice.

We then investigate the value of technological adaptability in the face of regulatory uncertainty by restricting the firm's ability to retrofit for CCS, examine the importance of technological adoption risk through sensitivity analysis on the IGCC cost risk premium, and determine the expected value of the private cost



imposed on firms due to regulatory uncertainty by calculating the expected value of perfect regulatory information.

Following this analysis on private decision making and impacts, we expand the analysis to consider social costs and regulatory effectiveness. In this analysis, we investigate how private firm decisions in all model variations impact expected CO<sub>2</sub> emissions streams and electricity production costs, as well as an abatement cost-effectiveness measure that enumerates the tradeoffs between the two.

### 3.1 Full Stochastic Model with Retrofit

Consider the optimal investment decisions in the full stochastic model with retrofit flexibility. With model parameters as given in Table 1 and a base case IGCC cost risk premium of \$50 per kW of capacity, we calculate that minimum expected private present value cost increases by 11.6% above the no regulation case; 6.8% of this increase being carbon taxes (Table 2). At the first decision period in 2005, the firm retains the existing coal-fired generation technology with certainty. Beyond this time, gas and carbon prices,  $P^{NG}$  and  $P^C$ , evolve stochastically yielding optimal investment decisions that are contingent on the value of these prices when decisions are made. The distributions in Figures 1(a-c) illustrate the probabilistic evolution of investment decisions by aggregating the probability of observing an optimal technology in each ( $P^{NG}$ ,  $P^C$ )-state over all possible plant ages and all possible paths of reaching that state.

**Table 2. Model Results Comparison to No Regulation Case**

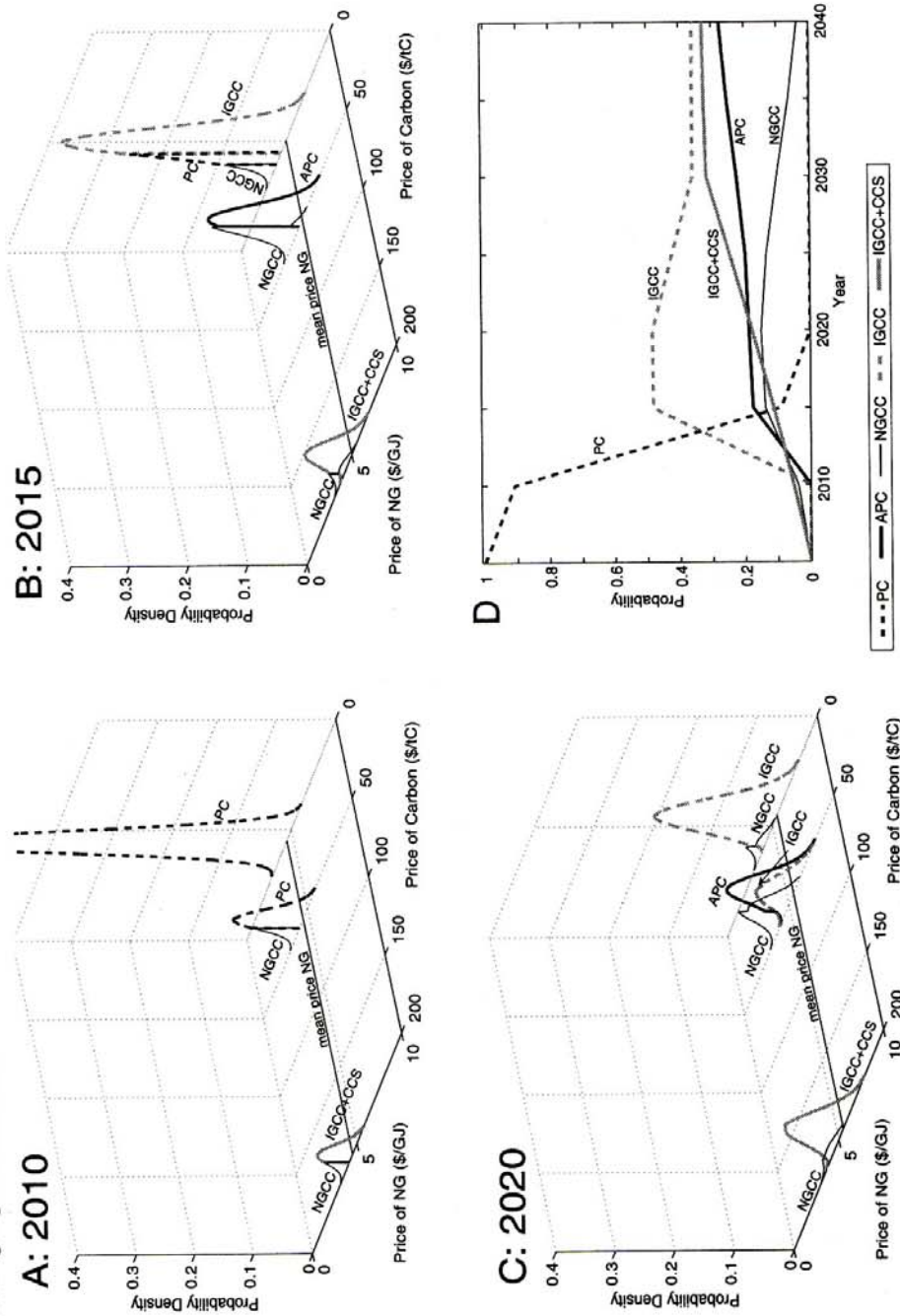
Results columns 1 through 3 give the percent change in present value costs and present value emissions relative to the no regulation case. Column 4 reports the social cost effectiveness of abatement measure equal to the change in social present value cost divided by the reduction in present value emissions.

	Private PV Cost (% change)	Social PV Elec. Cost (% change)	PV Emissions (% change)	Social Cost Effectiveness (\$/tC)
<b>With Retrofits</b>				
Full Stochastic	+ 11.6%	+ 10.8%	- 15.2%	\$ 76.37
Perfect Information	+ 11.4%	+ 9.7%	- 15.3%	\$ 68.55
<i>EVPRI</i>	+ 0.3%	+ 1.1%	0.0%	\$ 7.82
Certain Mean $P^C$ Ramp	+ 16.7%	+ 21.8%	- 28.6%	\$ 82.34
<b>Without Retrofits</b>				
Full Stochastic	+ 12.0%	15.5%	- 13.9%	\$120.17
Perfect Information	+ 11.7%	11.6%	- 15.4%	\$ 81.87
<i>EVPRI</i>	+ 0.3%	+ 3.8%	+ 1.5%	\$ 38.30
Certain Mean $P^C$ Ramp	+ 16.6%	+ 11.9%	- 13.6%	\$ 94.35

Private discount rate = 14%, Social discount rate = 4% , IGCC cost risk premium = \$50/kW. All table entries calculated with unrounded values.

**Figure 1. Time-evolution of Technology Probability Distributions**

Panels 'A'-'C' show the evolution of the state-contingent optimal technology choice over the first three model periods (2010, 2015 and 2020). At each period, optimal technology choice is contingent on the realized carbon and natural gas prices shown on the two horizontal axes as well as any investments in previous periods. The mean natural gas price (plotted as a line) increases from panel 'A' to 'C'. For carbon prices, only three discrete values are considered: note how the integrated probability moves from the \$0/tC to either the \$50/tC or \$200/tC carbon prices from panel 'A' to 'C'. Finally, panel 'D', shows evolution of technology probability integrated over uncertain gas price and carbon tax states.





In 2010 (Figure 1a), if no CO<sub>2</sub> regulations are implemented ( $P^C = \$0/tC$  which occurs with probability 80%), then the pre-existing coal plant is retained for all gas prices. Alternatively, if regulators implement low carbon prices ( $P^C = \$50/tC$  with probability 13.3%) and low natural gas prices are realized, then new NGCC plants are built; while at higher natural gas prices, this low carbon price is insufficient to induce retirement of the pre-existing plant. Finally, if regulators implement high carbon prices ( $P^C = \$200/tC$  with probability 6.7%), then building new NGCC is preferred at low gas prices while new IGCC+CCS is preferred at higher gas prices.

In 2015 (Figure 1b), the rising cost of maintaining the pre-existing PC plant induces investment in new technologies except over an intermediate interval of natural gas prices with zero carbon price. In this interval, the real option value of delaying new investment and paying the rapidly rising operating costs of the pre-existing plant until more information becomes available is decisive in delaying retirement. If gas prices remain in this range next period, the firm will replace this pre-existing PC plant with IGCC without CCS at zero carbon price, with NGCC at low carbon price, and with IGCC+CCS at the high carbon price. At gas prices below this intermediate interval, NGCC is the preferred technology, while at gas prices above this interval, the firm invests in IGCC because the loss of the option value of delaying investment and the cost of the real option to retrofit IGCC, which will not be exercised with 2/3 probability in future (the \$50/tC carbon state), is more than offset by the savings from avoiding the rapidly rising costs of the pre-existing plant and the value of the real option to retrofit IGCC in the 1/3-probability \$200/tC carbon state.

Over time, as there is a continued shift of probability from the no regulation state to the two regulation states, the technology probability distributions becoming ever more complex due to aggregation of multiple transition paths. For example, for a \$200/tC carbon tax in 2015 (Figure 1b), at low gas prices, prior period investment in NGCC combines with new investment to form the left half of the NGCC distribution. The right half of the NGCC distribution derives from the combination of prior period investment in NGCC and stochastically unfavorable rapidly increasing natural gas prices between 2010 and 2015.

Carbon capture retrofit introduces further complexities. In cases where regulation begins in 2020 (Figure 1c) prior period investment in IGCC without CCS is retained if carbon price transitions to \$50/tC but is retrofitted with CCS into a full IGCC+CCS plant for a transition to \$200/tC.

Figure 1(d) summarizes these results by integrating the probability distributions over all gas and carbon prices yielding the probability of observing each technology as a function of time. This figure illustrates the probabilistic retirement of the pre-existing PC fleet by 2020 with contingent replacement by each of the other generation technologies dependent on the information at the time investments are made. Beyond 2020, the probability of observing IGCC without CCS declines as it is CCS retrofitted if a \$200/tC carbon price is realized. Eventually, the probability of IGCC+CCS increases to nearly 33% both through retrofits and direct future invest-

ment in IGCC+CCS due to the 1/3 probability of a high carbon price. The generation technology for the remaining 2/3 probability at a low carbon price is divided between non-retrofitted IGCC, APC, and finally NGCC generation which peaks at 15% but then declines as the expected price of natural gas continues to rise.

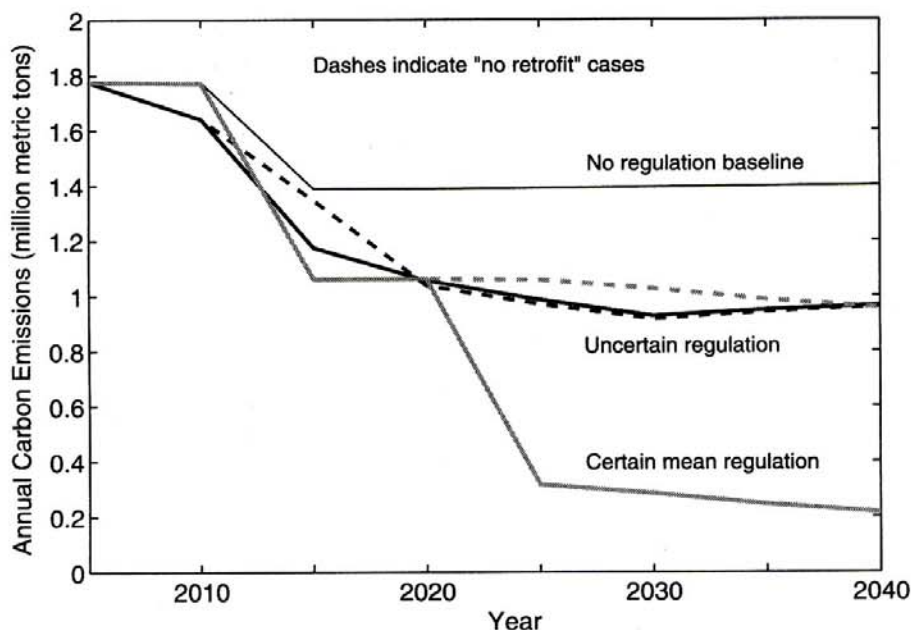
The expected CO<sub>2</sub> emissions time path (Figure 2) is derived by aggregating the probability times the emissions rate over all technologies. The expected emissions time path for the full stochastic model is compared to the more slowly declining baseline emissions time path, calculated with a zero carbon price but including the natural gas price uncertainty. Over the 40-year study horizon, the probabilistically specified uncertain CO<sub>2</sub> regulation reduces carbon emissions by 20% or 12.2 million metric tons of carbon. The impact of retrofit flexibility on emissions is discussed in the next section, and the certain mean regulation comparison case is discussed in Section 3.4.

### 3.2 The Value of Retrofit Flexibility to Firms

We assess the value of retrofit flexibility from the firm's perspective by rerunning the model without the option of investing in IGCC without CCS. The elimination of retrofits modestly decreases expected present value costs by 0.4% (Table 2). The difference in present value costs is quite small because the value afforded by flexibility under uncertainty most significantly alters decisions 10 to 25 years in the future where the discount factor declines from 0.27 to 0.04 with a 14% discount rate.

#### Figure 2. Expected Annual Carbon Emissions

Expected reductions in emissions of any policy are based on comparison with no regulation baseline case.





The impact of retrofit flexibility on technology choice and emissions is more significant. Without flexibility, there is an expected delay in retirement of the aging pre-existing PC fleet over both the retrofit and baseline no regulation cases. As seen in Figure 2, uncertain future regulations without retrofit flexibility raises expected emissions to nearly those of the no regulation case in 2015, as firms delay investment awaiting indication of the stringency of future regulations. On the other hand, the inability to retrofit also induces a slightly higher probability of early investment in NGCC. After 2015, the rapidly rising FOM of the pre-existing PC plants and the continued resolution of regulatory uncertainty cause retirement of all pre-existing PC plants, and beyond 2020 expected emissions without retrofit flexibility are slightly below the retrofit case owing to the higher probability of NGCC generation. However, as seen in the next section, the effect of retrofit flexibility on the social cost effectiveness of emissions abatement can be substantial when combining the net effect on emissions with an evaluation of future power generation costs at the social discount rate.

### **3.3 Social Cost Effectiveness of Abatement**

To ascertain the social cost effectiveness of abatement with the probabilistic regulatory specification, we calculate the expected cost increase and the expected emissions decrease in comparison to the no regulation case. Under the full stochastic model, the social expected present value electricity generation costs rise by 10.8% above the no regulation case, and the expected present value carbon emissions decline by 15.2% yielding an effective abatement cost of \$76/tC (see Table 2).

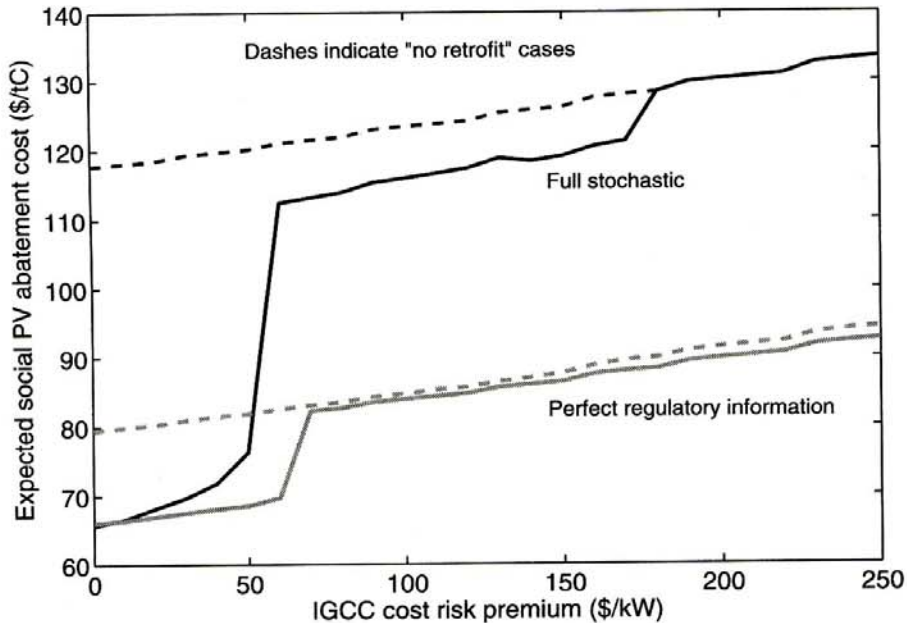
Technological adaptability has a substantial impact on social costs: without retrofit flexibility abatement costs increase by 57%. This significant change in cost effectiveness leads us to examine the importance of retrofit flexibility as a function of the IGCC cost risk premium. The perceived degree of technological and economic risk, implemented in the model as a capital cost risk premium, alters the competitiveness of IGCC relative to other technologies and thus the dynamics of technology choice. By varying the cost risk premium and re-calculating the complete stochastic model over the full time horizon, we graph abatement cost as a function of the IGCC cost risk premium in Figure 3.

An increasing slope, then two prominent steps, with nearly constant slope above each step, characterizes this function for the full stochastic model with retrofits. The general parallel positive slopes of all the graphs mainly reflect the increasing cost of IGCC+CCS as the IGCC cost risk premium increases, but also includes a smaller effect from the increasing competitiveness of NGCC versus IGCC+CCS in high carbon tax states and also versus IGCC without CCS on lower steps when pre-regulation investment in IGCC occurs.

The steps reflect technological “tipping points” where the optimal technology switches discontinuously based on the relative competitiveness of APC versus IGCC as the replacement for pre-existing PC plants prior to CO<sub>2</sub> regula-

### Figure 3. Expected Social PV Abatement Cost

Comparison of the expected social present value abatement cost under natural gas price and regulatory uncertainty with perfect regulatory information as a function of the IGCC cost risk premium proxy of IGCC commercial competitiveness. Note that the social cost of regulatory uncertainty is high either if retrofits are limited (dashed lines) or if IGCC is not commercially competitive (high IGCC cost risk premium).



tion at different times. The impacts on abatement cost effectiveness result from the two different components of the cost-effectiveness calculation: the first step is characterized by an abatement reduction while the second step is characterized by a cost increase.

Below the first step, as the IGCC cost risk premium increases from zero to \$50/kW, the increasing slope derives from the higher probability of delay in retirement of the pre-existing, high emissions PC plant. At zero cost risk premium, all pre-existing PC is retired by 2015. In this case, the ability to retrofit substantially reduces the cost of abatement should a \$200/tC tax occur and there is no cost penalty over APC should a \$50/tC tax occur, a tax too low to induce CCS retrofitting of IGCC. As the IGCC cost risk premium rises to \$50/kW, the cost penalty of IGCC over APC, which would be realized with the 2/3 probability of a future \$50/tC tax state, raises the probability of delaying investment and retaining pre-existing PC, indicated by an increase in the area of the intermediate window evident in Figure 1(b) for a zero carbon tax, leading to higher expected emissions and raising the unit cost of abatement.

At the first step, as the IGCC cost risk premium approaches \$60/kW, all early retirement of pre-existing PC plants in 2015 is eliminated, substantially raising emissions and lowering abatement cost effectiveness. However, IGCC without CCS is still preferred to APC in the zero carbon tax state in 2020 as the gains from ease of carbon capture retrofit at potential future higher carbon taxes more than compen-



sates for the cost penalty of IGCC over APC should lower carbon taxes occur.

Above the second step, all investment in IGCC without CCS prior to CO<sub>2</sub> regulation stops; the cost penalty of IGCC over APC has become too large. All remaining pre-existing PC in the no regulation state is retired and replaced by APC in 2020. Even though stand alone IGCC and APC have the same CO<sub>2</sub> emissions rate by our simplifying assumption and hence there is no impact on pre-regulation emissions, should a transition to a \$200/tC carbon tax state occur after 2020 (with 13.33% probability), it becomes optimal for the firm to abandon the APC plant recently purchased in the zero carbon tax state and replace it with a IGCC+CCS plant.<sup>5</sup> This expected abandonment results in the same CO<sub>2</sub> emissions as below the step, as IGCC+CCS occurs for \$200/tC tax in either case, but the cost differential between retrofitting an existing IGCC with CCS plant and building an IGCC+CCS plant to replace an existing APC plant causes the social cost of abatement to increase at this step.

From a regulator's perspective, the importance of the flexibility to cost-effectively retrofit IGCC plants is revealed by comparison of the social PV cost of abatement with and without retrofits in Figure 3. At low IGCC cost risk premiums, the lack of retrofit flexibility can increase the expected social cost of abatement by as much as 79%. At higher IGCC cost risk premiums where IGCC is less competitive, the value of retrofit flexibility is much smaller. The policy implications of this competitiveness and the interrelationship between the ability to retrofit and the expected value of perfect regulatory information are discussed in the next section.

### **3.4 Social Cost of Regulatory Uncertainty**

To examine the consequences of regulatory uncertainty on both firm decision making and eventual regulatory effectiveness, we compare the uncertain case to two specifications with uncertainty removed. First, since policy makers possess the ability to remove regulatory uncertainty, we model the simple case where regulators commit to a carbon tax that matches the expected value of the tax in our stochastic model. Second, we calculate the expected value of perfect regulatory information as discussed in Section 2.5.

As a conceptually simple comparison case, we assume that regulator's implement a carbon tax that ramps linearly from zero to \$100/tC in 2030 and is constant thereafter. This corresponds to the expected value in our stochastic model (Section 2.2), although none of the stochastic carbon tax trajectories follow this path. This tax specification produces much greater reductions in emissions than does the stochastic case (Figure 2). Emissions abatement increases from 15.2% to 28.6%, while the social unit cost of abatement increases by 8% (Table 2). Both effects result from substantial changes in technology choice as compared to the full stochastic case. Under the deterministic regulation ramp case, foresight on carbon prices above \$80/tC eliminates any investment in APC. As carbon prices ramp up, all pre-existing PC is retired by 2015 when the carbon tax reaches \$40/tC, re-

5. Including a high cost APC retrofit option would reduce the size of the resulting step.



placed with 40% probability by NGCC and 60% by IGCC with pre-investment for CCS. Installed IGCC is retrofitted with CCS once the carbon tax reaches \$80/tC in 2025, and by the end of the time horizon, the probability of NGCC declines to 13% while IGCC+CCS climbs to 87% as rising gas prices lead to abandonment of transitional NGCC plants.

The expected value of perfect regulatory information (EVPRI) provides a more rigorous measure of the cost of regulatory uncertainty. With the ability to retrofit, the EVPRI is quite small in relation to the total cost from both the private and social perspective: 0.3% and 1.1%, respectively, as seen in Table 2 when the IGCC cost risk premium is \$50/kW. However, firm decision making under perfect regulatory information reduces by 10% the expected social cost of abatement, the measure that most accurately reflects the tradeoff between electricity generation cost and emissions. Moreover, without the flexibility of retrofits, the EVPRI from the social perspective rises to 3.8%, and perfect regulatory information lowers the expected social cost of abatement by 32%.

To further explore this issue, we include the plots for the expected social cost of abatement as a function of the IGCC cost risk premium under perfect regulatory information in Figure 3. At very low cost risk premiums, the gains from making investment decisions under perfect regulatory information as measured by the social cost effectiveness of abatement are quite small because the flexibility afforded by retrofits can effectively neutralize the impact of regulatory uncertainty

However, as the purchase price of the IGCC retrofit flexibility option reflected in the cost risk premium rises above \$60/kW, the impact of regulatory uncertainty on abatement cost effectiveness becomes significant. Now under regulatory uncertainty, there is a higher probability of delaying the retirement of pre-existing PC facilities raising expected emissions coupled with higher expected costs of eventual investment in IGCC without CCS.

On the other hand, the decision-making flexibility accorded each regulatory time path under the perfect information construct does not result in delaying aging PC replacement with APC on all regulatory time paths with 2/3 total probability that lead to an eventual \$50/tC carbon tax; PC retirement delays are only optimal on time paths that lead to a \$200/tC carbon tax. The absence of this flexibility to differentially delay plant retirement under regulatory uncertainty raises the social cost of abatement by between 38% and 61%.

Without the ability to retrofit, regulatory uncertainty is consistently detrimental to the expected cost effectiveness of future regulations, even at low IGCC cost risk premiums. Over the full range of cost risk premiums considered, regulatory uncertainty raises the social cost of abatement a consistent 42% to 48%.

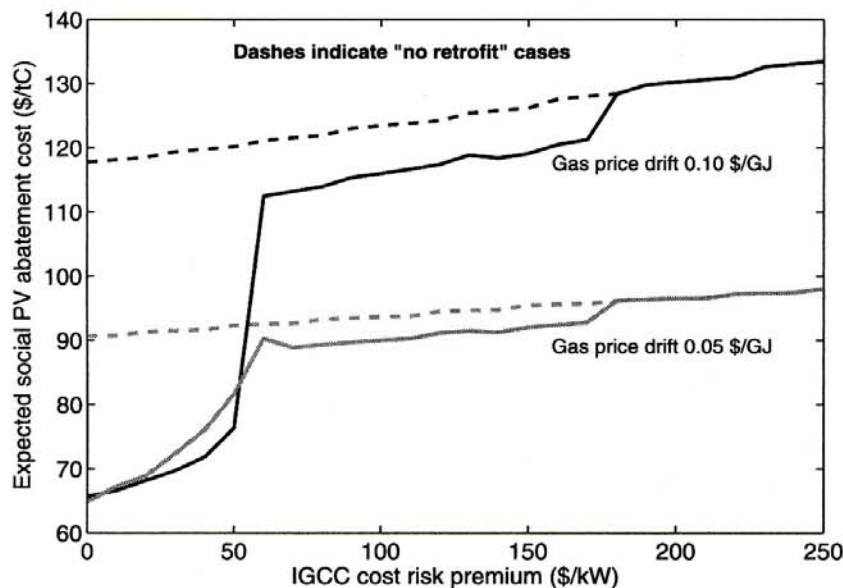
### **3.5 Sensitivity Analyses**

We examine the robustness of model results and policy implications with respect to key assumptions about gas prices and the operating cost growth rate proxy for rising conventional pollution control costs by means of a sensitivity analysis.



**Figure 4. Sensitivity of the Expected Social PV Abatement Cost to the Gas Price Drift Parameter**

This case shows that, as expected, lower gas prices decrease the expected social abatement costs unless IGCC with retrofit flexibility is a competitive substitute (low IGCC cost risk premium) when gas prices are high.



Given both the volatility in natural gas prices and the boom-and-bust investment in NGCC plants during the 1990s (Lapson and Hunter 2004), the impact of future natural gas prices holds particular interest. In our standard scenario, natural gas prices are high enough to limit the penetration of NGCC plants to a peak of 15% probability (Figure 1d); we therefore explore a lower gas price scenario, as might occur if LNG imports moderated prices, in which the annual gas price drift is reduced from \$0.10/GJ to \$0.05/GJ while maintaining the same random-walk variance.

In the low gas price scenario, gas generation plays a much larger role with the penetration of NGCC plants peaking at 50% probability in the full stochastic model with retrofits. Even under the low gas price scenario, the penetration of gas capacity is driven by expectations of future carbon constraints: in a zero carbon price future, penetration of NGCC peaks at only 13% probability. This suggests that carbon constraint expectations, in conjunction with expectations of low gas prices, may have played some role in driving recent construction of gas capacity.

Gas price assumptions interact with IGCC competitiveness and retrofit flexibility to constrain the cost effectiveness of regulations. Figure 4 illustrates the impact of the gas price drift rate assumption on regulatory cost effectiveness as a function of the IGCC cost risk premium.

In the absence of retrofit flexibility (or under high IGCC cost risk premiums), firms can use a NGCC low capital-cost bridging strategy while they await certainty about the level of the carbon constraint. Firms that must retire their PC

assets can then wait to choose between APC or IGCC+CCS once they know the carbon constraint, or if gas prices remain low they can retain NGCC. At high natural gas prices, the use of gas as a bridging strategy is constrained, driving the social cost effectiveness of regulation down and the cost of regulatory uncertainty up.

Conversely, if retrofit flexibility is available and competitive (low or zero IGCC cost risk premiums), then the gas price ramp has little impact on the social cost effectiveness of abatement even though gas prices affect the technological means and timing of abatement. From the firm's perspective IGCC retrofits and NGCC with low gas prices are substitutable or alternative means of managing the carbon price uncertainty. If both are eliminated (high gas prices and IGCC premium) then the social cost of abatement rises dramatically.

Finally, we examine the sensitivity of model results to the growth rate of fixed operating costs for the pre-existing PC plant, the proxy assumption used to represent the rising cost of conventional pollution control as well as plant aging. The general results on the cost of regulatory uncertainty with respect to IGCC competitiveness and retrofit flexibility remain, but the relative magnitude of the abatement cost differences declines while decreasing this parameter to 10% since this reduces the pressure to retire pre-existing PC plants earlier in the evolving uncertain regulation cycle. Similarly, model results demonstrate the same relationship between the retrofit and perfect information cases but the relative magnitude of the differences decreases as greater probability of retirement moves beyond the certain onset regulation. Decreasing the parameter even further to 5%, completely removes the incentive for early retirement of pre-existing PC and investment in IGCC prior to the certain onset of carbon regulation; thus the stochastic, perfect information and retrofit cases collapse into one. However, under alternative uncertain regulation specifications which extend regulatory uncertainty beyond the 25 years of our base case assumption, our general results reemerge. Any factor which drives the retirement of aging PC plants prior to the resolution of carbon regulation uncertainty will demonstrate the robustness of our general results.

#### **4. CONCLUSIONS AND POLICY IMPLICATIONS**

In all cases regulatory uncertainty raises the social cost of abatement (defined as present value cost per unit of carbon); however, the cost of regulatory uncertainty is strongly dependent on the competitiveness of generation technologies with low cost carbon capture retrofits and on the competitiveness of using natural gas as a transitional 'bridging strategy'. If a technology with low cost retrofit flexibility adds little to initial capital cost (low IGCC cost risk premium in our model), then regulatory uncertainty does not significantly increase abatement cost. Alternatively, if natural gas prices are expected to have a low growth rate, then natural gas generation offers a low capital cost 'bridging strategy' that can significantly lower the social cost of regulatory uncertainty.

Conversely, if the ability to retrofit is restricted and natural gas price expectations are high, then regulatory uncertainty causes firms to delay retirement



of pre-existing, high emissions PC plants, temporarily raising emissions to nearly the certain no regulation case, and greatly increasing social abatement cost.

In the current U.S. policy environment, if regulators anticipate that restriction of CO<sub>2</sub> emissions will be necessary to manage climate change, yet foresee continued delay in implementing CO<sub>2</sub> regulations, then they should pursue strategies that improve the cost-effectiveness of abatement when CO<sub>2</sub> emissions are eventually regulated. Policies that maximize industry's use of technologies with a comparatively low cost of retrofit can help to avoid technological traps that lead to high eventual abatement costs. One possibility is for regulators to provide incentives for gasification (IGCC) when new coal fired power plants are constructed. Methods such as we have demonstrated in this paper may serve a role in computing the appropriate level of incentive, the one that minimizes the expected social cost of abatement.

The European situation is somewhat different from the U.S. context that informed our choice of model parameters. Most obviously, the European emissions trading system imposes a carbon price on electricity generators. There is little evidence that prices have been high enough to stimulate significant investment in new generating technology although they appear to have driven some fuel switching (Carbon-Trust 2006). Our model assumes a carbon price which is monotonically increasing whereas the European price exhibited both short term volatility and dramatic downward correction in 2006. While it would be easy to alter the carbon price model used in our analysis, the choice of model is not obvious. One might choose a Brownian motion model like that used here for gas prices; however it is plausible to argue that long-term European prices will increase in steps of uncertain magnitude and timing driven by regulatory decisions about permit allocation and so such a model might not improve over the assumptions adopted here.

The European outlook also differs in that the mean age of existing plants is lower and more of them have advanced emissions controls, thus the increasing operating cost driving force for retirement prior to the meaningful resolution of uncertainty is likely to be lower than the U.S. The net result is a relatively lower magnitude expected cost of regulatory uncertainty in the E.U.

The issue of generation capacity expansion for electricity demand growth, discussed in the introduction but not explicitly modeled, is more appropriately modeled at the sectoral level, since capacity expansion is driven by the expectation of future prices resulting from the interplay of increasing demand and increasing supply as new firms enter or existing firms expand. On the other hand, the more significant plant replacement issue developed here is best modeled at the firm level since the firm's expectations of the cost of producing electricity with its aging plant relative to a replacement plant drives the decision. Nonetheless, insights can be gleaned from the current model for demand induced capacity expansion.

First, any factor that creates incentives for investment prior to the resolution of regulatory uncertainty creates the condition for a social cost of regulatory uncertainty. Second, the relative probability of each technology for capacity expansion will be similar to that from equipment replacement (Figure 1d) since



the optimal future technology choice at the time of investment commitment depends only of the relative cost of the alternatives. Third, the expected social cost of abatement related to the capacity expansion issue will be greater because the quantity of abatement will be lower (i.e. the no regulation baseline emissions will utilize NGCC at lower gas prices and APC at high gas prices rather than the much higher baseline emissions from aging coal plants for the equipment replacement issue.) Fourth, low-cost retrofit flexibility arising from IGCC competitiveness will reduce the social cost of regulatory uncertainty as measured by abatement cost effectiveness, but the relative magnitude of reduction will be smaller because of the absence of the opportunity afforded by early retirement of aging coal plants in the equipment replacement problem.

A few caveats are particularly salient. First, while the specific results reported here depend, of course, on assumptions about technology cost and performance, we anticipate that the interplay between the cost of regulatory uncertainty and the ability to manage that uncertainty through retrofits or use of low-capital cost natural gas generation is robust.

Second, we do not model the role of technological change since the focus of our model is the intermediate term transition away from aging coal-fired generation and because predictive modeling of technological change over long time scales is notoriously difficult. However, we do include emerging electricity generation (IGCC) and emissions abatement (CCS) technologies with potential for commercial adoption in the time frame of interest but without modeling learning by doing to predict future decreases in the average cost of these technologies (Riahi, Rubin et al. 2004). Non-mature technologies, such as IGCC and CCS, have a greater likelihood of experiencing cost reducing technological change or learning, which would imply more penetration of these technologies both pre- and post-regulation. To partially compensate for these omissions, we have used costs for IGCC and CCS that are somewhat lower than the average, but well within the range, of expert estimates for initial projects in the North American or European markets.

Third, we do not model correlations between natural gas and carbon prices. All else equal, a rise in carbon prices will encourage fuel switching from coal to natural gas. Such an effect might be felt almost instantaneously as the change in the relative fuel prices reshuffles the economic dispatch order in electric markets. The increase in electricity prices resulting from a rising carbon price would have complex macro-economic effects, but adopting the (reasonable) assumption that interfuel substitution will be more elastic than electricity demand it seems likely that the two prices will be positively correlated. Such correlations would make natural gas a less attractive option, reducing the already low probability of NGCC investment in our base model and could significantly affect the results of our low natural gas price case.

Finally, while we did not explicitly include nuclear power, many of the arguments presented here apply to nuclear. For example, because it shares the high capital cost and low emissions characteristics of IGCC+CCS, investment in nuclear also depends on uncertain carbon regulation and on the availability of



natural gas as a bridging strategy. Unlike IGCC, no retrofit option is possible. Like CCS, cost is not the only issue as public perception and long-run environmental risks will also play a role in any decision.

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## APPENDIX – MATHEMATICAL DETAILS

### Stochastic Dynamic Programming Model

Investment decisions are made each period over a finite time horizon. Let  $t = \{0, 1, 2, \dots, T\}$  be the set of time periods.  $T$  investment decisions are made in periods  $0, 1, \dots, T - 1$ . At any time  $t$ , a four-dimensional state vector  $s_t$  describes the electricity generation firm's current situation where  $s_t \in S$ , the state space (the set of possible states).

$$S = \{[\text{technology type, plant age, } P^C, P^{NG}]\}$$

with  $P^C$  the price of carbon emissions and  $P^{NG}$  the price of natural gas. The firm observes the current state and takes current investment action  $a_t$  from among the set of all alternative actions  $A$ .

$$A = \{1 - \text{keep existing technology plant,} \\ 2 - \text{build new advanced pulverized coal plant (APC),} \\ 3 - \text{build NGCC plant,} \\ 4 - \text{build IGCC plant with CCS,} \\ 5 - \text{build IGCC plant,} \\ 6 - \text{retrofit an existing IGCC plant}\}$$

where the availability of the 6<sup>th</sup> action is state dependent; in other words, this choice is only available if the existing technology state at the time of the decision is IGCC.

The value function  $V_t(s_t)$  represents the minimum cost to the end of time horizon from state  $s_t$  at time  $t$ . Let  $a_t^*(s_t)$  be the optimal decision at time  $t$  from state  $s_t$ , and let  $c(s_t, a_t)$  be the current period cost given state  $s_t$  and decision  $a_t$ . The discount factor is  $\beta$ . The current period cost function is composed of six elements: new capital investment in plant construction or retrofit ( $I$ ), fixed operating cost ( $FOM$ ), variable operating cost ( $VOM$ ), fuel cost ( $FUEL$ ), carbon emissions taxes ( $CTAX$ ), and carbon sequestrations costs ( $CSTOR$ ).

$$c(s_t, a_t) = I(\text{tech}_t) + FOM(\text{tech}_t, \text{age}_t) + VOM(\text{tech}_t) + \quad (A1) \\ FUEL(\text{tech}_t, P_t^{NG}) + CTAX(\text{tech}_t, P_t^C) + CSTOR(\text{tech}_t)$$

Annual carbon emissions taxes are the product of the tax rate per ton and the annual tons of carbon emitted.



Beginning implementation of Bellman's Optimality Principle with the period prior to the termination time  $T$ , the minimum cost to the end of the time horizon is

$$V_{T-1}(s_{T-1}) = \min_{a_{T-1} \in A} \{c(s_{T-1}, a_{T-1}) - \beta E[\Omega(s_T) | s_{T-1}, a_{T-1}]\} \quad (A2)$$

where  $\Omega(s_T)$  represents the terminal value of the electricity generation plant given terminal state  $s_T$ , and the expectation is taken from the perspective of period  $T-1$  with knowledge of the state and action at that time,  $s_{T-1}$  and  $a_{T-1}$ , respectively. The terminal or salvage value  $\Omega(s_T)$  is calculated by straight-line depreciation of the capital investment over a 25-year lifetime. Since this simple salvage estimate does not account for future gas price expectations and value differences based on the distribution of realized states at the end of the time horizon, the model calculation time horizon is doubled to alleviate end effects of transversality conditions on the first half of the time horizon that is the focus of this study. A sensitivity analysis varying calculation time horizon length to investigate the effects on investment decisions in the first 40-year focus of the time horizon, confirms that an 80-year time horizon is sufficient to eliminate nearly all end effects.

The value functions and optimal investment decisions in all prior periods ( $t = T-2, \dots, 1, 0$ ) are derived by backward induction from the recursive equations

$$V_t(s_t) = \min_{a_t \in A} \{c(s_t, a_t) + \beta E[V_{t+1}(s_{t+1}) | s_t, a_t]\} \quad (A3)$$

$$\min_{a_t \in A} \{c(s_t, a_t) + \beta \int V_{t+1}(s_{t+1}) f(s_{t+1} | s_t, a_t) ds_{t+1}\}$$

where  $f(s_{t+1} | s_t, a_t)$  is the probability density function of the transition to the next period state conditional on the current period state and action. Again, the expectations are taken with respect to the information that is available at time  $t$ , namely state  $s_t$  and the action  $a_t$  taken at that time.

Finally,  $V_0(s_0)$  the minimum expected present value cost to the end of the time horizon from  $t = 0$  can be obtained by evaluating the current value function  $V_0$  at the observed initial state vector  $s_0$ . The optimal investment policy resulting from the actions that minimize cost in Equation A3 is a contingent decision sequence,  $\{a_0^*(s_0), a_1^*(s_1), a_2^*(s_2) \dots\}$  (\* denotes optimal actions), contingent on the observed future period realizations of the state vector.

### Random Variable Assumptions

The natural gas price component of the probability density function is based on an assumption that price evolves by Brownian motion with drift

$$P_{t+1}^{NG} = P_t^{NG} + \alpha + \sigma \varepsilon_t \quad (A4)$$

where  $\alpha$  = annual drift parameter,  $\sigma^2$  = annual variance parameter, and  $\varepsilon_t \sim N(0,1)$ .

These assumptions yield a continuous probability distribution for  $P^{NG}$  with expected price changes  $E(\Delta p) = \alpha \Delta t$  and price variance  $Var(\Delta p) = \sigma^2 \Delta t$  for period length  $\Delta t$ .

The carbon price component of the probability density function is based on discrete distribution assumptions for both the timing and magnitude of a carbon tax. For simplicity, the carbon tax can take on two possible magnitudes: a low \$50/tC or a more stringent \$200/tC. When a regulation is adopted let  $q$  equal the probability of a low carbon price and  $1 - q$  equal the probability of a high carbon price. The base case assumes  $q$  equals  $2/3$ . The distribution for the timing of the carbon tax is based on an a priori 20% probability for implementation of CO<sub>2</sub> regulations in periods  $t = 1$  to 5 corresponding to 5-year time intervals beginning in 2010 to 2030. After implementation, the magnitude of the carbon price remains at either \$50/tC or \$200/tC.

At the beginning of the time horizon, let  $p(t)$  be the probability that CO<sub>2</sub> regulation will be adopted at the beginning of period  $t$ , for  $t = 1, 2, \dots, T-1$ . Once adopted, the regulation is assumed to remain the same to the end of the time horizon. If the regulation is not adopted in any period, the probability of adoption is updated the next period

$$p(t' \mid \text{no adoption } t < t') = p(t') / \sum_{t=t}^{T-1} p(t) \quad (\text{A5})$$

to maintain the a priori probability of regulation implementation each period.

### Model Solution Methodology

The conditional transition probabilities of the state vector in Equation A3 are a mixture of continuous and discrete probabilities corresponding to the different dimensions of the state vector. The technology and plant age components of the transition between periods are deterministic based on the prior period state and investment decision. The  $P^C$  dimension transition is modeled as discrete and the integral with respect to this dimension becomes a simple summation. On the other hand, the continuous  $P^{NG}$  dimension necessitates numerical approximation of the value function  $V$  over this dimension.

A smooth approximation of the value function using piecewise cubic interpolation over a grid  $\{P_0^{NG}, P_1^{NG}, \dots, P_{2m}^{NG}\}$  which subdivides the domain of this dimension into  $2m$  equal partitions is effectively calculated by numerical integration of Equation A3 over this dimension utilizing a composite Simpson quadrature algorithm. Since  $P^{NG}$  evolves by a deterministic drift plus a random shock with a normal distribution, there will always be some positive probability beyond the range of the partition. This is accounted for by adding a discrete probability at either end of the grid space ( $P_0^{NG}$  or  $P_{2m}^{NG}$ ) equal to the tail probability and verifying that these boundary effects do not significantly impact the overall integration. Choice of  $P_0^{NG} \geq 0$  eliminates unrealistic negative prices.



Beginning with the final period and proceeding by backward induction period by period to the beginning of the time horizon, the value function and the optimal action are calculated through minimization using Equation A3 for every possible state that could occur each period along the three discrete dimensions of the state vector and for each grid price along the continuous  $P^{NG}$  dimension, and the results are stored in a 4-dimensional array each period. The smooth approximation of the value function can then be obtained over the  $P^{NG}$  dimension with cubic spline interpolation.

Finally, calculations are performed in the forward direction to aggregate probabilities through time to determine the probability distributions of future power generation technologies, the probability of each technology in future time periods, and the expected CO<sub>2</sub> emissions time path.

The model operates on a 5-year time step, over an 80-year time horizon to minimize end effects, but reported results reflect only the first 40-year time horizon, the intermediate generation technology transition period focus of this study. The  $P^{NG}$  domain [0 \$/GJ, 16 \$/GJ] is partitioned into 400 subintervals. The model is programmed in Matlab and is available from the authors.

### Expected Value of Perfect Regulatory Information

To derive the expected value of perfect regulatory information (EVPRI), let the perfect regulatory information (PRI) value function  $V_{it}^{PRI}(s_{it})$  represent the minimum expected cost to the end of the time horizon from state  $s_{it}$  at time  $t$  over known regulatory time path indexed by  $i$ . Again, the state contingent value functions and optimal investment decisions for all prior periods are derived by backward induction using the recursive equation

$$V_{it}^{PRI}(s_{it}) = [ \min_{a_{it} \in A} \{ c(s_{it}, a_{it}) + \beta E^{P^{NG}} [ V_{i,t+1}^{PRI}(s_{i,t+1}) | s_{it}, a_{it} ] \} ] \quad (A6)$$

where the expectation operator  $E$  is now over only uncertain future natural gas prices. For each possible regulatory time path  $i$ , there is a different state contingent optimal investment policy  $\{ a_{i0}^*(s_0), a_{i1}^*(s_{i1}), a_{i2}^*(s_{i2}) \dots \}$  and a different minimum expected present value cost of electricity generation over the time horizon equal to  $V_{i0}^{PRI}(s_0)$ .<sup>6</sup> Then the expected value of perfect regulatory information can be expressed

$$EVPRI = V_0(s_0) - E^{P^C} [ V_{i0}^{PRI}(s_0) ] \quad (A7)$$

where the expectation in the second term on the right hand side is over all carbon price paths indexed by  $i$ .

6. The initial state  $s_0$  is the same for all perfect information regulatory time paths, and thus the regulatory time path index of the state vector can be dropped for the initial state only.