The Cost of Regulatory Uncertainty in Air Emissions For a Coal-fired Power Plant

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Abstract:

Uncertainty about the extent and timing of changes in environmental regulations for coal fired power plants makes the difficult problem of selecting a compliance strategy even harder. Capital investments made today under uncertainty can limit future compliance options or make them very expensive. In this paper, we present a method for computing the cost of operating a moderate-sized, coal-fired power plant under different conditions of future regulatory uncertainty. Using a Multi-Period Decision Model (MPDM) that captures the decisions (both capital investment and operating) that a power plant owner must make each year, the framework employs a Stochastic Optimization Model (SOM), nested in the MPDM to find the strategy that minimizes the expected net present value (ENPV) of plant operations over a fixed planning horizon. By comparing model runs under different uncertainty conditions, the cost of regulatory uncertainty can be calculated.

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1. Introduction

Uncertainty imposes costs to society by preventing optimal decisions to be recognized and pursued. One source of uncertainty is the legislative/regulatory process. This paper quantifies these costs in one important example in the electricity industry, uncertainty of future air emission regulations.

Significant changes in the regulations controlling emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), mercury (Hg), and carbon dioxide (CO_2) in the atmosphere will occur in the future, posing a serious challenge to the electricity generation sector and especially to coal-fired power plants. Uncertainty about the extent and timing of potential future regulations makes the difficult problem of selecting a compliance strategy even harder. These uncertainties may even be exacerbated by the industry if it follows the usual path of litigation.[1]

Significant emission reductions from coal-fired power plants could require installing expensive add-on controls, retrofitting the plant to burn alternative fuels, or even retiring the plant and replacing it with a new, cleaner one. The suitability of any compliance strategy is particularly dependent on which pollutants are regulated, when and how stringently they are regulated, and the details of the regulatory instruments. The same strategy that may look optimal under one regulatory scenario could prove to be very expensive under others.

Currently, SO_2 and NO_x emissions from power plants are regulated by a combination of command-and-control (CAC) and cap-and-trade (CAT) instruments, depending on pollutant and plant location. New regulations are scheduled to come into force in the next several years. However, there is uncertainty about the future of both current and upcoming SO_2 and NO_x regulations. At present, there are no Federal regulations on mercury emissions from power plants, but Congress has ordered the EPA to propose regulations on mercury emissions from coal- and oil-fired power plants by December 2003. Finally, while the current administration do not support CO_2 regulations in the near future, all credible observers believe that Federal controls on greenhouse gas (GHG) emissions for U.S. power plants will be required eventually.[2]

Several bills controlling some or all of these pollutants were introduced in the 107th Congress, and the issue is sure to arrive again in the upcoming session.

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[1] Although there is a deadline of May 2004 for the implementation of more stringent NO_x standards, recent suits by utilities could postpone the action. [Energy Argus Daily. Clean Air Regulations and Markets. Vol. 9 No 148 August 2002.]

[2] International treaties and recent laws appear to foretell Federal Controls: Consider for example: the State of New Hampshire House Bill 284-FN relative to additional emissions reductions from existing fossil fuel burning steam electric power plants
http://www.gencourt.state.nh.us/legislation/2002/hb0284.html.
Oregon Carbon Dioxide Emission Standards for New Energy Facilities, House Bill 3283.
http://www.leg.state.or.us/97reg/measures/hb3200.dir/hb3283.a.html.
State of Massachusetts DEP Regulation 310 that caps CO2 emissions from the six highest polluting power plants in 1,800lbs of carbon dioxide per megawatt-hour.
http://yosemite.epa.gov/globalwarming/ghg.nsf/actions/LegislativeInitiatives
California Automobiles/lemon law AB1058. http://www.dca.ca.gov/legis/2001 autolemon.htm

Many of this bills feature CAT systems to control all these pollutants, while a few rely on CAC approaches.[3]

Future regulations may have broad economic impacts on the cost of fuel, type of generation, and control technologies that will be required. Despite these uncertainties, plant owners and operators must still make investment decisions to keep up with electricity demand. Waiting to decide until all legislative, regulatory, judicial uncertainty is resolved could prove costly; however, "locking in" an emission-control technology too soon could be equally expensive. Changes in the legislative/regulatory process that reduced or eliminated some of the underlying uncertainties could provide significant economic savings for the industry.

In this paper, we present a method for computing the cost of operating a moderate-sized, coal-fired power plant under different conditions of future regulatory uncertainty. Using a Multi-Period Decision Model (MPDM) that captures the decisions (both capital investment and operating) that a power plant owner must make each year, the framework employs a Stochastic Optimization Model (SOM), nested in the MPDM to find the strategy that minimizes the expected net present value (ENPV) of plant operations over a fixed planning horizon. By comparing model runs under different uncertainty conditions, the cost of regulatory uncertainty can be calculated.

This paper is organized as follows. In Section 2, we discuss previous models that have been developed to evaluate regulatory uncertainty and show how the proposed model is different. In Section 3, we describe the structure of the MPDM and SOM models and how they interact. In Section 4, we present assumptions used in a baseline analysis. In Section 5, we present the baseline analysis and its results. In Section 6, we present several sensitivity studies on the base case, and in Section 7, we outline opportunities for future work.

2. Models for Analyzing Impacts of Environmental Regulations

There are different models that forecast the effects that environmental legislations may have on the U.S. electric sector, four of them are: 1) the National Energy Modeling System (NEMS)(EIA, 2001a), 2) the Argonne National Laboratory's AMIGA model (Hanson, 1999), 3) the EPA's Integrated Planning Model (IPM), and 4) the Carbon Capture and Sequestration in an Electric Market Dispatch Model (Johnson & Keith, 2002).

NEMS and AMIGA are general equilibrium models of the U.S. economy, while IPM and the Johnson model are bottom-up linear programming models of the electric power sector. All assume perfect foresight and forecast electric power sector decisions for a given set of environmental regulations.

The NEMS and AMIGA models forecast capacity additions, fuel dispatching, and electricity prices based on different endogenous and exogenous

[3] Consider for example Clean Power Act of 2001 Bill # S.556 (Jeffords) or Clean Power Act and Modernization Act of 2001 Bill # S.1131 (Leahy), or Presidents Bush "Clear Skies Proposal".

inputs of the electric sector and the U.S. economy. IPM forecasts decisions made from the national to the plant level in response to legislative requirements seeking to minimize the net present value of the cost of compliance over the full planning horizon.

A recent analysis using NEMS was prepared in response to a request by the U.S. Congress to examine the costs of imposing caps on power sector emissions of SO_2, NOx, Hg and CO_2. Some results of this analysis are contained in "Strategies for Reducing Multiple Emissions from Electric Power Plants" (EIA 2001d) and are used later in this paper as inputs for the baseline analysis.

AMIGA and IPM models have also been recently used (EPA 2001a) to assess the impacts of legislations to reduce emissions from the electricity sector.

The Johnson model forecasts capacity additions, retirements, retrofitting, and dispatching for different prices of carbon emissions within the Mid Atlantic Area Council Region (MAAC) of the North American Electric Reliability Council. Unlike the others, Johnson's considers Carbon Capture and Sequestration (CCS).

The model proposed here is different from the others in that it 1) is based on a unit-level analysis, 2) explicitly accounts for the uncertainty in future regulations, 3) allows future decisions to adjust to resolved uncertainties, and 4) can be used to determine the inherent costs of different types of regulatory uncertainty. It also varies from NEMS, AMIGA and IPM in that it considers CCS.

3. Modeling Decision Making of a Power Plant Operator

In this paper, we present a method to compute the cost of operating a power plant under different conditions of future regulatory uncertainty. To do so, the MPDM is used to model plant investment, operation, and allowance choices on a yearly basis. (Figure 1 shows model dynamics). In each year, the MPDM calls on the SOM to determine the optimal operating and investment strategy for that year that minimizes the cost of generating a fixed amount of electricity for the next 30 years, based on current and expected conditions.

3.1 Representing the uncertainty: Probabilities on plausible scenarios

In this analysis, uncertainty is characterized by a probability that is assigned to each member of a set of mutual-exclusive, exhaustive plausible "scenarios." A scenario defines a sequence of future regulations, emissions caps allowances prices and policy instruments. Every scenario is a "bundle" of assumptions on future regulations and allowances market behavior for every year of the planning horizon. Each scenario implies a deterministic trend for allowances prices, and therefore, when the uncertainty about regulations is resolved so are the uncertainties in allowances prices. Table 1 shows the five scenarios that will be considered for a baseline analysis.

Throughout this study, two types of cost calculations are computed using SOM at each time step: 1) if the actual future regulation scenario is known (a deterministic optimization problem), and 2) if the actual future scenario is not known to the decision maker but the decision maker has assigned a probability to each possible scenario. This set of probabilities (which we will define to be α) is subjective, will vary from decision maker to decision maker, and will evolve over time as new information about which scenarios are still possible is acquired. The evolution of these probabilities is assumed deterministic given an actual scenario occurring. However, the decision maker will not know how the probabilities will change, until the uncertainty is revealed to her.

For example suppose decision maker recognizes that it is very likely that a new regulation will come in less than ten years and the future will take the form of one of the scenarios represented in Table 1. Suppose also that she believes that scenario BAU is the least likely while scenario *3P+1* is the most likely; accordingly, she assigns a probability of occurrence to each scenario as shown in Table 2. As time passes and scenarios are found not to occur, the decision maker will reallocate her belief among the remaining scenarios (redistribute the probabilities). For this paper, this process is assumed "systematic" (maintaining the same relative distribution of probabilities).

3.2 Stochastic Optimization Model (SOM)

The optimization model finds the investment, operating, and allowance trading strategy that minimizes the expected cost to produce electricity subject to environmental constraints by selecting control or replacement technologies to install and use over a planning horizon.

A stochastic linear mixed integer programming model (see e.g., Birge & Louveaux, 1997) is used to find the plant's optimal compliance strategy for the remaining planning horizon. Tables 3 and 4 summarize the input parameters of the SOM.

The decision variables in SOM represent three kinds of decisions; capital investment, operational choice, and allowances trading. Capital investment decisions are represented by binary variables that indicate whether a particular control or replacement technology is installed in a given period. Operating decisions are also represented by binary variables that indicate whether an available technology is used. Allowances trading decisions are represented by variables that indicate how many allowances to sell and buy. Table 5 describes the decision variables of the optimization program[4].

The objective function is given by:

[4] The program is a "two-stage" stochastic program. Installation decisions are "first stage decisions" because need to be taken without full information about the scenarios, while the choice of which of the available technologies to use and number of allowances to trade are "second stage" or "corrective" decisions that are made to meet the constraints given for each particular scenario.

Minimize

$$\sum_c \sum_t (1+r)^{-t} I_{c,t} CC_{c,t} + \sum_s \pi_s \sum_t (1+r)^{-t} \left[\sum_c U_{s,c,t} OM_{c,t} + \sum_p AP_{s,p,t} (AB_{s,p,t} - AS_{s,p,t}) \right]$$

Subject to the following engineering and emissions constraints:

1. Allowances allocated for each pollutant plus net trading have to be greater than or equal to zero for each period, in each scenario. Banking is not allowed.

$$AA_{s,p,t} + AB_{s,p,t} - AS_{s,p,t} - \sum_c U_{s,c,t} \left(1 - EPR_{c,p,t}\right) IE_p \geq 0 \qquad \forall \quad s,p,t$$

2. Unit emission rates have to be lower than maximum emissions rates allowed by regulation.[5]

$$IER_p \sum_c U_{s,c,t} \left(1 - EPR_{c,t}\right) \leq MER_{s,p,t} \qquad \forall \quad s,p,t$$

3. Control technologies used in first period have to be initially available in Period 1.

$$U_{s,c,1} \leq AC_c \qquad \forall \quad s,c$$

4. Control technologies used in second Period have to be initially available in Period 1 or 2.

$$U_{s,c,2} \leq AC1_c + AC2_c \qquad \forall \quad s,c$$

5. Control technologies used from Period 3 on have to be initially available in Periods 1 or 2 or installed at least two Periods before being used.

$$U_{s,c,t} \leq AC1_c + AC2_c + AC3_c + I_{c,t-2} \qquad \forall \quad s,c \quad \forall \quad t \geq 3$$

6. Only one control technology can be used in any period. (Different combinations of control technologies are defined as different technologies.)

$$\sum_c U_{s,c,t} = 1 \qquad \forall \quad s$$

7. If allowances cannot be traded, then number of allowances bought and sold has to be zero.

$$If \quad T_{s,p,t} = 0 \Rightarrow AB_{s,p,t} = 0 \qquad \forall \quad s,p,t$$

$$If \quad T_{s,p,t} = 0 \Rightarrow AS_{s,p,t} = 0 \qquad \forall \quad s,p,t$$

[5] The scenarios considered here do not consider specific emission rates requirements. See appendix A for details on formulation model.

8. Non negativity constraints

$$AB_{s,p,t} \geq 0$$
$$AS_{s,p,t} \geq 0$$
$$U_{s,c,t} \in \{0,1\}$$
$$I_{c,t} \in \{0,1\}$$

The optimization program has been implemented as a mixed integer program (MIP) in the Optimization Programming Language OPL, with inputs preprocessed by Visual Basic in Excel.[6]

3.3 Multi-period decision model

The decision variables obtained from the optimization model define a plan of which technologies to install and use every period for a given scenario. In this analysis, it is assumed that for the first several periods, more than one regulatory scenario is possible, and that all uncertainty will eventually be resolved.

For each time period, the decision maker takes three actions: 1) updates the probability set for future scenarios, 2) uses SOM to design an optimal plan for future periods based on the plant's current conditions and the new probability set, and 3) executes the plan previously designed for the current period. Optimal plans designed in each period consider that period's regulation, expectation on future scenarios, and the capital investments made in previous years.

The multi-period decision process has been implemented as a Script in OPL. Table 6 describes inputs for the MPDM.

The result of the MPDM is vector of yearly cash flows (recorded as costs) over the entire time horizon. In any given year, capital and operating expenses incurred, and trading allowances bought or sold. This cash flow is discounted back to current dollars using a single discount factor.

3.4 Expected value of perfect information

The effects of the regulatory uncertainty are assessed by comparing the decisions made when there is one certain future scenario, to those made when several regulatory scenarios are plausible. The concept of "expected value of perfect information" EVPI (see, e.g., Clemen & Reilly, 2001) can be used to measure the effects of regulatory uncertainty.

Consider an analysis for the planning horizon *1, ...j, ...T*. Suppose that $d^*(\alpha, s)$ represents the optimal strategy when scenario *s* happens but the decision maker does not know this until the uncertainty is resolved in period *j* and has to make decisions in periods *1, ...j* based on a set of probabilities α. Suppose $d^*(s)$

[6] Constraints that are specific to combination of control technologies are also included.

represents the strategy followed when scenario *s* is known to occur by decision maker in first period. If α_s represents the initial subjective probability of each scenario being the reality then the EVPI for decision maker α is given by:

$$EVPI(\alpha) = \sum_{s \ \ in \ \ scenarios} \alpha_s \left(NPV\left(d^*(\alpha, s)\right) - NPV\left(d^*(s)\right) \right)$$

To calculate the EVPI(α) the MPDM needs to be run 10 times. Table 7 describes the runs needed.

4. Base Case Assumptions

4.1 Power plant studied:

We will illustrate how uncertainties on regulatory scenarios can impact power plant decisions and lead to uneconomical choices, studying one hypothetical coal-fired generating unit whose characteristics are typical to many in the current U.S. electric sector.

The unit chosen generates 3.5 billion of kW-hr every year and has the characteristics shown in Table 8. The plant currently complies with the SO_2 cap trading allowances in the clean air market. The allowances allocated annually cover 35% of plant's current emissions. Current NO_x emissions rate for this plant is under the maximum limit allowed by law. Also, the plant is not placed in any of the 19 states that will be affected by new emissions standards in year 2004. (e.g. Kansas). The coal used is a mix of 55% low sulfur coal and 45% High sulfur Bituminous. Information on current emissions was retrieved using the Integrated Environmental Control Model (IECM, 2002[7].

4.2 Scenarios

For the preliminary analysis, we consider five hypothetical scenarios that differ in the number of pollutants addressed and timing. All scenarios assume a cap and trade system and no constraint on emission rates.[8]

For the business-as-usual (BAU) scenario, it is assumed that allowances or permits will be allocated to power plant at no cost in a quantity that covers all its current emissions of NO_x, Hg, and CO_2 and 35% of SO_2 emissions.

4.2.1. Allowance prices

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[7] Plant characteristics not specified here are equal to default case in IECM.

[8] Note that any general regulation for coal-fired power plants may imply different reduction requirements for each unit. For example a regulation that imposes a cap 90% below current NO_x emissions for the power sector would not necessarily imply a requirement of 90% reduction in emissions from the unit considered here. Because of this, the scenarios considered by the power plant are not generic legislations, but specific programs that will directly affect its operation.

In a cap-and-trade system, expected allowance prices may play a key role in compliance decisions. Forecasting allowance prices has proved to be a particularly difficult task in the past. For instance, when the Clean Air Amendment was enacted, the cost of compliance with the Acid Rain Program was estimated to be $400-$1000/ton, but by 2000, allowances ranged in price from $130 to $155(Acid Rain Program. Annual Progress Report, 2000) and have remained close to $140. The NO_x Budget offers another example; although forecasts of marginal control costs ranged from $500/ton to about $2,500/ton and in very few cases close to $5,000/ton, some trades in early 1999 occurred about $7000/ton but prices later fell to less that $1000/ton. (Farrell, 2000)

Estimation of allowance prices under multi-pollutant regulation posses additional difficulties, due mainly to synergies between the control of the criteria pollutants and CO_2. For example while under an scenario with stringent regulations only on SO_2 leads to allowance prices of $300, $700 and $1,000 in years 2008, 2010 and 2020(in 1999 dollars) an scenario with the same stringent cap of SO_2 and stringent caps for NO_x and CO_2, leads to prices of $100, $100 and $50 for the same years (EIA: Strategies for reducing Multiple Emissions From Power Plants, 2001). A complete analysis of how stringent controls in some pollutants lower the cost of control of the other the allowance supply curve under different regulatory scenario presents a challenge that would exceed the scope of this analysis. For the baseline analysis, we will assume allowances prices for SO_2, NO_x, and Hg based on those forecasted by NEMS model[9]. For CO_2 we will assume that allowance prices start at $25 the first year of the cap and increase by $5 annually. See in appendix A allowance prices for each scenario.

4.3 Control Technologies

Alternatives considered are add-on technologies and plant replacement with new generation technologies. Table 8.1 summarizes the alternative technologies as well as the assumption and information sources for performance and costs. (See details in Appendix B)

It is assumed that different control technologies can be installed simultaneously or in different stages and can be turned off as desired, so there is always the option to run the base plant in its initial conditions. Costs and performance data for different combinations of control technologies was retrieved using the IECM model.

Similarly it is assumed that new capacity and environmental controls can be installed in stages at no additional cost.

Even after installing new capacity the option of running the original plant remains open, as if the plant were “moth-balled” at no cost.

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[9] NEMS forecasted allowance prices for regulatory scenarios assume that emission caps would be phased in beginning 2002. Also NEMS does not consider any 3P scenario, so prices assumed although based on NEMS do not exactly replicate those.

Baseline model assumes no "learning -by-doing" so capital costs for all technologies remain constant in year 2000 dollars for the entire planning horizon. Based on fuel price predictions contained in Annual Energy Outlook AEO 2003, O&M costs for coal plants are assumed to decrease by 0.09% annually as a result of declining coal prices, while O&M for natural gas plants are assumed to increase by 2% annually[10]. Starting gas price is assumed to be $3.06/Gj (2000 dollars)(EIA 2001b) and gas heat content is assumed to be 1,020 Btu per cubic foot. (EIA 2001c).

4.4. Lead time, discount rate, and other assumptions

For base case we will assume that the calendar time between the announcement of the program and the compliance date (lead time) is shorter than the time required for constructing any of the control technologies considered (construction time). In the base case we will use a discount rate of 10% (real)

5. Baseline Analysis

5.1 Optimal strategy under no uncertainty

The first stage to calculate the expected value of perfect information is finding the capital and operating costs under no uncertainty. Table 9 summarizes the optimal operating and investment decisions $d^*(s)$ made when each scenario is known to occur from the beginning.

- Given that the BAU scenario is known to occur (there are no new environmental regulations over the next 30 years), the optimal strategy involves no new capital investments.
- Given that the 2P+1 scenario is known to occur (there are additional SO_2, NO_x and mercury regulations), the optimal strategy involves investing in SCR in 2005 and later in 2007 in CI equipment.
- Given that the 3P scenario is known to occur (there are different SO_2, NO_x and mercury regulations), the optimal strategy involves investing in SCR and CI simultaneously in 2005.
- Given that the 3P+1 scenario is known to occur (there are different SO_2, NO_x and mercury regulations and a CO_2 cap), the optimal strategy involves investing in NGCC with SCR in 2005 and then in 2015 installing FGD and CCS on the original coal plant.

[10] Since AEO predictions extend only to the year 2025, for specifying expected prices for 2026 to 2032, it is assumed that price trends forecasted for the period 2015-2025 continue in a linear fashion to the end of the planning horizon.

- Given that the 4P scenario is known to occur (there are still different SO_2, NO_x and mercury regulations and a CO_2 cap), the optimal strategy involves investing in FGD, SCR, and CCS in 2009.

For the 3P+1 and 4P scenarios, the decision to install a CCS might not take place if we had to account for dispatching (i.e., held a utility perspective). The high energy-penalties associated with the FGD and CCS technologies might make these options infeasible if demand levels have to be met. Also it is important to note that the NGCC plant in the 3P+1 scenario would provide the necessary CO_2 emission reductions (66%). If the CO_2 cap were higher, then this "control" would not be sufficient. (e.g., it would to install a NGCC with SCR and CCS or to install a CCS on the original plant). Costs of these strategies are presented in Table 10.

The NPV under 3P is higher than 2P+1 because the cap on mercury is set earlier. It is also higher than 3P+1 because there are no possibilities of selling CO_2 allowances. Case 4P has a lower NPV because all the caps are set in year 2011.

5.2 Sequential decisions under uncertainty

The baseline analysis corresponds to a decision maker with initial set of subjective probabilities α as in Table 2. Every year, probabilities will be updated as information about which regulations are still possible is revealed. In these scenarios, it is assumed that all of the uncertainty will be resolved at or before 2010, the time that the last program will be known. Every year before the uncertainty is fully resolved, the decision maker has to decide how to operate the plant (e.g., which of the available control technologies to use) and what capital investments to make if any. Since we have assumed that the future must be one of the five scenarios described, the probabilities will be updated accordingly the values in Tables 11-15. For example, if BAU occurs, then, no new environmental programs will ever be announced and probabilities in scenarios will have to be redistributed each year. If by 2006 no new regulations have been announced, then scenarios 2P+1, 3P and 3P+1 are not longer possible (because these involve reductions in year 2007 that would have to be announced in 2006) and therefore the probabilities for scenarios BAU and 4P have to be updated. We assume that new probabilities are updated preserving the initial ratios, so scenario 4P is twice as likely as scenario BAU. Finally if in year 2010 there is no legislation announced then that implies that scenario 4P will not happen and therefore the probability of scenario BAU becomes 1.0. Note that scenario's probabilities do not change during the first three years in any model run.

Running MPDM with this probability sets results in the optimal strategies shown in Table 16. In all cases, the strategy that minimizes the ENPV is to install a NGCC with SCR before any of the uncertainty is resolved (i.e., in year 2005).

- If the BAU scenario occurs, though constructed, the NGCC plant is never used.
- If the 2P+1 scenario occurs, then the NGCC plant is started in 2007 and replaced by the coal plant with SCR and CI in 2026.

- If the 3P scenario occurs, then the NGCC plant is started in 2007 and replaced by the coal plant with SCR and CI (identical to the 2P+1 scenario).
- If the 3P+1 scenario occurs, then the NGCC plant is started in 2007 and replaced in 2017 by the coal plant with FGD and CCS.
- If the 4P scenario occurs, the NGCC plant sits idle for four years before being used. And the coal plant with FGD and CCS controls is used from 2018 to the end of the planning period.

This cycling between the NGCC plant and the modified coal plant occurs because of the increasing O&M costs associated with gas prices, the low coal costs, and in the 3P+1 and 4P scenarios, the profitability of selling CO_2 allowances at a high price. Table 17 shows costs associated with optimal strategies under the five scenarios.

5.3 Calculating the expected value of perfect information

Given the cost data shown in Tables 10 and 17 it is possible to calculate the expected value of perfect information using the equation presented in Section 3.4. Inputs to this equation can be found in Table 18. The calculation is the weighted difference between the no uncertainty case and the case with uncertainty summed over all scenarios.

If the actual scenario could be known in 2003, it would be worth $41 million (2000$) to the plant operator. The relative contribution to this value for each of the scenarios is closely related to initial probabilities that the decision maker had. Because the decision maker felt that the BAU scenario was unlikely, if it turns out to occur, she will have to pay a hefty penalty ($212 million (2000$). If the decision maker's most likely scenario, 3P+1 occur, then no penalty is incurred. A different set of initial probabilities could result in different set of optimal strategies and a larger or smaller expected value of perfect information.

6. Sensitivity Cases

To understand the intricacies of the problem space, many inputs to the decision problem can be changed. In this section, we explore how changes to 1) the initial probabilities, 2) CO2 cap and 3) the relative costs of coal and gas fuel affect the strategies selected and the expected value of perfect information.

6.1 Changing the initial probabilities

As was noted in the previous section, different initial probabilities of scenarios can affect the decisions made and in turn the expected value of perfect information. To explore this, we changed the probabilities from the baseline analysis so that BAU and 4P had zero probability (could not occur) and then waited 2P+1, 3P, and 3P+1 equally (all with probability 0.333). See Table 19.

Results for this combination of probabilities are very similar to the baseline case. In fact the optimal decisions under uncertainty given that each scenario occurs are exactly the same and an NGCC is installed in 2005.

- If the 2P+1 scenario occurs, then the NGCC plant is started in 2007 and replaced by the coal plant with SCR and CI in 2026.
- If the 3P scenario occurs, then the NGCC plant is started in 2007 and replaced by the coal plant with SCR and CI (identical to the 2P+1 scenario).
- If the 3P+1 scenario occurs, then the NGCC plant is started in 2007 and replaced in 2017 by the coal plant with FGD and CCS

Since the same decisions are being made given the scenario that occurs, the differences between the no uncertainty case and uncertain case are the same. See Table 20. The EVPI for this probability set is $36 million.

6.2. A more stringent CO_2 cap

To explore how a minor change in the CO2 cap will affect the decisions and value of information, the 2P+1 and 3P scenarios were used with a modified 3P+1 scenario. The new 3P+1 scenario increased the CO_2 emissions reduction from 60% to 70%. All three scenarios were assumed to be equally likely (see Table 21).

Because of the changes to 3P+1 scenario, the no uncertainty case for this scenario had to be calculated (the other two remain unchanged):

- Given that the 2P+1 scenario is known to occur, the optimal strategy involves investing in SCR in 2005 and later in 2007 in CI equipment.
- Given that the 3P scenario is known to occur, the optimal strategy involves investing in SCR and CI simultaneously in 2005.
- Given that the 3P+1 modified scenario is known to occur, the optimal strategy involves investing in CI in 2005 and then in 2007 installing a new coal plant with FGD, SCR and CCS controls. (See Table 22).

Because of this change in the 3P+1 scenario, the optimal strategies given uncertainty are now totally different than before. In year 2005 SCR and CI controls are installed. (See Table 23)

- If the 2P+1 scenario occurs, then the SCR is used from 2007 and the CI from 2009.
- If the 3P scenario occurs, then SCR and CI are used from 2007 (same as the no uncertainty case above).
- If the 3P+1 modified scenario occurs, then SCR and CI are used in 2007-08 and then FGD and CCS are used.

EVPI is $3 million. See Tables 24 and 25.

6.3 Changes in fuel price

For the last example we consider 2P+1, 3P and 3P +1 with equal probabilities assuming smaller differences in O&M costs for coal and gas[11]. All the deterministic cases involve installing an NGCC plant with SCR. See Table 26

Given that the 2P+1 scenario is known to occur, the optimal strategy involves investing in SCR in 2005 and later in 2007 in CI equipment.

- Given that the 2P+1 modified scenario is known to occur, an NGCC/SCR is used in year 2009, when the cap on mercury is set.
- Given that the 3P modified scenario is known to occur, the optimal strategy involves installing and using the NGCC with SCR from year 2007.
- Given that the 3P+1 modified scenario is known to occur, the optimal strategy involves installing an NGCC/SCR in year 2005 and then installing a CCS so that can be used from period 2015 when CO2 allowance prices are at $55.

See the NPV for these scenarios in Table 27.

Optimal strategies under uncertainty are presented in Table 28. For scenarios 3P and 3P+1 the strategies are equal to the strategies in the deterministic case. For scenario 2P+1 the NGCC is installed 2 years before than in the deterministic case. EVPI is $6M. See Tables 29-30.

7. Limitations, Conclusions, and Future Work

7.1 Limitations

Because of the complexity of the problem space, this study had to make a large set of simplifying assumptions. These assumptions fall into four general categories.

- Assumptions about the plant: location, life span, efficiency, costs/feasibility of new technologies,
- Assumptions about regulations: CAT system, no banking allowed, only five regulations studied at one time.
- Assumptions about the market: based on EIA projections, deterministic trend for prices,
- Assumptions about how the decision process: discount rate, expected value decision rule, "systematic" updating of probabilities,

We were only able to explore the sensitivity of the results to a few of these assumptions. Future work should expand the exploration of the decision space and conduct a series of controlled experiments in order to understand the importance of

[11] This time we assume that O&M costs for a coal plant remain flat while for a gas plant increase by 0.05% per year.

the various factors. In order to analyze the importance of plant characteristics, a number of "representative plants" [12] should be studied.

Unfortunately, limitations with optimization software may severely limit the size of studies that can be run. In order to complete necessary number of optimizations, it will be necessary to reduce several of the problems dimensions (e.g., planning time horizon, number of technologies) while increasing the number of regulation scenario considered.

Nevertheless, valuable insights were gleaned.

7.2 Conclusions

Cost of uncertainty can be significant. In our baseline study we found that the expected cost of uncertainty was $40 million in 2000$ is approximately 80% of the plant's yearly O&M and 5% of the cost of a new plant. When spread across the 400[13] plants that are similar, the $16 billion cost is important.

Uncertainty costs can be small if the solution set is small. Several factors can limit the number of technologies that are likely to make sense. If there is a narrow set of possible regulations (i.e., they all require tight controls on CO2 emissions) then the choice of plant controls is obvious and though it may be expensive, there is little cost in not know which regulation will finally occur. Likewise, if there is dominant technology because of other economic factors, (extremely low relative fuel prices or cheap control technologies), then the solution set will be small, and the cost of uncertainty will be small.

Minor changes in regulations can have major impact on the optimal strategies. There are some very sensitive regulatory thresholds around which optimal decisions are very dependent. For example, we demonstrated that adjusting the CO2 cap between 60% and 70% could lead to very different new generating technologies (NGCC or new coal plant with CCS). Even having one scenario that includes the higher limit completely changed the strategies. However, adding this scenario greatly reduced the cost of uncertainty (see previous conclusions).

7.3 Future Work

Also, releasing the assumption of "zero allowance banking" can make a difference in the EVPI as decision makers could use this mechanism to hedge against uncertainty and delay capital investments.

To achieve better understanding of how uncertainties can cause uneconomical options, several scenarios need to be considered including those that

[12] Such plants could be identified via cluster analysis (see e.g., Hair et al. 1992). All U.S. coal-fired power plants could be placed in groups or clusters suggested by the emissions data, not defined a priori, such that those plants in a given cluster tend to be similar to each other in some sense, and plants in different clusters tend to be dissimilar. By analyzing the "average" plant in each cluster one could have an idea of how the analysis would look for all the country.

do not provide cap-and-trade systems and the ones that claim for old plants retirements.

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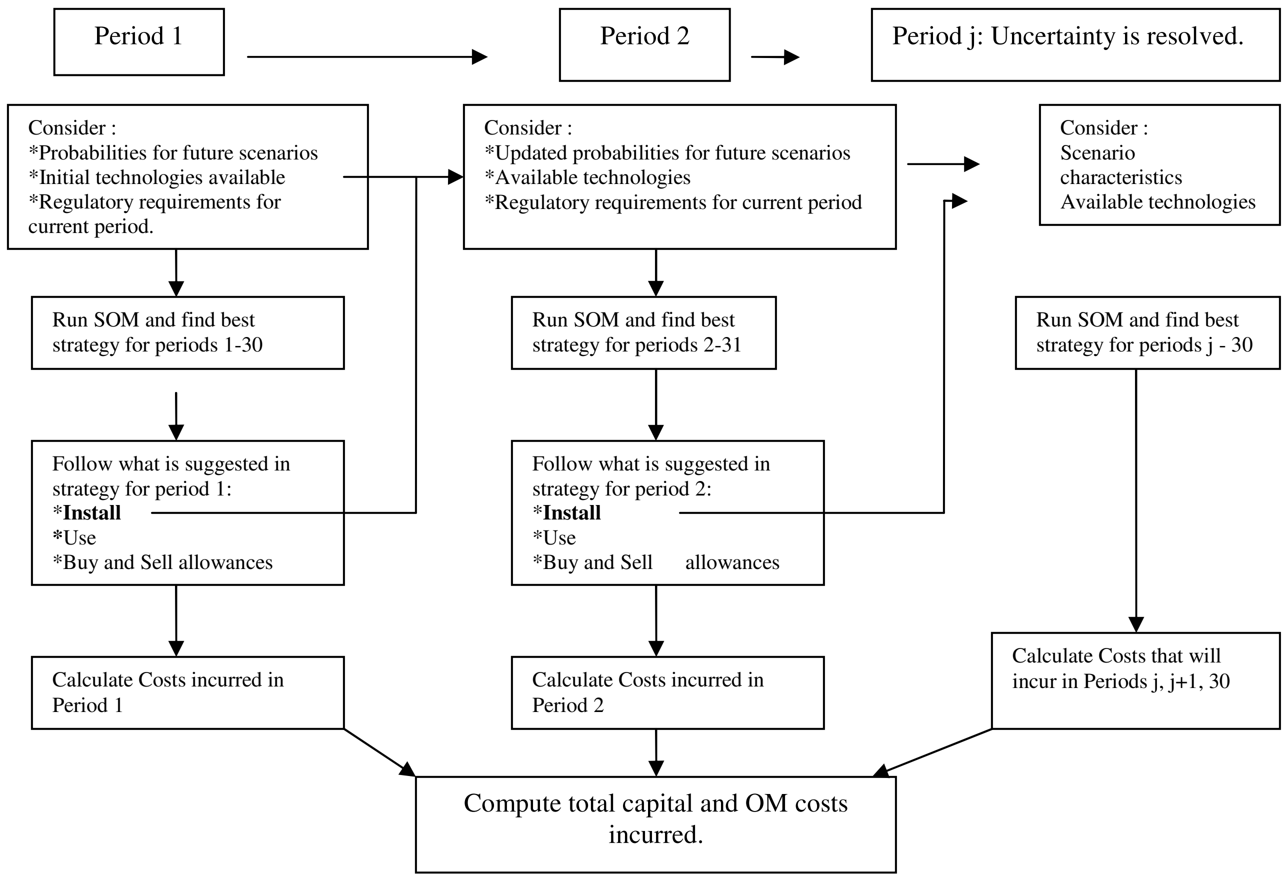

Figure 1. Multi-Period decision Model

Scenario Name		BAU	2P+1		3P	3P+1		4P
Number of phases		1	2		1	2		1
Year of implementation		2003	2007	2009	2007	2007	2009	2011
SO_2	Reduction in allowances allocated	-	63%	63%	63%	63%	63%	63%
	Max Emissions Rate (lb/mbtu)							
	Policy Instrument	Trade	Trade	Trade	Trade	Trade	Trade	Trade
NO_x	Reduction in allowances allocated	-	60%	60%	60%	60%	60%	60%
	Max Emissions Rate (lb/mbtu)							
	Policy Instrument		Trade	Trade	Trade	Trade	Trade	Trade
Hg	Reduction in allowances allocated	-	-	60%	60%	60%	60%	60%
	Max Emissions Rate (lb/mbtu)							
	Policy Instrument		Trade	Trade	Trade	Trade	Trade	Trade
CO_2	Reduction in allowances allocated	-	-	-	-	-	60%	60%
	Max Emissions Rate (lb/kWh)							
	Policy Instrument		Trade	Trade	Trade	Trade	Trade	Trade

Table 1. Scenarios for baseline analysis.

Scenario	BAU	2P+1	3P	3P+1	4P
Initial Probabilities	0.05	0.15	0.20	0.50	0.10

Table 2. Initial probabilities α

Dimension	**Index**	**Range**
Scenario	s	1-5[1]
Pollutant	p	1-4
Year	t	1-30
Control	c	1-49

Table 3. Dimensions in SOM

[1] For baseline analysis 5 scenarios are considered.

	Description	Notation	Units
Plant Initial Conditions:			
Initial emissions	Plant's initial annual emissions of pollutant p.	IE_p	-Tons/year for SO_2, NO_x and CO_2. -Lbs/year for Hg.
Initial emission rates	Plants Initial emission rates of pollutant p.	IER_p	-Lbs/MBtu for SO_2, NO_x and Hg. -Lbs/kWh for CO_2
Controls that are available from period 1		$AC1_c$	=1 if control *c* is available, =0 otherwise.
Controls that will be available from period 2	Availability in next year	$AC2_c$	=1 if control *c* will be available in next period, 0 otherwise.
Controls that will be available from period 3	Availability in next two years	$AC3_c$	=1 if control *c* will be available in two periods, =0 otherwise.
Scenarios			
Number of allowances allocated	Number of allowances allocated under scenario *s*, for pollutant *p*, in year *t*.	$AA_{s,p,t}$	-Tons/year for SO_2, NO_x and CO_2. -Lbs/year for Hg.
Maximum emissions rate allowed	Maximum emissions rate allowed under scenario *s*, for pollutant *p*, in year *t*.	$MER_{s,p,t}$	-Lbs/MBtu for SO_2, NO_x and Hg. -Lbs/kWh for CO_2
Allowances prices	Allowances prices under scenario s, for pollutant *p*, in year *t*.	$AP_{s,p,t}$	In year $2000 /allowance.
Policy instrument	Policy instrument: (Tradable allowances, taxes or emission standards)		In the scenarios presented here it will be assumed a CAT approach
Probability of Scenario s being "reality"	Probability of scenario *s*	π_s	
Capital cost for installing the new technology.	Capital cost for installing the control *c* in year *t*.	$CC_{c,t}$	Year 2000 dollars
O&M costs	Total O&M costs of the plant with the new technology used (including fixed O&M, variable O&M and fuel costs)	$OM_{c,t}$	Year 2000 dollars/year
Emissions reduction (as a percentage of initial emissions)	Emissions Percentage reduction of control c, for pollutant *p*, in time *t*.	$EPR_{c,p,t}$	Percentage reduction from initial emissions.
Other Parameters			
Discount rate used by power plant operator to calculate NPV of the capital and operating expenses	Discount rate used by decision maker to calculate NPV of the capital and operating expenses	r	Percent

Table 4, Input parameters for optimization program.

Installation Variables	Description	Notation	Variable type
Controls installed:	Whether the technology is installed or not.	$I_{c,t}$	Binary 1 = Installed
Operating variables			
Technology used	Whether a particular available technology is used.	$U_{s,c,t}$	Binary 1 = Used
Allowances Bought	Number of allowances bought	$AB_{s,p,t}$	Continuous ≥ 0
Allowances Sold	Number of allowances sold	$AS_{s,p,t}$	Continuous ≥ 0

Table 5 Outputs (Decision variables) of the SOM.

Inputs	Description
Years of uncertainty	The number of years until the uncertainty is resolved.
Lead time	Time between the announcement of regulation and the implementation of the program when the emissions constraints must be met.
Probability set	A set with the probability of occurrence for each of the plausible scenarios, for every year of uncertainty.
Reality	The scenario that is occurring.
Available technologies	The initial availability of technologies

Table 6. Inputs for the MPDM.

	Model Run	*Scenario*	*1*	2	3	4	5
			BAU	2P+1	3P	3P+1	4P
No uncertainty	$d^*(1)$	Initial Probabilities	1				
		Reality	1				
	$d^*(2)$	Initial Probabilities		1			
		Reality		1			
	$d^*(3)$	Initial Probabilities			1		
		Reality			1		
	$d^*(4)$	Initial Probabilities				1	
		Reality				1	
	$d^*(5)$	Initial Probabilities					1
		Reality					1

		Scenario	1	2	3	4	5
			BAU	2P+1	3P	3P+1	4P
		Initial Probabilities	0.05	0.15	0.2	0.5	0.1
Uncertainty: Alpha Runs	$d^*(\alpha,1)$	Reality	1	-	-	-	-
	$d^*(\alpha,2)$	Reality	-	1	-	-	-
	$d^*(\alpha,3)$	Reality	-	-	1	-	-
	$d^*(\alpha,4)$	Reality	-	-	-	1	-
	$d^*(\alpha,5)$	Reality	-	-	-	-	1

Table 7. MPDM runs to find the EVPI(α)

Nameplate Capacity (MW)		500
Steam Cycle Heat Rate (Btu/kWh)		10,900
Capacity Factor		85%
Firing Type		Tangential
Environmental Controls		ESP- Low NO_x Burner
Years On line		30
SO_2	(lbs/MBtu)	3.02
	Tons per year	70,059
NO_x	(lbs/MBtu)	0.40
	Tons per year	9,166
Hg	(lbs/MBtu)	6.12E-06
	Lbs per year	284
CO_2	(lbs/kWh)	2.73
	Tons per year	4,785,544
Coal	Heat Content (Btu/lb)	10,819
	Carbon Content (nearest 0.01%)	60.92
	Sulfur Content (nearest 0.01%)	1.60
	Nitrogen Content (nearest 0.01%)	1.10
	Ash Content (nearest 0.01%)	9.58
	Moist Content (nearest 0.01%)	14.33
	Mercury content (ppm)	12.00
	Price (Delivered) ($/ton)	22.90

Table 8. Plant characteristics, current emissions, and coal properties for the hypothetical power plant.

Add-on Control Technologies	
SO_2: Wet Flue Gas Desulfurization (WFGD) with no bypass and limestone as a reagent	Emissions, capital and O&M costs from IECM, using plant specifications as in Table 4.1. and retrofit factor of 1.2. O&M costs assumed to decrease by 0.09% annual becauseof declining coal prices.
NO_x: Hot Side Selective Catalytic Reduction (SCR)	
Hg: Carbon Injection. (Assumes plant has already a particulates control)	
CO_2: Carbon Capture and Sequestration (CCS) Amine System. MEA as a sorbent and Direct Contact Cooler DCC used	
Replacement of plant with new capacity	
New Coal Fired Power Plant with all the environmental controls.	Performance and O&M costs given by IECM model.
Integrated Coal Gasification Combined Cycle Plant (IGCC) with SCR	Performance and O&M costs of base plant with SCR from IECM results for an 800MW plant. CCS Capital and O&M costs from estimates for a 500MW. (Chen, 2002)
IGCC with SCR and CCS via Selexol Process	
Natural Gas Combined Cycle Power Plant (NGCC) + Dry SCR	Emissions and costs based on a 540 MW plant reported by The Northwest Power Planning Council (August 2002).
NGCC+SCR+CCS	CCS capital and O&M costs from Herzog 1999
New Coal Plant with all environmental controls.	Performance and O&M costs given by IECM model.

Table 8.1 Control Technologies

Run	$d^*(1)$		$d^*(2)$		$d^*(3)$		$d^*(4)$		$d^*(5)$	
	Scenario 1 (BAU)		**Scenario 2 (2P+1)**		**Scenario 3 (3P)**		**Scenario 4 (3P+1a)**		**Scenario 5 (4P)**	
	Install	**Operate**	**Install**	**Operate**	**Install**	**Operate**	**Install**	**Operate**	**Install**	**Operate**
2003	-	Coal	-	Coal	-	Coal	-	Coal	-	Coal
2004	-	Coal	-	Coal	-	Coal	-	Coal	-	Coal
2005	-	Coal	SCR	Coal	SCR/CI	Coal	NGCC/SCR	Coal	-	Coal
2006	-	Coal	-	Coal	-	Coal	-	Coal	-	Coal
2007	-	Coal	CI	SCR	-	SCR/CI	-	NGCC/SCR	-	Coal
2008	-	Coal	-	SCR	-	SCR/CI	-	NGCC/SCR	-	Coal
2009	-	Coal	-	SCR/CI	-	SCR/CI	-	NGCC/SCR	FGD/SCR/CCS	Coal
2010	-	Coal	-	SCR/CI	-	SCR/CI	-	NGCC/SCR	FGD/SCR/CCS	Coal
2011	-	Coal	-	SCR/CI	-	SCR/CI	-	NGCC/SCR	-	FGD/SCR/CCS
2012	-	Coal	-	SCR/CI	-	SCR/CI	-	NGCC/SCR	-	FGD/SCR/CCS
2013	-	Coal	-	SCR/CI	-	SCR/CI	-	NGCC/SCR	-	FGD/SCR/CCS
2014	-	Coal	-	SCR/CI	-	SCR/CI	-	NGCC/SCR	-	FGD/SCR/CCS
2015	-	Coal	-	SCR/CI	-	SCR/CI	Coal/FGD/CCS	NGCC/SCR	-	FGD/SCR/CCS
2016	-	Coal	-	SCR/CI	-	SCR/CI	-	NGCC/SCR	-	FGD/SCR/CCS
2017	-	Coal	-	SCR/CI	-	SCR/CI	-	Coal/FGD/CCS	-	FGD/SCR/CCS
2018	-	Coal	-	SCR/CI	-	SCR/CI	-	Coal/FGD/CCS	-	FGD/SCR/CCS
2019	-	Coal	-	SCR/CI	-	SCR/CI	-	Coal/FGD/CCS	-	FGD/SCR/CCS
2020	-	Coal	-	SCR/CI	-	SCR/CI	-	Coal/FGD/CCS	-	FGD/SCR/CCS
...	...	...	...	...	...	...	...	...	...	FGD/SCR/CCS
2032	-	Coal	-	SCR/CI	-	SCR/CI	-	Coal/FGD/CCS	-	FGD/SCR/CCS

Table 9. Results for deterministic runs $d^*(s)$.

Model Run	$d^*(1)$	$d^*(2)$	$d^*(3)$	$d^*(4)$	$d^*(5)$
NPV(Capital)	-	36.78	39.44	313.35	204.01
NPV(O&M)	566.62	755.03	796.06	833.15	843.48
NPV(SO2 Allowances)	89.09	105.29	100.70	17.41	38.07
NPV(NOx Allowances)	-	-2.98	-2.97	-22.77	-0.91
NPV(Hg Allowances)	-	-60.75	-79.48	-101.36	-62.61
NPV(CO2 Allowances)	-	-	-	-307.44	-348.96
Total NPV (2000 M$)	656	833	854	732	673

Table 10. NPV of capital and operating costs for deterministic runs $d^*(s)$.(In year 2000 $M)

If BAU	Year							
	2003	2004	2005	2006	2007	2008	2009	2010
Probabilities of scenario BAU	0.05	0.05	0.05	0.33	0.33	0.33	0.33	1
Probabilities of scenario 2P+1	0.15	0.15	0.15	-	-	-	-	-
Probabilities of scenario 3P	0.20	0.20	0.20	-	-	-	-	-
Probabilities of scenario 3P+1	0.5	0.5	0.5	-	-	-	-	-
Probabilities of scenario 4P	0.1	0.1	0.1	0.66	0.66	0.66	0.66	-

Table 11. Probabilities set for run $d^{*}(\alpha,1)$

If 4P	Year							
	2003	2004	2005	2006	2007	2008	2009	2010
Probabilities of scenario BAU	0.05	0.05	0.05	0.33	0.33	0.33	0.33	-
Probabilities of scenario 2P+1	0.15	0.15	0.15	-	-	-	-	-
Probabilities of scenario 3P	0.20	0.20	0.20	-	-	-	-	-
Probabilities of scenario 3P+1	0.5	0.5	0.5	-	-	-	-	-
Probabilities of scenario 4P	0.1	0.1	0.1	0.66	0.66	0.66	0.66	1

Table 12. Probabilities set for run $d^{*}(\alpha,5)$

If 2P+1	Year							
	2003	2004	2005	2006	2007	2008	2009	2010
Probabilities of scenario BAU	0.05	0.05	0.05	-	-	-	-	-
Probabilities of scenario 2P+1	0.15	0.15	0.15	1	1	1	1	1
Probabilities of scenario 3P	0.20	0.20	0.20	-	-	-	-	-
Probabilities of scenario 3P+1	0.5	0.5	0.5	-	-	-	-	-
Probabilities of scenario 4P	0.1	0.1	0.1	-	-	-	-	-

Table 13. Probabilities set for run $d^{*}(\alpha,2)$

If 3P	Year							
	2003	2004	2005	2006	2007	2008	2009	2010
Probabilities of scenario BAU	0.05	0.05	0.05	-	-	-	-	-
Probabilities of scenario 2P+1	0.15	0.15	0.15	-	-	-	-	-
Probabilities of scenario 3P	0.20	0.20	0.20	0.29	0.29	1	1	1
Probabilities of scenario 3P+1	0.5	0.5	0.5	0.71	0.71	-	-	-
Probabilities of scenario 4P	0.1	0.1	0.1	-	-	-	-	-

Table 14. Probabilities set for run $d^{*}(\alpha,3)$

If 3P+1	Year							
	2003	2004	2005	2006	2007	2008	2009	2010
Probabilities of scenario BAU	0.05	0.05	0.05	-	-	-	-	-
Probabilities of scenario 2P+1	0.15	0.15	0.15	-	-	-	-	-
Probabilities of scenario 3P	0.20	0.20	0.20	0.29	0.29	-	-	-
Probabilities of scenario 3P+1	0.5	0.5	0.5	0.71	0.71	1	1	1
Probabilities of scenario 4P	0.1	0.1	0.1	-	-	-	-	-

Table 15. Probabilities set for run $d^{*}(\alpha,4)$

Run	$d^*(\alpha,1)$		$d^*(\alpha,2)$		$d^*(\alpha,3)$		$d^*(\alpha,4)$		$d^*(\alpha,5)$	
	Scenario 1 (BAU)		**Scenario 2 (2P+1)**		**Scenario 3 (3P)**		**Scenario 4 (3P+1a)**		**Scenario (4P)**	
	Installation	**Operation**	**Installation**	**Operation**	**Installation**	**Operation**	**Installation**	**Operation**	**Installation**	**Operation**
2003	-	Coal	-	Coal	-	Coal	-	Coal	-	Coal
2004	-	Coal	-	Coal	-	Coal	-	Coal	-	Coal
2005	NGCC/SCR	Coal	NGCC/SCR	Coal	NGCC/SCR	Coal	NGCC/SCR	Coal	NGCC/SCR	Coal
2006	-	Coal	-	Coal	-	Coal	-	Coal	-	Coal
2007	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR	-	Coal
2008	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR	-	Coal
2009	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR	-	Coal
2010	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR	-	Coal
2011	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2012	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2013	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2014	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2015	-	Coal	-	NGCC/SCR	-	NGCC/SCR	FGD/CCS-Coal	NGCC/SCR	-	NGCC/SCR
2016	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR	FGD/CCS-Coal	NGCC/SCR
2017	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	Coal/FGD/CCS	-	NGCC/SCR
2018	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	Coal/FGD/CCS	-	Coal/FGD/CCS
2019	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	Coal/FGD/CCS	-	Coal/FGD/CCS
2020	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	Coal/FGD/CCS	-	Coal/FGD/CCS
2021	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	Coal/FGD/CCS	-	Coal/FGD/CCS
2022	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	Coal/FGD/CCS	-	Coal/FGD/CCS
2023	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	Coal/FGD/CCS	-	Coal/FGD/CCS
2024	-	Coal	SCR/CI-Coal	NGCC/SCR	SCR/CI-Coal	NGCC/SCR	-	Coal/FGD/CCS	-	Coal/FGD/CCS
2025	-	Coal	-	NGCC/SCR	-	NGCC/SCR	-	Coal/FGD/CCS	-	Coal/FGD/CCS
2026	-	Coal	-	Coal/SCR/CI	-	Coal/SCR/CI	-	Coal/FGD/CCS	-	Coal/FGD/CCS
...	...	...	...	...	...	...	...	...	...	...
2032	-	Coal	-	Coal/SCR/CI	-	Coal/SCR/CI	-	Coal/FGD/CCS	-	Coal/FGD/CCS

Table 16. Optimal Investment and operating decisions, under uncertainty given each scenario. "$d^*(\alpha,s)$".

Model Run	$d^*(\alpha,1)$	$d^*(\alpha,2)$	$d^*(\alpha,3)$	$d^*(\alpha,4)$	$d^*(\alpha,5)$
NPV(Capital)	212.25	218.68	218.68	313.35	304.16
NPV(O&M)	566.62	815.58	815.58	833.15	768.68
NPV(SO2 Allowances)	89.09	21.08	21.08	17.41	38.7
NPV(NOx Allowances)	-	-49.72	-49.57	-22.77	-6.65
NPV(Hg Allowances)	-	-92.88	-122.24	-101.36	-52.53
NPV(CO2 Allowances)	-	-	-	-307.44	-249.52
Total NPV (2000 M$)	868	913	884	732	803

Table 17. NPV of capital and operating costs for $d^*(\alpha, s)$. (In year 2000 $M)

Scenario S	1 BAU	2 2P+1	3 3P	4 3P+1	5 4P
$NPV[d^*(\alpha,s)]-NPV[d^*(s)]$	212	79	30	0	130
Initial probabilities	0.05	0.15	0.20	0.5	0.10
EVPI (in year 2000 $M)	41				

Table 18. EVPI(α)

Scenario	(2) 2P+1	(3) 3P	(4) 3P+1
Initial Probabilities	1/3	1/3	1/3

Table 19. Initial β probabilities.

Scenario S	2 2P+1	3 3P	4 3P+1
$NPV[d^*(\beta,s)]-NPV[d^*(s)]$	79	30	0
Initial probabilities	1/3	1/3	1/3
EVPI (in year 2000 $M)	36		

Table 20. EVPI(β)

Scenario	(2) 2P+1	(3) 3P	(6) 3P+1b
Initial Probabilities	1/3	1/3	1/3

Table 21. Initial λ probabilities.

Run	$d^*(6)$	
	Scenario 6 (3P+1b)	
	Installation	**Operation**
2003	-	Coal
2004	-	Coal
2005	CI	Coal
2006	-	Coal
2007	New Coal Plant+ALL	CI
2008	-	CI
2009	-	New Coal + ALL
2010	-	New Coal + ALL
2024	-	New Coal + ALL
2025	-	New Coal + ALL
...	...	...
2032	-	New Coal + ALL

Table 22.1. Results for deterministic run for scenario 6. (3P+1 with stringent CO_2 cap)

Model Run	$d^*(6)$
NPV(Capital)	506.52
NPV(O&M)	790.55
NPV(SO2 Allowances)	29.67
NPV(NOx Allowances)	8.89
NPV(Hg Allowances)	-102.09
NPV(CO2 Allowances)	-125.71
Total NPV (2000 M$)	1,109

Table 22.2. NPV of capital and operating costs for scenario 6 (3P+1 with stringent CO_2 cap) $d^*(6)$. (In year 2000 $M)

Run	$d^*(\lambda,2)$		$d^*(\lambda,3)$		$d^*(\lambda,6)$	
	Scenario 2 (2P+1)		**Scenario 3 (3P)**		**Scenario 6 (3P+1b)**	
	Installation	**Operation**	**Installation**	**Operation**	**Installation**	**Operation**
2003	-	Coal	-	Coal	-	Coal
2004	-	Coal	-	Coal	-	Coal
2005	SCR/CI	Coal	SCR/CI	Coal	SCR/CI	Coal
2006	-	Coal	-	Coal	-	Coal
2007	-	Coal/SCR	-	Coal/SCR/CI	FGD/CCS	SCR/CI
2008	-	Coal/SCR	-	Coal/SCR/CI	-	SCR/CI
2009	-	Coal/SCR/CI	-	Coal/SCR/CI	-	SCR/CI/FGD/CCS
…	-	…	-	…	…	…
2032	-	Coal/SCR/CI	-	Coal/SCR/CI	-	SCR/CI/FGD/CCS

Table 23. Optimal strategies under uncertainty. "$d^*(\lambda,s)$"

Model Run	$d^*(\lambda,2)$	$d^*(\lambda,3)$	$d^*(\lambda,6)$
NPV(Capital)	39	39	254
NPV(O&M)	755	796	962
NPV(SO2 Allowances)	105	101	30
NPV(NOx Allowances)	-3	-3	-2
NPV(Hg Allowances)	-61	-79	-101
NPV(CO2 Allowances)	-	-	-31
Total NPV (2000 M$)	836	854	1,111

Table 24 NPV capital and operating costs for $d^*(\lambda,s)$

Scenario *S*	2 2P+1	3 3P	6 3P+1b
$NPV[d^*(\lambda,s)]-NPV[d^*(s)]$	2..52	0	3..58
Initial probabilities	0..33	0..33	0..33
EVPI (in year 2000 $M)	3		

Table 25. EVPI(λ)

	$d^*(7)$		$d^*(8)$		$d^*(9)$	
	Scenario 7 (2P+1c)		**Scenario 8 (3Pc)**		**Scenario 9 (3P+1c)**	
	Installation	**Operation**	**Installation**	**Operation**	**Installation**	**Operation**
2003	-	Coal	-	Coal	-	Coal
2004	-	Coal	-	Coal	-	Coal
2005	-	Coal	NGCC/SCR	Coal	NGCC/SCR	Coal
2006	-	Coal	-	Coal	-	Coal
2007	NGCC/SCR	Coal	-	NGCC/SCR	-	NGCC/SCR
2008	-	Coal	-	NGCC/SCR	-	NGCC/SCR
2009	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2010	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2011	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2012	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2013	-	NGCC/SCR	-	NGCC/SCR	CCS	NGCC/SCR
2014	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2015	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR/CCS
2016	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR/CCS
...	...	...	...	...	...	...
2032	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR/CCS

Table 26. Optimal strategies for deterministic runs on “Low Gas Prices”

Model Run	$d^*(7)$	$d^*(8)$	$d^*(9)$
Scenario	2P+1c	3Pc	3P+1c
NPV(Capital)	175.41	212.25	311.26
NPV(O&M)	782.2	806.68	894.65
NPV(SO2 Allowances)	27.13	10.23	17.42
NPV(NOx Allowances)	-27.72	-54.19	-31.47
NPV(Hg Allowances)	-95.28	-124.64	-124.64
NPV(CO2 Allowances)	-	-	-344.94
Total NPV (2000 M$)	862	850	722

Table 27. NPV of capital and operating costs for Scenarios 7, 8 and 9.

Model Run	$d^*(\omega,7)$		$d^*(\omega,8)$		$d^*(\omega,9)$	
	Scenario 7 (2P+1c)		**Scenario 8 (3Pc)**		**Scenario 9 (3P+1c)**	
	Installation	**Operation**	**Installation**	**Operation**	**Installation**	**Operation**
2003	-	Coal	-	Coal	-	Coal
2004	-	Coal	-	Coal	-	Coal
2005	NGCC/SCR	Coal	NGCC/SCR	Coal	NGCC/SCR	Coal
2006	-	Coal	-	Coal	-	Coal
2007	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2008	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2009	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2010	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2011	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2012	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2013	-	NGCC/SCR	-	NGCC/SCR	CCS	NGCC/SCR
2014	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR
2015	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR/CCS
2025	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR/CCS
...	-	...	...	...	...	...
2032	-	NGCC/SCR	-	NGCC/SCR	-	NGCC/SCR/CCS

Table 28. Optimal strategies for probabilities ω.

Model Run	$d^*(\omega,7)$	$d^*(\omega,8)$	$d^*(\omega,9)$
Scenario	2P+1c	3Pc	3P+1c
NPV(Capital)	212.25	212.25	311.26
NPV(O&M)	806.68	806.68	894.65
NPV(SO2 Allowances)	9.54	10.23	17.42
NPV(NOx Allowances)	-54.34	-54.19	-31.47
NPV(Hg Allowances)	-95.28	-124.64	-124.64
NPV(CO2 Allowances)	-	-	-344.94
Total NPV (2000 M$)	879	850	722

Table 29. NPV of capital and operating costs under scenarios with "Low Gas Prices".

Scenario *S*	7 2P+1c	8 3Pc	9 3P+1c
$NPV[d^*(\omega,s)]-NPV[d^*(s)]$	17.11	0	0
Initial probabilities	0.33	0.33	0.33
EVPI (in year 2000 $M)	6		

Table 30. EVPI(ω)

Appendix A

Scenario 1. BAU.

Parameter	Pollutant	2003	2004	2005	2006	2007	2008 -2032
Allowances Allocated	SO_2	35% of current emissions					
	NO_x	100% of current emissions					
	Hg	100% of current emissions					
	CO_2	100% of current emissions					
Maximum Emissions Rate Allowed	SO_2	Maximum emissions rate allowed > Current plant emissions rate					
	NO_x	Maximum emissions rate allowed > Current plant emissions rate					
	Hg	Maximum emissions rate allowed > Current plant emission rate					
	CO_2	Maximum emissions rate allowed > Current plant emissions rate					
Allowance Prices	SO_2	$142	$149	$157	$166	$175	$184 - $383
	NO_x	-	-	-	-	-	-
	Hg	-	-	-	-	-	-
	CO_2	-	-	-	-	-	-
Policy Instrument	SO_2	Cap and Trade (Can buy and sell allowances)					
	NO_x	-	-	-	-	-	-
	Hg	-	-	-	-	-	-
	CO_2	-	-	-	-	-	-

Scenario 2. 2P+1.

<table>
<tr><th>Parameter</th><th>Pollutant</th><th>2003</th><th>2004</th><th>2005</th><th>2006</th><th>2007</th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012-2032</th></tr>
<tr><td rowspan="4">Allowances Allocated</td><td>SO_2</td><td colspan="4">35% of current emissions</td><td colspan="6">13% of current emissions</td></tr>
<tr><td>NO_x</td><td colspan="4">100% of current emissions</td><td colspan="6">40% of current emissions</td></tr>
<tr><td>Hg</td><td colspan="6">100% of current emissions</td><td colspan="4">40% of current emissions</td></tr>
<tr><td>CO_2</td><td colspan="10">100% of current emissions</td></tr>
<tr><td rowspan="4">Maximum Emissions Rate Allowed</td><td>SO_2</td><td colspan="10">Maximum emissions rate allowed > Current plant emissions rate</td></tr>
<tr><td>NO_x</td><td colspan="10">Maximum emissions rate allowed > Current plant emissions rate</td></tr>
<tr><td>Hg</td><td colspan="10">Maximum emissions rate allowed > Current plant emissions rate</td></tr>
<tr><td>CO_2</td><td colspan="10">Maximum emissions rate allowed > Current plant emissions rate</td></tr>
<tr><td rowspan="4">Allowance Prices</td><td>SO_2</td><td>$142</td><td>$149</td><td>$157</td><td>$166</td><td>$182</td><td>$245</td><td>$162</td><td>$173</td><td>$184</td><td>$196 - $331</td></tr>
<tr><td>NO_x</td><td>-</td><td>-</td><td>-</td><td>-</td><td>$2,477</td><td>$2,558</td><td>$2,490</td><td>$2,497</td><td>$2,404</td><td>$2,510 - $2,648</td></tr>
<tr><td>Hg</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>$207,198</td><td>$200,340</td><td>$193,710</td><td>$187,299 - $95,546</td></tr>
<tr><td>CO_2</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td rowspan="4">Policy Instrument</td><td>SO_2</td><td colspan="10">Cap and Trade (Can buy and sell allowances)</td></tr>
<tr><td>NO_x</td><td colspan="4"></td><td colspan="6">Cap and Trade (Can buy and sell allowances)</td></tr>
<tr><td>Hg</td><td colspan="6"></td><td colspan="4">Cap and Trade (Can buy and sell allowances)</td></tr>
<tr><td>CO_2</td><td colspan="10">Cap and Trade (Can buy and sell allowances)</td></tr>
</table>

Scenario 3. 3P.

Parameter	Pollutant	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012-2032
Allowances Allocated	SO_2	35% of current emissions				13% of current emissions					
	NO_x	100% of current emissions				40% of current emissions					
	Hg	100% of current emissions				40% of current emissions					
	CO_2	100% of current emissions									
Maximum Emissions Rate Allowed	SO_2	Maximum emissions rate allowed > Current plant emissions rate									
	NO_x	Maximum emissions rate allowed > Current plant emissions rate									
	Hg	Maximum emissions rate allowed > Current plant emissions rate									
	CO_2	Maximum emissions rate allowed > Current plant emissions rate									
Allowance Prices	SO_2	$142	$49	$157	$166	$143	$152	$162	$173	$184	$196-$331
	NO_x	-	-	-	-	$2,477	$2,484	$2,490	$2,497	$2,504	$2,510 - $2,648
	Hg	-	-	-	$221,624	$214,289	$207,198	$200,340	$193,710	$187,299	$181,101 $95,546
	CO_2	-	-	-	-	-	-	-	-	-	-
Policy Instrument	SO_2	Cap and Trade (Can buy and sell allowances)									
	NO_x					Cap and Trade (Can buy and sell allowances)					
	Hg					Cap and Trade (Can buy and sell allowances)					
	CO_2	100% of current emissions									

Scenario 4. 3P+1.

Parameter	Pollutant	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012-2032
Allowances Allocated	SO_2	35% of current emissions				13% of current emissions					
	NO_x	100% of current emissions				40% of current emissions					
	Hg	100% of current emissions				40% of current emissions					
	CO_2	100% of current emissions						40% of current emissions			
Maximum Emissions Rate Allowed	SO_2	Maximum emissions rate allowed > Current plant emissions rate									
	NO_x	Maximum emissions rate allowed > Current plant emissions rate									
	Hg	Maximum emissions rate allowed > Current plant emissions rate									
	CO_2	Maximum emissions rate allowed > Current plant emissions rate									
Allowance Prices	SO_2	$142	$49	$157	$166	$143	$152	$134	$117	$102	$90 - $6
	NO_x	-	-	-	-	$2,477	$2,484	$2,490	$2,181	$1,911	$1,674 - $118
	Hg	-	-	-	-	$221,624	$214,289	$207,198	$200,340	$193,710	$187,299 - $95,546
	CO_2	-	-	-	-	-	-	$25	$30	$35	$40 - $140
Policy Instrument	SO_2	Cap and Trade (Can buy and sell allowances)									
	NO_x					Cap and Trade (Can buy and sell allowances)					
	Hg					Cap and Trade (Can buy and sell allowances)					
	CO_2							Cap and Trade (Can buy and sell allowances			

Scenario 5. 4P.

Parameter	**Pollutant**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011-2032**
Allowances Allocated	SO_2	35% of current emissions								13% of current emissions
	NO_x	100% of current emissions								40% of current emissions
	Hg	100% of current emissions								40% of current emissions
	CO_2	100% of current emissions								40% of current emissions
Maximum Emissions Rate Allowed	SO_2	Maximum emissions rate allowed > Current plant emissions rate								
	NO_x	Maximum emissions rate allowed > Current plant emissions rate								
	Hg	Maximum emissions rate allowed > Current plant emissions rate								
	CO_2	Maximum emissions rate allowed > Current plant emissions rate								
Allowance Prices	SO_2	$142	$49	$157	$166	$175	$184	$194	$205	$102 - $6
	NO_x	-	-	-	-	-	-	-	-	$1,911 - $118
	Hg	-	-		-	-	-	-	$193,710	$187,299 - $95,546
	CO_2	-	-	-			-	-	-	$25 - $130
Policy Instrument	SO_2									Cap and Trade (Can buy and sell allowances
	NO_x									Cap and Trade (Can buy and sell allowances
	Hg									Cap and Trade (Can buy and sell allowances
	CO_2	Cap and Trade (Can buy and sell allowances								

Scenario 6. 3P+1b. (Stringent CO_2 cap)

Parameter	Pollutant	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012-2032
Allowances Allocated	SO_2	35% of current emissions				13% of current emissions					
	NO_x	100% of current emissions				40% of current emissions					
	Hg	100% of current emissions				40% of current emissions					
	CO_2	100% of current emissions						**30% of current emissions**			
Maximum Emissions Rate Allowed	SO_2	Maximum emissions rate allowed > Current plant emissions rate									
	NO_x	Maximum emissions rate allowed > Current plant emissions rate									
	Hg	Maximum emissions rate allowed > Current plant emissions rate									
	CO_2	Maximum emissions rate allowed > Current plant emissions rate									
Allowance Prices	SO_2	$142	$49	$157	$166	$143	$152	$134	$117	$102	$90 - $6
	NO_x	-	-	-	-	$2,477	$2,484	$2,490	$2,181	$1,911	$1,674 - $118
	Hg	-	-	-	-	$221,624	$214,289	$207,198	$200,340	$193,710	$187,299 - $95,546
	CO_2	-	-	-	-	-	-	$25	$30	$35	$40 - $140
Policy Instrument	SO_2	Cap and Trade (Can buy and sell allowances)									
	NO_x					Cap and Trade (Can buy and sell allowances)					
	Hg					Cap and Trade (Can buy and sell allowances)					
	CO_2							Cap and Trade (Can buy and sell allowances)			

Appendix B

N	Control	Percentage Reductions from Base Plant				Costs (In year 2000 $M)			
N	Control	SO_2	NO_x	Hg	CO_2	Capital	O&M	CC Annual Increase %	O&M Annual Increase %
1	WFGD	0.802	0.000	0.700	-0.008	78.0	73.9	0.0000	-0.0090
2	SCR	0.009	0.620	0.000	0.000	38.6	68.3	0.0000	-0.0090
3	CI	0.000	0.000	0.855	0.000	13.9	102.9	0.0000	-0.0090
4	CCS	0.995	0.011	0.000	0.900	378.6	504.7	0.0000	-0.0090
5	FGD + SCR	0.803	0.620	0.945	-0.008	116.6	77.0	0.0000	-0.0090
6	FGD+CI	0.802	0.000	0.855	-0.008	81.9	80.8	0.0000	-0.0090
7	FGD+CCS	1.000	0.012	0.700	0.899	349.0	137.7	0.0000	-0.0090
8	SCR+CI	0.009	0.620	0.855	0.000	52.4	106.2	0.0000	-0.0090
9	SCR+CCS	0.995	0.625	0.000	0.900	425.6	505.9	0.0000	-0.0090
10	CI+CCS	0.995	-0.820	0.855	0.900	392.6	543.0	0.0000	-0.0090
11	FGD+SCR+CI	0.803	0.620	0.945	-0.008	125.8	79.1	0.0000	-0.0090
12	FGD+SCR+CCS	1.000	0.625	0.945	0.899	397.6	143.2	0.0000	-0.0090
13	FGD+CI +CCS	1.000	-0.820	0.855	0.899	353.7	145.2	0.0000	-0.0090
14	SCR+CI+ CCS	0.995	0.625	0.855	0.900	439.5	544.1	0.0000	-0.0090
15	ALL: FGD+SCR+CI+CCS	1.000	0.625	0.945	0.899	397.6	143.3	0.0000	-0.0090
16	Having FGD installing SCR	0.803	0.620	0.945	-0.008	38.6	77.0	0.0000	-0.0090
17	Having FGD installing CI	0.802	0.000	0.855	-0.008	3.9	80.8	0.0000	-0.0090
18	Having FGD installing CCS	1.000	0.012	0.700	0.899	271.1	137.7	0.0000	-0.0090
19	Having SCR installing FGD	0.803	0.620	0.945	-0.008	78.1	77.0	0.0000	-0.0090
20	Having SCR installing CI	0.009	0.620	0.855	0.000	13.9	106.2	0.0000	-0.0090
21	Having SCR installing CCS	0.995	0.625	0.000	0.900	387.1	505.9	0.0000	-0.0090
22	Having CI installing FGD	0.802	0.000	0.855	-0.008	68.1	80.8	0.0000	-0.0090
23	Having CI installing SCR	0.009	0.620	0.855	0.000	38.6	106.2	0.0000	-0.0090
24	Having CI installing CCS	0.995	-0.820	0.855	0.900	378.7	543.0	0.0000	-0.0090
25	Having CCS installing FDG	1.000	0.012	0.700	0.899	0.5	137.7	0.0000	-0.0090
26	Having CCS installing SCR	0.995	0.625	0.000	0.900	47.0	505.9	0.0000	-0.0090
27	Having CCS installing CI	0.995	-0.820	0.855	0.900	14.0	543.0	0.0000	-0.0090
28	Having FGD+SCR installing CI	0.803	0.620	0.945	-0.008	9.2	79.1	0.0000	-0.0090
29	Having FGD+SCR installing CCS	1.000	0.625	0.945	0.899	281.0	143.2	0.0000	-0.0090
30	Having FGD+CI installing SCR	0.803	0.620	0.945	-0.008	43.9	79.1	0.0000	-0.0090
31	Having FGD+CI installing CCS	1.000	-0.820	0.855	0.899	271.8	145.2	0.0000	-0.0090
32	Having FGD+CCS installing SCR	1.000	0.625	0.945	0.899	48.5	143.2	0.0000	-0.0090
33	Having FGD+CCS installing CI	1.000	-0.820	0.855	0.899	4.6	145.2	0.0000	-0.0090
34	Having SCR+CI installing FGD	0.803	0.620	0.945	-0.008	73.4	79.1	0.0000	-0.0090
35	Having SCR+CI installing CCS	0.995	0.625	0.855	0.900	387.1	544.1	0.0000	-0.0090
36	Having SCR+CCS installing FGD	1.000	0.625	0.945	0.899	0.5	143.2	0.0000	-0.0090
37	Having SCR+CCS installing CI	0.995	0.625	0.855	0.900	13.9	544.1	0.0000	-0.0090
38	Having CI+CCS installing FGD	1.000	-0.820	0.855	0.899	0.5	145.2	0.0000	-0.0090
39	Having CI+CCS installing SCR	0.995	0.625	0.855	0.900	46.9	544.1	0.0000	-0.0090
40	Having FGD+SCR+CI installing CCS	1.000	0.625	0.945	0.899	271.8	143.3	0.0000	-0.0090
41	Having FGD+SCR+CCS installing CI	1.000	0.625	0.945	0.899	0.5	143.3	0.0000	-0.0090
42	Having FGD+CCS+CI installing SCR	1.000	0.625	0.945	0.899	43.9	143.3	0.0000	-0.0090
43	Having SCR+CI+CCS installing FGD	1.000	0.625	0.945	0.899	0.5	143.3	0.0000	-0.0090
44	Base Plant	0.000	0.000	0.000	0.000	0.0	65.2	0.0000	-0.0090
45	IGCC+SCR	0.996	0.491	1.000	0.367	730.0	69.3	0.0000	-0.0090
46	Having IGCC+SCR installing CCS	0.996	0.491	1.000	0.863	118.7	76.3	0.0000	-0.0090
47	NGCC+SCR	1.000	0.974	1.000	0.659	282.5	79.1	0.0000	0.0200

48	Having NGCC+SCR installing CCS	1.000	0.974	1.000	0.900	282.5	104.4	0.0000	0.0200
49	New Coal Plant All Controls	0.99993	0.72705	0.950	0.927	799.0	105.8	0.0000	-0.0090