AN INTEGRATED MODELING FRAMEWORK FOR CARBON MANAGEMENT TECHNOLOGIES

Volume 1 – Technical Documentation: Amine-Based CO_2 Capture and Storage Systems for Fossil Fuel Power Plant

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ABSTRACT

CO_2 capture and storage (CCS) is gaining widespread interest as a potential method to control greenhouse gas emissions from fossil fuel sources, especially electric power plants. Commercial applications of CO_2 separation and capture technologies are found in a number of industrial process operations worldwide. Many of these capture technologies also are applicable to fossil fuel power plants, although applications to large-scale power generation remain to be demonstrated. This report describes the development of a generalized modeling framework to assess alternative CO_2 capture and storage options in the context of multi-pollutant control requirements for fossil fuel power plants. The focus of the report is on post-combustion CO_2 capture using amine-based absorption systems at pulverized coal-fired plants, which are the most prevalent technology used for power generation today. The modeling framework builds on the previously developed Integrated Environmental Control Model (IECM). The expanded version with carbon sequestration is designated as IECM-cs. The expanded modeling capability also includes natural gas combined cycle (NGCC) power plants and integrated coal gasification combined cycle (IGCC) systems as well as pulverized coal (PC) plants.

This report presents details of the performance and cost models developed for an amine-based CO_2 capture system, representing the baseline of current commercial technology. The key uncertainties and variability in process design, performance and cost parameters which influence the overall cost of carbon mitigation also are characterized.

The new performance and cost models for CO_2 capture systems have been integrated into the IECM-cs, along with models to estimate CO_2 transport and storage costs. The CO_2 control system also interacts with other emission control technologies such as flue gas desulfurization (FGD) systems for SO_2 control. The integrated model is applied to study the feasibility and cost of carbon capture and sequestration at both new and existing PC plants as well as new NGCC plants. The cost of CO_2 avoidance using amine-based CO_2 capture technology is found to be sensitive to assumptions about the reference plant design and operation, as well as assumptions about the CO_2 capture system design. The

case studies also reveal multi-pollutant interactions and potential tradeoffs in the capture of CO_2, SO_2, NO_2 and NH_3.

The potential for targeted R&D to reduce the cost of CO_2 capture also is explored using the IECM-cs in conjunction with expert elicitations regarding potential improvements in key performance and cost parameters of amine-based systems. The results indicate that the performance of amine-based CO_2 capture systems can be improved significantly, and the cost of CO_2 capture reduced substantially over the next decade or two, via innovations such as new or improved sorbents with lower regeneration heat requirements, and improvements in power plant heat integration to reduce the (currently large) energy penalty of CO_2 capture. Future work will explore in more detail a broader set of advanced technology options to lower the costs of CO_2 capture and storage.

Volume 2 of this report presents a detailed User's Manual for the IECM-cs computer model as a companion to the technical documentation in Volume 1.

Table of Contents

List of Figures

List of Tables

1. INTRODUCTION

Today fossil fuels provide a major share of the total electricity generated in the United States The 300 GW of coal-fired power generation capacity in the U.S. provides 51% of all power generation and accounts for 79% of carbon emissions coming from electric utilities (EIA 2000). Even with the expected growth in natural gas for new generating capacity, coal's share of the electricity supply is still projected to be about 44% in 2020, and higher in absolute amount compared to today, according to recent DOE/EIA projections. Natural gas use is projected to account for 31% of power generation in 2020. At the same time, there is significant concern about the potential climate change impacts of increased CO_2 emissions to the atmosphere, to which fossil fuel power plants are the largest contributor. Thus, any new policies to significantly reduce CO_2 emissions during the next few decades must consider not only the technology options for new power plants, but also the retrofitting or repowering of existing coal and natural gas plants which will continue to operate for several decades to come. In all cases, improved modeling tools are needed to reliably estimate the performance and cost of alternative options, including the potential use of CO_2 capture and storage (CCS) as a CO_2 reduction strategy.

1.1 Technology Options for CO_2 Capture

A wide range of technologies currently exist for separation and capture of CO_2 from gas streams, although they have not been designed for power plant scale operations (Desideri and Corbelli 1998). Figure 1.1 and Table 1.1 briefly summarize the salient features of these technology options (Riemer, Audus et al. 1993; Hendriks 1994; Mimura, Satsumi et al. 1999; Audus 2000; Jeremy 2000; White, Strazisar et al. 2003). They are based on different physical and chemical processes including absorption, adsorption, membranes and cryogenics. Apart from these four types of processes that generate a concentrated stream of CO_2 product (which needs to be sequestered later), there is another set of biological systems (*e.g.* forestry, microbial/ algal processes etc.) that capture CO_2 and bio-chemically transform it into some other compounds (and hence also get sequestered simultaneously).

The choice of a suitable technology depends upon the characteristics of the gas stream from which CO_2 needs to be separated, which mainly depends on the power plant technology. At present, the majority of the plants in the U.S. are conventional combustion-based plants that generate a flue gas that is a dilute stream of CO_2 due to large amount of nitrogen in the combustion air. Future power plants may be designed so as to separate out CO_2 from coal before combustion (*e.g.* coal gasification systems), or they may employ pure oxygen combustion instead of air so as to obtain a concentrated CO_2 stream for treatment. **Error! Reference source not found.** shows the variety of power plant fuels and technologies that affect the choice of CO_2 capture systems.
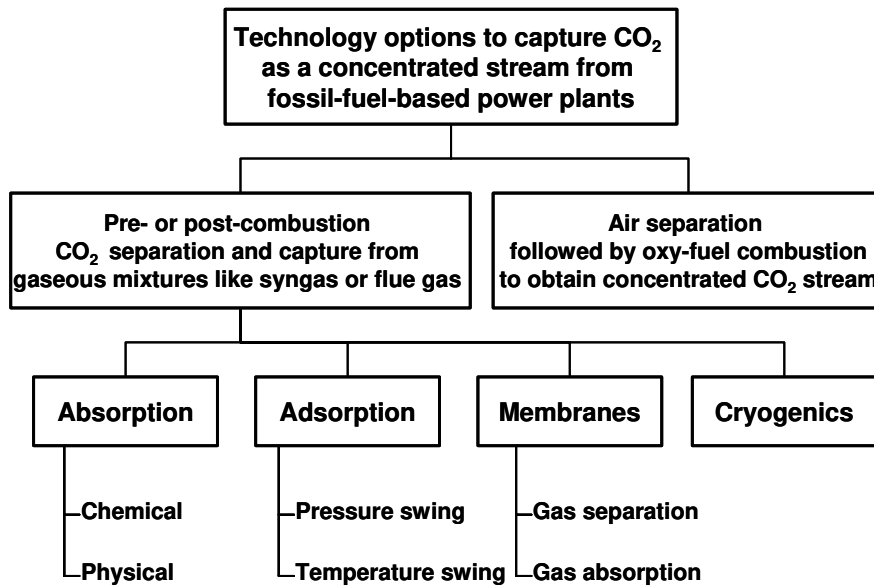
Figure 1.1. Technology options for CO_2 separation and capture

1.2 Options for CO_2 Sequestration

Once the CO_2 is captured, it needs to be securely stored (sequestered). Again, there is a range of options potentially available, as shown in **Error! Reference source not found.**. Geologic formations including deep saline reservoirs, depleted oil and gas wells, and unmineable coal seams are some of the potentially attractive disposal sites (Adams, Ormerod et al. 1993; Byrer and Guthrie 1998; Lindeberg and Holloway 1998). Some of these options, such as enhanced oil recovery (EOR) and enhanced coal bed methane

(ECBM), can be revenue generating as well, as they lead to production of valuable products like oil and methane,.

Table 1.1. *Comparison of technology options for CO_2 separation and capture*

Technology Option	System Requirements	Advantages	Problems/ Drawbacks
Absorption (Chemical)	Absorber and stripper sections Chemical sorbent (*e.g.* MEA, HPC)	Suitable even for dilute CO_2 streams (typical flue gas from power plants) Operates at ordinary temperature & pressure Commercially available, proven technology	The heat of sorbent regeneration is very high Significant sorbent losses; pre-processing (*e.g.* S removal) may be required
Absorption (Physical)	Absorber and stripper sections Physical sorbent (*e.g.* Selexol)	Suitable only for gas streams with high partial pressure of CO_2 (typical syngas from gasification systems) Less energy required, assuming that the gas stream to be processed is already at high pressure Sorbents are less susceptible to the impurities in the gas stream	Requires high operating pressure Works better only with gas streams having high CO_2 content; so it is not suitable for flue gas processing
Adsorption	Adsorber bed(s)	Commercially available gas separation process	Low capacity and CO_2 selectivity of available adsorbents
Membranes	Membrane filter(s)	Upcoming, promising technology with diverse applications Space efficient	Requires high operating pressures Lower product purity; need for multiple stages/ recycle
Cryogenics	Refrigeration and distillation units	Direct production of liquid CO_2	Requires very large amount of energy for refrigeration (not suitable for dilute streams)
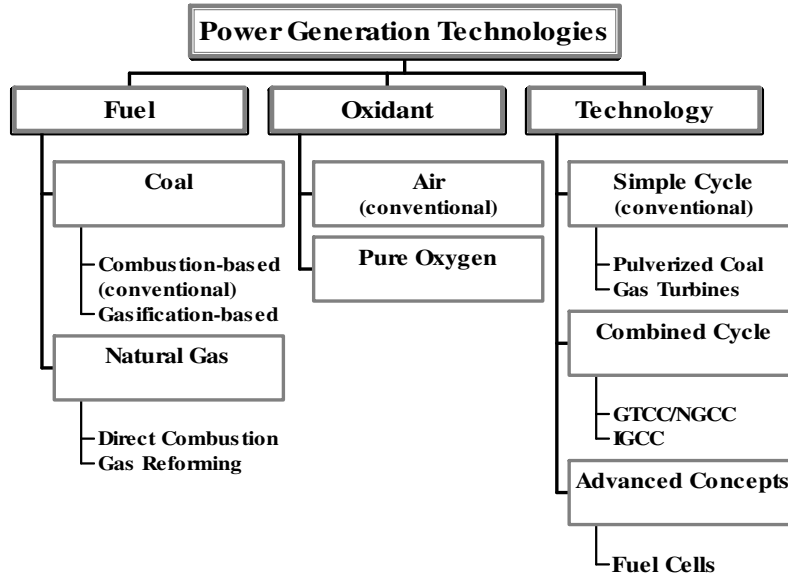
Figure 1.2. Technology options for fossil-fuel based power generation
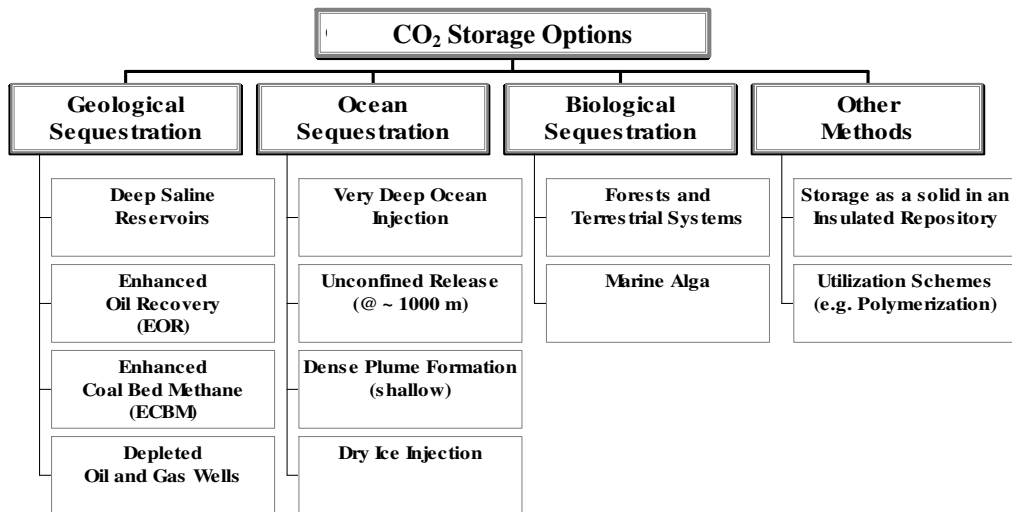
Figure 1.3. Options for CO₂ sequestration

respectively. Ocean storage is another option being studied (Herzog 1998; Spencer 1998)

The distance to a secure storage site, the availability and cost of transportation infrastructure, and the regulatory framework all affect the choice of disposal option. In general, studies indicate that geologic formations are the most plentiful and attractive

option for U.S. power plants (Bergman and Winter 1995). While the economic costs of CO_2 storage appear to be low, its social and political acceptability are not yet clear, especially with regard to ocean sequestration (CO2-Experiment 2001; USDOE/NETL 2001). Issues related to geologic sequestration of CO_2, including. potential sites, storage capacities, environmental impacts, monitoring requirements and leakage are well summarized elsewhere (White, Strazisar et al. 2003).

1.3 Scope of this Project

Efforts by DOE/NETL and others to develop new or improved technologies for CO_2 capture and storage (CCS) can be assisted substantially by improved analytical tools to assess the overall effectiveness, costs, and carbon sequestration potential of alternative CCS approaches. Especially important for R&D planning and management is an ability to systematically compare advanced systems and concepts to current commercial technologies that also are evolving. To help provide this capability, this project described in this report builds upon the Integrated Environmental Control Model (IECM) developed under a prior DOE/NETL research contract (DE-AC22-92PC91346). The IECM was designed to provide preliminary performance, emissions and cost estimates for alternative environmental control options for coal-fired power plants, with a focus on SO_2, NO_x, particulates and (most recently) mercury emissions. The model simulates a single user-specified facility, and is built in a modular fashion that allows models of individual technologies to be incorporated into the overall framework. A user can then select different options to configure and evaluate a particular plant design involving current commercial technology or advanced emission control systems.

The current project extends the IECM capabilities to include technology options for carbon management. This version of the model is referred to as the IECM-cs. The CCS options include a set of "baseline" technologies representing currently available fossil-fuel power plants, plus a selected set of advanced process designs that promise improved performance and/or lower cost. In addition to coal combustion plants, the IECM-cs framework has been expanded to include natural gas combined cycle (NGCC) plants plus integrated coal gasification combined cycle (IGCC) systems. Pipeline transport and alternative CO_2 storage options also have been added. The IECM-cs thus provides a

comprehensive yet easy-to-use modeling tool for evaluating technological options in a total systems context.

The focus of this report is on the modeling of CCS systems for a pulverized coal-fired (PC) power plant, which is the most widely used technology for electric power generation. Models of NGCC and IGCC plants with CO_2 capture systems are undergoing further refinement as part of a continuing project which will issue reports on these technologies later in 2004. As detailed in the section below, the scope of the present report covers the development and illustrative applications of the baseline coal-fired power plant model employing an amine CO_2 capture system together with pipeline transport to a geological storage site. An advanced post-combustion CO_2 capture system design also is developed and evaluated to assess the potential benefits of R&D. Further details on the design and use of the IECM-cs software package can be found in Volume 2 of this report, which provides a complete User's Manual for the coal-fired plant model.

Some of the key research questions that are addressed in this report include:

- What technologies and design configurations are most suitable for capture and storage of CO_2 from coal or gas-fired power plants?
- What are the key parameters that affect the performance, cost and environmental acceptability of different options?
- How do alternative options compare in terms of these considerations?
- What are the technical and economic uncertainties associated with different options?
- What are the potential benefits of continued R&D on CCS technology?

1.4 Organization of this Report

The organization of this report is as follows. Chapter 2 gives a brief overview of amine-based CO_2 capture systems, including historical developments and process description. Chapter 3 documents the performance model developed in this research, including the model configurations, methodology, parameters and performance equations. Chapter 4 next describes the associated cost model, which is directly linked to the performance model. Then, Chapter 5 illustrates the applications of the new performance and cost models. Several case studies applying current amine-based CO_2 capture technology to coal and natural gas power plants (new and retrofits) are presented. Following this,

together with an expert elicitation study, Chapter 6, uses the model to explore potential future cost reductions and R&D management. Finally, Chapter 7 presents some concluding remarks and directions to future work. Additional details concerning amine systems, characterization of uncertainties and variability, probability distributions for model parameters, case study results, and expert elicitation study are included as Appendices A-E.

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2. AMINE-BASED CO2 CAPTURE SYSTEMS: AN OVERVIEW

In conventional coal plants, which use air for combustion, CO_2 can be separated from the post-combustion flue gas stream.   Past studies have shown that amine-based CO_2 absorption systems are the most suitable for combustion-based power plants for the following reasons:

- These systems are effective for dilute CO_2 streams, such as coal combustion flue gas which typically contains about 10%-15 % CO_2 by volume.

- Amine-based CO_2 capture system is a proven technology that is commercially available today.

- Amine-based systems are similar to other post-combustion environmental control units used at power plants. These units are operated at ordinary temperature and pressure.

- A major effort is being made worldwide to improve this process in the light of its potential role in CO_2 abatement. Thus, one can anticipate future benefits from technology advances.

2.1 Historical Developments

Although the amine-based CO_2 capture technology has gained increasing attention in the recent times, this technology has been around for several decades now. Amine-based absorption/stripping has been a commercial technology for CO_2 removal from natural gas and hydrogen (Yeh 2003). The basic amine process was first patented by R. R. Bottom in 1930 as absorbents for acidic gas treating (Bottoms 1930). Alkanolamines (referred to as "amines" in this document) are a family of organic compounds that are derivatives of alkanols (compounds with functional group "OH" group, commonly called as alcoholic group), that also have an "amino" (NH_2) group attached to one of the carbon atoms. The amine-based gas treating basic process flow scheme has remained relatively unchanged over the years. Members of alkanolamine family were subsequently introduced into gas purification market and still remain the technology of choice for the removal of H_2S and CO_2 for gas purification (Kohl and Blohm 1950; Kohl and Nielsen 1997).

The idea of separating CO_2 from flue gas streams started back in 1970's, not with concern about the greenhouse effect, but as a possible economic source of CO_2, mainly for enhanced oil recovery (EOR) operations. Flue gas, a gaseous product stream resulting from the combustion of fossil fuels in air, mainly contains nitrogen, carbon dioxide, and water vapor along with small quantities of many other gases. Depending upon the carbon content of the fuel and the quantity of air used for combustion of the fuel, the flue gas stream may contain as high as 15% CO_2 and is a potential source of CO_2 which is available at no cost. Even today, about 80% of CO_2 production is used for EOR (Chapel et al., 1999), most of which is obtained from natural CO_2 domes. CO_2 is also produced for other industrial applications such as carbonation of brine and production of products like dry ice, urea and beverages.

Several commercial CO_2 capture plants were constructed in the US in the late 1970's and early 1980's (Kaplan 1982; Pauley, Simiskey et al. 1984). Some of these plants are still in operation today. But all these plants are much smaller than a typical power plant in terms of tonnage of CO_2 handled. Figure 2.1 gives a rough idea about the various industrial applications of CO_2 capture technologies and their relative magnitude of operations.

Unless there is an application that can make use of the captured CO_2, it has to be securely stored (sequestered) to prevent it from entering the atmosphere. However, there is little experience with CO_2 sequestration technologies other than EOR. The first commercial CO_2 sequestration facility started in Norway in September 1996 in response to a Norwegian carbon tax. Since then, Statoil has been storing about 1 million tonnes of CO_2 per year from the Sleipner West gas field into a sandstone aquifer 1000 m beneath the North Sea (DOE 1999; Statoil 2001). The international research community is closely monitoring this facility to enhance the understanding of this geological experiment.

All these plants (Figure 2.1) capture CO_2 with processes based on chemical absorption using a monoethanolamine (MEA) based sorbent. MEA is a primary amine with high pH

status	EOR	Fertilizer	Soda Ash	Food-grade	Sleipner Gasfield	500MW gross Coal Plant
status	shut down	operational	operational	operational	operational	prospective
year	'80s	'90s	1978	'90's	1996	2010?
tonne CO2/day	1200	150	800	320	3000	9600
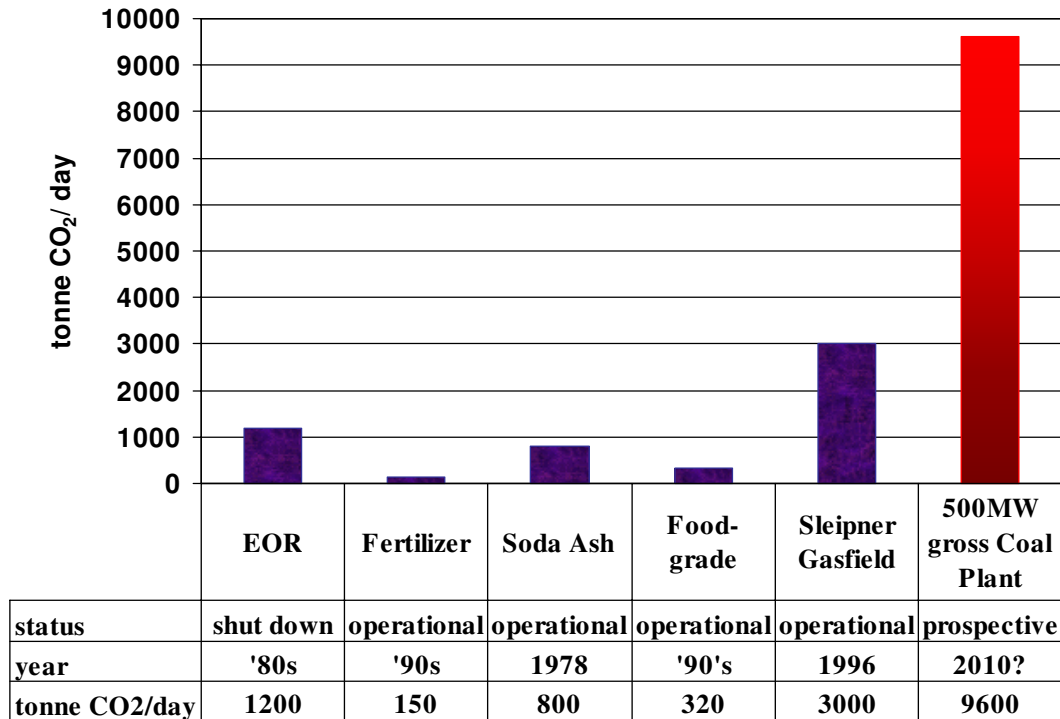
Figure 2.1. Major industrial applications of amine-based CO_2 capture systems

and has the lowest molecular weight of the available amines. It is completely soluble in water and is readily biodegradable (Dow 2000). It is a fairly reactive compound and is classified as a corrosive material. It was developed over 60 years ago as a general, non-selective sorbent to remove acidic gas impurities (e.g. H_2S, CO_2) from natural gas streams (Herzog 1998). The process was then adapted to treat flue gas streams for CO_2 capture. Dow Chemical Co. (and later Fluor Daniel Inc.), Kerr-McGee Chemical Corp. and ABB Lummus Crest Inc., are some of the key players in the development of MEA-based technology for CO_2 capture. About 75%-96% CO_2 may be captured using this technology to yield a fairly pure (>99%) CO_2 product stream.

Today there are two main MEA-based processes available for commercial CO_2 recovery plants: the Fluor Daniel Econamine FG process and the ABB Lummus Crest MEA process (Wong, Gunter et al. 2000). The brief commercial history of these processes is as follows.

2.1.1. Fluor Daniel's Econamine FG process

Dow Chemical and Union Carbide developed inhibited 30 wt.% MEA processes. These absorption processes use a sorbent containing MEA diluted in water to 30 % w/w (by weight) *i.e.,* each 100 kg of total sorbent contains 30 kg of MEA, for the recovery of CO_2 from flue gases in the 1970's and 1980's primarily for the EOR market. Dow Chemical's process was known as the GAS/SPEC FT-1^{TM} process till 1989. Several plants were built in West Texas to recover CO_2 from boiler flue gas for EOR purposes between 1982 and 1986. These plants were technical and commercial successes and were shut down only because of the crude oil price collapse in 1986. As the price of crude oil dropped dramatically in 1986, the EOR market disappeared and these licensors (Dow Chemical and Union Carbide) became less active. Dow Chemical sold its GAS/SPEC FT-1™ process to Fluor Daniel, Inc. in 1989. Fluor Daniel renamed the technology as Econamine FG℠. Sixteen commercial plants have been built, including nine large plants (60 tonne/d and larger) and seven skid-mounted plants (Chapel, Ernst et al. 1999). Seven of the large plants are still operating. Fluor Daniel licensed three of these commercial plants: a 320 tonne/d CO_2 plant in Bellingham, Massachusetts for Northeast Energy Associates, a 150 tonne/d plant for Sumitomo Chemical in Chiba, Japan, and a 90 tonne/d plant for Prosint Produtos Sintéticos in Rio de Janeiro, Brazil. Fluor Daniel also constructed the Bellingham plant. Prior to this, Dow had licensed six commercial plants ranging from 6 to 1000 tonne/d. The seven facilities employing skid-mounted Econamine FG process units have capacities ranging from 6 to 40 tonne/d and were manufactured by the Wittemann Company of Palm Coast, Florida.

It may be noted that all of the large commercial plants use flue gas resulting from the combustion of natural gas, except the Sumitomo plant that fires a variety of fuels including heavy fuel oil. The Econamine FG process has also been demonstrated with coal-derived flue gas in three pilot plants: a 4.5 tonne/d plant in Yokosuka, Japan for Tokyo Electric Power Co, a 2 tonne/d unit at the Sundance Generating Plant in Alberta, and a 4 tonne/d unit at the Boundary Dam Power Plant in Saskatchewan (IEA-GHGRDP 2002). Fluor Daniel has also licensed a natural gas-fired 2 tonne/d pilot plant in Osaka, Japan for KEPCO. Commercial operations at the Warrior Run Power Plant in Maryland

started in February 2000. The Econamine FG scrubber system is used to capture CO_2 from a portion of the flue gases from this 180 MWe AES cogeneration plant that burns only Western Maryland coal with a clean coal technology using a circulating fluidized bed boiler. The extracted CO_2 from this commercial-scale production facility is used for food processing and related processes. Recently, Fluor has announced an improved version of this process named as "Fluor Econamine FG Plus" that addresses some of the problems in the Econamine FG process (Reddy and Roberts 2003), although no commercial plants are yet in existence.

The performance and cost model developed in this thesis for current commercial systems is based primarily on the Econamine FG process, which uses 30% w/w MEA solution with an oxygen inhibitor. The inhibitor helps in two ways – reduced sorbent degradation and reduced equipment corrosion (Chapel, Ernst et al. 1999). It may be noted that this process is *not* applicable to reducing gas streams that contain large amounts of CO and H_2, or contain more than 1 ppm of H_2S, or contain less than 1% O_2 v/v.

2.1.2. The Kerr-McGee/ ABB Lummus amine process

Kerr-McGee started up their 800 tonne/d CO_2 recovery unit in 1978. The Trona unit has been fed flue gases from boilers fired with natural gas, coal and coke. During the first several years of operation, the installation was improved in terms of reliability and cost effectiveness. In late 1990, Kerr-McGee and Lummus Global concluded a joint licensing agreement whereby Lummus gained worldwide exclusive marketing rights to Kerr-McGee's CO_2 recovery technology and became responsible for marketing and basic engineering. Kerr-McGee maintains the continuing role in technology transfer, process improvement, quality control of new designs, operator training, and licensing(ALSTOM, AEP et al. 2001).

Two units have been licensed using this technology. They are:

1)   Applied Energy System, Poteau, Oklahoma. This 300 MW coal-fired co-generation plant incorporates a 200 TPD food-grade liquid CO_2 unit as the steam host. Startup was completed in January 1991. Lummus Crest was responsible for engineering, procurement and construction of the entire facility, including the

power plant. Lummus Crest made several design improvements to the AES facility.

2)   Soda Ash Botswana, Pty. Ltd., Sue pan, Botswana. This soda ash facility, incorporating a 300 TPD CO_2 unit, started up in March 1991.

The Kerr-McGee/ ABB Lummus amine process uses a 15%-20% w/w MEA solution without any inhibitor (Marion, Nsakala et al. 2001). This technology can capture more than 96% of the CO_2 from flue gases, but the lower sorbent concentration leads to economic disadvantages in terms of greater capital requirements due to larger equipment size and higher energy requirements due to higher amount of dilution water per unit of sorbent. At the same time, it may be noted that this process has already been proven for coal-fired flue gas applications at commercial scale.

2.2 Process Description

Amine-based CO_2 capture process is based on the principle of chemical absorption. Chemical absorption systems tend to be more efficient than the other systems shown in Figure 1.1, as the process is accompanied by a chemical reaction that enhances the overall mass transfer from gas phase to liquid phase. Here, a continuous scrubbing system is used to separate CO_2 from a gaseous stream. The system consists of two main elements, an absorber, where CO_2 is absorbed into a sorbent and a regenerator (or stripper), where CO_2 is released (in concentrated form) and the original sorbent is recovered.

In a power plant application (Figure 2.2) cooled flue gases flow vertically upwards through the absorber countercurrent to the sorbent (MEA in a water solution, with some additives). The MEA reacts chemically with the CO_2 in the flue gases to form a weakly bonded compound (carbamate). The scrubbed gases are then washed and vented to the atmosphere. The CO_2-rich sorbent stream leaves the absorber and passes through a heat exchanger, then further heated in a reboiler using low-pressure steam. The weakly bonded compound formed during absorption is broken down by the application of heat, regenerating the sorbent, and producing a concentrated CO_2 stream. The hot CO_2-lean sorbent is then returned to the heat exchanger, where it is cooled, and then sent back to

the absorber. Some fresh MEA is added to make up for the losses incurred in the process (see section 2.5.2 for details).
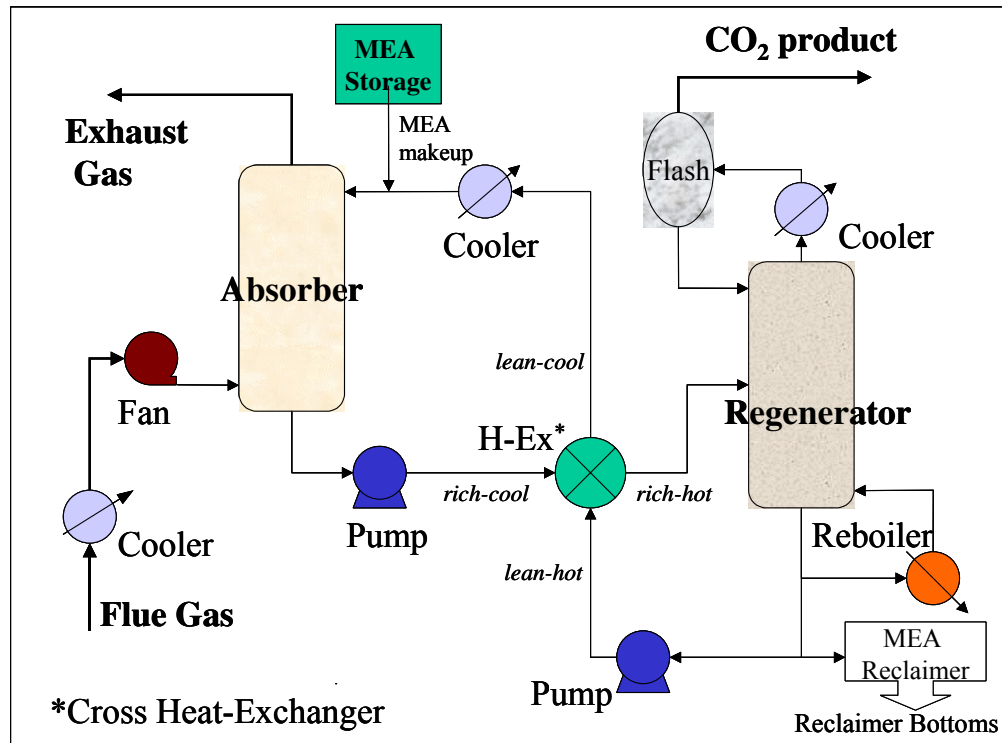
Figure 2.2. Flowsheet for CO₂ capture from flue gases using amine-based system

The CO₂ product is separated from the sorbent in a flash separator, and then taken to the drying and compression unit. It is compressed to very high pressures (about 2000 psig) so that it is liquefied and easily transported over long distances to the designated storage or disposal facility.

2.3 Process Chemistry

There are mainly three compounds, *viz.* carbon dioxide (CO_2), amine (MEA) and water (H_2O) that are active in this system. The following equilibrium reactions occur in the bulk of the liquid (Al-Baghil, Pruess et al. 2001):

Water hydrolysis: $2H_2O \leftrightarrow H_3O^+ + OH^-$

Bicarbonate formation: $2H_2O + CO_2 \leftrightarrow H_3O^+ + HCO_3^-$

15

Carbonate formation: $H_2O + HCO_3^- \leftrightarrow H_3O^+ + CO_3^{-2}$

Amine protonation: $H_3O^+ + R\text{-}NH_2 \leftrightarrow H_2O + R\text{-}NH_3^+$

Carbamate formation: $R\text{-}NH_2 + HCO_3^- \leftrightarrow H_2O + R\text{-}NH\text{-}COO^-$
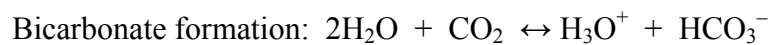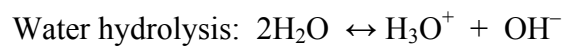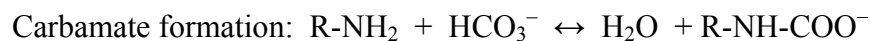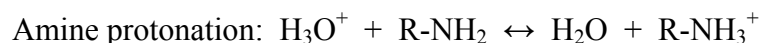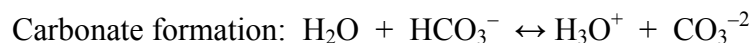
Here, MEA has been represented as $R\text{-}NH_2$, where "R" stands for $HO\text{-}CH_2CH_2$.

The process chemistry is complex, but the main reactions taking place are (Desideri and Paolucci 1999):

CO$_2$ Absorption: $2\ R\text{-}NH_2 + CO_2 \rightarrow R\text{-}NH_3^+ + R\text{-}NH\text{-}COO^-$

MEA Regeneration: $R\text{-}NH\text{-}COO^- + R\text{-}NH_3^+ + (\text{Heat}) \rightarrow CO_2 + 2\ R\text{-}NH_2$
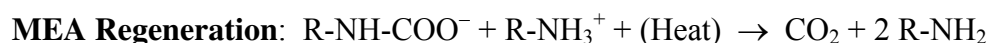
Pure MEA (with $R = HO\text{-}CH_2CH_2$) is an "unhindered" amine that forms a weakly bonded intermediate called "carbamate" that is fairly stable. Only half a mole of CO_2 is absorbed per mole of amine, as shown in the CO_2 absorption equation above. On application of heat, this carbamate dissociates to give back CO_2 and amine sorbent, as shown in the second equation above. Since the carbamate formed during absorption is quite stable, it takes a large amount of heat energy to break the bonds and to regenerate the sorbent. When MEA is used as the sorbent, the theoretical minimum heat requirement to reverse this reaction is about 1900 kJ/ kgCO$_2$.

MEA is a reactive compound. The reversible reactions allow us to make use of the same sorbent mass repeatedly, by capturing CO_2 in the absorber column and then regenerating the sorbent in the stripper or the regenerator column. In spite of dilution with water and use of inhibitors, a small quantity of MEA is lost through various unwanted reactions, mainly the polymerization reaction (to form long-chained compounds) and the oxidation reaction forming organic acids and liberating ammonia. Appropriate measures must be taken in order to avoid accumulation of these unwanted chemical species in the circulating sorbent.

Acid gas impurities that might be present in the flue gas are another potential source of sorbent loss. This is especially true for the flue gas from coal-fired combustion. Acid

gases like SO_2, HCl, and NO_2 react with MEA to form heat-stable salts that reduce the CO_2 absorption capacity of the sorbent. Thus, very low concentrations of these gases (on the order of 10 ppm) are desirable to avoid excessive loss of expensive sorbent. The problem is especially acute for SO_2 because its concentration in flue gases is typically 700 to 2500 ppm at coal-fired plants. NO_x is less of a problem because most of the NO_x is nitric oxide (NO), whereas only NO_2 (typically about 5% of total NO_x) is reactive with MEA. Hence, from a multi-pollutant perspective, there are important interactions between the CO_2 capture system and the control of other air pollutants, especially SO_2 and NO_x emissions.

For other "hindered" amines (e.*g.*, where R is a bulky group), the carbamate formed is not stable, and an alternate reaction leads to formation of bicarbonate ions and hence a higher theoretical capacity of one mole of CO_2 per mole of amine, as shown in the CO_2 absorption equation below (Sartori, Ho et al. 1994; Herzog, Drake et al. 1997).

$$\textbf{CO}_2 \textbf{ Absorption: } R\text{-}NH_2 + CO_2 + H_2O \rightarrow R\text{-}NH_3^+ + HCO_3^-$$

$$\textbf{MEA Regeneration: } HCO_3^- + R\text{-}NH_3^+ + (\text{less Heat}) \rightarrow CO_2 + H_2O + R\text{-}NH_2$$
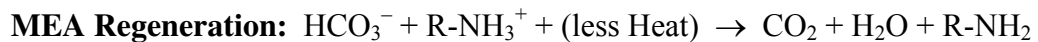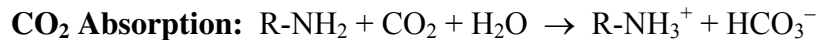
The regeneration of these amines requires lesser amount of heat energy as compared to the unhindered amines. But the CO_2 uptake rate of hindered amines is very low. Efforts are underway to formulate better sorbents by combining favorable properties of these two groups of amines.

2.4 Process Areas

The CO_2 capture and separation system consists of the following process equipment:

Direct contact cooler: The flue gases coming out of a power plant are quite hot. The temperature of flue gas may be ranging from as low as 60 deg. C (in case of coal-fired power plants with wet SO_2 scrubbers) to more than 550 deg. C (in case of natural gas fired simple cycle power plants). It is desirable to cool down the flue gases to about 45-50 deg. C, in order to improve absorption of CO_2 into the amine sorbent, to minimize sorbent losses, and to avoid excessive loss of moisture with the exhaust gases. Absorption being an exothermic process is favored by low temperatures, and higher

temperature may also lead to sorbent losses due to evaporation and degradation. In case of gas-fired power plants or majority of coal-fired power plants without wet scrubbers for SO_2 removal, a direct contact cooler needs to be installed to reduce the temperature of the flue gas stream to acceptable levels. In case of coal-fired power plant applications that have a wet FGD (flue gas desulfurization) unit upstream of the amine system, the wet scrubber helps in substantial cooling of the flue gases, and additional cooler may not be required.

Flue gas blower: The flue gas enters at the bottom of the absorber column and flows upwards, countercurrent to the sorbent flow. Thus, it needs to overcome a substantial pressure drop as it passes through a very tall absorber column. Hence the cooled flue gas must be pressurized using a blower before it enters the absorber.

Absorber: This is the vessel where the flue gas is made to contact with the MEA-based sorbent, and where the CO_2 from the flue gas is dissolved into the sorbent. The column may be plate-type or packed. Most of the CO_2 absorbers are packed columns using some kind of polymer-based packing to provide large interfacial area.

Rich/lean cross heat exchanger: The CO_2-loaded sorbent must be heated in order to strip off CO_2 and regenerate the sorbent. On the other hand, the regenerated (lean) sorbent coming out of the regenerator must be cooled down before it can be circulated back to the absorber column. Hence, these two sorbent streams are passed through a cross heat exchanger, where the rich (CO_2-loaded) sorbent gets heated and the lean (regenerated) sorbent gets cooled.

Regenerator: This is the column where the weak intermediate compound (carbamate) formed between the MEA-based sorbent and dissolved CO_2 is broken down by the application of heat. The CO_2 is separated from the sorbent to leave reusable sorbent behind. In case of unhindered amines like MEA, the carbamate formed is stable and requires large amounts of energy to dissociate. It also consists of a flash separator, where CO_2 is separated from most of the moisture and evaporated sorbent to produce a fairly concentrated CO_2 stream.

Reboiler: The regenerator is connected with a reboiler that is basically a heat exchanger where low-pressure steam extracted from the power plant is used to heat the loaded sorbent.

Steam extractor: In case of coal-fired power plants that generate electricity in a steam turbine, a part of the LP (low pressure)/IP (intermediate pressure) steam has to be diverted to the reboiler for sorbent regeneration. Steam extractors are installed to take out steam from the steam turbines.

MEA reclaimer: The presence of acid gas impurities (SO_2, SO_3, NO_2 and HCl) in the flue gas leads to formation of heat stable salts in the sorbent stream, which can not be dissociated even on application of heat. In order to avoid accumulation of these salts in the sorbent stream and to recover some of this lost MEA sorbent, a part of the sorbent stream is periodically distilled in this vessel. Addition of a strong alkali such as caustic helps in release of some of the MEA. The recovered MEA is recycled to the sorbent stream while the bottom sludge (reclaimer waste) is sent for proper disposal.

Sorbent processing area: The regenerated sorbent needs to be further cooled even after passing through the rich/lean cross heat exchanger using a cooler. This is so that the sorbent temperature can be brought back to an acceptable level (about 40 deg C). In order to make up for the sorbent losses, a small quantity of fresh MEA sorbent must be added to the sorbent stream. So, the sorbent processing area primarily consists of a sorbent cooler, MEA storage tank, and a mixer. It also consists of an activated carbon bed filter that adsorbs impurities (degradation products of MEA) from the sorbent stream.

CO_2 drying and compression unit: The CO_2 product may have to be carried over very long distances via pipelines. Hence it is desirable that it does not contain any moisture in order to avoid corrosion in the pipelines. Of course, the CO_2 product specifications may vary depending upon the end use (or storage/ disposal method) and the material of construction of the pipeline. Also, it has to be compressed to very high pressures so that it gets liquefied and can overcome the pressure losses during the pipeline transport. The multi-stage compression unit with inter-stage cooling and drying yields a final CO_2

product at the specified pressure (about 2000 psig) that contains acceptable levels of moisture and other impurities (e.g. N_2).

CO_2 transport facility: The CO_2 captured at the power plant site has to be carried to the appropriate storage/ disposal site. Considering the scale of the operation (thousands of tonnes of CO_2 per day), pipelines are the suitable mode of transportation. There is fair amount of industrial experience and expertise in the field of the construction (and operation) of pipelines for CO_2 transport. Recently, a 325-km pipeline carrying CO_2 from the Great Plains Synfuels Plant in Beulah, North Dakota (owned by Dakota Gasification Company of Bismarck, North Dakota) to the Weyburn oil fields in Saskatchewan, Canada went operational (EnCana 2003). In case of retrofit applications, where construction of new pipelines might be prohibitively expensive (and questionable in terms of public acceptance, especially in densely populated regions), transport via tankers may have to be considered.

CO_2 disposal facility: Once the CO_2 is captured, it needs to be securely stored (sequestered). Again, there are a wide range of options potentially available (see Figure 1.3). Geologic formations such as underground deep saline reservoirs, depleted oil and gas wells, and abandoned coal seams are some of the potentially attractive disposal sites (Adams, Ormerod et al. 1993; Byrer and Guthrie 1998; Lindeberg and Holloway 1998). Ocean disposal and terrestrial sinks are additional options being studied (Herzog 1998; Spencer 1998). The distance to a secure storage site and the availability and cost of transportation infrastructure also affect the choice of disposal option. In general, studies indicate that geologic formations are the most plentiful and attractive option for U.S. power plants (Bergman and Winter 1995). Transport of CO_2 to a storage site is typically assumed to be via pipeline. While the economic costs of CO_2 storage appear to be low, the social and political acceptability of different options are not yet clear.

2.5 Limitations of the MEA Process

Although MEA-based absorption process is the most suitable technology available today for post-combustion capture of CO_2 from power plant flue gases, it has several important drawbacks. The main problems may be listed as follows:

2.5.1. Energy Penalty

The stable carbamate ion requires substantial energy to break the bonds. Because MEA is diluted with lot of water, a large amount of heat is required to regenerate the sorbent. Substantial energy also is needed to compress the captured CO_2 for pipeline transport to a storage site. This heat and electricity requirement reduces the net efficiency of the power plant if it is extracted internally by de-rating the power plant. Alternatively, a much bigger power plant must be built in order to achieve the same "net" power generation capacity as it would have been without CO_2 capture. In case of retrofit applications, an auxiliary gas-fired boiler and steam turbine might be added to maintain the power output.

2.5.2. Loss of Sorbent

Sorbent is lost during the process because of a variety of reasons including degradation, entrainment, vaporization and mechanical losses (Stewart and Lanning 1994; Stewart and Lanning 1994). All the sorbent entering the stripper does not get regenerated. Flue gas impurities, especially oxygen, sulfur oxides and nitrogen dioxide react with MEA to form heat-stable salts, thus reducing the CO_2-absorption capacity of the sorbent. Proprietary inhibitors are available that make the sorbent tolerant to oxygen. Flue gas NO_x is not a major problem since nitric oxide (NO) is the predominant form ($\sim$ 90-95%) of total NO_x in the flue gas, and does not react with inhibited amines (Suda, Fujii et al. 1992; Leci 1996). But, SO_2 does degenerate MEA sorbent, so very low inlet concentrations (10 ppm) are desirable to avoid excessive loss of sorbent. However, untreated flue gases of coal-fired power plants contain about 700 to 2500 ppm SO_2 (plus roughly 10-40 ppm NO_2). The interaction of SO_2 with CO_2 control system is thus particularly important. The heat-stable salts that are formed may be treated in a side stream MEA-reclaimer, which can regenerate some of the MEA. Technologies such as electro-dialysis are also being proposed for this purpose (Yagi, Shibuya et al. 1992).

Most of the previous studies on reactions of MEA had focused on natural gas purification processes and were conducted with pure gases under laboratory-controlled conditions. However, the flue gas generated by a fossil-fuel-fired boiler is a complex mixture of various chemical species. It has been shown that there are chemical degradation reactions that occur under plant conditions which do not occur in laboratory experiments

with pure gases (Strazisar, Anderson et al. 2003). Better understanding of the mechanisms and chemical pathways associated with MEA degradation in actual power plant applications may help reduce or eliminate its negative impacts.

2.5.3. Corrosion

MEA is a reactive compound and the MEA solution in water in the presence of oxygen and carbon dioxide is a highly corrosive system. Irreversible side reactions with CO_2 and other flue gas components lead to the formation of various degradation products. These byproducts are associated with increased corrosion in this system. Hence, corrosion control is very important in amine systems processing oxygen-containing flue gases. In order to reduce corrosion rates, corrosion inhibitors, lower concentrations of MEA, appropriate materials of construction, and mild operating conditions are recommended (Barchas and Davis 1992).

2.5.4. Environmental Emissions

In case of MEA-based CO_2 capture systems, environmental problems may arise from the spent sorbent slurry discharged from the MEA reclaimer (also called "reclaimer bottoms") and the emissions of MEA and ammonia (NH_3) carried by the treated flue gas. Details about the potential environmental impacts of these emissions are discussed in *Appendix A*. The spent sorbent is treated as a hazardous waste. Entrainment of MEA with the treated flue gas is at most a few ppm and is likely to go down with the improvements in the absorber design (wash section at the top). The emission rate of NH_3 from a CO_2 capture plant is substantially higher than that from a power plant without amine-based CO_2 capture system. However, these NH_3 emissions are much smaller than those coming from other sources (animals, farms). At this time, it is not very clear if these emissions are likely to have significant environmental impacts. Hence, these aspects must be carefully looked into before a widespread application of this technology.

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3. PERFORMANCE MODEL DEVELOPMENT

A performance model of a chemical technology essentially consists of the simulation of mass and energy balances around the system. In case of an environmental control technology such as amine-based CO_2 capture, it keeps track of various material flows (e.g. flow of flue gas and its individual components, flow of the sorbent and its degradation products, flow of other chemical reagents) and energy flows (e.g. thermal energy requirement for sorbent regeneration, electrical energy required for mechanical devices such as pumps, fans, compressors).

The rate of removal of CO_2 from flue gas using an amine scrubber depends on the gas-liquid mass transfer process. The chemical reactions that permit diffusion of CO_2 in the liquid film at the gas-liquid interface enhance the overall rate of mass transfer. So, the CO_2 removal efficiency in the absorber is a function of various parameters that affect the gas-liquid equilibrium (*e.g.*, flow rates, temperature, pressure, flue gas composition, MEA concentration, equipment design, *etc*.). Absorption of CO_2 in an alkaline medium may be considered as a first order reaction. Higher CO_2 concentration thus improves the efficiency of the absorption system. Even at low concentration of CO_2, MEA has great affinity for CO_2. The solubility of CO_2 in MEA is much higher as compared to many other conventional sorbents. Similarly, the design of and conditions in the regenerator affect the energy requirement and the overall performance of the system.

A number of previous studies have reported some cost and/or performance data for specific amine-based systems, including hypothetical applications to coal-fired power plants (Smelser, Stock et al. 1991; Hendriks 1994; Kohl and Nielsen 1997; Chakma and Tontiwachwuthikul 1998; Herzog 1998; Simbeck 1998; Chapel, Ernst et al. 1999; Marion, Nsakala et al. 2001). However, there are no generally available process models that can be used or modified for detailed studies of CO_2 removal options. Cost data also are relatively limited and often incomplete.

The performance model for amine-based CO_2 capture system was developed for use in the IECM modeling framework, which simulates the performance and cost of a coal-fired power plant equipped with multiple emission control systems (Rubin, Kalagnanam et al.

1997). The performance model of the CO_2 capture system is a response-surface model with about two dozen parameters; developed from numerous runs of a detailed process simulation model. The performance model estimates all of the key flow rates and energy requirements. The output from the performance model is then used by the cost model to estimate various costs of the system.

In this chapter, the process simulation packages used are described in section 3.1, the overall model development methodology is laid out in section 3.2 and the various performance parameters are discussed in section 3.3. The actual performance equations employed in the model are listed in section 3.4 and the model outputs are explained in section 3.5. Finally, section 3.6 discusses the characterization of uncertainty in the performance parameters.

3.1   Process Simulation Model

Two process simulators, viz. *ASPEN-Plus* and *ProTreat* have been used to derive the performance equations. The CO_2 capture and separation model is based on the *ProTreat* simulations while the CO_2 compression model is based on the *ASPEN-Plus* simulations.

- **ProTreat** is a software package for simulating processes for the removal of H_2S, CO_2, and mercaptans from a variety of high and low pressure gas streams by absorption into thermally regenerable aqueous solutions containing one or more amines (ProTreat[TM] 2002).   The **ProTreat** package makes exclusive use of a column model that treats the separation as a mass transfer rate process.

- *ASPEN-Plus* is a widely used process engineering tool for the design and steady-state simulation and optimization of process plants (Aspen-Plus[R] 2002).

3.2   Methodology

A large number of process simulation runs have been conducted to cover a reasonable range of values for the key parameters. The details are presented in the following sections.

3.2.1. ProTreat Simulation Runs for CO_2 capture and separation from flue gas

The CO_2 capture and separation system consists of a flue gas cooler, compressor, absorber, heat exchangers, regenerator, MEA reclaimer, sorbent circulation pumps and other accessories. Based on the literature review, parameters relevant to the overall performance of the CO_2-capture process were identified and were varied within reasonable ranges in the *ProTreat* model runs. Table 3.1 summarizes the parameters that were varied and the ranges for each parameter.

Table 3.1. ProTreat parameter ranges (total number of simulation runs = 1983)

No.	Parameter	Type	Units	Range
1	CO_2 content in flue gas (y_{CO2})	Input	mole %	3.5-13.5
2	Flue gas flow rate (G)	Input	kmole/hr	9000-24000
3	Inlet flue gas temperature (T_{fg})	Input	deg C	40-65
4	MEA concentration (C)	Input	wt %	15-40
5	Sorbent flow rate (L)	Input	kmole/hr	16000-70000
6	L/G (calc.)	Input	-	0.7-5.6
7	Reboiler heat duty (Q)	Input	GJ/hr	95-664
8	Q/L (calc.)	Input	MJ/kmole	2.4-22.5
9	CO_2 capture efficiency	Output	%	40-99
10	CO_2 product flow rate	Output	kmole/hr	333-2840
11	Lean sorbent CO_2 loading	Output	moleCO_2/mole MEA	0.05-0.34
12	Rich sorbent CO_2 loading	Output	moleCO_2/mole MEA	0.27-0.55
13	Absorber diameter	Output	ft	26-42
14	Regenerator diameter	Output	ft	12-42
15	Exhaust flue gas temperature	Output	deg C	40-72

The following set of parameters related to the design/configuration of the CO_2 capture system were held constant. These values were set for those of a typical commercial application based on experts' suggestions.

- Absorber height: 40 ft

- Absorber packing: Rasching rings, metallic, 1-inch packing size

- Inlet flue gas pressure: 3 psi

- Sorbent pumping pressure: 30 psi

- Number of trays in regenerator: 24 (tray spacing = 2 ft, weir height = 3 inches)

3.2.2. ASPEN-Plus Simulation Runs for CO_2 Compression

The concentrated CO_2 product stream obtained from sorbent regeneration is compressed and dried using a multi-stage compressor with inter-stage cooling. The *ASPEN-Plus* module used for this simulation consists of 4 stages of compression with inter-stage cooling that deliver the compressed product at 35^oC. The compressor efficiency, CO_2 product pressure and purity were used as the main control variables. These parameters were varied over the following ranges

- Compressor efficiency: 60-100 %

- CO_2 product pressure: 500-2500 psi

- CO_2 stream purity: 99-100 %

3.2.3. Regressions to derive performance equations

A set of algebraic equations were derived from the process simulation runs to provide a performance model for use in the IECM (Rubin, Kalagnanam et al. 1997; IECM 2001). The key performance output variables were regressed against all the input variables to obtain a set of relationships among them. The data collected from the process simulation runs was used to carry out these multivariate regressions using a statistical package called SAS (SAS 1999-2001). Only those variables with significance value greater than 0.9995 were retained in the performance equations. Details are presented later in section 3.5.

3.3. Model Configuration Options

For post-combustion CO_2 capture from flue gas, the amine-based CO_2 capture system requires substantial thermal energy in the form of heat or steam for sorbent regeneration. Depending upon how this energy is supplied, there are three configuration options available in the model. These are shown graphically in Figure 3.1 and described below.

a)   **Reference base plant**

b)   **Capture plant with internal derating**

c)   **Capture plant with an auxiliary boiler and a secondary steam turbine**

d)   **Post-capture CO$_2$ transport and disposal options**
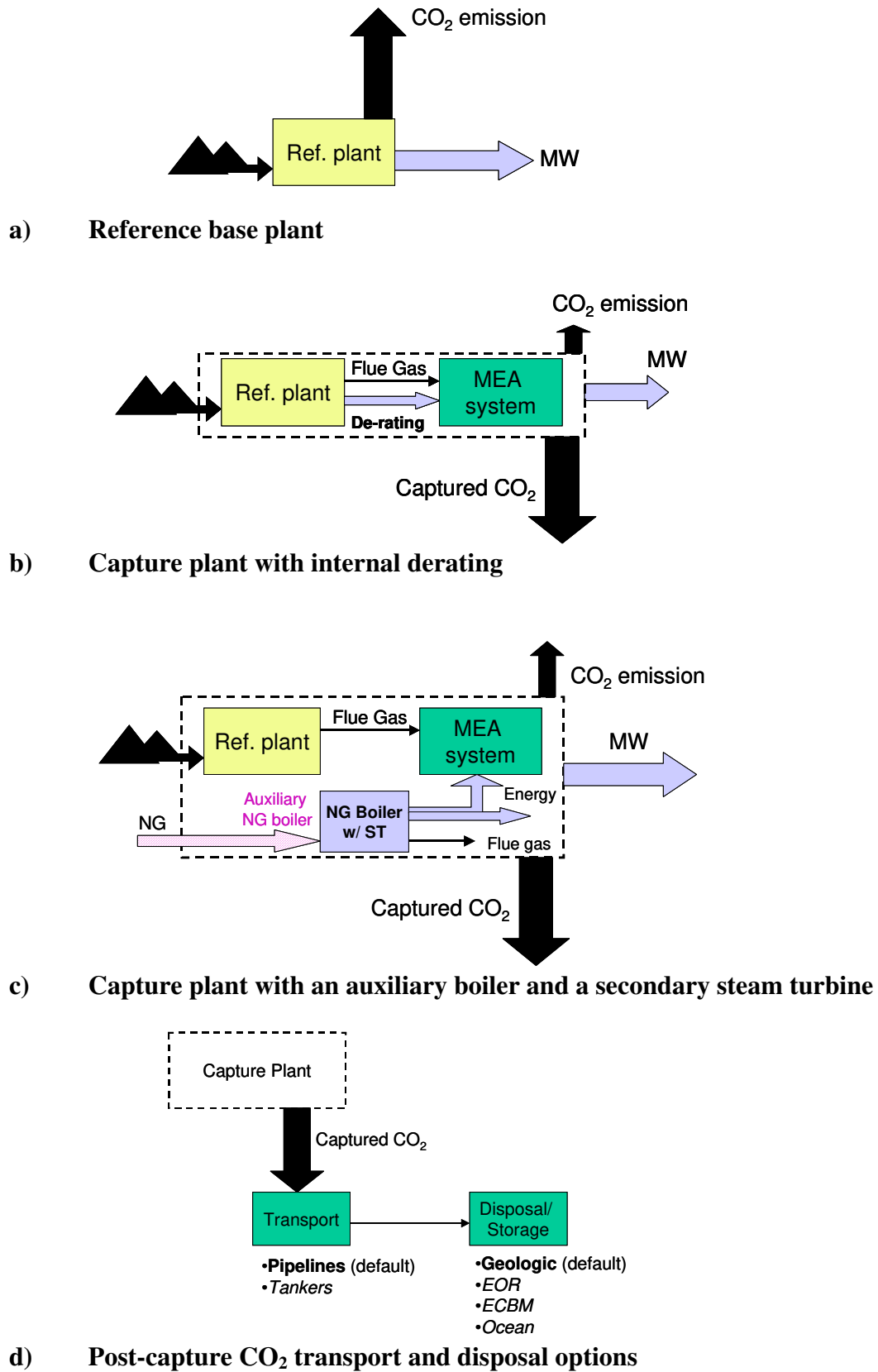
Figure 3.1. CO$_2$ capture plant configuration options

Base plant de-rating: Heat extracted from the base plant can provide energy for the amine system. Here, the low-pressure (LP) steam is extracted from the steam cycle of the power plant and supplied to the reboiler for sorbent regeneration. Extraction of steam leads to loss of power generation capacity, and the net plant output decreases substantially. In case of a new plant to be designed with a CO_2 capture system, it is possible to optimally design the steam cycle to take care of the steam requirement of the amine system, and proper heat integration may help in reducing the energy penalty. In case of an existing coal plant to be retrofitted with an amine system, optimal heat integration may not be achievable, and is likely to lead to a much higher energy penalty due to steam extraction.

Auxiliary Natural Gas Boiler (w/ Steam Turbine): Another potential option to provide the energy for the amine system is an auxiliary natural gas (NG)-fired boiler. Often it would be combined with a steam turbine to generate some additional power (*e.g.* to supply electrical energy demand of CO_2 capture unit), where the LP steam would be then used for sorbent regeneration. Thus, the original steam cycle of the power plant remains unperturbed and the net power generation capacity of the power plant does not get adversely affected. Again, it comes at an additional cost of capital requirement for the boiler (and turbine) and the cost of supplemental natural gas fuel. Also, the combustion of natural gas leads to additional CO_2 emissions (and NO_x emissions). So, there are at least two possible sub-options available:

1. The flue gas from the auxiliary boiler is cooled down to acceptable exhaust temperature and then directly vented to the atmosphere. Here, the <u>net</u> CO_2 capture efficiency of the system is substantially lowered because of the additional CO_2 emissions from natural gas boiler. Also, the total NO_x emissions may exceed the allowable levels of emission.

2. The CO_2 capture system may be designed so as to capture CO_2 from the auxiliary boiler as well. In this case, the secondary flue gas stream (after cooling and NO_x removal, if required) may be merged with the main flue gas stream before it enters the CO_2 capture system. With higher amount of flue gas to be treated (and

31

more CO_2 to be captured), the amine-system would require more steam and thus a still bigger auxiliary NG boiler would be required (which means more secondary flue gas!). The auxiliary NG boiler size may be determined by an iterative calculation procedure, so that it matches the sorbent regeneration steam requirement of the CO_2 capture system treating the total flue gas. Thus, the CO_2 capture level is maintained at the originally desired level, but it requires a large auxiliary NG boiler facility. Our preliminary analysis as well as other studies suggest that this option is quite costly (Simbeck and McDonald 2000), hence in the present version of IECM, this configuration option is not included.

In terms of the configuration of the CO_2 capture system shown in Figure 3.1, the user can make the following choices as well.

Direct contact cooler: The default design of an amine system includes a direct contact cooler (DCC) to cool the flue gas before it enters the amine system. The temperature of the flue gas affects the absorption reaction because absorption of CO_2 in MEA sorbent is an exothermic process favored by lower temperatures. Also, the volumetric flow rate of the flue gas stream, which is a key determinant of the sizes of various equipments (*e.g.*, direct contact cooler, flue gas blower, absorber), is directly related to the flue gas temperature. Hence lower flue gas temperature is desired. The typically acceptable range of flue gas temperature is less than 50-60 ^{o}C. If the flue gas is coming from wet sulfur scrubber, additional DCC may not be required. But in case of flue gas from NG-fired boiler, which often does not pass through a sulfur scrubber, DCC is essential. Exclusion of the DCC is an option available in the model.

Choice of sorbent: At this time, MEA is the only sorbent used in the model. The nominal values of various parameters are based on a process simulation model that uses only MEA. However, the users can overwrite the nominal values of these parameters if they wish to use a different sorbent and have the relevant data. The model could include other sorbents in the future by providing the appropriate values for the key parameters.

CO_2 transport: As shown in Figure 3.1(d), the default mode of CO_2 transport is via pipelines. This is the suggested mode of transporting large quantities of CO_2 that would

be captured in a typical power plant application. The user can specify the distance over which CO_2 needs to be carried to, and the unit cost of CO_2 transportation. This module may be expanded in the future to include more detailed parameters regarding pipeline transport and other transport options.

CO_2 storage/ disposal: The default option for CO_2 disposal is underground geological storage (see Figure 3.1(d)). Studies indicate that geologic formations are the most plentiful and attractive option for U.S. power plants (Bergman and Winter 1995). A nominal cost of $5/ tonne CO_2 has been suggested, which can be changed by the user to match the specific details about the location. If CO_2 is being used as a byproduct for EOR or ECBM activity, it may generate some revenue. This module, which is represented by a single cost parameter, may be expanded in future to include details about the various storage/ disposal options.

3.4. Performance Parameters

There are three types of input parameters to the CO_2 performance model:

- **Parameters from the "reference plant"**: These include the flow rate, temperature, pressure and composition of the flue gas inlet to the CO_2 absorber, and the gross power generation capacity of the power plant.

- **Parameters to configure the CO_2 system**: The CO_2 module provides a menu of options from which the user may select a CO_2 capture technology, CO_2 product pressure, mode and distance of CO_2 product transport, and CO_2 storage/ disposal method. At this stage, a model of the MEA-based absorption system with pipeline transport and geologic sequestration has been developed; other options are still under construction.

- **Parameters controlling the performance of the CO_2 system**: The main parameters include the CO_2 capture efficiency, MEA concentration, lean sorbent CO_2 loading, regeneration heat requirement, pressure drop across the system, MEA make-up requirement, pump efficiency, compressor efficiency and several others.

33

These parameters are used to calculate the sorbent flow rate, MEA requirement, and energy penalty of the CO_2 system.

Functional relationships and default values for all model parameters were developed based on engineering fundamentals, a detailed review of the literature, and contacts with experts in the field. All of these performance parameters directly affect the cost of the system. Here is a brief description of the various input parameters to the CO_2 system.

3.4.1. *Parameters obtained from the "reference base plant"*

The amine-based CO_2 capture system gets the following inputs from the (reference) base plant:

- Gross plant size = MW_g

- Net plant size (prior to environmental controls) = MW_{noctl}

- Flue gas composition and flow rate (as entering into the amine system): This is an array of molar flow rates of different gas components that include N_2, O_2, H_2O, CO_2, CO, HCl, SO_2, SO_3, NO, NO_2 and mass flow rate of particulates.

- The total molar flow rate of the flue gas = G,

- The molar fraction of CO_2 in the flue gas = y_{CO2}.

- Temperature of flue gas = T_{fg}

- Plant capacity factor = PCF (%)

- Annual hours of operation = HPY = (PCF/100)*365.25*24 hrs/yr

3.4.2. *Parameters to configure the CO_2 system*

These are the choices the user can make in order to configure the CO_2 capture system. These configuration choices have been described in section 3.3, and could be summarized as follows:

- Flue gas cooler: Whether to include DCC (default) or exclude it

34

- Sorbent regeneration steam source: Steam extraction from the base plant (default, internal derating) or steam generated from an auxiliary natural gas boiler with (or without) a secondary steam turbine

- Mode of CO_2 product transportation: Via pipelines (default) or any other means.

- Mode of CO_2 storage/ disposal: Underground geologic reservoir (default), EOR, ECBM, Depleted oil/gas wells, or Ocean

3.4.3. *Parameters controlling the performance of the CO₂ system*

Input parameters are given to allow the model user to control the performance of the CO2 capture system. These parameters then determine the intermediate and final output results. It may be noted that the user can override any of these values, but may want to change values of all the relevant parameters to avoid inconsistencies. These are the key input parameters below:

i) CO₂ capture efficiency (η_{CO_2})
The overall CO_2 capture efficiency of the system is the fraction of CO_2 present in the incoming flue gas stream captured in this system.

$$\eta_{CO_2} = 100 \times (\text{Moles } CO_2 \text{ in } - \text{ Moles } CO_2 \text{ out}) / (\text{Moles } CO_2 \text{ in})$$

Most of the studies report the CO_2 capture efficiency of the amine-based systems to be 90%, with few others reporting as high as 96% capture efficiency. Here, it has been assumed to be 90% as the nominal value, but the user can specify the desired level of CO_2 capture efficiency.

ii) MEA concentration (C_{MEA})
The sorbent used for CO_2 absorption is a mixture of mono-ethanol-amine (MEA) with water. The presence of water enhances the chemical absorption reaction of MEA with CO_2. MEA is a highly corrosive liquid, especially in the presence of oxygen and carbon dioxide, and hence needs to be diluted. Today the commercially available MEA-based technology supplied by Fluor Daniel uses 30% w/w MEA sorbent with the help of some corrosion inhibitors. Other suppliers, who do not use this inhibitor, prefer to use lower

MEA concentrations in the range of 15%-20% w/w. Here we use 30% as the nominal value for the sorbent concentration with an acceptable range between 15-40%.

iii) Lean sorbent CO₂ loading (ϕ_{min})

Ideally, the sorbent will be completely regenerated on application of heat in the regenerator section. Actually, even on applying heat, not all the MEA molecules are freed from CO_2. So, the regenerated (or lean) sorbent contains some "left-over" CO_2. The level of lean sorbent CO_2 loading mainly depends upon the initial CO_2 loading in the sorbent and the amount of regeneration heat supplied, or alternatively, the regeneration heat requirement depends on the allowable level of lean sorbent loading. Here we use a nominal value of 0.2 based on the values reported in the literature, and the user may specify any desired value in the range (0.1-0.25).

iv) Liquid to gas ratio (L/G)

The liquid to gas ratio is the ratio of total molar flow rate of the liquid (MEA sorbent plus water) to the total molar flow rate of flue gas being treated in the absorber. This is a calculated parameter and is derived by the process simulation model.

v) Liquid flow rate (L)

The liquid flow rate is the total molar flow rate of sorbent plus dilution water being circulated in the CO_2 capture system. It is obtained by multiplying (L/G), which is derived from the process simulation model, by the total flue gas flow rate (G) entering the CO_2 capture system.

$$L = (L/G) \times (G)$$

vi) Acid gases removal efficiency ($\eta_{acid\ gas}$) and stoichiometric MEA loss ($n_{MEA,acidgas}$)

As discussed before, MEA is an alkaline sorbent that has strong affinity for various acid gases. In fact, gases such as hydrogen chloride and oxides of sulfur are much more reactive towards MEA than carbon dioxide itself. These gases form heat stable salts (HSS) with MEA that can not be broken down even after application of heat. So, they cause a permanent loss of MEA sorbent that may be estimated according the stoichiometry of their reactions with MEA. The typical removal efficiencies of these gases in the absorber using MEA sorbent designed for 90% removal of CO_2 are given in Table 3.2.

Table 3.2. Removal efficiency of acid gases due to MEA sorbent (90% CO_2 removal)

Acid gas	Removal efficiency (%)	MEA loss (mole MEA/mole acid gas)
SO_2	$\eta_{SO_2} = 99.5\%$	$n_{MEA, SO_2} = 2$
SO_3	$\eta_{SO_3} = 99.5\%$	$n_{MEA, SO_3} = 2$
NO_2	$\eta_{NO_2} = 25\%$	$n_{MEA, NO_2} = 2$
NO	$\eta_{NO} = 0$	$n_{MEA, NO} = 0$
HCl	$\eta_{HCl} = 95\%$	$n_{MEA, HCl} = 1$

v) Temperature of the flue gas entering the CO_2 capture system ($T_{fg,in}$)

The desirable temperature of the flue gas entering the CO_2 capture system is about 45-50 deg C. If a direct contact cooler is installed upstream of CO_2 capture system, then this temperature level may be achieved.

The temperature of the flue gas affects the absorption reaction as absorption of CO_2 in MEA sorbent is an exothermic process favored by lower temperatures. Also, the flue gas temperature directly affects the volumetric flow rate of the flue gas stream, which is a key determinant of the sizes of various equipments (*e.g.*, direct contact cooler, flue gas blower, absorber).

vi) Nominal MEA loss ($\dot{m}_{MEA, nom}$)

MEA is a reactive sorbent. In spite of dilution with water and use of inhibitors, a small quantity of MEA is lost through various unwanted reactions, mainly the polymerization reaction to form long-chained compounds and the oxidation reaction forming organic acids and liberating ammonia. In general, this nominal loss of MEA is estimated as about 1.5 kg MEA/ tonne CO_2.

It is assumed that 50 % of this MEA loss is due to polymerization:

$$\dot{m}_{MEA, polym} = = 50\% \text{ of } (\dot{m}_{MEA, nom})$$

The remaining 50% of the MEA loss is due to oxidation to acids:

$$\dot{m}_{MEA,\ oxid} = 50\%\ of\ (\dot{m}_{MEA,\ nom})$$

vii) NH₃ Generation (n_{NH₃})

The oxidation of MEA to organic acids (oxalic, formic, etc.) also leads to formation of NH_3. Each mole of MEA lost in oxidation liberates a mole of ammonia (NH_3).

$$\text{Rate of ammonia generation, } n_{NH_3} = \frac{1\ mole\ NH_3}{mole\ MEA\ oxidized}$$

viii) Heat-Stable Salts (HSS)

The organic acids (product of MEA oxidation) combine with MEA to form some other heat stable salts (HSS). The exact nature of these salts is not known. The most conservative estimate, assuming that the organic acids are mono-basic, is that each mole of organic acid takes up one mole of fresh MEA. So, each mole of MEA lost in oxidation takes up additional mole of MEA in HSS formation.

$$n_{MEA,\ organics} = \frac{1\ mole\ MEA}{mole\ organic\ acid}$$

ix) Caustic Consumption in Reclaimer ($\dot{m}_{NaOH}$)

Caustic in the form of NaOH is added in the reclaimer so that some of the MEA could be regenerated from HSS. $\dot{m}_{NaOH}$ is the quantity (mass) of caustic (as NaOH) consumed in MEA reclaimer per tonne of CO_2 captured. A typical value is 0.13 kg NaOH/ tonne CO_2.

x) Reclaimed MEA

Caustic regenerates stoichiometric amount of MEA from the HSS in the reclaimer. Each mole of NaOH regenerates 1 mole of MEA, and adds the corresponding sodium salt of organic acid to the reclaimer bottoms.

$$\dot{n}_{MEA,\ reclaimed} = \text{no. of moles of MEA reclaimed using caustic}$$

$$= \text{no. of moles of caustic added}$$

$$= \dot{n}_{NaOH}$$

$$= \dot{m}_{NaOH} \text{ / (Molecular Weight of NaOH)}$$

$$= \dot{m}_{NaOH} \text{ / 40}$$

xi) Removal efficiency for particulates (η_{partic})

Amine-based absorption system for CO_2 removal is a wet scrubbing operation. So, it also leads to removal of particulate matter from the flue gas to certain extent. Based on the experience of other scrubbing systems, the removal efficiency for particulates has been assumed to be 50%.

xii) Density of sorbent ($\rho_{sorbent}$)

MEA has a density of 1.022 g/cc that is similar to that of water. So, the overall density of the MEA based sorbent (with almost 70% water) is assumed to be same as that of water ~1 tonne/ m^3.

xiii) Activated Carbon Requirement ($\dot{m}_{act-C}$)

An activated carbon bed in the sorbent circuit removes the long chained/ cyclic polymeric compounds formed from the degenerated MEA. Over a period of time (~3-6 months) the carbon-bed needs to be replaced and the used bed is sent back to the suppliers. $\dot{m}_{act-C}$ is the average amount of activated carbon consumed per tonne of CO_2 captured. This consumption is estimated to be about 0.075 kg C/ tonne CO_2.

xiv) Total moles of CO_2 captured (n_{CO2})

This is the molar flow rate of CO_2 captured from the flue gas. It is obtained by multiplying the total CO_2 content in the inlet flue gas (kmole CO_2/ hr) by the CO_2 capture efficiency of the system.

$$n_{CO2} = (\eta_{CO_2} / 100)*(\text{Moles } CO_2 \text{ in}) = (\eta_{CO_2} / 100)*(G*y_{CO2})$$

Since the molecular weight of CO_2 is 44, the total amount of CO_2 captured (m_{CO2}, tonne/ hr) is

$$m_{CO2} = n_{CO2} * (44/1000)$$

xv) CO₂ product purity (α)

The final CO_2 product has to meet certain specifications depending upon the mode of transport and final destination. Impurities such as nitrogen are undesirable as they may pose problems during compression and liquefaction of CO_2. In order to avoid corrosion in the pipelines during transport, the moisture levels must be controlled. The acceptable level of purity of CO_2 product for most of the applications is about 99.8%.

xvi) Reboiler duty per mole of liquid (Q/L)

This is the total amount of heat energy input required for the regeneration of the sorbent per unit of liquid circulated. This is mainly dependent on lean sorbent loading, CO_2 capture efficiency, MEA concentration and CO_2 content of the flue gas and is a calculated value derived from the process simulation model.

xvii) Total heat requirement for sorbent regeneration (Q)

This is the total amount of heat energy required in the reboiler for sorbent regeneration. It is obtained by multiplying (Q/L) above, by the total sorbent circulation molar flow rate (MEA sorbent plus dilution water) in the CO_2 capture system.

$$Q = (Q/L) \times (L)$$

xviii) Unit heat of sorbent regeneration (q_regen)

This is the amount of heat required for the regeneration of the MEA sorbent (loaded with CO_2) in the stripper/ regenerator section. It is expressed as the amount of heat (in kJ or Btu) per unit mass (kg or lb) of CO_2 captured. Theoretically, the heat of reaction that needs to be supplied in order to reverse the absorption reaction between CO_2 and MEA is about 1900 kJ/ kg CO_2 (*i.e.* about 825 Btu/ lb CO_2). The actual amount of heat required for regeneration of the sorbent is much higher, about 2-3 times higher than this theoretical minimum. This is because of the large amount of latent heat taken up by the dilution water in the sorbent. A wide range of numbers have been reported for the regeneration heat requirement of MEA system. The majority of the sources report a heat requirement of about 4000 kJ/kg CO_2. Here it is obtained by dividing the total heat requirement for sorbent regeneration (Q) by the total amount of CO_2 captured (m_{CO2}).

$$q_{regen} = Q / m_{CO2}$$

xix) Enthalpy of regenerating steam (h_{steam})

The regeneration heat is provided in the form of LP (low pressure) steam extracted from the steam turbine in case of coal-fired power plants and combined-cycle gas plants, through the reboiler (a heat exchanger). In case of simple cycle natural gas fired power plants, a heat recovery unit maybe required. (h_{steam}) is the enthalpy or heat content of the steam used for sorbent regeneration. Typically, the LP steam is around 300°C and 60-80 psi. From the steam-tables, the enthalpy (heat content) of such steam is found to be about 2000 kJ/ kg steam.

xx) Heat-to-electricity equivalence factor (F_{HE})

The extraction of LP (low pressure) steam for sorbent regeneration results in some loss of power generation capacity of the plant. The factor (F_{HE}) gives the equivalent loss of power generation capacity due to the heat requirement for sorbent regeneration.

Let us try to understand what this factor stands for and how it is derived. According to the Second Law of Thermodynamics, thermal energy cannot be fully converted to work. Electrical energy is a form of work. The efficiency of converting heat into electricity depends upon the temperature and pressure conditions of the working fluid, *i.e.* steam in case of a conventional coal plant. Even the advanced steam plants (using super-critical or ultra-super-critical boilers) can achieve net plant efficiencies of about 42-45 percent by using high quality steam (steam at high pressure and temperature, *e.g.* 31 MPa and 590 °C) (Rubin 2001). In general, steam at lower pressure and temperature will have still lower efficiency to convert heat into electric energy. The steam used for regeneration of sorbent is low quality steam (low pressure, ~0.5 MPa and low temperature, ~120 °C), and hence the equivalent loss of power generation is much lower than the power plant efficiency. Again, the electric energy penalty due to steam extraction also depends on the overall heat integration within the plant. Factor (F_{HE}) may be looked upon as the power generation efficiency of the LP steam extracted from the steam cycle of the power plant for sorbent regeneration. So, the equivalent loss in power generation capacity of the base plant may be estimated by multiplying the total sorbent regeneration heat requirement by this factor.

From the data obtained from the available studies (Smelser, Stock et al. 1991; Hendriks 1994; Mimura, Simoyoshi et al. 1997; Bolland and Undrum 1998; Marion, Nsakala et al. 2001), this factor has been found to lie in the range (9, 19) for a new plant and (20, 25) for retrofit cases. So, the nominal value (for this new plant application) has been taken as 14%.

For example, if 10,000 kJ/hr is the regeneration heat requirement for the CO_2 capture operation, then the corresponding loss in power generation capacity of the power plant is estimated as 14% of 10,000 kJ/hr i.e. 1400 kJ/hr, or (1400/3600 =) 0.39 kW. It may be noted that, in case of retrofit applications, the energy penalty might be significantly higher due to poor heat integration, and F_{HE} may be approximately 22%.

xxi) Blower pressure head (ΔP_{fg})

Prior to entering into the absorber column, the flue gas has to be compressed in a flue gas blower so that it can overcome the pressure drop in the absorber tower. (ΔP_{fg}) is the pressure head that needs to be provided to the flue gas in the blower, and is about 14 kPa (~2 psi).

xxii) Blower (fan) efficiency (η_{blower})

This is the efficiency of the fan/blower to convert electrical energy input into mechanical work output. Typically, the value of blower efficiency (η_{blower}) is about 75%.

xxiii) Sorbent pumping head ($\Delta P_{sorbent}$)

The sorbent has to flow through the absorber column through packed media, countercurrent to the flue gas flowing upwards. So, some pressure loss is encountered in the absorber column and sufficient sorbent head has to be provided to overcome these pressure losses. ($\Delta P_{sorbent}$) is the pressure head to be provided to the sorbent using sorbent circulation pumps. A typical value is about 200 kPa (~ 30 psi).

xxiv) Pump efficiency (η_{pump})

This is the efficiency of the sorbent circulation pumps to convert electrical energy input into mechanical energy output. Typically, the value of (η_{pump}) is assumed to be 75%.

xxv) CO_2 product pressure (P_{CO_2})

The CO_2 product may have to be carried over long distances. Hence it is necessary to compress and liquefy it to very high pressures (P_{CO_2}), so that it may be delivered to the required destination in liquid form and with minimal recompression facilities en route. The critical pressure is the minimum pressure required to liquefy a gas at its critical temperature, which is the temperature above which it is not possible to liquefy a gas. For CO_2 this is about 1070 psig. The typically reported value of final pressure to which the product CO_2 stream is pressurized using compressors before it is transported is about 2000 psig (about 137 atm).

xxvi) Energy required for CO_2 compression (e_{comp})

This is the electrical energy required (kWh per tonne CO_2) to compress a unit mass of CO_2 product stream to the designated pressure (P_{CO_2}) expressed in psig. Compression of CO_2 to high pressures requires substantial energy, and is a principle contributor to the overall energy penalty of a CO_2 capture unit in a power plant.

xxvii) CO_2 compression efficiency (η_{comp})

This is the effective efficiency of the compressors used to compress CO_2 to the desirable pressure. Typically, the value of compressor efficiency (η_{comp}) is about 80%. It may be noted that the energy requirement calculated from the performance equation (e_{comp}) has to be corrected by this efficiency factor in order to get the total energy required for CO_2 compression.

The following set of parameters are relevant only if the CO_2 capture system has been configured to include an auxiliary NG boiler to supply sorbent regeneration heat.

xxviii) Heating value of natural gas (NGHV)

This is the high heating value (HHV, MJ/ kmole NG) of the natural gas used as fuel for the auxiliary boiler.

xxix) Density of natural gas (ρ_{NG})

This is the density (lb/ft^3) of the natural gas used as fuel for the auxiliary boiler.

xxx) Average molecular weight of natural gas (mw_{NG})

This is the average molecular weight (kg/ kmole NG) of the natural gas used as fuel for the auxiliary boiler. This is a function of the molar composition of the natural gas.

xxxi) Flow rate of natural gas (m_{NG})

This is the total molar flow rate (kmole NG/ hr) of the natural gas used as fuel for the auxiliary boiler. It is a function of the total heat requirement for sorbent regeneration in the amine system.

xxxii) Auxiliary NG boiler efficiency (η_{NGB})

This is the efficiency of the auxiliary boiler that uses natural gas as fuel input. It is defined as the ratio of total thermal energy (in the from of steam) delivered by the boiler divided by the total heat energy input (in the form of heating value of the natural gas input).

xxxiii) Secondary steam turbine power generation efficiency (η_{ST2})

This is the efficiency of the secondary steam turbine added with the auxiliary NG boiler to generate electrical power. It may be defined as the ratio of electrical energy generated (MW_{ST2}) by the steam turbine divided by the total thermal energy (in the form of steam) input from the auxiliary NG boiler. It is assumed that the rest of the thermal energy is contained in the LP exhaust steam from the turbine, which is sent to the reboiler for sorbent regeneration.

3.5. Performance Equations

The performance equations define the functional relationships among various key performance parameters. They have been derived as multivariate linear or log-linear regression equations from the data obtained from the process simulation model runs.

$$(L/G) = \exp (-1.4352 + 0.1239*y_{CO2} + 3.4863*\phi_{lean} + 0.0174*\eta_{CO2} - 0.0397*C + 0.0027*T_{fg,in}) \qquad [\text{adj. } R^2 = 0.92] \qquad (3\text{-}1)$$

$$(Q/L) = \exp (-2.4452 - 0.0037*y_{CO2} - 6.2743*\phi_{lean} + 0.0254*C)$$
$$[\text{adj. } R^2 = 0.96] \qquad (3\text{-}2)$$

$$(T_{fg,out}) = 41.15 + 0.062*T_{fg,in} + 1.307*y_{CO2} - 18.872*\phi_{lean} + 0.270*C$$
$$[\text{adj. } R^2 = 0.92] \qquad (3\text{-}3)$$

$(\text{mw}_{\text{lean}}) = 16.907 + 2.333 * \phi_{\text{lean}} + 0.204 * C$

$$[\text{adj. } R^2 = 0.95] \qquad (3\text{-}4)$$

$(e_{\text{comp}}) = -51.632 + 19.207 * \ln(P_{CO2} + 14.7)$

$$[\text{adj. } R^2 > 0.99] \qquad (3\text{-}5)$$

where,

L = total sorbent flow rate (kmole/ hr)

G = total inlet flue gas flow rate (kmole/ hr)

(L/G) = total liquid (sorbent) applied per unit flue gas flow rate in absorber (ratio of molar flow rates)

Q = total sorbent regeneration heat requirement (GJ/ hr)

(Q/L) = total regeneration heat supplied per unit of sorbent flow (MJ/ kmole)

y_{CO2} = CO_2 concentration in the inlet flue gas (mole %)

ϕ_{lean} = lean sorbent CO_2 loading (mole CO_2/ mole MEA)

η_{CO2} = CO_2 capture efficiency (%)

C = MEA concentration in the sorbent (wt %)

$T_{\text{fg,in}}$ = Temperature of the flue gas entering the CO_2 absorber (deg C)

$T_{\text{fg,out}}$ = Temperature of the flue gas leaving the CO_2 absorber (deg C)

mw_{lean} = Average molecular weight of the lean sorbent (kg/ kmole sorbent)

e_{comp} = Unit energy requirement for CO_2 compression (kWh/ tonne CO_2)

P_{CO2} = Desired CO_2 product pressure (psig)

3.6. Model Outputs

The key outputs of the amine system performance model include:

- **MEA makeup requirement**. This depends mainly on the mass flow rate of CO_2 in the flue gas, the desired CO_2 capture efficiency, MEA concentration, and CO_2 loadings in the sorbent. Depending on the level of impurities in the flue gas, there is some loss of sorbent. If the power plant does not have emission controls for SO_x and NO_x, the cost imposed due to amine loss may be significant.

- **Energy requirement**. Heat for sorbent regeneration is derived from low-pressure steam available in the power plant, which decreases power generation efficiency. Additional electrical energy is required for CO_2 product compression, sorbent circulation, and other system requirements. The energy requirement is one of the most important results, as it dictates the net size of the power plant, and hence the net cost of power generation and CO_2 avoidance.

The following material and energy flows are estimated using the above stated inputs

1.1.1. *Total quantity of CO_2 captured:*

$$m_{CO2} \text{ (tonne/hr)} = n_{CO2} \times (MolWt)_{CO2}$$

$$= \eta_{CO2} \times n_{CO2,inlet} \times (MolWt)_{CO2}$$

where,

n_{CO2} = Total moles of CO_2 captured (kmole CO_2/ hr)

$n_{CO2,inlet}$ = Molar flow rate of CO_2 in the inlet flue gas (kmole CO_2/hr)

$(MolWt)_{CO2}$ = Molecular weight of CO_2 = 0.044 tonne/ kmole CO_2

3.6.2 *MEA makeup requirement:*

3.2.1.

$$\dot{m}_{MEA,makeup}$$

= Net loss of MEA

$$= \begin{pmatrix} \text{loss due to acid gas} \\ impurities \end{pmatrix} + \begin{pmatrix} \text{loss due to} \\ \text{polymerization} \end{pmatrix}$$

$$+ \begin{pmatrix} \text{loss due to} & \text{Gain in} \\ \text{HSS formation} & - & \text{Reclaimer} \end{pmatrix} + \begin{pmatrix} \text{loss with} \\ \text{fluegas exhaust} \end{pmatrix}$$

46

3.6.3 Total sorbent circulation flow rate:

From the performance equations, we find

$L/G = f(y_{CO2}, \phi_{lean}, \eta_{CO2}, C, T_{fg,in})$, and $L = G*(L/G)$

Including the MEA makeup requirement gives the total sorbent flow rate (m^3/hr)

$$L_{tot,v} = \{G*(L/G)*mw_{lean} + \dot{m}_{MEA,makeup}*(100/C)\}*\rho_{sorbent}$$

3.6.4 Waste generated from reclaimer:

$$m_{waste} = \begin{pmatrix} MEA\ lost\ due\ to \\ acid\ gases \end{pmatrix} + \begin{pmatrix} Total\ qty\ of \\ acid\ gases\ removed \end{pmatrix} + \begin{pmatrix} MEA\ loss\ due \\ to\ oxidation \end{pmatrix}$$
$$+ \begin{pmatrix} MEA\ loss\ due\ to \\ HSS\ format^n \\ -\ Gain\ in\ reclaimer \end{pmatrix} + \begin{pmatrix} Caustic\ added \\ to \\ Reclaimer \end{pmatrix}$$

Considering ($f_{w,waste}$) as the water content (% w/w) in the waste, the actual mass flow rate of waste is obtained as:

$M_{waste,total} = m_{waste}/(1 - f_{w,waste})$ kg/hr

Typically, the reclaimer waste contains about 40% water.

3.6.5 Activated carbon consumption:

$$m_{act-C} = \dot{m}_{act-C} \times m_{CO_2}\ \text{kg act-C/hr}$$

3.6.6 Caustic consumption in reclaimer:

$$m_{Caustic} = \dot{m}_{NaOH} \times m_{CO_2}\ \text{kg NaOH/ hr}$$

3.6.7 Process water requirement:

Unit process water makeup = $\dot{m}_{pw}$ (tonne/ hr)/MW(net)

Typically, the value of $\dot{m}_{pw}$ is about 0.114 tonne/hr per MW(net) (Smelser, Stock et al. 1991). Therefore, the process water requirement is:

$(M_{pw}) = \dot{m}_{pw} \times MW_{net}$ tonne/hr

3.6.8   *Cooling water requirement:*

If there is a direct contact cooler installed, the required flow rate of cooling water is estimated based on the following assumptions

Specific heat of water, $SH_w = 4.2$ kJ/kg ^{o}C

Specific heat of flue gas = SH_{fg} (Generally, this is around 1.2 kJ/kg ^{o}C)

Temperature rise in the cooling water (once through system) = ΔT_w

Drop in flue gas temperature = $\Delta T_{fg} = (T_{fg,i} - T_{fg})$ ^{o}F

where,

$T_{fg,i}$ = Temperature of flue gas entering the direct contact cooler

T_{fg} = Temperature of flue gas exiting the direct contact cooler

Mass flow rate of flue gas = m_{fg} tonne/ hr

So, the required cooling water flow rate,

$M_{cw} = m_{fg}*(\Delta T_{fg} / \Delta T_w)*(SH_{fg} / SH_w)$ tonne/hr

3.6.9   *Steam requirement:*

LP steam is extracted from the power plant steam turbine or secondary steam turbine in order to provide the sorbent regeneration heat in the reboiler. Based on the regeneration heat requirement and enthalpy of regeneration steam, the flow rate of steam may be estimated as follows:

From the performance equations,

$(Q/L) = f(y_{CO2}, \phi_{lean}, C)$

Total regeneration heat requirement,

$$Q \text{ (MJ/ hr)} = (Q/L)*(L)$$

Mass flow rate of steam,

$$m_{steam} \text{ (tonne/hr)} = Q / q_{steam}$$

The equivalent energy penalty due to regeneration steam requirement is (E_{regen}). Depending upon the CO_2 capture system configuration (source of regeneration steam supply), E_{regen} has to be estimated in two different ways.

1. In case of steam extraction from the base plant steam cycle (derating)

$$E_{regen} = Q*F_{HE}$$

2. In case of steam supplied from an auxiliary NG boiler,

$$E_{regen} = - E_{ST2} = - (m_{NG}*NG_{HV}*\eta_{NGB}*\eta_{ST})$$

It maybe noted that in the case of auxiliary NG boiler, the energy penalty term is negative, implying that there is an increase in the net power generation of the plant.

3.6.10 *Electrical energy requirement:*

Total electricity requirement of CO_2 capture system is:

$$E_{CO_2, tot} = E_{regen} + E_{pumping} + E_{compr}$$

where,

$$E_{regen} = \text{as explained above}$$

$$E_{pumping} = E_{blower} + E_{pump}$$

$$E_{blower} \text{ (hp)} = \frac{144 \, Q_{fg} \Delta P_{fg}}{33000 \cdot \eta_{blower}}$$

where Q_{fg} and ΔP_{fg} are expressed in ft^3/min and psi respectively,

49

$$E_{pump} \text{ (hp)} = \frac{Q_{\text{solvent}} \, \Delta P_{solvent}}{1714 \cdot \eta_{\text{pump}}}$$

where Q_{sorbent} and $\Delta P_{\text{sorbent}}$ are expressed in gal/min and psi respectively, and

$$E_{\text{compr}} = e_{\text{comp}} * m_{\text{CO2}} / \eta_{\text{comp}}$$

where e_{comp} is given by equation *(3-5)*.

3.7. Characterization of Uncertainty and Variability

Any techno-economic analysis, and especially that of new energy and environmental control technologies that are still in the research phase, involves uncertainties regarding the performance and costs. These uncertainties come from incomplete information available and numerous assumptions and approximations built into simulations. Some parameters, especially the cost parameters, are influenced by a larger set of factors outside the scope of the particular study and fluctuations in these quantities may be seen as "inherent randomness" when viewed within this limited focus area. In addition, there may be significant variability in plant or process design assumptions across different studies or organizations.

One of the distinguishing features of this modeling effort is a probabilistic capability that allows model inputs to be represented by probability distributions rather than single deterministic values. Probability distributions for these parameters reflect the ranges of values reported in the literature, the evolving nature of the technology, and practical considerations in running such plants. Also, it is possible to use probability distributions for more than one parameter (or all the parameters together) simultaneously.

Table 3.3 lists the uncertainty distributions developed for performance model parameters based on the current literature on amine-based (MEA) systems. These distributions reflect both uncertainty and variability in system designs. Details are presented in *Appendix B* and *Appendix C*. The data sources from which the parameter values were

Table 3.3. Amine system performance model parameters and uncertainties

Performance Parameter	Units	Data (Range)	Nominal Value	Unc. Representation (Distribution Function)
CO_2 removal efficiency	%	Mostly 90	90	-
SO_2 removal efficiency	%	Almost 100	99.5	Uniform(99,100)
NO_2 removal efficiency	%	20-30	25	Uniform(20,30)
HCl removal efficiency	%	90-95	95	Uniform(90,95)
Particulate removal eff.	%	50	50	Uniform(40,60)
MEA concentration	wt%	15-50	30	Triangular (20,30,40)
Lean sorbent CO_2 loading	mol CO_2/mol MEA	0.15-0.30	0.2	Triangular(0.1,0.2,0.25)
Nominal MEA make-up	kg MEA/tonne CO_2	0.5-3.1	1.5	Triangular(0.5,1.5,3.1)
MEA loss (SO_2)	mol MEA/mol SO_2	2	2	-
MEA loss (NO_2)	mol MEA/mol NO_2	2	2	-
MEA loss (HCl)	mol MEA/mol HCl	1	1	-
NH_3 generation	mol NH_3/mol MEA oxidized	1	1	-
Caustic consumption in MEA reclaimer	kg NaOH/tonneCO_2	0.13	0.13	-
Activated carbon use	kg C/tonne CO_2	0.075	0.075	-
Gas-phase pressure drop	kPa	4-37	14	Triangular(4,14,37)
Fan efficiency	%	70-80	75	Uniform (70,80)
Sorbent pumping head	kPa	200	200	Triangular(150,200,250)
Pump efficiency	%	70-80	75	Uniform (70,80)
Equiv. elec. requirement	% regeneration heat	9-19	14[a]	Uniform (9,19)
CO_2 product pressure	MPa	7.58-15.16	13.79	Triangular(7.58,13.79,15.16)
Compressor efficiency	%	75-88	80	Uniform (75,88)

[a] For retrofit applications, nominal value is 22.

obtained also included peer-reviewed journal articles, conference papers, books, technical reports, and technical judgments given by experts.

Almost all the sources reported a CO_2 capture efficiency of 90%. Hence this value has been used as the default nominal value without any default probability distribution. Nonetheless, the user is allowed to use a probability distribution for this parameter as well.

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4. COST MODEL DEVELOPMENT

The CO_2 capture and sequestration system cost model is directly linked to the performance model. The cost model follows the framework used in the IECM (Rubin, Kalagnanam et al. 1997) to ensure consistency in economic calculations. There are four types of cost calculated by this model based on the available data (Smelser, Stock et al. 1991; Hendriks 1994; Leci 1996; Mariz 1998; Simbeck 1998; Chapel, Ernst et al. 1999; Desideri and Paolucci 1999; Jeremy and Herzog 2000). They are capital cost, operation and maintenance (O&M) cost, incremental cost of electricity (COE) and cost of CO_2 avoidance.

4.1 Capital Cost

The total capital requirement (TCR) of a system is calculated as the sum of direct equipment costs (which depend on one or more performance variables that determine the size or capacity of the component), plus various indirect costs that are estimated as fractions of the total direct cost following the EPRI cost estimating guidelines (TAG 1993; TAG 1999).

The capital cost model is primarily based on detailed information obtained from Fluor Daniel Inc. (Fluor 1998). To develop a generalized cost model applicable to different plant sizes and material flow rates, the Fluor Daniel data are used as a reference point for the application of engineering "scaling laws". For example, where multiple trains are required to perform the CO_2 capture operation, the maximum train size is taken to be 5000 tonnes per day of CO_2, based on current design. Based on the actual CO_2 capture rate (m_{CO2}) the number of trains required to be installed (N_{min}) is determined.

Different components have different maximum capacity limits. $E_{n,i}$ defines the number of components required per train. Each train consists of the following pieces of equipment ($E_{n,i}$):

- Direct contact cooler (DCC), flue gas blower, absorber, heat exchanger, regenerator, steam extractor, MEA reclaimer - 1 per each train

- Pumps - 2 per train

- Reboilers - 4 per train

Special cases:

1. Only one installation is required for the sorbent processing area, auxiliary natural gas boiler, secondary steam turbine, CO_2 transport facility and CO_2 disposal facility.

2. In case of CO_2 compressors, which have higher capacity (~ 7200 tonnes per day of CO_2), the number of compressors required is calculated accordingly.

The unit cost of each component of this system (absorber, regenerator, flue gas blower *etc*.) is scaled based on the flow rate of the material being handled by that particular device, using the 0.6 power law commonly used in chemical engineering costing (Peters and Timmerhaus 1991). For example, the cost of an absorber is scaled on the basis of the flue gas flow rate entering the CO_2 system, with the data obtained from Fluor Daniel serving as the reference basis for this scaling. Thus, in general, the capital cost of a component of arbitrary size (less than the maximum size) may be estimated as:

$$C_i = C_{i,\text{ref}} \cdot \left(\frac{X_i}{X_{i,\text{ref}}} \right)^{0.6}$$

where,

C_i = Component cost

$C_{i,\text{ref}}$ = Cost of reference size

X = actual flow rate (for scaling)

$X_{i,\text{ref}}$ = Flow rate of reference plant

Once the cost of a particular equipment (C_i) is calculated, it needs to be multiplied by the total number of equipment installed (Z_i) in order to get the total cost of installation for that process area (i).

The overall amine system is divided into a number of process areas for which some physical quantity is identified as the basis for scaling of the capital cost. For example, flue gas flow rate, sorbent flow rate, CO_2 product flow rate, CO_2 compression energy requirement, steam flow rate, and makeup MEA flow rate are used for scaling he capital cost of various process areas.

The direct capital cost (process facilities cost) of CO_2 capture and separation system consists of the following cost areas:

Direct contact cooler: In case of coal-fired power plant applications that have a wet FGD (flue gas desulfurization) unit upstream of the amine system, the wet scrubber helps in substantial cooling of the flue gases, and additional cooler may not be required. In case of gas-fired power plants or majority of coal-fired power plants that do not have wet scrubbers for SO_2 removal, a direct contact cooler has to be installed to bring down the temperature of the flue gas stream to acceptable levels. A direct contact cooler is a large vessel where the incoming hot flue gas is made to contact with the cooling water. The size of this unit is a function of the volumetric flow rate of the flue gas, which in turn depends upon the temperature and pressure conditions of the flue gas stream. The capital cost of the unit is estimated as:

$$C_{dcc} = C_{dcc, \, ref} \cdot \left(\frac{V_{fg}}{V_{fg,ref}} \cdot \frac{T_{fg}}{T_{fg,ref}} \right)^{0.6}$$

Flue gas blower: The cooled flue gas is pressurized using a blower before it enters the absorber. The size (and the cost) of the blower is again a function of the volumetric flow rate of the flue gas as it enters the blower. So, the cost may be estimated as:

$$C_{blower} = C_{blower, \, ref} \cdot \left(\frac{V_{fg,1}}{V_{fg,1,ref}} \cdot \frac{T_{fg,1}}{T_{fg,1,ref}} \right)^{0.6}$$

Absorber: This is the vessel where the flue gas is made to contact with the MEA-based sorbent, and some of the CO_2 from the flue gas gets dissolved in the sorbent. Again, the size of this unit is mainly a function of the volumetric flow rate of the flue gas, which in turn depends upon the temperature and pressure conditions of the flue gas stream, as it

enters this vessel. The cost of the unit is again estimated on the basis of the cost information available for a particular reference case:

$$C_{absorber} = C_{absorber,\ ref} \cdot \left(\frac{V_{fg,in}}{V_{fg,in,ref}} \cdot \frac{T_{fg,in}}{T_{fg,in,ref}} \right)^{0.6}$$

Rich/lean cross heat exchanger: The rich (CO_2-loaded) and lean (regenerated) sorbent streams are passed through this cross heat exchanger, where the rich sorbent gets heated and the lean sorbent gets cooled. So, the size (and cost) of this unit is a function of the volumetric sorbent flow rate in the absorber. It is assumed that this volumetric flow rate is constant in the range of temperature and pressure conditions found in this system. The capital cost of the unit is estimated as:

$$C_{crossHEx} = C_{crossHEx,\ ref} \cdot \left(\frac{V_{solvent}}{V_{solvent,ref}} \right)^{0.6}$$

Regenerator: This is the column where the CO_2-loaded sorbent is regenerated with the application of heat. Sorbent flow rate is the main physical quantity that decides the size (and cost) of this unit, for a given residence time, which is a function of many parameters including the sorbent concentration, desired CO_2 capture efficiency, *etc*. So, the cost may be estimated as above:

$$C_{regenerator} = C_{regenerator,\ ref} \cdot \left(\frac{V_{solvent}}{V_{solvent,ref}} \right)^{0.6}$$

Reboiler: The regenerator is connected with a reboiler, which is a heat exchanger where low-pressure steam extracted from the power plant is used to heat the loaded sorbent. So, the size (and cost) of this unit is a function of mainly the flow rate of the sorbent as well as the flow rate of steam. The cost of the unit is estimated as:

$$C_{reboiler} = C_{reboiler,\ ref} \cdot \left(\frac{V_{solvent}}{V_{solvent,ref}} \cdot \frac{M_{steam}}{M_{steam,ref}} \right)^{0.6}$$

It may be noted that the ratio of mass flow rates of LP steam (M_{steam}/ $M_{steam,ref}$) has been used in place of the ratio of volumetric flow rates of LP steam, assuming that the temperature and pressure conditions of the LP steam in both cases (actual and reference) are approximately the same.

Steam extractor: Steam extractors are installed to take LP steam from the steam turbines in the power plant. The size (and the cost) of the steam extractor is assumed to be a function of the steam flow rate.

$$C_{steam\_extractor} = C_{steam\_extractor,\ ref} \cdot \left(\frac{M_{steam}}{M_{steam,ref}} \right)^{0.6}$$

This cost item is included if the CO_2 capture system is configured to make use of steam extracted from the steam cycle of the base plant. Alternatively, an auxiliary NG boiler and a secondary steam turbine may be used, and the next two cost items (C_{NG_boiler} and C_{ST2}) are included in its place.

Auxiliary boiler <u>with steam turbine</u>:   The cost of the NG boiler is estimated on the basis of the steam flow rate generated by the boiler using a cost estimation formula reported by Simbeck (Simbeck and McDonald 2000):

$$C_{NG\_boiler} = \$15 \cdot (\text{steam flow rate expressed in lb/hr})$$

Since the steam flow rate (m_{steam}) in the model is given as tonnes/hr, the following expression is obtained after accounting for the unit conversions

$$C_{NG\_boiler} = \$33000 \cdot (m_{steam})$$

The cost of the secondary steam turbine is estimated on the basis of the electrical power generated from this new turbine again using a cost estimation formula reported by Simbeck (Simbeck and McDonald 2000):

$$C_{ST2} = \$300 \cdot (E_{ST2})$$

Where,

$$E_{ST2} = \text{Power generation from secondary steam turbine expressed in MWe}$$

Auxiliary boiler without steam turbine: If a NG boiler is installed to provide only LP steam (and not to generate any electrical power using a secondary steam turbine), then the boiler cost is lower than that of high pressure boiler discussed earlier. According to Simbeck (Simbeck 2002)its cost is estimated as:

$$C_{NG\_boiler\_only} = \$22000 \cdot (m_{steam})$$

MEA reclaimer: In order to avoid accumulation of the heat stable salts in the sorbent stream and to recover some of the lost MEA sorbent, a part of the sorbent stream is periodically distilled in this vessel. Addition of caustic helps in freeing of some of the MEA. The amount of MEA makeup requirement may be taken as an indicative of the amount of heat stable salts formed and the quantity of sorbent to be distilled in the reclaimer. So, the mass flow rate of makeup MEA requirement is used as a scaling parameter to estimate the cost of this unit:

$$C_{MEA\_reclaimer} = C_{MEA\_reclaimer,\ ref} \cdot \left(\frac{M_{MEA\_makeup}}{M_{MEA\_makeup,ref}} \right)^{0.6}$$

Sorbent processing area: The sorbent processing area primarily consists of sorbent cooler, MEA storage tank, and a mixer. It also consists of an activated carbon bed filter that adsorbs impurities (degradation products of MEA) from the sorbent stream. So, the size (and cost) of this unit (together) will be a function of the total sorbent flow rate, and may be estimated as follows:

$$C_{solvent\_proc} = C_{solvent\_proc,\ ref} \cdot \left(\frac{V_{solvent}}{V_{solvent,ref}} \right)^{0.6}$$

CO$_2$ drying and compression unit: The multi-stage compression unit with inter-stage cooling and drying yields the final CO$_2$ product at the specified pressure (about 2000 psig) that contains only acceptable levels of moisture and other impurities (e.g. N$_2$). The size (and cost) of this unit will be a function of the CO$_2$ product flow rate, and may be estimated as follows:

$$C_{CO2\_compr} = C_{CO2\_compr,\ ref} \cdot \left(\frac{M_{CO2}}{M_{CO2,ref}} \right)^{0.6}$$

The sum of all these individual process area equipment costs is termed as process facilities capital (PFC). The various indirect costs are then estimated as fractions of the PFC following the EPRI cost estimating guidelines (TAG 1993; TAG 1999). Table 4.1 lists the elements of total capital cost. Because of data limitations some of the indirect cost factors for the amine system are estimated based on other similar technologies.

Table 4.1. MEA capital cost model parameters and nominal values

	Capital Cost Elements	Value
A	Process Area Equipment Costs	$A_1, A_2, A_3, \ldots, A_{10}$
B	Total Process Facilities Capital (PFC)	ΣA_i
C	Engineering and Home Office	7% PFC
D	General Facilities	10% PFC
E	Project Contingency	15% PFC
F	Process Contingency	5% PFC
G	Total Plant Cost (TPC) = sum of above	B+C+D+E+F
H	AFUDC (interest during construction)	Calculated
I	Royalty Fees	0.5% PFC
J	Pre-production	1 month's fixed O&M cost
K	Pre-production	1 month's variable O&M cost
L	Inventory (startup) Cost	0.5% TPC
M	Total Capital Requirement (TCR)[a]	G+H+I+J+K+L

The total plant cost (TPC) is the sum of the process facilities capital (PFC), general facilities capital (GFC, which is the total construction cost of the general facilities, including roads, office buildings, shops, laboratories etc.), engineering and home office (EHO) overhead, and contingencies – project and process. The project contingency is a capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design at an actual site. On the other hand, the process contingency is a capital cost contingency factor (added cost) applied to a technology to reflect its level of maturity. TPC is developed on the basis of instantaneous

("overnight") construction – occurring at a single point in time, and is generally expressed in mid-year dollars of a reference year.

The total capital requirement (TCR) includes all the capital necessary to complete the entire project, including interest during construction (AFUDC, allowance for funds during construction) and owner costs, which include royalties, startup costs, inventory capital *etc*.

4.2 O&M Cost

The major operating and maintenance (O&M) cost consists of fixed costs and variable cost elements as listed in Table 4.2

Table 4.2 MEA O&M cost model parameters and nominal values

O&M Cost Elements	Typical Value
Fixed O&M Costs	
Total Maintenance Cost	2.5% TPC
Maintenance Cost Allocated to Labor ($f_{maintlab}$)	40% of total maint. cost
Admin. & Support Labor Cost (f_{admin})	30% of total labor cost
Operating Labor (N_{labor})	2 jobs/shift
Variable O&M Costs	
Reagent (MEA) Cost	$1200/ tonne
Water Cost	$0.8/ 1000 gallon
Solid Waste Disposal Cost	$175/ tonne waste
CO_2 Transport Cost	$0.02/ tonne CO_2 per km
CO_2 Storage/Disposal Cost	$5/ tonne CO_2

4.2.1. Fixed O&M Costs

The *fixed O&M* (FOM) costs in the model include the costs of maintenance (materials and labor) and labor (operating labor, administrative and support labor). They are estimated on annual basis ($M/yr) as follows:

$$FOM = FOM_{labor} + FOM_{maint} + FOM_{admin}$$

$$FOM_{labor} = labor \times N_{labor} \times 40(hrs/week) \times 52(weeks/yr)$$

61

$$\text{FOM}_{\text{maint}} = \Sigma_i \, (f_{\text{maint}})_i \times \text{TPC}_i \quad \text{where } i = \text{process area}$$

$$\text{FOM}_{\text{admin}} = f_{\text{admin}} \times (\text{FOM}_{\text{labor}} + f_{\text{maintlab}} \times \text{FOM}_{\text{maint}})$$

where,

> $\text{labor} =$ the hourly wages to the labor (\$/hr)

> $N_{\text{labor}} =$ number of operating labor required

> $(f_{\text{maint}})_i =$ total annual maintenance cost expressed as the fraction of the total plant cost (TPC)

> $f_{\text{admin}} =$ the administrative labor cost expressed as the fraction of the total labor cost

4.2.2. Variable O&M Costs

The *variable O&M* (VOM) costs depend on the capacity factor (or load factor) of the plant. They include costs of chemicals consumed (MEA, inhibitor, other reagents such as caustic and activated carbon), utilities (water, steam, power), fuel (natural gas, in case of auxiliary boiler) and services used (waste disposal, CO_2 transport and storage). These quantities are determined in the performance model. The unit cost of each item (e.g., dollars per ton of reagent, or dollars per ton of CO_2 stored) is a parameter specified as a cost input to the model. The total annual cost of each item is then calculated by multiplying the unit cost by the total annual quantity used or consumed. Total annual quantities depend strongly on the plant capacity factor, which is defined as the ratio of total annual generation (kWh per year) to maximum possible generation (which is the product of plant capacity times total hours per year). The plant capacity factor is one of the crucial assumptions that influences the overall economics of the plant, especially in the case of a capital-intensive technology.

The individual components of variable O&M costs are as follows:

Cost of MEA reagent (VOM_{MEA}):   The makeup MEA requirement estimated in the performance model is transformed into dollar amount by using the unit cost of MEA, which is a user-controlled cost input variable.

$$VOM_{MEA} = M_{MEA,makeup} \times UC_{MEA} \times HPY$$

where, UC_{MEA} is the unit cost of MEA, and HPY is the equivalent annual hours per year of plant operation at full capacity (*e.g.*, a capacity factor of 75% is equivalent to about 6575 hours per year, assuming an average of 365.25 days per year).

Cost of inhibitor ($VOM_{inhibitor}$):   Addition of inhibitor makes it possible to use higher concentrations of MEA sorbent in the system with minimal corrosion problems. Inhibitors are special compounds that come at a cost premium.   The cost of inhibitor is estimated as 20% of the cost of MEA.

$$VOM_{inhibitor} = 0.2 \times VOM_{MEA}$$

Cost of other reagents ($VOM_{reagents}$):   The cost of other reagents, such as, caustic and activated carbon are also calculated from their physical quantities estimated in the performance model and the unit costs of these reagents.

$$VOMreagents = VOM_{Caustic} + VOM_{act-C}$$

$$= \{(m_{Caustic} \times UC_{Caustic}) + (m_{act-C} \times UC_{act-C})\} \times HPY$$

where $UC_{Caustic}$ and UC_{act-C} are the unit costs of the reagents caustic and activated carbon, respectively.

Cost of waste disposal (VOM_{waste}):   Another important variable operating cost item is the cost incurred in disposal of the spent sorbent *i.e.*, the reclaimer waste. The quantity estimated in the performance model is:

$$VOM_{waste} = M_{waste,total} \times UC_{waste} \times HPY$$

where, UC_{waste} is the unit cost of waste disposal for the reclaimer waste.

Cost of CO₂ transport ($VOM_{transport}$): Transportation of CO_2 product is assumed to take place via pipelines. The cost of CO_2 transport is estimated on the basis of two user-specified parameters, *viz.*, transportation distance (TD, in km) and unit cost of transport ($UC_{transport}$, \$/km per tonne CO_2), plus the CO_2 product flow rate (calculated result from performance model).

$$VOM_{transport} = M_{CO2} \times UC_{transport} \times TD \times HPY$$

Cost of CO₂ storage ($VOM_{disposal}$): Depending upon the method of CO_2 disposal or storage, either there may be some revenue generated (as in enhanced oil recovery, or enhanced coal bed methane), or an additional cost (all other disposal methods). The total cost or revenue of CO_2 disposal/ storage is estimated from the unit cost and CO_2 product flow rate (UC_{disp}).

$$VOM_{disposal} = M_{CO2} \times UC_{disp} \times HPY$$

Cost of energy (VOM_{energy}): By default, all energy costs are handled internally in the model by de-rating the overall power plant based on the calculated power requirement. The CO_2 capture unit is charged for the total electricity production foregone because of CO_2 capture and compression ($E_{CO2,\,tot}$).

For power plants with multi-pollutant controls the desire to quantify costs for a single pollutant requires an arbitrary choice of how to charge or allocate certain costs. This is especially relevant for energy-intensive processes like CO_2 capture systems.

The unit cost of electricity (COE_{noctl}) is estimated by the base plant module, or may be overridden by a user-specified value if this energy is assumed to be supplied from an external source. Since energy cost is one of the biggest O&M cost items for the CO_2 unit, the way in which it is accounted for is important when calculating the mitigation cost.

$$VOM_{energy} = E_{CO2,tot} \times HPY \times COE_{noctl}$$

Alternatively, when regeneration steam and additional electricity is provided by an auxiliary NG boiler, the cost of energy is estimated from the total annualized cost of the

new boiler and secondary steam turbine, which takes into account their capital cost requirements and cost of natural gas fuel.

Cost of water (VOM_{water}): Water is mainly required for process cooling and also as process makeup. Generally this is a minor cost item in the overall plant operation, but it is included over here for the sake of completeness, based on the amount of water needed (M_w) and the unit cost of water (UC_{water}):

$$VOM_{water} = M_w \times UC_{water} \times HPY$$

The total variable O&M (VOM, $/yr) cost is obtained by adding all these costs:

$$VOM = VOM_{MEA} + VOM_{reagents} + VOM_{waste} + VOM_{transport} + VOM_{disposal} + VOM_{energy} + VOM_{water}$$

Finally, the total annual O&M cost (TOM, $/yr) may be obtained as:

$$TOM = FOM + VOM$$

4.3 Incremental Cost of Electricity

Once the total capital requirement and the total O&M costs are known, the total annualized cost of the power plant may be estimated as follows:

$$\text{Total annual revenue requirement, TRR (\$/yr)} = (TCR \times CRF) + TOM$$

where, TCR = Total capital requirement of the power plant ($), and

$$CRF = \text{Capital recovery factor (fraction)}$$

The capital recovery factor, or fixed charge factor (FCF), is the factor that annualizes the total capital requirement of the plant. It depends on the applicable interest rate (or discount rate) and useful lifetime of the plant.

It can be seen that a higher value of this factor (*e.g.* from assumptions of shorter plant life and/or higher interest rate) leads to a higher overall annualized cost. Hence the assumption about this factor (a user-defined parameter) is crucial in the overall economics of the plant.

The IECM framework calculates the cost of electricity (COE) for the overall power plant by dividing the total annualized plant cost ($/yr) by the net electricity generated (kWh/yr). Results are expressed in units of $/MWh (equivalent to mills/kWh).

Cost of electricity, COE ($/MWh) $= TRR / (MW_{net}*HPY)$

where, TRR = Total annual revenue requirement ($/yr)

MW_{net} = Net power generation capacity (MW)

HPY = Annual hours of operation (hrs/yr)

Note that the COE includes the cost of all environmental control systems, not just the CO_2 control system. Thus, by running two scenarios of the power plant model, one without CO_2 capture (reference plant) and one with CO_2 capture (CO_2 capture plant), we obtain the incremental capital costs, O&M costs, and total annualized costs attributed to CO_2 capture. The addition of a CO_2 capture and sequestration system increases the COE for the plant; this incremental cost of electricity is attributed to CO_2 control.

4.4 Cost of CO_2 Avoidance

Analysts often express the cost of an environmental control system in terms of the cost per unit mass of pollutant removed. However, for energy-intensive CO_2 controls there is a big difference between the cost per tonne CO_2 "removed" and the cost per tonne "avoided" based on *net* plant capacity. Since the purpose of adding a CO_2 unit is to reduce the CO_2 emissions per net kWh delivered, the "cost of CO_2 avoidance" is the economic indicator that is widely used in this field. It can be calculated as:

$$Cost\ of\ CO_2\ Avoided\ (\$/tonne) = \frac{(\$/kWh)_{after} - (\$/kWh)_{before}}{(tonne\ CO_2/kWh)_{before} - (tonne\ CO_2/kWh)_{after}} \quad (4\text{-}1)$$

In contrast, the cost per unit of CO_2 removed or captured is simply the additional expenses incurred in the capture of CO_2, divided by the total quantity of CO_2 captured.

This can be calculated as the difference between the total annualized cost of the plant (TRR, M$/yr) with and without CO_2 control, divided by the total quantity of CO_2 captured (tonne CO_2/ yr), with the net power generated by the two plants remaining the same. Hence, the CO_2 avoidance cost, as calculated in equation *4-1*, is quite different from the cost per unit of CO_2 captured. In case of CO_2 control using an energy-intensive technology like amine-scrubbing, the *cost of CO_2 avoidance* may be substantially higher than *cost of CO_2 capture*.

The cost of CO_2 avoidance has another interpretation in terms of a carbon-tax scenario. Consider a scenario where a power plant must pay a fixed tax (C-tax) that is proportional to its CO_2 emissions. Now consider a reference plant (that does not control its CO_2 emissions) and the same plant with CO_2 capture (*e.g.*, 90% of its CO_2 emissions). The COE for the reference plant is initially lower, but increases much faster as compared to the COE for the capture plant, in response to increasing levels of the C-tax. Eventually, a C-tax level is reached where the COE for both the plants are the same (see Figure 4.1).
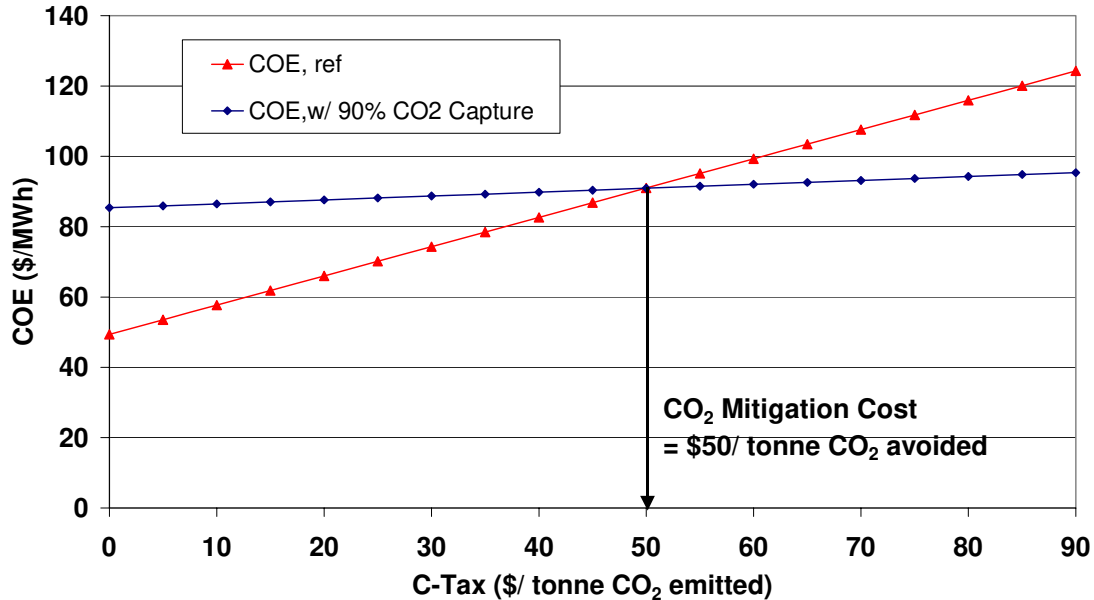
Figure 4.1. Cost of electricity (COE) as a function of carbon-tax

At this C-tax level, the power plant might be indifferent between paying the C-tax or incurring the cost of the CO_2 capture unit. The cost of CO_2 avoidance is this C-tax level,

where the COE for the reference plant and capture plant become equal. Note that this comparison assumes that both the reference plant and capture plant operate at the same annual capacity factor. In practice, load factors may vary for plants with and without emission controls in the context of a specific regional situation (Johnson 2002).

4.5 Cost of Electricity (COE) as a Function of Carbon Tax

As mentioned earlier, the IECM modeling framework has probabilistic capabilities that allow model inputs to be represented by probability distributions. In addition to uncertainties or variability in performance model parameters, there is also uncertainty and/ or variability in cost model parameters.

Table 4.3 lists the uncertainty distributions developed for the cost model parameters based on the current literature on amine-based (MEA) systems, the evolving nature of the technology, and views expressed by professionals working in this field. These distributions reflect both uncertainty and variability in the cost of these systems. Additional details are presented in *Appendix B* and *Appendix C*.

The last three parameters listed in Table 4.3 reflect the cost of CO_2 transport and storage. The storage cost or revenue expected from CO_2 product stream is the area of largest uncertainty. Various factors including the possibility of government regulation of CO_2 emission, the evolution of national and/or international markets for CO_2, and site-specific conditions will significantly influence the cost (or credits) for CO_2 disposal. The distributions in Table 4.3 reflect the variety of options and costs commonly cited in the current literature.

Other parameters that directly contribute to the overall distribution of cost estimates for this technology include fuel prices, plant capacity factor, and fixed charge factor or capital recovery factor. These are the parameters that essentially belong to the reference plant (base plant) itself, and have nothing to do with amine-based CO_2 capture. So, in order to assess the uncertainty associated with the amine-based CO_2 capture technology, distributions on these parameters as well for the CO_2 transport and disposal cost parameters should not be used.

Table 4.3. Amine system cost model parameters and uncertainties

Cost Parameter	Units	Nominal Value	Unc. Representation (Distribution Function)
Process facilities	M$	calc	*Normal(1.0,0.1)
Engineering and home office	% PFC	7	Triangular (5,7,10)
General facilities	% PFC	10	Triangular (5,10,15)
Project contingency	% PFC	15	Triangular (10,15,20)
Process contingency	% PFC	5	Triangular (2,5,10)
Royalty fees	% PFC	0.5	Triangular (0,0.5,0.5)
Startup cost	Month of TOM	1	Triangular(0.5,1,1)
Inventory cost	% TPC	0.5	Triangular(0.4,0.5,0.6)
Total maintenance cost	% TPC	2.5	Triangular(1,2.5,5)
Operating labor	Jobs/shift	2	Triangular(1,2,3)
MEA cost	$/ tonne MEA	1200	Uniform (1100,1300)
Waste disposal cost	$/ tonne waste	175	*Normal(1.0,0.1)
CO_2 transport cost	$/ tonne CO_2/ km	0.02	Triangular (0.004,0.02,0.08)
CO_2 storage/disposal cost	$/ tonne CO_2	5	-
Revenue from CO_2 usage in EOR or ECBM[b]	$/ tonne CO_2	-18[a]	-

*This function is used as a multiplier to the nominal value.
[a] The negative sign indicates that it is a revenue rather than cost to the system.
[b] Individual scenarios may be run with the assumptions about revenue generation from CO_2 product usage in EOR/ECBM applications, instead of additional cost for CO_2 storage/ disposal. Alternatively, a chance function may be used that will assign either cost or revenue for CO_2 product stream during each individual run.

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5. MODEL APPLICATIONS

One of the major objectives behind building the IECM-CS model is to provide an analytical tool to compare various technological options for controlling CO_2 emissions from fossil-fuel based power plants on a consistent basis. Such assessments of the technical, environmental, and economic impacts of including CO_2 control systems in power plant applications are important for greenhouse gas control policy analysis. Policy aspects of controlling CO_2 emissions from power plants might include questions such as:

1) Within the spectrum of fossil-fuel based power plants, are there any particular categories that are better candidates for applying this technology?

2) What levels of emission reduction are possible? Are there any secondary environmental benefits associated with this process? Are there any potential environmental concerns? Are there any local pollution control problems or benefits arising from this process?

3) How does CO_2 capture affect the overall performance (and cost) of the power plant?

4) How much would it cost in terms of capital requirement, incremental cost of electricity and cost per unit of CO_2 avoided? What are the uncertainties associated with these estimates?

5) In case of conventional combustion-based power plants, is it cheaper to control CO_2 emissions from a coal plant than from a gas plant?

6) Is it feasible to retrofit the existing power plants with this technology? If yes, are there any crucial issues of system integration in this case? How would the costs for a retrofit application compare to that for a greenfield case?

7) What are the key factors that affect these costs? Is there any scope for improvement in this technology through targeted R&D efforts? What are the possible cost reductions that could be realized through such improvements?

The IECM-CS model may be used to generate various scenarios that can provide useful insights into these questions. It may be noted that all these questions address issues related to the techno-economic and environmental feasibility of CO_2 capture and separation alone. There is another whole set of questions related to the issues concerning the large-scale transport and storage/disposal of concentrated CO_2 stream generated in this process, *viz.* technical feasibility, long-term environmental impacts, public perceptions, potential risks, uncertainties in the cost estimates *etc*. However, these are beyond the scope of the present study.

This chapter will address such questions by means of specific case studies of greenfield and retrofit applications of this technology presented in subsequent sections. The last question will be addressed later in the next chapter.

5.1. Case Study of a New Coal-fired Power Plant

Let us consider the case of a new conventional coal-fired power plant, and impact of adding a post-combustion amine-based CO_2 capture unit to it. The basic assumptions and input parameters are listed in Table 5.1.

Table 5.1 Design parameters for case study of new pulverized coal plant

Parameter	Value	Parameter	Value
Gross plant size (MW)	500, 670	Emission standards	2000 NSPS[d]
Base plant steam cycle type	SC[a]	NO_x Controls	LNB[e] +SCR[f]
Gross plant heat rate (kJ/kWh)	8359[a]	Particulate Control	ESP[g]
Plant capacity factor (%)	75	SO_2 Control	FGD[h]
Coal characteristics		CO_2 Control	MEA[i]
Rank	Sub-bit.	CO_2 capture efficiency (%)	90
HHV (kJ/kg)	19,346	CO_2 product pressure (kPa)	13,790[j]
% S	0.48	Distance to storage (km)	165
% C	47.85		
Mine-mouth cost ($/tonne)	13.73	Cost year basis (constant dollars)	2000
Delivered cost ($/tonne)	23.19[c]	Fixed charge factor	0.15[k]

[a]Nominal case is a super-critical unit. Unc. = Uniform(8167, 8560) ; [b]Unc = Triangular(65,75,85); [c]Unc = Triangular(15.94,23.19,26.81); [d]NO_x = 65 ng/J, PM = 13 ng/J, SO_2 = 70% removal (upgraded to 99% with MEA systems); [e]LNB = Low- NO_x Burner; [f]SCR = Selective Catalytic Reduction; [g]ESP = Electrostatic Precipitator; [h]FGD = Flue Gas Desulfurization; [i]MEA = Monoethanolamine system;
[j]Unc. = Triangular(7580,13790,15160); [k]Corresponds to a 30-year plant lifetime with a 14.8% real interest rate (or, a 20-year life with 13.9% interest); Unc = Uniform(0.10,0.20)

The reference plant (without CO_2 control unit) is New Source Performance Standard (NSPS) compliant coal-fired power plant and the complete plant with multi-pollutant environmental controls is simulated using IECM. The FGD system is assumed to remove 95% of the SO_2 emissions, reflecting the best available technology, yielding lower emissions than what is required under the present NSPS. This assumption is crucial as the "CO_2 avoidance cost" depends on the reference plant design as well. Wyoming Powder River Basin coal has been assumed to be used. The model outputs are presented later in Table 5.2 in comparison with the estimates for the CO_2 capture plant.

In case of the CO_2 capture plant, the following changes have been assumed as compared to the reference plant:

1) Air leakage has been reduced to 10% (reference plant uses the default value which is about 19%).

2) The FGD system is assumed to be further upgraded to 99% SO_2 removal efficiency.

3) MEA-based CO_2 capture system including CO_2 product compression, transport and storage has been added.

The values for other parameters are listed in Tables 3.3, 4.1 and 4.2 in the previous chapters.

Since we know that the CO_2 capture system is going to consume a lot of energy, we will be comparing two alternative cases of CO_2 capture plant:

A) Using the same coal input (same MW_{gross} size), so that the CO_2 capture plant will end up with lower net power generation, called as *Case-A*.

B) Starting with a bigger base plant (higher MW_{gross} size, larger coal input), so that the CO_2 capture plant produces the same net power as generated by the reference plant. The exact size of this plant has to be found by trial-and-error method, and this case will be referred as *Case-B*. From a practical point of view, this is a more useful case to consider, since the

ultimate objective of a power plant is to generate (a certain amount of) electricity. Hence, this case will be used as a base case in further analysis.

5.1.1. Deterministic Results

We examine the model first for the reference power plant (without CO_2 capture) and then for the same plant including CO_2 capture (case A) and for a similar but bigger plant including CO_2 capture (case B). Table 5.2 quantifies the impact of the CO_2 unit on plant performance, plant discharges and plant costs. More detailed results (including those for Case-A) have been provided in *Appendix D*. Here we refer to the results from the case-B capture plant in comparison to the reference plant.

The CO_2 capture system is energy intensive, and puts a large parasitic load on the base plant. Hence, the net heat rate of the capture plant (11,550 Btu/kWh) is higher than that of the reference plant (8,657 Btu/kWh). Energy requirements consume about 22% of gross plant capacity, mostly for sorbent regeneration (54%) and CO_2 product compression (36%). Sorbent circulation and fan power account for the remaining share (10%) of the total energy consumption of CO_2 capture unit.

It may be observed that the new CO_2 capture plant is significantly bigger (+34%) than the reference plant. This implies that the capture plant has greater environmental impacts in terms of higher emissions of solid wastes (bottom ash, fly ash, FGD waste etc.) and ammonia in absolute quantities. This plant uses much more coal, hence it is also responsible for the externalities associated with extraction and transport of this extra coal, although these environmental impacts are beyond the scope of this study. It must be noted that the capture plant has lower SO_x, NO_x, and particulate emissions, in addition to lower CO_2 emissions. However, it has higher emission rate of NO_x (mass of NO_x emitted per unit of power generated, 0.78 g/kWh) as compared to the reference plant (0.59 g/kWh). This happens because of the large energy penalty of the CO_2 capture system. Finally, the capture plant generates two new discharge streams, *viz.* spent sorbent (which is treated as a hazardous waste) and a large concentrated CO_2 stream. It is assumed that the CO_2 product is transported via pipelines to the final storage or disposal site.

Table 5.2. Case study results for new pulverized coal plants

Parameter	Reference Plant	Capture Plant (B)	% change
Gross capacity (MW)	500	670	+34%
FGD efficiency (%)	95	99	
CO_2 capture efficiency (%)	-	90	
Net power generation (MW)	458	458	NO CHANGE
Net cycle heat rate (Btu/kWh)	8,657	11,550	+33%
Coal consumption (tonne/hr)	215.5	287.5	+33%
Limestone consumption (tonne/hr)	2.3	3.2	+39%
CO_2 emission (tonne/ hr)	381.3	50.9	-87%
NO_x emission (kg/ hr)	269.5	355.2	+32%
SO_x emission (kg/ hr)	76.4	0.14	-99.8%
NH_3 emission (kg/ hr)	5.35	40.0	+648%
CO_2 emission (gCO_2/ kWh)	833.3	111.2	-87%
NO_x emission (gNO_x/ kWh)	0.59	0.78	+32%
SO_x emission (gNO_x/ kWh)	0.17	0.0003	-99.8%
FGD waste (tonne/hr)	4.2	5.8	+39%
Spent MEA sorbent (tonne/hr)	-	1.4	
CO_2 product (tonne/ hr)	-	458	
TCR (M$)	616	963	+56%
TCR ($/ kW)	1345	2104	+56%
COE ($/ MWh)	49.4	85.7	+73%
$/ tonne CO_2 avoided	-	50.2	
$/ tonne CO_2 delivered	-	36.2	

Because the CO_2 capture plant is a bigger plant (670 MW gross), the total plant capital cost increases from $616M (for the reference plant) to $963M. It maybe noted that this plant benefits from economies of scale. This is evident from the fact that the total capital requirement for case A (500 MW_{gross} with CO_2 capture) is $760M ($2228/kW). In terms of operational costs, the steam and power cost and CO_2 transport and storage/ disposal cost are two most important cost items, and contribute to about 34% and 23% to the total

75

annualized cost of CO_2 capture. MEA makeup requirements contribute to about 8% of this cost. Figure 5.1 shows the relative contributions from various cost areas in the overall annualized cost of CO_2 capture unit.

The presence of SO_2 impurities can substantially increase the reagent costs, so the cost of CO_2 avoidance is sensitive to the SO_2 removal efficiency of the FGD unit located upstream of the MEA system. Tradeoff studies showed that overall plant costs were minimized by reducing the SO_2 concentration to about 10 ppm inlet to the MEA absorber. Therefore, in this case study the SO_2 removal system was upgraded to 99% removal with CO_2 controls, as against 95% SO_2 removal in the reference case. The costs of this upgrade were charged to the CO_2 unit.

Figure 5.2 shows graphically the relationship of electricity cost to CO_2 emissions for the two cases; the slope of the line connecting the two points represents the cost of CO_2 avoided, which is $50/tonne for this case. Most of this cost (77%) is associated with the CO_2 capture process (including product compression); CO_2 transport (9%) and storage (14%) account for the remainder.
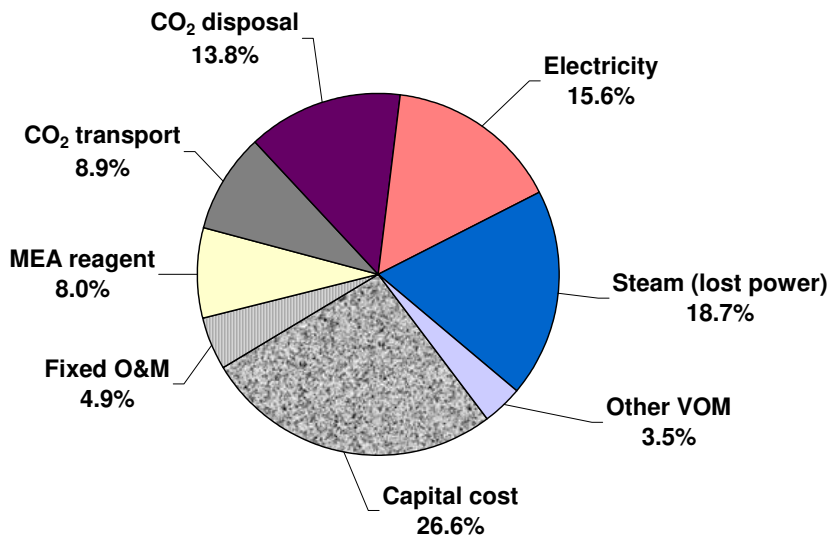
Figure 5.1. Breakup of annualized cost of CO_2 capture unit
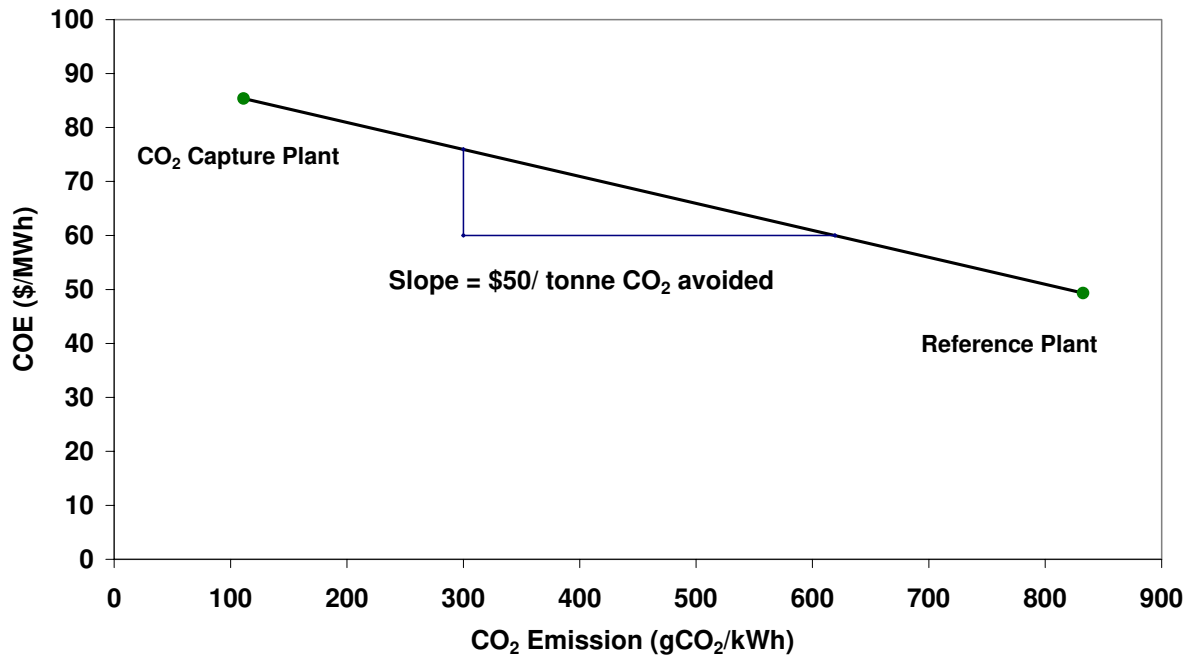
Figure 5.2. Estimation of CO₂ avoidance cost for a new low-S coal plant

It may be noted that the CO_2 avoidance cost (\$50/ tonne CO_2 avoided) is much higher than the CO_2 capture cost (\$36/ tonne CO_2 delivered).

5.1.2. Probabilistic Results

How much is it likely to cost to avoid CO_2 emissions using MEA-based CO_2 capture systems from a new pulverized coal (PC) plant in the US today? The question sounds quite simple; however one needs to make a lot of assumptions in order to answer it. Different assumptions about power plant design, coal properties, plant operation and CO_2 capture system design can have a significant effect on CO_2 mitigation costs, and are responsible for many of the cost differences found in the literature. To systematically characterize the effects of different assumptions, parameters that vary across design studies are represented here by probability distributions, with values selected based on the current literature, experts' opinions and (in some cases) my own judgment. Note that the term "uncertainty" is used loosely here to include parameter variability. More discussion about this issue may be found in *Appendix B* and *Appendix C*.

We can set the characteristics of the PC plant (*e.g.*, configuration, heat rate, capacity factor) and that of the fuel used (*e.g.*, coal properties, coal price) in order to define the reference case, *i.e.* power plant without CO_2 capture. Now we want to estimate the cost of CO_2 avoidance for this plant using MEA-based CO_2 capture system. Again, there are many parameters that need to be defined for this system. If we use a

77

single value for each of them, we are looking at a unique system configuration with well defined design variables and operating conditions. Thus we get a deterministic cost estimate. However, if we are considering the whole population of potential configurations of MEA-based CO_2 capture systems, most of those parameters would rather be represented as ranges of values (probability distributions) in place of the precise values. Various combinations of these parameter values then represent the set of possible configurations of a new commercial CO_2 capture system if built today.

Figure 5.3 first shows the effect of considering uncertainties and design variability only in the performance parameters of the amine system (from Table 3.3). The resulting distribution for cost of CO_2 avoidance has a 95-percentile range of \$34-54/ tonne CO_2 avoided. The main contributors to this range are the lean sorbent CO_2 loading, sorbent concentration (both of which determine the reboiler duty), and equivalent electrical penalty of the regeneration steam requirement. It may be noted that most of the distributions for the input parameters are triangular, which is also reflected in this result to a certain extent. The tapering tails with low probability generally imply some combinations of design conditions and performance parameter values that are either too idealistic (*e.g.* high sorbent concentration, high lean loading) or too conservative (*e.g.* lower sorbent concentration, lower lean loading). For example, as explained earlier, amine systems with high sorbent concentration and high lean loading would have to deal with more severe corrosion problems, making them less practical at this time. Such interactions are not well quantified and, hence, not reflected in the current model. However, R&D efforts could be targeted to make these potentially "better performing, low cost systems" practical in future. The median value (and its vicinity) represents a more realistic and near-optimal set of design conditions for current commercial systems.

Figure 5.4 shows the effect of uncertainty in CO_2 cost model parameters, excluding the costs of the CO_2 pipeline transport and geologic storage (see Table 4.3). Also included is the distribution obtained by considering uncertainties only in the cost parameters of the capture system. It shows that the uncertainties in the cost parameters of amine system have a very small effect on the overall distribution of the cost of CO_2 avoidance, which is dominated by the variability and uncertainty in design and performance variables.

Next, we consider the effect of assumptions about the cost of transport and storage/ disposal of CO_2 product on the distribution of the cost of CO_2 avoidance developed in Figure 5.4. Figure 5.5 shows the effect of considering costs of different options to store or dispose the CO_2 product stream. Curve A(0) represents a case that assumes zero storage cost. Next, curve B(5) is the case where storage of CO_2 stream (*e.g.*, in a geologic formation such as underground saline reservoir) incurs a cost of $5/ tonne CO_2. Finally, curve C(-18) shows a case that assumes a revenue of $18/ tonne CO_2 generated through EOR activity, represented as negative cost. The assumption about the cost of disposal of CO_2 product has a significant impact on the distribution of CO_2 avoidance cost. The 95-percentile ranges for these 3 cases are $36-60 (case A(0)), $43-68 (case B(5)) and $12-31 (case C(-18)) per tonne CO_2 avoided. These may be compared to the 95-percentile range of $34-54/ tonne CO_2 avoided for the case presented earlier in Figure 5.4. So the option B(5), that assumes an additional cost of $5/tonne CO_2 for storage, not only increases the overall cost of CO_2 avoidance (shifting the curve to the right), but also increases the 95-percentile range. On the other hand, option C(-18) leads to lower overall cost of CO_2 avoidance (shifting the curve to the left) as well as slightly narrower range.

Figure 5.6 shows the effect of additional uncertainties (or variability) for the assumed power plant efficiency (heat rate), plant capacity factor, fixed charge factor, and coal price (see Table 3.1). These parameter values are identical for the reference plant and capture plant. Here we are now looking at the probability distribution of CO_2 mitigation cost for a general population of pulverized coal plants using amine systems. The COE of each plant is strongly affected by assumptions about the base plant parameters. Also, the range in the CO_2 avoidance cost increases for all the three options A(0), B(5) and C(-18) to $33-63/tonne, $40-71 and $8-36/tonne, respectively.
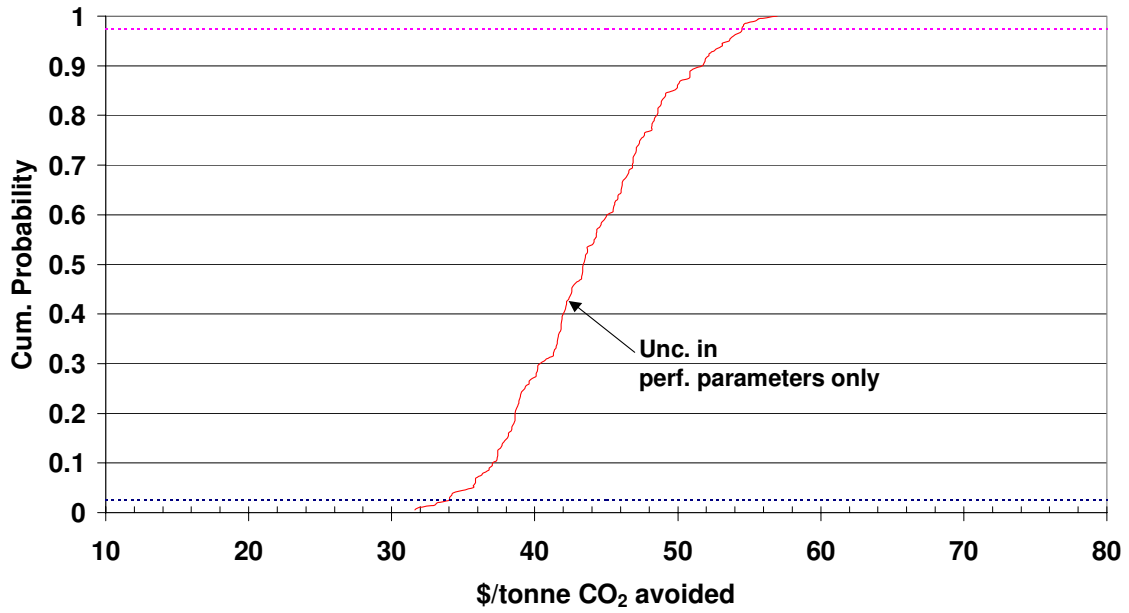
Figure 5.3. Probability distribution for the CO_2 avoidance cost, with only the uncertainties in performance parameters of amine system considered.
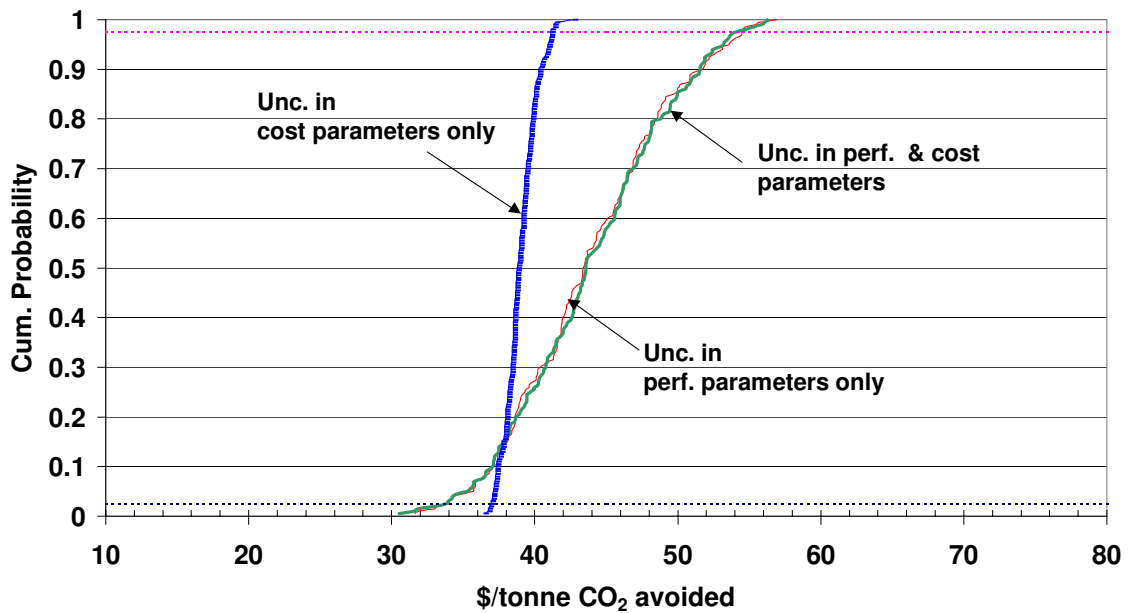
Figure 5.4. Probability distribution for the CO_2 avoidance cost, with the uncertainties in performance and cost parameters of amine system considered.
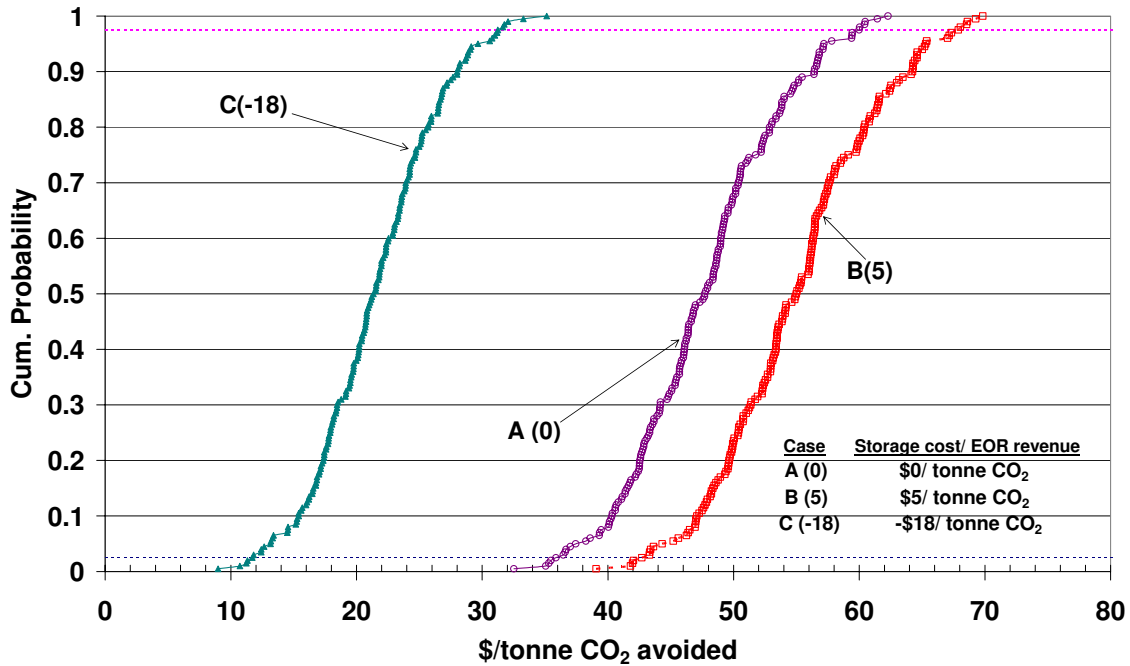
Figure 5.5. Effect of considering three different options for CO_2 storage/disposal, assuming either no cost (A(0)), storage cost of $5/tonne CO_2 (B(5)), or revenue of $18/ tonne CO_2 from EOR (C(-18)), on the distribution of the CO_2 avoidance cost (with uncertainties in amine system parameters).
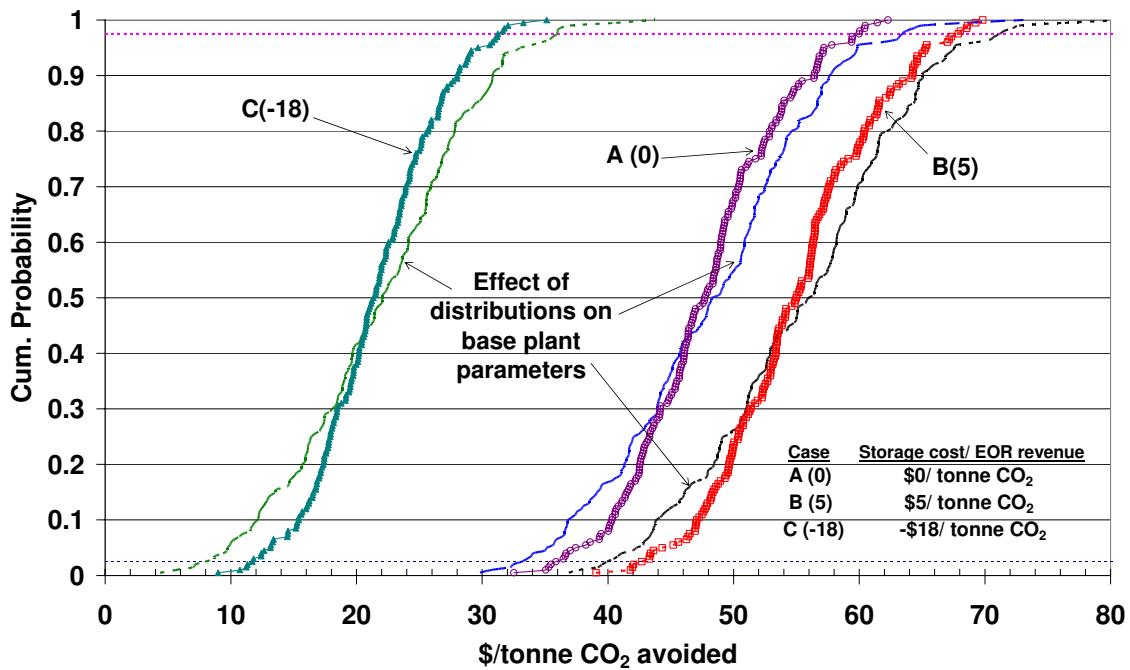
Figure 5.6. Effect of considering uncertainty in base plant parameters (viz. base plant gross cycle heat rate, plant capacity factor, fixed charge factor and coal price) on the distribution of CO_2 avoidance cost derived in figure 5.5.

81

5.2. Applications to CO_2 Retrofits

As discussed earlier, a large number of existing coal-fired power plants may be candidates for CO_2 retrofits under a sufficiently stringent climate policy. Because of multi-pollutant interactions, the cost of CO_2 mitigation will be affected by policies for other pollutants, especially SO_2. Considering that most (~ 70%) of the current coal-based capacity in the U.S. does not have SO_2 scrubbers, several cases were modeled to analyze the impacts of adding post-combustion CO_2 capture systems to existing coal plants (see Table 5.3).

These cases are based on the analysis of the existing US coal plants database that includes details about 2294 units in as many as 85 fields including plant location, heat rate, plant capacity factor, cola characteristics, and environmental controls (NETL 2002). Two sets of power plants have been identified, *viz.* those without any sulfur controls and those with wet scrubbers (FGD systems) for SO_2 emission control. Some of the key distinguishing features of these sets have been listed in Table 5.4.

Table 5.3. Scenarios for retrofit studies of existing coal-fired power plants

Case	Base plant (PC+ESP)	SO$_2$ Capture System (FGD)	CO$_2$ Capture System (MEA)	Auxiliary NG Boiler	Sec. Steam Turbine
Reference plant without any sulfur control (R)					
R	✔	-	-	-	-
A1	✔	-	New	-	-
A2	✔	-	New	New	-
A3	✔	-	New	New	New
B1	✔	New, 99%	New	-	-
B2	✔	New, 99%	New	New	-
B3	✔	New, 99%	New	New	New
Reference plant with FGD system (Rf)					
Rf	✔	✔	-	-	-
C1	✔	✔	New	-	-
C2	✔	✔	New	New	-
C3	✔	✔	New	New	New
D1	✔	Upgrade, 99%	New	-	-
D2	✔	Upgrade, 99%	New	New	-
D3	✔	Upgrade, 99%	New	New	New

Table 5.4 Typical key features of existing coal-fired power plants in U.S.

Characteristic	Plants without any sulfur capture	Plants with FGD systems
No. of units	946	109
Total nameplate capacity	232 GW	51 GW
Plant size (gross)	540 MW	441 MW
Plant capacity factor	73%	76%
Net plant heat rate	10,150 Btu/kWh	10,530 Btu/kWh
Sulfur content in coal	~ 0.7% w/w	~ 1.1% w/w

Table 5.3 lists the various cases modeled using IECM-CS. The first set uses a typical plant without any sulfur control as the reference plant (R). It complies with federal standards for plants constructed before July 1978. Here, one needs to install a sulfur scrubber prior to the amine system during CO_2 retrofitting as per the process requirements for an amine system (B1-B3). A case where only an amine-system is added to the reference plant (A1-A3) is without any practical relevance and is included only for the sake of completeness of this analysis, and it reinstates the importance of SO_2 control as a pre-requisite for CO_2 control using amine system.

The second set of cases uses a typical plant already equipped with an FGD system that meets federal New Source Performance Standards (NSPS) (which in this case is 73% SO_2 removal) as reference (Rf). Here, the SO_2 removal efficiency of these systems are just enough to meet the existing emission standards (CFR 1999), however they do emit a substantial amount of SO_2 (about 390 ppm) that maybe undesirable for amine-based CO_2 capture system. This plant has the option of upgrading the existing SO_2 scrubber in addition to installing an MEA system. It would be preferable to upgrade the existing FGD system to 99% removal efficiency. Hence, CO_2 retrofit options here include 2 alternatives, *viz.* adding only amine system (C1-C3) and adding amine system with

upgraded FGD system (D1-D3). The reference plants (R & Rf) for these two sets of CO_2 capture plant cases are based on the characteristics presented in Table 5.4.

For each CO_2 retrofit case, there are three potential configurations in terms of the mode of supplying energy required for the amine based CO_2 capture system.

1) Base plant derating: Regeneration steam is extracted from the existing steam cycle of the base plant. Also the electrical energy for pumps, fans and compressors is obtained from the base plant. Hence, the net output of this plant is substantially lower than that of the reference plant.

2) Auxiliary NG boiler: Here, the regeneration steam is provided by adding a new NG-fired boiler so as to avoid steam extraction and subsequent derating of the existing base plant. However, the electrical energy requirement of CO_2 capture system is fulfilled through the base plant, and hence the overall output of the capture plant is lower than reference case. It maybe noted that adding a new NG-fired boiler to produce only low-pressure steam for sorbent regeneration is not a very practical approach, and is included here only for the sake of completeness of this analysis.

3) Auxiliary NG boiler plus secondary steam turbine: In this case, an auxiliary NG-fired boiler is installed to generate high pressure steam that can be passed through a turbine to generate some electricity. The exhaust from the steam turbine is then used to regenerate the sorbent. The electricity generated by this unit is often more than the electrical energy requirement of the CO_2 capture unit, and hence the overall power generation of the capture plant may exceed that of the reference plant.

In contrast to the new plant analysis presented earlier, the retrofit scenarios assume, as a bounding case, that all existing capital equipment has been fully amortized. The cost of electricity is then determined only by plant O&M costs, plus any new capital expenditures for CO_2 control. The latter includes the costs of any new sulfur removal systems that are installed to minimize the cost of CO_2 avoidance. We may also credit the

84

CO_2 unit for the market value of additional SO_2 allowances that are generated and traded under the national acid rain control program. The remaining plant life is assumed to be at least 15 years. The base capital cost of the CO_2 capture unit is the same as that for a greenfield site, but we then consider an additional retrofit cost premium to account for site-specific retrofit difficulties. We also assume higher plant heat rates and energy penalties in providing steam to the MEA system.

5.2.1. *Results for plants without any sulfur control*

The results from the case study of CO_2 retrofitting of existing PC plants without any sulfur control have been summarized in Table 5.5. The coal used in this case study was Appalachian low-S bituminous coal with 0.64% sulfur content and heating value of 13,080 Btu/lb. The delivered price of this coal was assumed to be $37.1/tonne which is about $0.96/ MMBtu.

As noted earlier (Rao and Rubin 2002), we find that addition of FGD system along with MEA-based CO_2 capture system reduces the overall cost. Cost of electricity and that of CO_2 avoidance are substantially lower (almost 50% or less) in cases B1-B3 (in which FGD system was also installed) as compared to cases A1-A3 (in which only MEA-based CO_2 capture system was retrofitted). In cases A1 and B1 where steam and electricity required for CO_2 capture system is extracted from the base plant, the net plant output goes down to about 55-60% of the original plant output. This may have serious implications in terms of capacity planning and dispatch. On the other hand, option B3, which seems to be the most economic way (based on COE) to retrofit an existing PC plant with CO_2 capture system, leads to additional power generation and is expected to have a matching demand. Although the CO_2 capture system is designed to capture 90% of the CO_2 emissions generated by the reference plant, the options using auxiliary NG-fired boilers end up avoiding only about 60-65% of the emissions. In case of a very stringent climate policy, even the CO_2 emissions from the newly added NG-fired boilers may have to be captured.

Again, it must be noted that these results are sensitive to the assumptions made about the depreciation of the reference plant, retrofit factors in capital cost estimation, and the price

85

of natural gas. Table 5.6 shows the effect of some of these factors on the costs in cases B1 and B3.

Table 5.5. Case study results for plants with FGD systems

	R	A1	A2	A3	B1	B2	B3
Gross capacity (MW)	540	540	540	540	540	540	540
Net power generation (MW)	507.3	320.2	442.2	580.7	309.6	427.5	561.4
Net cycle heat rate (Btu/kWh)	10,150	16,010	16,810	13,790	16,560	17,210	14,090
Coal consumption (tonne/hr)	178.5	177.7	177.7	177.7	177.7	177.7	177.7
NG consumption (tonne/hr)	-	-	45.96	57.44	-	44.43	55.54
CO_2 emission (tonne/ hr)	469.3	46.7	170.4	201.3	46.9	166.5	196.3
NO_x emission (tonne/ hr)	1.34	1.32	1.58	1.65	1.32	1.57	1.64
SO_x emission (kg/ hr)	2214	11	11	11	0.13	0.13	0.13
CO_2 emission (gCO_2/ kWh)	925.1	145.9	385.3	346.7	151	389.4	349.7
NO_x emission (gNO_x/ kWh)	2.64	4.11	3.58	2.83	4.25	3.68	2.91
SO_x emission (gNO_x/ kWh)	4.36	0.03	0.025	0.019	0.0004	0.0003	0.0002
FGD waste (tonne/hr)	-	-	-	-	7.1	7.1	7.1
Spent MEA sorbent (tonne/hr)	-	17.1	17.1	17.1	1.4	1.4	1.4
CO_2 product (tonne/ hr)	-	420.6	420.6	420.6	421.9	421.9	421.9
CO_2 emissions captured (%)	-	90%	64%	57%	90%	65%	58%
CO_2 emissions avoided (%)	-	84%	58%	63%	84%	58%	62%
TCR (M$)	0*	235.5	270.8	365.6	239.2	273.4	367.8
TCR ($/ kW)	0*	735.3	612.5	629.5	772.7	639.4	655.2
COE ($/ MWh)	18.28	107.4	99.07	83.59	70.33	72.11	63.19
$/ tonne CO_2 avoided	-	114.4	149.7	112.9	67.2	100.5	78.1

*The existing plant is assumed to be completely depreciated.

In case B1, the cost of electricity and cost of avoidance both increase with either increase in reference plant capital cost (assuming less than 100% depreciation) or an increase in retrofitting capital cost requirement (assuming retrofit factor >1). The CO_2 avoidance cost may increase as high as 18% relative to the base case B1 discussed earlier depending upon the particular assumptions presented here in Table 5.6. However, these estimates

are not affected by natural gas price change, since we are not adding any auxiliary NG boiler in this case.

Table 5.6 Case study results for plants without FGD systems: sensitivity analysis

Case	R	B1		B3	
	COE	COE	$/tonne	COE	$/tonne
	($/MWh)	($/MWh)	CO_2 av.	($/MWh)	CO_2 av.
Nominal case (100% depreciation, NG price = $4/mcf, rf=1)	18.3	70.33	67.2	63.19	78.0
Nominal case + SO_2 control credits	18.3	69.26	65.8	62.60	77.0
80% depreciation of reference plant	23.3	78.46	71.3	67.69	77.1
50% depreciation of reference plant	30.9	90.62	77.1	74.46	75.7
Retrofit factor (rf) = 1.25	18.3	75.58	74.0	67.58	85.6
Retrofit factor (rf) = 1.5	18.3	79.47	79.0	71.2	91.9
NG price = $2.5/mcf	18.3	70.33	67.2	56.28	66.0
NG price = $5.5/mcf	18.3	70.33	67.2	70.09	90.0
80% deprec., rf=1.25, NG =$2.5/mcf	23.3	83.71	78.0	65.19	72.8
80% deprec., rf=1.25, NG =$4/mcf	23.3	83.71	78.0	72.09	84.8
80% deprec., rf=1.25, NG =$5.5/mcf	23.3	83.71	78.0	78.99	96.8

In case B3, although the cost of electricity is lower than case B1, the CO_2 avoidance cost is higher owing to the additional CO_2 emissions coming from the auxiliary NG boiler. These costs are highly sensitive to natural gas prices. Changing the natural gas price from a low $2.5/mscf to $5.5/mscf leads to 25% increase in COE and 36% increase in the CO_2 avoidance cost. Only at the low natural gas price assumption is option B3 found to be cheaper than option B1 in terms of the CO_2 avoidance cost. The cost of electricity and cost of avoidance both increase with an increase in retrofitting capital cost requirement when we assume retrofit factor greater than 1. However, assumption about higher capital cost of the reference plant (assuming less than 100% depreciation) leads to increase in cost of electricity but a nominal decrease in the cost of CO_2 avoidance. At 50% depreciation level, the CO_2 avoidance cost was estimated to be about 3% lower than the base case B3 (100% depreciation). The CO_2 avoidance cost may increase as high as 44%

relative to the base case B1 discussed earlier depending upon the particular assumptions presented in Table 5.6.

5.2.2. Results for plants with FGD systems

The results from the case study of CO_2 retrofitting of existing PC plants with FGD sulfur control have been summarized in Table 5.7. The coal used in this case study was medium-S bituminous with 1.4% sulfur content and heating value of 12,180 Btu/lb. The delivered price of this coal was assumed to be $30.6/ tonne which is about $0.78/ MMBtu.

Table 5.7. Case study results for plants with FGD systems

	R	C1	C2	C3	D1	D2	D3
Gross capacity (MW)	441	441	441	441	441	441	441
Net power generation (MW)	405.3	244.5	351.7	473.6	245.7	346.0	459.9
Net cycle heat rate (Btu/kWh)	10370	17130	17670	14190	17040	17580	14260
Coal consumption (tonne/hr)	156.6	155.9	155.9	155.9	155.9		155.9
NG consumption (tonne/hr)	-	-	40.43	50.54	-	37.79	47.25
CO_2 emission (tonne/ hr)	400.3	39.86	148.7	175.9	40.0	141.7	167.1
NO_x emission (tonne/ hr)	1.175	1.155	1.386	1.444	1.155	1.372	1.425
SO_x emission (kg/ hr)	1960	9.752	9.752	9.752	0.24	0.24	0.24
CO_2 emission (gCO_2/ kWh)	987.8	163.0	422.8	371.4	162.8	409.6	363.4
NO_x emission (gNO_x/ kWh)	2.9	4.7	3.94	3.05	4.7	3.96	3.1
SO_x emission (gNO_x/ kWh)	4.84	0.04	0.03	0.02	0.001	0.0007	0.0005
FGD waste (tonne/hr)	9.8	9.8	9.8	9.8	13.18	13.18	13.18
Spent MEA sorbent (tonne/hr)	-	14.54	14.54	14.54	1.364	1.364	1.364
CO_2 product (tonne/ hr)	-	358.8	358.8	358.8	360	360	360
CO_2 emissions captured (%)	--	90%	63%	56%	90%	65%	58%
CO_2 emissions avoided (%)	--	83%	57%	62%	84%	59%	63%
TCR (M$)	0*	181.3	213.1	296.5	153.1	182.7	263.3
TCR ($/ kW)	0*	741.7	605.9	626.1	623.0	528.0	527.4
COE ($/ MWh)	20.04	118.3	105.4	86.87	69.19	71.14	61.94
$/ tonne CO_2 avoided	-	119.1	151.1	108.4	59.6	88.4	67.1

*The existing plant is assumed to be completely depreciated.

In cases C1 and D1 where steam and electricity required for CO_2 capture system is extracted from the base plant, the net plant output goes down to about 60% of the original plant output. On the other hand, options C3 and D3 lead to about 15% increase in power generation capacity. Again we find that upgrading the FGD system (to 99% SO_2 removal efficiency) along with the addition of MEA-based CO_2 capture system does help in reducing the overall cost. Cost of electricity and that of CO_2 avoidance are substantially lower (about 30-40% and 40-50% lower, respectively) in cases D1-D3 (in which FGD system was upgraded) as compared to cases C1-C3 (in which only MEA-based CO_2 capture system was retrofitted).

Again, it must be noted that these results are sensitive to the assumptions made about the depreciation of the reference plant, retrofit factors in capital cost estimation, and the price of natural gas. Table 5.8 shows the effect of some of these factors on the costs in cases D1 and D3.

Table 5.8. Case study results for plants with FGD systems: sensitivity analysis

Case	R	D1		D3	
	COE ($/MWh)	COE ($/MWh)	$/tonne CO_2 av.	COE ($/MWh)	$/tonne CO_2 av.
Nominal case (100% depreciation, NG price = $4/mcf, rf=1)	20.04	69.19	63.5	61.94	72.8
Nominal case + SO_2 control credits	20.00	68.13	62.1	61.36	71.8
80% depreciation of reference plant	25.88	78.74	68.3	66.97	71.4
50% depreciation of reference plant	34.64	93.02	75.4	74.7	69.6
Retrofit factor (rf) = 1.25	20.04	73.04	68.5	65.35	78.7
Retrofit factor (rf) = 1.5	20.04	76.89	73.4	68.88	84.9
NG price = $2.5/mcf	20.04	69.19	63.5	54.77	60.4
NG price = $5.5/mcf	20.04	69.19	63.5	69.11	85.3
80% deprec., rf=1.25, NG =$2.5/mcf	25.88	82.59	73.3	63.33	65.1
80% deprec., rf=1.25, NG =$4/mcf	25.88	82.59	73.3	70.5	77.5
80% deprec., rf=1.25, NG =$5.5/mcf	25.88	82.59	73.3	77.67	90.0

We observe similar trends in cases C1-C3 Vs D1-D3, as we had noted earlier in cases A1-A3 Vs B1-B3. In general, derating seems to be the cheaper option than adding an auxiliary NG boiler, on the basis of CO2 avoidance cost. Adding auxiliary NG boiler may be cheaper if the reference plant is not completely depreciated or if NG is available at low price (below $2.5-3/mscf).

5.2.3. *Comparison with other technological options for CO_2 retrofitting*

It is also of interest to compare the results obtained for the amine-based CO_2 retrofit cases to other possible technological options available to the existing older pulverized coal power plants. In the recent times, IGCC (Integrated Gasification Combined Cycle) has been developed as an alternative technology for coal-based power generation. IGCC re-powering of old, less efficient and more polluting pulverized coal plants might be an attractive option that can also facilitate CO_2 capture. In a recent case study that we conducted to compare this option, we found that although IGCC re-powering with CO_2 capture requires a lot of new capital investment, it might be cheaper in terms of final cost of electricity and CO_2 mitigation cost (Chen, Rao et al. 2003). Some of the key assumptions made in this study were as follows:

1) Reference plants are fully amortized and equipped with FGD systems
2) Performance parameters for the reference base plant are based on DOE/NETL's database(NETL 2002)
3) Gross capacity: 270MW
4) Gross plant heat rate: 10,734 Btu/kWh
5) CO_2 emission rate: 1004 gCO_2/ kW
6) Plant capacity factor: 76%
7) CO_2 capture efficiency: 90%
8) Financial parameters: Plant life = 20 years, Interest rate = 9%
9) Amine-based retrofit: Adding 30% MEA-based CO_2 capture system
10) Re-powering: Texaco, O_2-blown, quench, GE MS7001F, Selexol-based CO_2 capture
11) Identical assumptions have been made about CO_2 product compression (2000 psig), transport and storage/disposal costs etc.

In case of amine-based CO_2 retrofits, two options were considered, *viz.* base plant derating (AR1) and adding an auxiliary NG-fired boiler with secondary steam turbine

90

(AR2). The case of IGCC re-powering was analyzed using an IGCC performance and cost model developed within the IECM modeling framework (CEES 2003). Again, two options have been considered, *viz.* Heat recovery re-powering (IR1, using existing steam turbine and land) and site re-powering (IR2, completely new IGCC on the existing land). The key results have been summarized in Table 5.9.

It may be noted that cost of electricity (and hence that of CO_2 mitigation) is a strong function of the natural gas price in case of amine-based CO_2 capture using auxiliary NG boiler and a turbine. Only at very low natural gas price can this configuration (AR2) compete with IGCC re-powering options (IR1 & IR2) in terms of the final cost of electricity. However, the later has the lowest CO_2 avoidance cost. This observation has also been supported by the probabilistic analysis we conducted for these options.

Table 5.9. Comparison of amine-based CO_2 capture and IGCC re-powering options for an existing pulverized coal plant

Parameter	Reference plant	Amine-based retrofits		IGCC Re-powering	
		AR1	AR2	IR1	IR2
Gross capacity (MW)	270				
Net capacity (MW)	248	140	282	590	599
CO_2 emission (gCO_2/ kWh)	1004	177	369	99	98
TCR ($/ kW)	0*	837	650	1493	1698
COE ($/ MWh)					
@ $4.7/mcf NG	21	83	70	62	67
@ $2.4/mcf NG			59		
CO_2 avoidance cost ($/ tonne CO_2 avoided)					
@ $4.7/mcf NG	-	75	77	46	51
@ $2.4/mcf NG			61		

*The existing plant is assumed to be completely depreciated.

The cost results (COE and cost of CO_2 avoidance) of the probabilistic analysis have been presented in Figure 5.7 and Figure 5.8. Under the set of assumptions stated before, amine-retrofit with internal derating of the base plant is clearly the most expensive option. The amine-retrofit option with auxiliary NG-fired boiler and a secondary steam

91

turbine may be able to compete with the more efficient IGCC repowering options, only on the basis of cost of electricity. However, since the auxiliary NG boiler generates secondary CO_2 emissions, this option is less effective in terms of avoiding CO_2 emissions. So, the IGCC repowering options, which are also more energy efficient, are cheaper than the amine-retrofits, in terms of the CO_2 avoidance costs. Even though the amine-retrofit with internal derating is much more expensive in terms of the cost of electricity generated than that with auxiliary NG boiler, the probability distribution for the CO_2 avoidance cost for these options indicate that there is a small probability that the derating option might be cheaper than adding auxiliary NG boiler, based on the assumptions of this analysis.

5.3. Discussion of Results

5.3.1. Greenfield vs. retrofit applications

Case studies of new and retrofit application of amine-based CO_2 capture system at power plants have been presented in sections 5.1 and 5.2. All these cases have been summarized in Figure 5.9. Here COE for each case has been plotted against its CO_2 emission rate (CO_2/ kWh). It may be recalled that the slope of the line joining a capture plant with the respective reference plant gives the CO_2 avoidance cost for that plant. The new reference and capture plant (discussed earlier in section 5.1.1 and shown in Figure 5.2) has also been included for comparison.

It may be noted that a much higher energy penalty is expected in case of retrofit applications. This makes the cost of avoidance in these cases higher than that in the case of an efficient new plant with CO_2 capture. However, since the older plants are assumed to be completely paid of in terms of capital requirement, the retrofit applications are much cheaper than their greenfield counterparts. In the retrofit case, the cost of electricity is essentially based on the operating costs of the base plant and costs associated with the installation and operation of the CO_2 capture equipment. Hence, in terms of cost of electricity produced, the retrofit applications are much cheaper than the new pulverized coal plants with CO_2 capture.
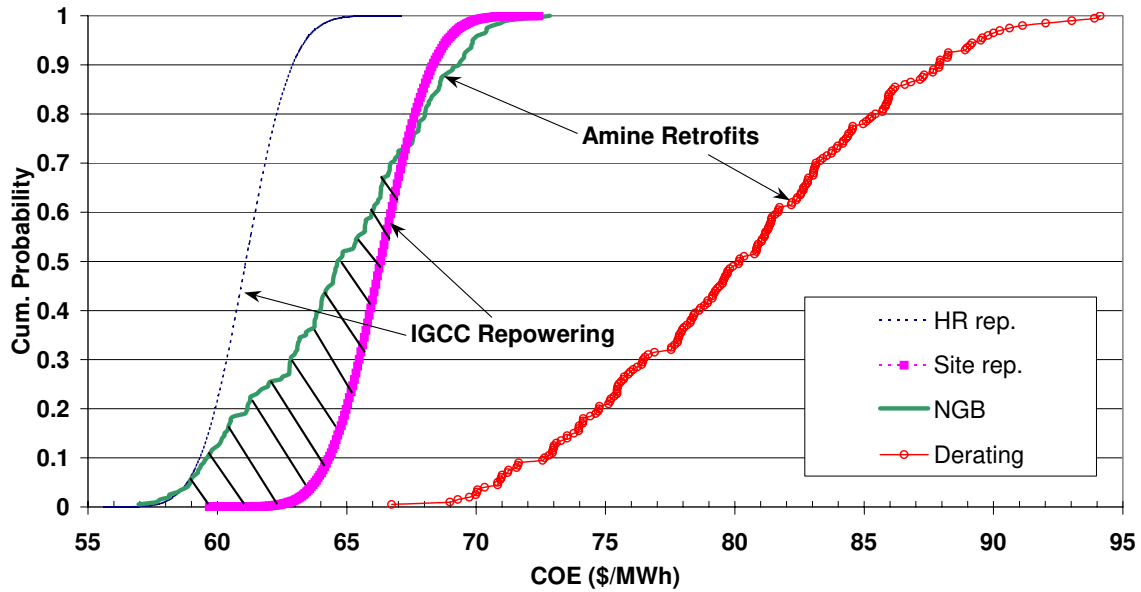
Figure 5.7. Comparison of CO_2 retrofitting options: cost of electricity
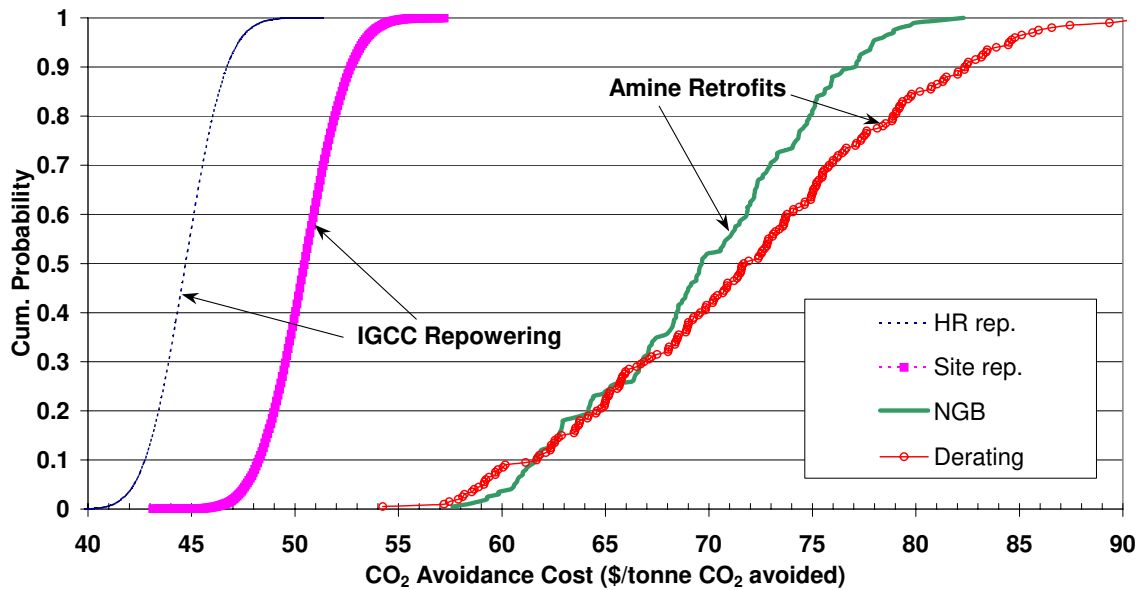
Figure 5.8. Comparison of CO_2 retrofitting options: cost of CO_2 avoidance

Given a sufficiently stringent CO_2 reduction requirement, will utilities invest in new plants with CO_2 capture, or will they prefer to spend less for retrofit applications, although it maybe a less effective measure to control CO_2 emissions? Will the

government provide any incentives (subsidies, tax rebates *etc.*) to any of the power generation options that help in reducing CO_2 intensity of electricity sector? Answers to such questions will have a major impact on how the power industry reacts to any future regulation of CO_2 emissions and technological choices available.

Similarly, there is another set of issues related to electricity demand and supply management, dispatch dynamics, availability and price of natural gas, evolution of a domestic and/or global market for CO_2 trade, access to other (cheaper?) sources of CO_2 control credits, role of renewable energy sources (especially wind, biomass *etc.*) in the total energy mix, and other factors that will play a major role in CO_2 mitigation strategies. These factors are beyond the scope of this study, and analysis of such questions requires higher level modeling tools, such as discussed elsewhere (Johnson and Keith 2001; Johnson 2002).
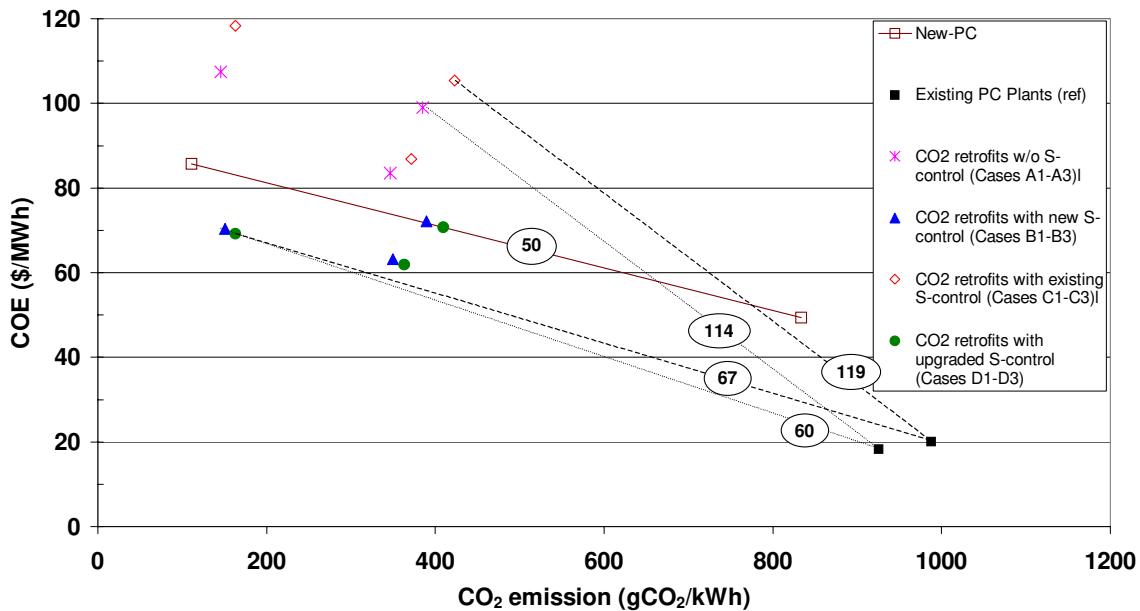
Figure 5.9. Estimation of CO_2 avoidance cost for pulverized coal plants: greenfield vs. retrofit application

5.3.2. Base plant derating vs. Auxiliary NG-fired boiler options

As we have seen in the case studies of the existing coal plants (sections 5.2.1, 5.2.2), the CO_2 capture system configurations with auxiliary NG-fired boiler and steam turbine (B3

& D3) have the lowest COEs (for natural gas price < \$5.5/mscf, see Figure 5.10) than the other CO_2-retrofitting alternatives in their respective categories. Another advantage of these options is that they increase the net power generation capacity of the plant. So, they are likely to be the preferred applications of this technology. Assuming availability of enough space for this retrofit and that of natural gas fuel, this option may be looked upon as a convenient way to boost the generation capacity of existing older power plants.
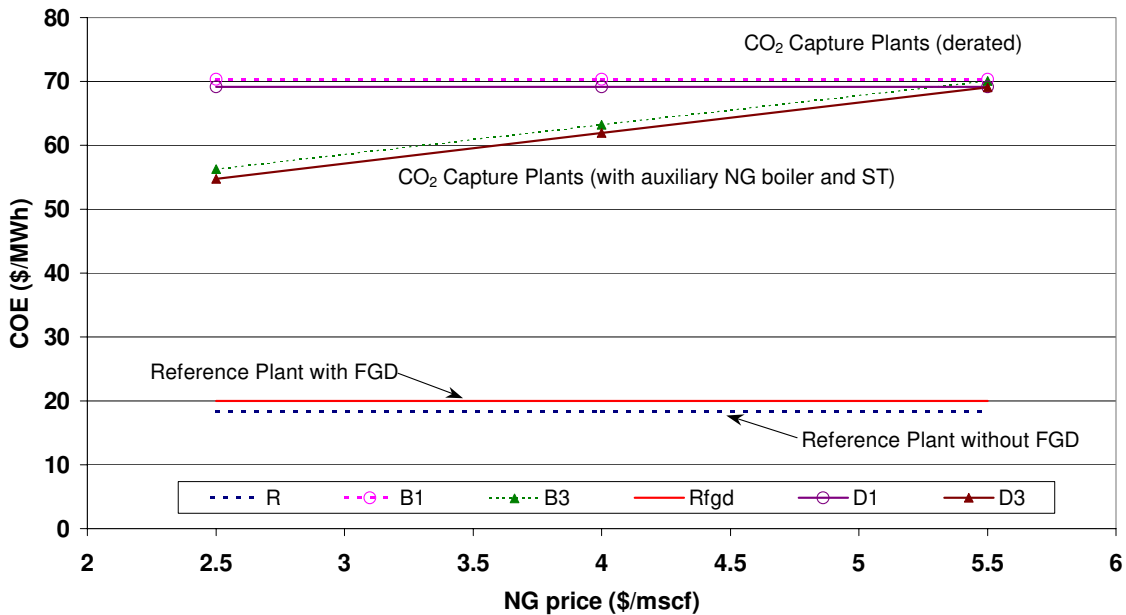
Figure 5.10. Effect of natural gas price on COE in CO_2 retrofit applications

However, their economics is very sensitive to the natural gas price. At the nominal gas price assumption of \$4/mscf, their cost of CO_2 avoidance is higher than those estimated for the respective options (B1 & D1) that derate the base plant; and they can break even only at low gas prices (less than \$2.5-3/mscf), as seen in

Figure 5.11. Also, assuming that CO_2 emissions from the auxiliary boiler are not controlled, the overall CO_2 emissions avoided in these cases is only about 60-65%. Whether this level of CO_2 mitigation is acceptable, depends upon the stringency of the CO_2 mitigation regulation and other market mechanisms. If new combustion sources are regulated for their emissions of criteria pollutants with concerns about the local pollution,

then one may also have to account for NO_x-control devices in this option (not accounted for in the present analysis).
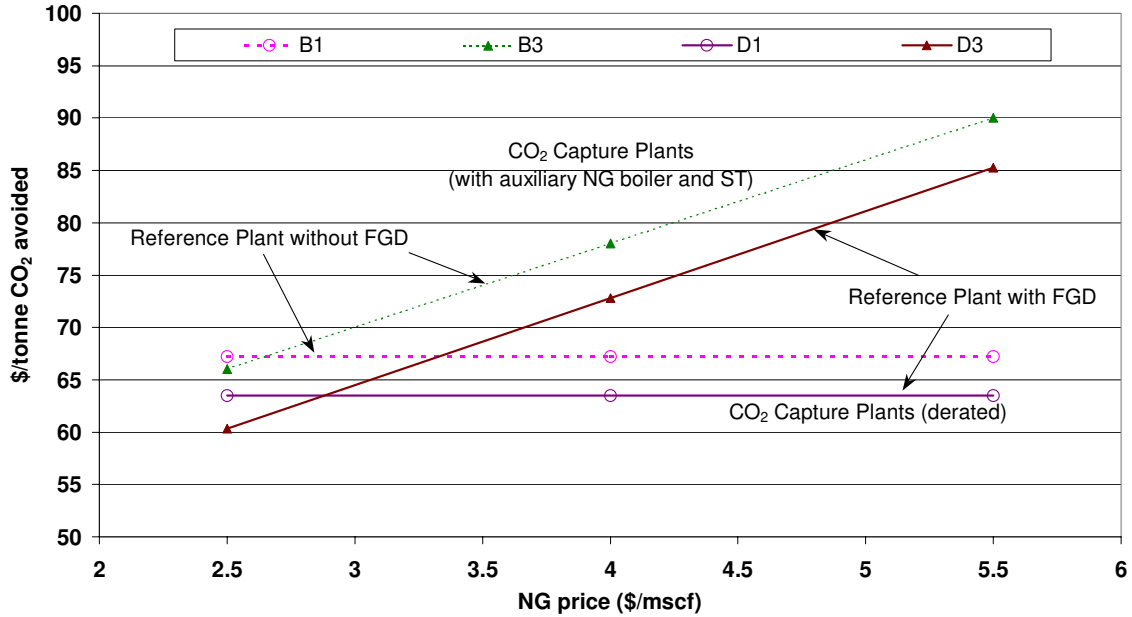
Figure 5.11. Effect of natural gas price on CO_2 avoidance cost in CO_2 retrofit applications

On the other hand, the CO_2 capture options (B1, D1) that derive their energy requirement from the base plant itself, offer higher levels of CO_2 avoidance (> 80%) and are independent of NG price fluctuations. But these options put a large energy penalty on the reference plant and the net power generation capacity of the plant may decrease by as much as 40%, depending on the site specific design of existing coal-fired units. This may have serious implications in terms of power supply capacity planning and supply management.

5.3.3. CO_2 control from coal-fired vs NG-fired power plants

The IECM-CS also has a performance and cost model of an NGCC system. Table 5. compares the results from the simulation of a new NGCC system with and without CO_2 capture with those from the case study of a coal plant presented earlier in section 5.1.

It may be noted that the capital cost of NGCC plant is quite low ($521/kW) and even after adding CO_2 capture system, it is cheaper than the reference coal plant. This lower

cost may be attributed to the higher efficiency of combined cycle technology and also to the use of cleaner fuel that cuts down the cost of environmental controls, as compared to a coal plant. NGCC plant with CO_2 capture has substantially lower CO_2 emissions and produces a smaller stream of concentrated CO_2 for storage/ disposal. In comparison with PC plant with CO_2 capture, it has much lesser (or no) environmental discharges. Although the COE from an NGCC plant (even with CO_2 capture) is substantially lower than that from a coal plant with CO_2 capture, the cost of CO_2 avoidance is much higher.

Table 5.10. Comparison of CO_2 control from a new NGCC and a new PC plant

	NGCC		PC	
	Ref.	**Capture**	**Ref.**	**Capture**
Gross capacity (MW)	518	518	500	500
Capacity factor (%)	75	75	75	75
Fuel cost ($/GJ)	3.5	3.5	1.2	1.2
Net power generation (MW)	518	445	458	341
Net cycle heat rate (Btu/kWh)	6,383	7,435	8,657	11,560
Coal consumption (tonne/hr)	-	-	215.5	214.6
NG consumption (tonne/hr)	65.9	65.9	-	-
CO_2 emission (tonne/ hr)	180.8	18.1	381.3	38.0
CO_2 emission (gCO_2/ kWh)	349.0	40.7	833.3	111.3
FGD waste (tonne/hr)	-	-	4.2	4.3
Spent MEA sorbent (tonne/hr)	-	0.39	-	1.0
CO_2 product (tonne/ hr)	-	163	-	342
CO_2 emissions captured (%)	-	90	-	90
CO_2 emissions avoided (%)	-	88	-	87
TCR (M$)	270	383	616	760
TCR ($/ kW)	521	861	1345	2228
TRR (M$/yr)	126	179	149	202
COE ($/ MWh)	36.7	61.3	49.4	89.9
$/ tonne CO_2 avoided	-	79.2	-	56.0

Figure 5.12 plots the COE and CO_2 emission rates for NGCC plant with and without CO_2 capture for various assumptions about natural gas price and plant capacity factor. As

described earlier, the slope of the line joining a reference plant and a capture plant on this plot gives the CO_2 avoidance cost. It appears that even at low gas price ($2.5/mscf) and high capacity factor (85%), cost of CO_2 avoidance from an NGCC plant is about 30% higher than that for a PC plant of comparable net power output. However, the COE at such low gas price is even lower than the COE estimated for a PC without CO_2 control. So, even at low gas prices, controlling CO_2 from NGCC plants makes sense only if COE is the major concern rather than the cost of CO_2 mitigation.
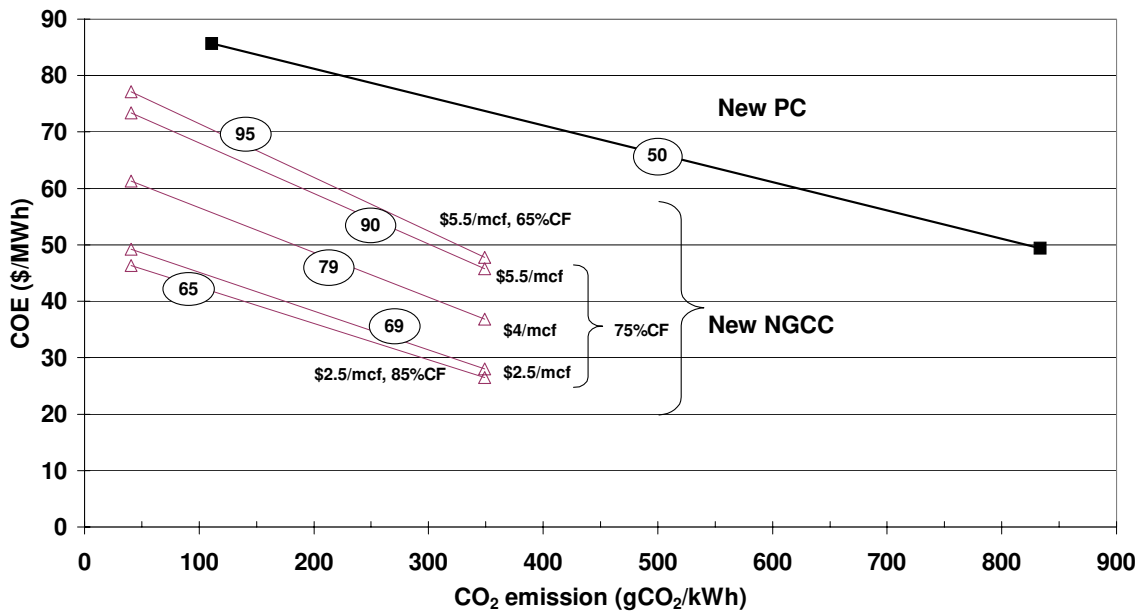
Figure 5.12. Comparison of the cost of CO_2 control from a new NGCC and a new PC plant (the numbers in the circles represent the cost of CO_2 avoidance)

Natural gas combined cycle (NGCC) is an efficient, cleaner and less capital-intensive technology. This attractive power generation technology is growing in capacity very fast and is expected to grow further in the coming decades (EIA 2000). An NGCC plant produces only about 50% CO_2 per unit of electricity as compared to a conventional coal plant. It might be desirable to capture these emissions under a stringent climate policy, and especially if it is economical (which is not the case, as seen above). Flue gas from an NGCC plant is much cleaner (due to the cleaner fuel) as compared to the flue gas from a coal plant and hence it inflicts less operational difficulties, *viz.* corrosion and disposal of spent sorbent.   Today majority of the CO_2 capture plants using amine systems are

installed to scrub CO_2 from gas-fired power plants and hence there is more experience with this application. However, the flue gas from an NGCC plant is less concentrated in CO_2 and it takes more energy to regenerate the sorbent per unit of CO_2 captured. This partly explains why the cost of CO_2 avoidance from these plants was found to be higher than that from a PC plant. Also, the economics of these plants is highly sensitive to the price of natural gas. Often these plants are operated at lower capacity factors as well, which may actually lead to higher avoidance costs. So, based on this analysis, it seems that capture of CO_2 from NGCC plants, although technically feasible and favorable, is likely to be more expensive as compared to that from coal plants.

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6. R&D MANAGEMENT: POTENTIAL IMPROVEMENTS AND COST REDUCTION

Technological innovations in CO_2 capture and storage technologies are being pursued worldwide under a variety of private and government-sponsored R&D programs. While much of this R&D is directed at novel concepts and potential breakthrough technologies, there are also substantial efforts to improve CO_2 capture technologies already in use. As discussed before, amine-based CO_2 capture systems have been proposed as one of the solutions for existing as well as new conventional coal-fired power plants. This technology is commercially available today, though it is highly energy intensive and costly, as found in this study and elsewhere (Smelser, Stock et al. 1991; Hendriks 1994; Leci 1996; Simbeck 1998; Desideri and Paolucci 1999; Laboratories 1999; Mariz and al. 1999; Jeremy and Herzog 2000; Parsons Infrastructure & Technology Group 2002; Rao and Rubin 2002).

Hence, there is a major effort being made to improve amine systems for post-combustion CO_2 capture application at power plants. How far can these systems be improved in near future? Technical experts in this field can have a sense about this. As part of this research we sought to quantify the informed judgments of experts to derive uncertainty distributions for various key parameters that will affect the performance and cost of these systems in the future. This is accomplished following the "expert elicitation" protocol widely discussed in the literature and a generally accepted norm to estimate uncertainty when data is lacking (Morgan and Henrion 1990; Frey 1991; Morgan and Keith 1995).

Here we have made an effort to understand what the experts in this field think about future amine systems. Further, we have used the experts' judgments as input to our model (IECM-CS) to estimate the possible cost reductions in future systems.

6.1 Methodology

The following procedure was used to estimate the probability distributions for key performance parameters of future amine systems.

6.1.1. Identification of the parameters

As described before, a model (IECM-CS) has been developed to simulate the performance and cost of post-combustion CO_2 capture using amine-based systems at fossil fuel power plants. Analysis of the various parameters helped us identify the key parameters that have a substantial influence on the performance and cost of these systems. Consideration also was given to the clarity of parameter definition, frequency of mention in the literature, and total number of questions to be asked of experts. On this basis, the following set of parameters related to the amine-based CO_2 capture system were selected:

- Sorbent concentration (wt %)
- Sorbent regeneration heat requirement (kJ/ kg CO_2 captured)
- Sorbent loss (kg/ tonne CO_2 captured)
- Sorbent cost (US$/ tonne sorbent)

In addition to these, the following parameters were also included in the questionnaire:

- CO_2 compressor efficiency (%)
- Net plant efficiency of the power plant (with and without CO_2 capture)
- Total capital requirement (TCR, $/kW) for the power plant (with and without CO_2 capture)
- Cost of electricity (COE, cents/ kWh) (with and without CO_2 capture)

6.1.2. Identifying the experts

Professionals working in the area of amine-based CO_2 capture were identified through their authorship of technical papers and participation in International Conferences. Experts were contacted via email and requested to participate in this study. The initial response to this appeal was quite encouraging, and within the time constraints available, final responses were obtained from about a dozen experts. The experts' participation in this study was completely voluntary. There was balanced representation from industry, academia, independent research laboratories and private consultancies. Experts from all over the world participated in this study. The names of these experts have been listed in the acknowledgement section.
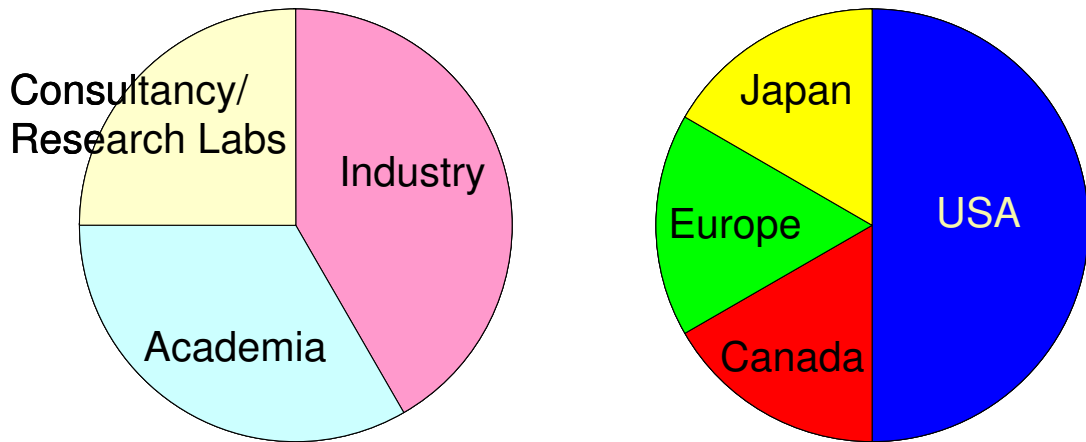
Figure 6.1. Experts' affiliations (N=12)

The initial email sent to the potential experts described the purpose of this exercise. Most of the subsequent communication was carried out via email and was supplemented by personal/ telephonic interviews.

6.1.3. The questionnaire

Once the key process parameters were identified, a detailed questionnaire was designed (see *Appendix E*). It included a brief description of the current amine-based CO_2 capture systems. This was helpful to set the stage and to ensure consistent use of terminology. Next, it included a checklist of parameters of a current amine-based system. Experts were asked to comment ("OK" or "not OK") on the typical values and ranges of these parameters and to provide replacements if the original numbers were "not OK". This part of the questionnaire helped to know the individual perceptions of the experts about the current systems (baseline). Next, there were detailed questions designed to obtain the uncertainty distributions for the parameters identified above, for a particular scenario of CO_2 capture using future amine system at power plants. Assumptions about the size, location, capture efficiency of this system at a new low-sulfur coal-fired power plant for the year 2015 were outlined. The final part of the questionnaire asked the experts to prioritize various research objectives aimed at improving the performance of amine systems and reducing the cost of CO_2 capture at power plants.

6.1.4. The questionnaire responses

Responses were obtained from 12 experts over a period of 3 months. Results were processed to plot the uncertainty distributions for various parameters as indicated by all the experts. These compiled results were sent back to all the respondents. This was done in order to avoid any misinterpretation of the responses during data analysis/ units conversion *etc*. and also to give the experts another chance to review their responses. The respondents were requested to reply within a stipulated timeframe if they wanted to make any changes to their original responses. Only a couple of experts changed their responses during this step. Figure 6.6, Figure 6.7, Figure 6.8, and Figure 6.9 show the final set of distributions for the four parameters derived from the experts' responses about the parameter values for future amine-systems. Some of the data points in these distributions (either min/max values or 5-percentile/95-percentile values, whichever were not provided by an expert) have been extrapolated or interpolated on the basis of the rest of the data points provided by the expert.

6.2 Expert Judgments on Current Amine-based CO_2 Capture Systems

The initial pages of the questionnaire included a checklist of parameters of a current amine-based system. The parameters included were:

- Absorber inlet flue gas pressure

- Temperature of flue gas entering the absorber

- Lean sorbent CO_2 loading (mole CO_2/ mole sorbent)

- Heat required for sorbent regeneration (kJ/ kg CO_2)

- Allowable levels of other components in flue gas

- Maximum train size (tonnes CO_2 per day)

- Energy required for CO_2 compression to 2000 psig (kWh/ tonne CO_2)

Experts were asked to comment ("OK" or "not OK") on the typical values and ranges of these parameters that were provided (based on current IECM-CS defaults) and to provide replacements if the original numbers were "not OK". This part of the questionnaire helped to know the individual perceptions of the experts about the current systems

(baseline). The last item in this list (related to CO_2 compression) was not related to the amine-based CO_2 capture system. Nonetheless, some of the experts did respond to this parameter as well. Responses to this parameter were also obtained from a separate questionnaire (containing the same question about CO_2 compression energy) that was sent to another set of experts on post-capture processing of CO_2.

The responses for these parameters have been summarized in Figure 6.2, Figure 6.3, Figure 6.4, and Figure 6.5. The experts have been represented by letters A, B, C *etc*. that have been randomly assigned to the experts. The responses to the question on the allowable levels of other components in flue gas have been summarized below:

1) SO_2 (< 10 ppmv): Most of the experts believe that a limit of 10 ppmv SO_2 is good enough, with few exceptions. One expert suggested that it should be less than 5 ppmv. Another one suggested that the number could lie in the range 2-50 ppmv, and the limit should be decided by the economics of makeup (sorbent requirement) and (spent sorbent) disposal. Lastly, there was an expert who questioned if the suggested limit of 10 ppmv was practical as he believed that even with a caustic polishing, real plants might achieve SO_2 levels of about 20 ppmv.

2) NO_2 (< 10 ppmv): Almost all of the experts agreed with this limit, except one person who questioned if this number has any practical basis, and suggested that this number may lie in the range 5-50 ppmv.

3) O_2 (~ 3.5% v/v): Most of the experts found this limit acceptable. Two experts believed that higher O_2 levels could be allowed, one of them quoting 8% as the limit, another one claiming that the system can work even with 17% O_2, while a third expert said that these systems can work at any oxygen levels although the sorbent degradation economics may worsen at higher levels.

6.3 Expert judgments on Future Amine-based CO_2 Capture Systems

The next section of the questionnaire tried to gather technically informed probabilistic judgments about some of the key parameters of a future amine-based CO_2 capture system built around the year 2015. The basic assumptions laid out included the following:

- An amine-based plant that treats the flue gas stream from a coal-combustion source which is about 12% CO_2 and which has been pre-treated for removal of SO_x and NO_x, and removes 90% of CO_2 from the flue gas stream.

- The plant has been optimized for the lowest overall cost of CO_2 avoidance ($/ tonne CO_2 avoided), considering both capital and operating costs (including energy costs) over the life of the plant.

- R&D support for this technology continues to steadily grow at a modest rate through 2015, and includes several new large-scale applications to coal-fired power plants.

The responses to these questions have been processed to obtain the probability distributions presented in Figures 6.6-6.9. It may be seen that there is considerable diversity in these responses, especially in comparison to the distributions for the case of a current commercial amine-based CO_2 capture system. Also, not all the experts responded to all the questions.

Most of these responses are optimistic, in the sense they predict an improvement in the parameter value in future systems. For example, consider the sorbent regeneration heat requirement, the parameter that is crucial to the overall energy penalty of this system. Figure 6.10 shows the "best guess" estimates for the current and future systems, as given by each expert. The future estimates are consistently lower than the current ones, implying better performance in the future.
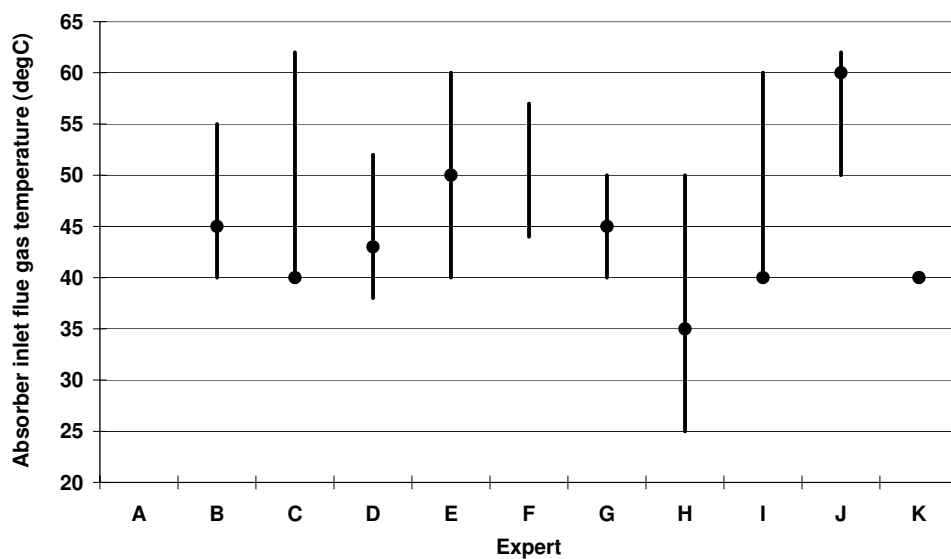
Figure 6.2. Expert judgements on current commercial amine systems for CO$_2$ capture from flue gases: absorber inlet flue gas temperature (deg C)
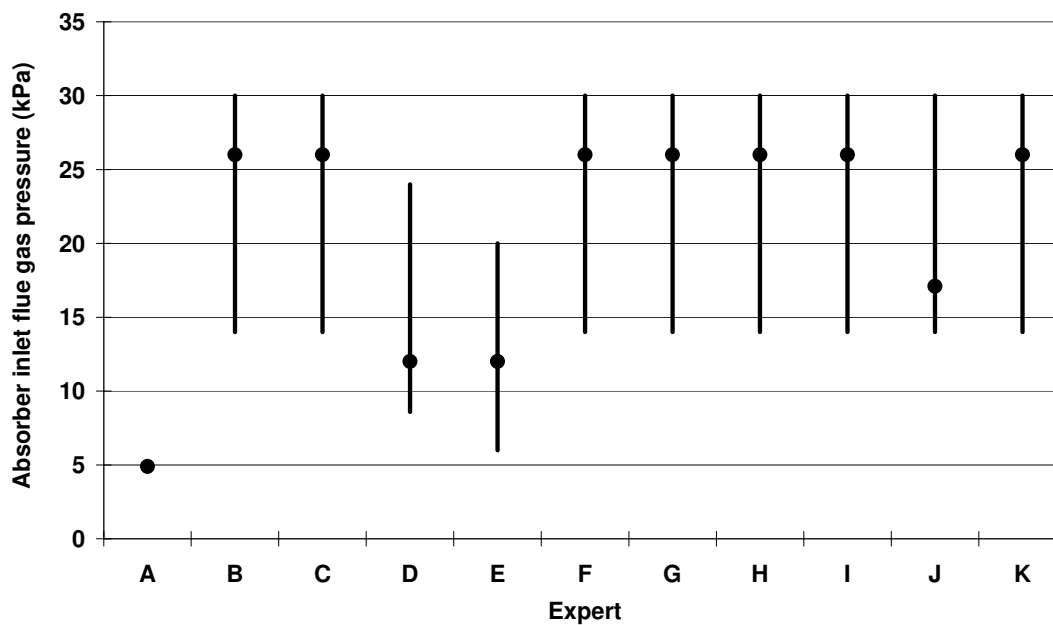
Figure 6.3. Expert judgements on current commercial amine systems for CO$_2$ capture from flue gases: absorber inlet flue gas pressure (kPa)
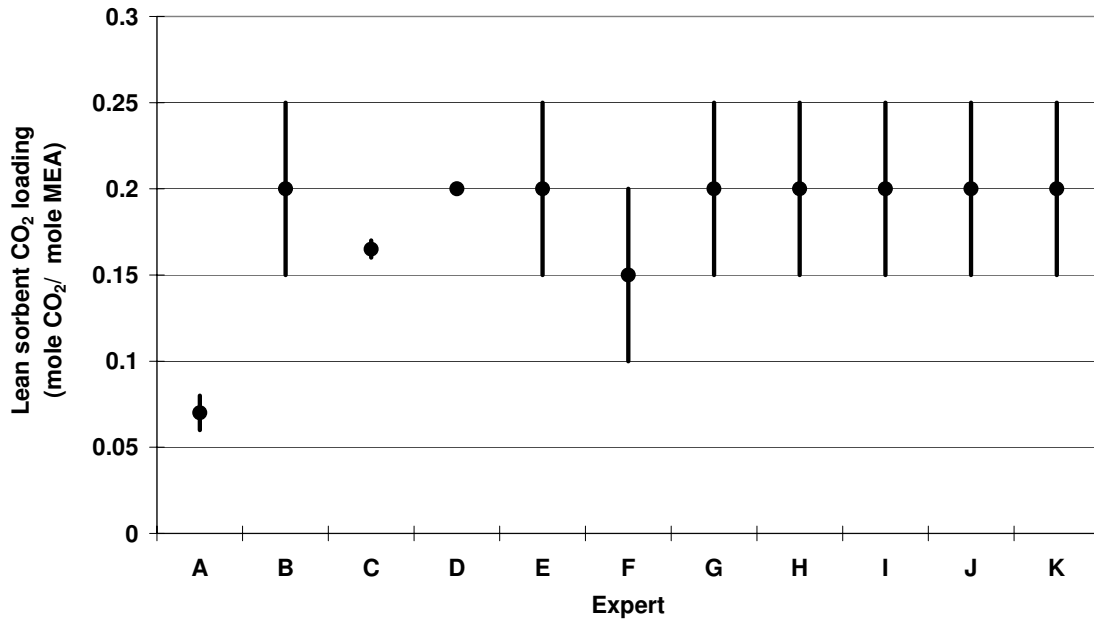
Figure 6.4. Expert on current commercial amine systems for CO_2 capture from flue gases: lean sorbent CO_2 loading (mole CO_2 / mole MEA)
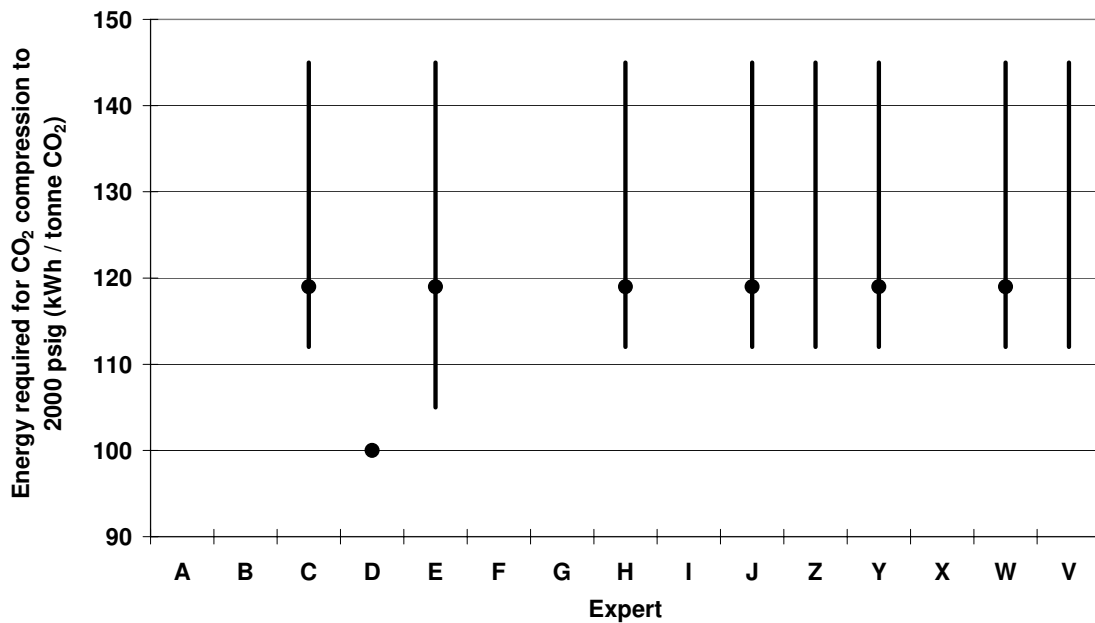
Figure 6.5. Expert on current commercial amine systems for CO_2 capture from flue gases: energy required for CO_2 compression to 2000 psig (kWh / tonne CO_2)

The basic motivation behind this study was to understand what experts in this field believe about the possible scope for improvement in the performance of amine-based CO_2 capture systems and for reduction in the cost of CO_2 capture. From the experts' responses, improvement in the various parameters relative to the current baseline was estimated. The "best guess" judgments gave a nominal/ most probable improvement, while the minimum or maximum values (depending upon the parameter) led to the "most optimistic" estimation of improvement. The relative improvement is calculated as the difference in the current and future estimate expressed as a percentage of the current baseline.

$$\text{Relative improvement in parameter Z (\%)} = (f_Z) * \frac{(Z)_{future} - (Z)_{current}}{(Z)_{current}} \times 100$$

Where, Z_{future} = Expert's judgment about the value of parameter Z in a future system

$Z_{current}$ = Current baseline value of parameter Z

f_Z = Parameter specific multiplier that reflects the "improvement"

= (+1) for Z = Sorbent concentration

= (-1) for other three parameters viz. sorbent regeneration heat requirement, sorbent loss and sorbent cost
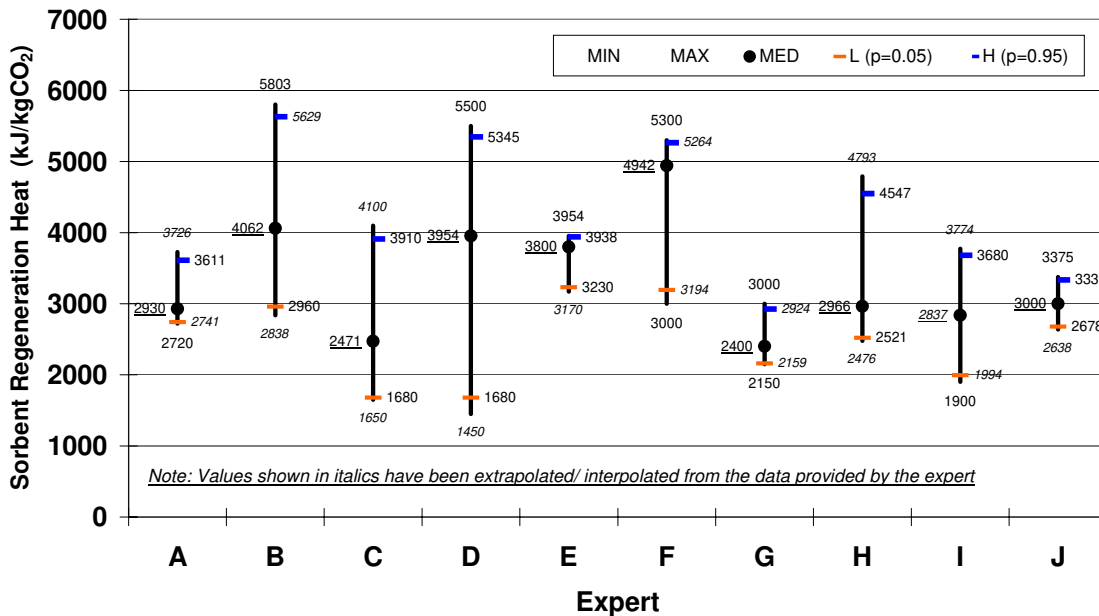
Figure 6.6. Expert judgments on future commercial amine systems: Parameter 1: sorbent regeneration heat (kJ/ kgCO₂)
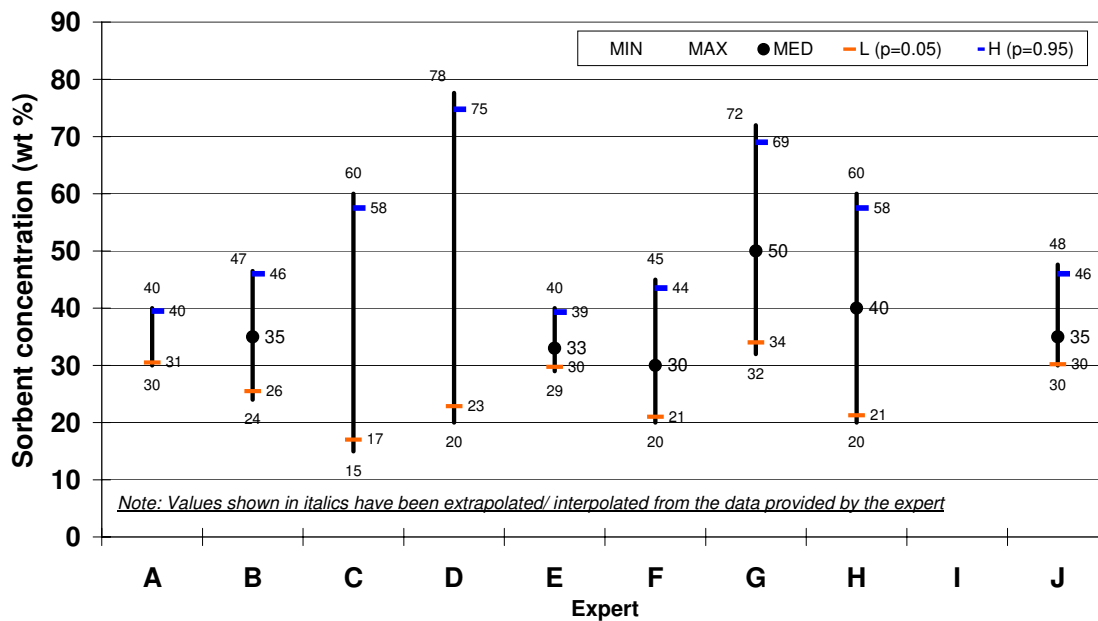
Figure 6.7. Expert judgments on future commercial amine systems: Parameter 2: sorbent concentration (% w/w)
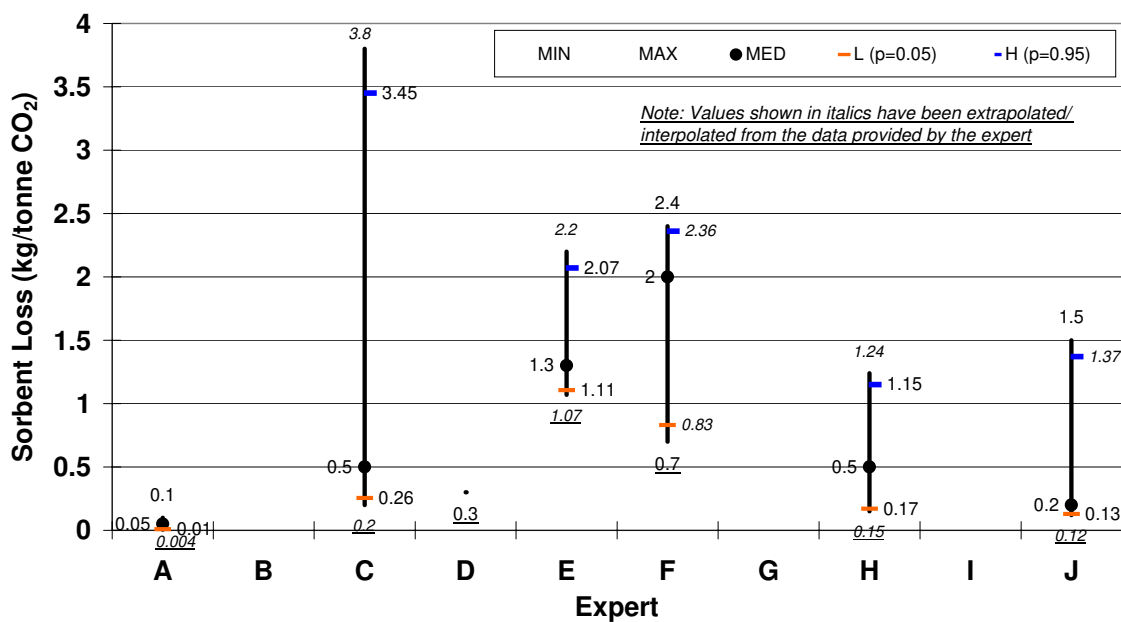
Figure 6.8. Expert judgments on future commercial amine systems: Parameter 3: sorbent loss (kg MEA/ tonne CO$_2$)
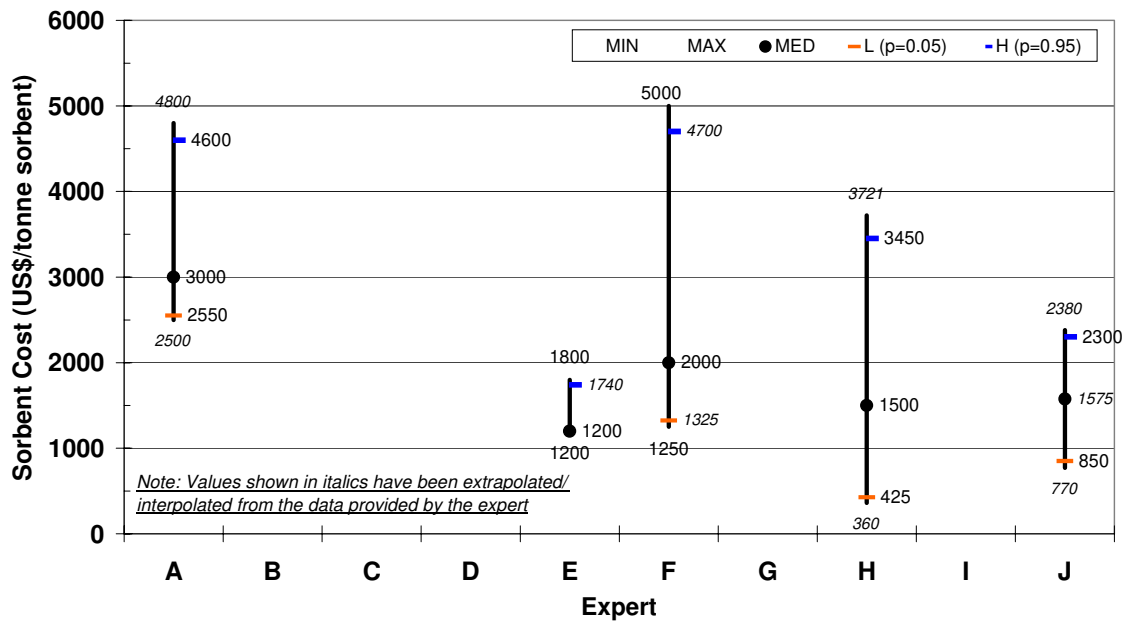
Figure 6.9. Expert judgments on future commercial amine systems: Parameter 4: sorbent loss (US$/ tonne CO₂)

Based on the "best guess" and "most optimistic" future judgments, the relative improvement is estimated and the results have been summarized in Tables Table 6.1, Table 6.2, Table 6.3, and Table 6.4.

6.3.1. Parameter 1: Sorbent Regeneration Heat Requirement

As we have seen before, this parameter determines the energy penalty of the amine system. Figure 6.10 shows the absolute values of this parameter as predicted by the various experts for a future system, compared against their own current baseline "best guess" values.

110

It may be noticed that all the experts are optimistic about future improvements in the performance of the amine-based CO_2 capture systems and predict that the sorbent regeneration heat requirement would be lower in the future. The best guess estimates predict an improvement in the range of 5 to 40 percent as compared to the experts' individual current estimates. The average improvement is about 23%. The most optimistic judgments are in the range of 15-73%, averaging about a 43% improvement.
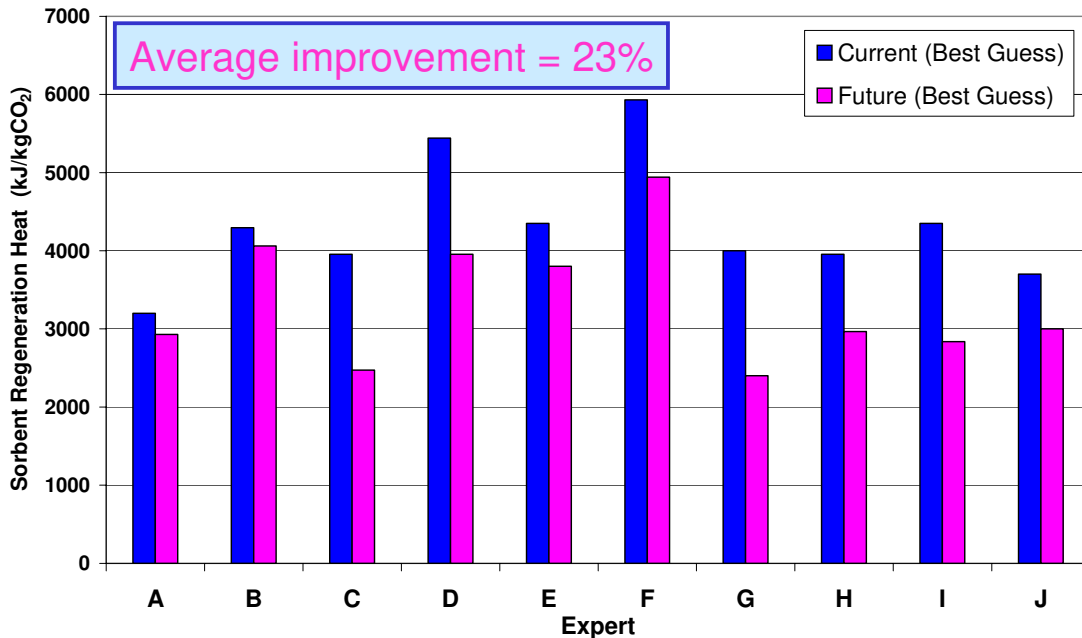
Figure 6.10. Sorbent regeneration heat requirement (kj/ kgco₂): current baseline vs. future projections

Table 6.1. Relative improvement in sorbent regeneration heat requirement

Based on	Average	Range
"Best Guess" future judgments	23%	5%-40%
"Most Optimistic" future judgments	43%	15%-73%

Experts cited advanced amines, hindered amines, special mixtures of amines, or equipment change as possible strategies to achieve these improvements. A few said they

111

had "no idea" as to how the improvements would be achieved, but were optimistic nonetheless that such improvements were achievable.

6.3.2. Parameter 2: Sorbent Concentration

Most of the current commercial systems use an amine sorbent concentration of less than or equal to 30% w/w. Many experts believe that using a higher concentration of sorbents may help reduce the energy penalty of this system and improve the overall performance. At the same time, there are a few experts who believe that sorbent concentration is a non-issue.

Table 6.2.   Relative improvement in sorbent concentration

Based on	Average	Range
"Best Guess" future judgments	23%	0%-67%
"Most Optimistic" future judgments	80%	33%-160%

The "best guess" value for sorbent concentration in a future system averaged about 37% w/w (which is about 23% improvement over the current baseline), while the most optimistic future judgments average to about 54% w/w (which is 80% improvement over the current baseline). The main breakthroughs that would enable the use of such higher concentrations are reported to be solving corrosion problem, special additives, corrosion inhibitors, improved metallurgy in the absorber, specially formulated amines, and lower oxygen content in flue gas.

6.3.3. Parameter 3: Sorbent Loss

The current baseline for sorbent loss is about 1.5 kg sorbent lost per tonne of CO_2 captured. Although most of the experts believe that the sorbent loss in future amine systems will be lower than that in the current systems, there are few experts who think otherwise. Hence the range of "best guess" estimates of improvement includes a few negative numbers.   Across all experts, however, they average out to about a 50% improvement, *i.e.*, the sorbent losses in future systems are most likely to be about half of the current levels (*i.e.* about 0.76 kg sorbent/ tonne CO_2). The most optimistic judgments averaged across all the experts predict a much lower sorbent loss (on an average, about

0.36 kg sorbent/ tonne CO_2) in future systems, which is more than a 75% improvement over the current baseline. The key research requirements that can lead to such performance include better sorbents, better inhibitors, better design and operating conditions, and zero oxygen content in flue gas.

Table 6.3. Relative improvement in sorbent loss

Based on	Average	Range
"Best Guess" future judgments	49%	(33%)-97%
"Most Optimistic" future judgments	76%	29%-100%

6.3.4. Parameter 4: Sorbent Cost

While the current baseline cost of the amine (MEA) sorbent is about \$1.2/ kg sorbent, the expected improvements in future amine systems may come at a cost premium.

Table 6.4. Relative improvement in sorbent cost

Based on	Average	Range
"Best Guess" future judgments	(48%)	(140%)-4%
"Most Optimistic" future judgments	3%	(100%)-71%

Based on the "best guess" estimates of each expert, on average the future sorbents may cost almost 50% more. The most optimistic judgments estimated that the cost of future sorbents may be almost the same as that of the current sorbents, or even slightly cheaper. According to the various experts, there are several factors that may affect the cost of future sorbents, *viz.* natural gas (the ultimate feedstock) availability and prices, demand, and generic versus specialized application.

6.4 Estimation of Future Cost Reductions

Next, we sought to estimate the process cost reductions that would result from the improvements in future amine systems as envisaged by the various experts. For this purpose, we used the experts' responses about the four parameter values noted above as input to the IECM-CS model. All other model parameters were kept at their default

values. In these cost estimates, we assumed that the CO_2 product is compressed to 2000 psig. The cost of CO_2 transport and storage is not included.

The main cost parameters of interest are the capital cost of the CO_2 capture system, the incremental cost of electricity and the cost of CO_2 avoidance. Table 6.5, Table 6.6, and Table 6.7 give the estimated cost reductions as percentages of the estimates for current systems.

Table 6.5. Expected reduction in capital cost from improvements in four process parameters (relative to current baseline)

Based on	Average	Range
"Best Guess" future judgments	6%	(2%)-9%
"Most Optimistic" future judgments	16%	7%-19%

Table 6.6. Expected reduction in incremental COE from improvements in four process parameters (relative to current baseline)

Based on	Average	Range
"Best Guess" future judgments	18%	(8%)-29%
"Most Optimistic" future judgments	35%	20%-37%

Table 6.7. Expected reduction in cost of CO_2 avoidance from improvements in four process parameters (relative to current baseline)

Based on	Average	Range
"Best Guess" future judgments	18%	(8%)-30%
"Most Optimistic" future judgments	36%	21%-38%

It must be noted that these results reflect expert judgments on only 4 parameters of the amine system model. Even in this case, the average expected cost reductions, especially in the incremental cost of electricity and cost of CO_2 avoidance, are quite encouraging. There are many more parameters that may help to reduce overall system costs, *e.g.*, better power plant heat integration, improved column designs, shorter construction times and improvements to the base plant characteristics (lower heat rate, lower air leakage *etc.*). Thus, future amine-based CO_2 capture technology may be a more cost effective option to control greenhouse gas emissions from fossil fueled power plants in the next two decades or so. However, future improvements in this technology (and resulting cost reductions)

114

will depend a lot on continuing R&D investments and incentives for deployment resulting from government actions and policies (Taylor and etal 2003).

6.5 Assessing R&D Priorities

In the last section of the questionnaire, (see *Appendix E*), experts were asked to indicate their R&D priorities as to reduce the cost of CO_2 capture and the cost of CO_2 avoidance using amine-based system by year 2015.   Items (B1-B13) are related specifically to amine-based systems, while items (A1-A4) are related to the reference plant characteristics and items (C1-C3) are related to post-capture processing of CO_2 product stream.   In all, 19 research objectives were listed, and the experts were requested to classify these items into the following three categories:

- High Priority (H)

- Medium Priority (M)

- Low Priority (L)

Table 6.8 briefly summarizes the experts' responses to this question. While there were diverse views on the relative importance of each research objective, all the experts agreed (almost unanimously) on the following items as the top priority issues:

1) To develop sorbents with lower regeneration energy requirement [B4]

2) To develop less expensive technologies for CO_2 storage/ disposal [C3]

3) To improve heat integration within the power plants (to reduce the energy penalty due to steam extraction for sorbent regeneration) [A4]

4) To develop more efficient power plants (lower heat rate) [A1]

Clearly the topmost priority R&D objective (ranked "High Priority" by 82% of the experts) is to develop sorbents having lower regeneration energy requirement. From our

Table 6.8. Summary of research priorities identified by the experts

No.	Research Objective	% of experts who believe that this item is of:		
		High Priority	Medium Priority	Low Priority
A1	To develop more efficient power plants (lower heat rate)	50%	20%	30%
A2	To improve boiler designs so that fuel can be burned with lower excess air (typically for a coal plant, ~20% excess air is used)	40%	10%	50%
A3	To develop more efficient technologies for SO_x and NO_x control so as to reduce the acidic gas impurities in the flue gas stream	27%	27%	45%
A4	To improve heat integration within the power plants to reduce the energy penalty for CO_2 capture due to steam extraction for sorbent regeneration	55%	27%	18%
B1	To develop more efficient fans for flue gas handling	0%	27%	73%
B2	To develop CO_2 absorbers that can handle higher sorbent concentrations	36%	27%	36%
B3	To develop sorbents with higher CO_2 loading capacity	45%	27%	27%
B4	To develop sorbents with lower regeneration energy requirement	82%	18%	0%
B5	To develop absorber columns offering lower pressure drops	18%	73%	9%
B6	To develop absorber columns offering higher CO_2 capture efficiencies	27%	27%	45%
B7	To develop more efficient pumps for sorbent circulation	0%	9%	91%
B8	To develop more efficient heat exchanging devices	0%	45%	55%
B9	To reduce the cost of sorbent manufacturing	9%	64%	27%
B10	To develop sorbents with lower makeup requirements (less losses)	27%	64%	9%
B11	To develop less expensive technologies for disposal of spent sorbents	18%	45%	36%
B12	To develop better instrumentation/ automation in the CO_2 capture system so as to reduce the labor requirement	0%	18%	82%
B13	To develop better construction materials so as to reduce the losses due to corrosion	27%	36%	36%
C1	To develop more efficient compressors for CO_2 compression	0%	60%	40%
C2	To develop a transport technology that can handle low-pressure CO_2 streams	9%	18%	73%
C3	To develop less expensive technologies for CO_2 storage/ disposal	64%	36%	0%

previous analysis, this parameter is crucial in determining the overall energy penalty of this system, and hence affects the overall cost of CO_2 avoidance. The other complimentary factor that helps determine the overall energy penalty is the level of heat

integration between the power plant and the amine system. Significant improvements are required on these fronts so as to make amine-based CO_2 capture economically competitive. Researchers around the world have been working in this direction, and the initial results seem to be promising (Mimura, Matsumoto et al. 2000; Iijima and Kamijo 2002; Veawab, Tontiwachwuthikul et al. 2002; Reddy and Roberts 2003).

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7. CONCLUDING REMARKS

The basic objective of this research was to carry out a technical, environmental, and economic assessment of the amine-based CO_2 capture technology for greenhouse gas control at power plants. This chapter summarizes the key findings presented in this thesis.

7.1 Model Development

Performance and cost model of this technology were developed that served as the analytical tool for this assessment. The performance model was derived using a detailed chemical process simulator together with data obtained from process developers and through personal communication with experts. It was directly linked to the cost model, which used cost data from published literature. Cost estimates for any technology that has not been widely implemented for the application of interest (in this case, large-scale power generation) is inherently subject to uncertainty. Thus, the model has probabilistic capabilities, which allow the user to use uncertainty distributions rather than a single value for various model parameters. In the model applications discussed below, such distributions were based on multiple data sources *viz.*, published literature, technical reports, and experts' technical judgment. Finally, the amine system model was integrated with a larger fossil-fuel based power generation modeling framework (IECM) in order to study multi-pollutant interactions and to assess various CO_2 control options on a consistent basis.

7.2 Model Applications

Today there is a growing consensus in the global scientific community on the need to control CO_2 emissions to mitigate the problem of global climate change problem. Capture and sequestration of CO_2 is being proposed as a medium term solution that can allow continued use of conventional fossil-fuel resources over the next century without significantly contributing to global carbon emissions from electric power generation (and, potentially, other industrial sources). Electric utilities, being one of the largest stationary sources of CO_2 emissions, are likely to be the early targets in this effort. Thus, the performance and cost model developed in this research were used to study the option of post-combustion CO_2 capture from a new PC plant using amine-based system. This can

serve as a reference against which other CO_2 mitigation options could be compared. Also, as we have discussed before, there exists a large existing fleet of coal-fired capacity that may have to be retrofitted under a stringent greenhouse gas control policy. Thus, retrofit applications as well as new plant applications are of interest.

7.2.1. New Plants

Using the model, we conducted case studies of a new coal-fired power plant with an amine-based CO_2 capture plant. It was concluded that in order to capture CO_2 from a pulverized coal plant, a much bigger plant has to be built in order to provide the same net power output as a plant without CO_2 capture. This is because approximately 22% of the gross power generation is consumed by the CO_2 capture and compression systems. It was found that a capture plant designed to capture 90% of the CO_2 mass emissions effectively "avoids" about 87% of the emissions per net kWh generated because the CO_2 capture system itself consumes substantial energy and contributes to CO_2 emissions. An amine system also reduces the total emissions of SO_x and particulates to very low levels. However, the capture plant has higher emission rates of NO_x and ammonia (per kWh). The capture plant uses 33% more coal to deliver the same amount of electricity, and therefore also has larger amounts of bottom ash, fly ash and FGD waste to be disposed. The capture plant also has to dispose of the spent sorbent (from the amine system) and the CO_2 product stream.

The addition of CO_2 capture and storage increases the capital requirement as well as the cost of electricity generated. Our case studies showed the capital cost of the new plant to increase by 56% to 66% (based on $/kWh), while the COE increased by about 73% to 82% for a plant with 90% capture. Cost results were found to be sensitive to assumptions about the plant capacity factor and fixed charge factor.

The CO_2 avoidance cost was estimated to be about $50/ tonne CO_2 avoided. As mentioned earlier, it is higher than the CO_2 capture cost ($36/ tonne CO_2 delivered). This estimate includes about $8/ tonne CO_2 captured for transport and storage/ disposal of the concentrated CO_2 product stream. From the probabilistic analysis, the 95% confidence interval was estimated as $39-71/ tonne CO_2 avoided. It may be noted that these results

120

are within reasonable agreement with some of recent estimates published by other studies (Simbeck and McDonald 2000; Stork Engg Consultancy B.V. 2000; ALSTOM, AEP et al. 2001; Parsons Infrastructure & Technology Group 2002; Singh, Croiset et al. 2002).

7.2.2. Retrofit Applications

Retrofit application of this technology to existing coal-fired plants is another important scenario to be considered. Several cases have been modeled and presented in section 5.2. If the existing plant already has a sulfur-control system, it helps in reducing the cost of CO_2 capture using amine-based systems. Optimization studies showed that it is further helpful if the existing sulfur-control system is upgraded to the maximum achievable removal efficiency to minimize SO_2 removal in the amine system. It is necessary to add a new, highly efficient sulfur scrubber upstream of amine-based system if one does not already exist at the reference plant. If all the energy required for CO_2 capture and compression system is extracted from the base plant ("derating" case), the net output of the plant falls substantially (by almost 40%), much more so that at a new plant, because of generally poorer heat integration potential at older plants. Accordingly, the cost of electricity may go up by 150-300% as compared to that of reference plant, for various cases analyzed. Adding an auxiliary natural-gas-fired boiler (with a secondary steam turbine) may be a lower-cost option for providing auxiliary energy if lower levels of CO_2 avoidance (~ 60-65%) are acceptable and if natural gas is available at low price. The flue gas from the auxiliary natural gas boiler is more dilute in CO_2 content, so capturing this CO_2 is not cost effective. This additional CO_2 emission from the auxiliary natural gas boiler reduces overall CO_2 avoidance level of the system. The cost of electricity (and that of CO_2 avoidance) in this case may be lower than that of the derating case; however, it is very sensitive to the cost and availability of natural gas and assumptions about the retrofit factors. This option might be attractive if the gas price is below \$2.5/mscf.

7.2.3. Capacity Factor Assumption

Typically, in a plant-level analysis like this, it is assumed that the CO_2 capture plant has the same capacity factor as that assumed for the reference plant (Jeremy and Herzog 2000; Simbeck and McDonald 2000; Stork Engg Consultancy B.V. 2000; ALSTOM, AEP et al. 2001; Parsons Infrastructure & Technology Group 2002; Singh, E.Croiset et

al. 2002). The resulting cost difference with CO_2 capture then reflects the added cost under identical operating conditions. In practice, however, any number of parameters affecting overall plant costs – such as the capacity factor – may differ in plants with and without a CO_2 capture system. Based on dispatch models for two regions of the U.S., recent studies by Johnson and Keith found that the CO_2 capture plants would be operated at higher capacity factors (Johnson 2002; Johnson and Keith 2004). However, there are other factors that could discourage the higher utilization of these plants. For example, plants using amine-based CO_2 capture system were shown earlier to have NO_x emission rates that are substantially higher than that for a similar reference plant without CO_2 capture (see Table 5.2). This could reduce their use under regional NO_x caps. In general, the capacity factor of a plant will be determined by a number of factors related to the overall generation mix and the constraints under which plants in a utility system operate. While such factors are clearly important, they are beyond the scope of this thesis. However, the models developed here can be readily used to explore the cost implications of alternative assumptions regarding the capacity factor and other base plant parameters.

7.3 Expert Elicitations

The technical judgment of various experts in this field was elicited to explore the potential for reducing the cost of current amine systems. The experts belonged to academia, industries, research laboratories and private consultancies.

7.3.1. Scope for improvement

The experts' responses indicate that future amine-based systems can perform significantly better as compared to their current counterparts, given a substantial program of R&D. The average relative improvement in various parameters as predicted by the experts is reported below in Table 7.1. The numbers in the parentheses represent the range of estimates provided by various experts.

Various possible strategies are cited to achieve these improvements. Most experts emphasize development of better sorbents (advanced amines or special mixtures of amines). Other items on the list of suggestions included equipment change, special additives, corrosion inhibitors, improved metallurgy for absorbers, better design and

operating conditions, and reducing the oxygen levels in the flue gas to zero. All these improvements in performance parameters will help in reducing the future cost of CO_2 avoidance.

Table 7.1. Relative improvement in amine-system parameters

Model Parameter	Improvement estimates based on	
	"Best Guess" judgments	"Most Optimistic" judgments
Sorbent Regeneration Heat Requirement (kJ/ kg CO_2)	**23%** (5%-40%)	**43%** (15%-73%)
Sorbent Concentration (wt %)	**23%** (0%-67%)	**80%** (33%-160%)
Sorbent Loss (kg MEA/ tonne CO_2)	**49%** ((33%)-97%)	**76%** (29%-100%)
Sorbent Cost ($/ tonne MEA)	**(48%)** ((140%)-4%)	**3%** ((100%)-71%)

However, the cost of improved sorbents is expected to be substantially higher than current prices, or at best remain at the current level under the most optimistic scenario. Higher sorbent costs were also attributed to natural gas (the ultimate feedstock) availability and prices, demand, and generic versus specialized application.

7.3.2. Possible future cost reductions

The experts' responses about the four parameter values for future amine systems (Table 7.1) were used as input to the IECM-CS model along with the other parameter defaults. Table 6.2 gives the results obtained using the average improvement numbers reported in Table 7.1 (in bold), with the range obtained using individual responses given in the parentheses.

It may be noted that all the four parameters under consideration, *viz.* sorbent regeneration heat requirement, sorbent concentration, sorbent loss and sorbent cost, directly affect the total energy penalty and makeup sorbent requirement cost (the most important variable cost items of this technology). However these parameters only indirectly affect the

123

capital cost of this system and hence have less impact on the same. This fact is reflected in the cost reductions that are expected to be lower in case of capital requirement as compared to those in cost of electricity.

Table 7.2. Expected reduction in future cost of CO_2 avoidance

Cost Parameter	Expected cost reduction based on	
	"Best Guess" judgments	**"Most Optimistic" judgments**
Total Capital Cost (M$)	**6%** ((2%)-9%)	**16%** (7%-19%)
Cost of Electricity ($/MWh)	**18%** ((8%)-29%)	**35%** (20%-37%)
Cost of CO_2 avoidance ($/ tonne CO_2 av.)	**18%** ((8%)-30%)	**36%** (21%-38%)

7.3.3. Probabilistic distribution of current and future costs of CO_2 avoidance

In case of probabilistic runs, most of the experts seem to be optimistic about the potential for substantial cost reductions in future.

Figure 7.1 shows the cumulative probability distributions for avoidance cost based on the four parameter distributions for current and future systems. The average of the experts' responses have been used as input to the model to generate these curves. The distribution for future costs shows substantially lower values than the current cost distribution. The cost difference (cost reduction) maybe accredited to the R&D inputs being invested to improve this technology. In other words, this cost difference or cost saving maybe looked upon as the benefit of R&D investments in this technology. From Figure 7.1, the difference in the median values of mitigation cost in current versus future scenario is about $8/ tonne CO_2 avoided, or about 20% of the current value; and the difference between the average value of each distribution is about $9/ tonne CO_2 avoided, or about 21% of the current value. When the distributions are derived for each individual expert, the difference in the median as well as the average values of mitigation cost is found to

124

have a range of \$2-9/ tonne CO_2 avoided, or about 3-24% of the current value. Based on these measures of the benefit of R&D, the wider the application of this technology, the larger the number of tonnes of CO_2 avoided and the bigger the overall benefit.
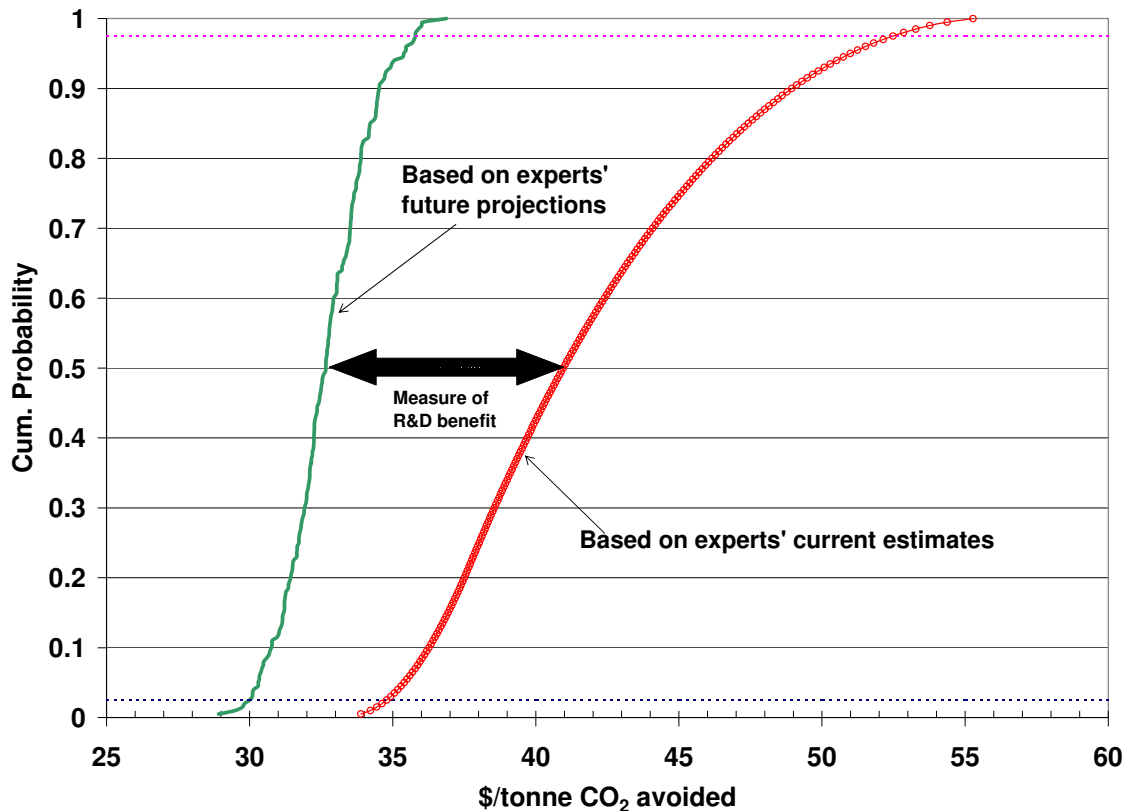
Figure 7.1. Probabilistic estimate of future cost reduction

7.3.4. R&D priorities

Although there were diverse views on the relative importance of various research objectives, all the experts seem to agree (almost unanimously) on the following items as the top priority issues:

5) To develop sorbents with lower regeneration energy requirement [B4]

6) To develop less expensive technologies for CO_2 storage/ disposal [C3]

7) To improve heat integration within the power plants (to reduce the energy penalty due to steam extraction for sorbent regeneration) [A4]

8) To develop more efficient power plants (lower heat rate) [A1]

So, the topmost priority R&D objective is believed to be to develop sorbents having lower regeneration energy requirement. Together with more effective heat integration schemes, this may be the key to the success of this technology for CO_2 capture applications in future. Various researchers around the world have been working in this direction, and the initial results seem to be promising

7.4 Directions for Future Work

There are several directions in which this work may be furthered. First, the post-capture CO_2 processing modules (for transport, storage or usage of CO_2 product) could be developed in more detail. Then, there are also a few areas in the current performance and cost models for amine system that could be improved with the availability of additional data. For example, it is likely that there are correlations between some of the performance and cost parameters (e.g. sorbent concentration, lean sorbent loading and maintenance costs) which are not established in the current model. Also, default values for various parameters for CO_2 absorption systems using sorbents other than MEA could be included in the present model.

It would also be useful to elicit appropriate group of experts on other parameters of interest, such as equivalent energy penalty factor (F_{HE}), direct and indirect capital costs, *etc*. A more elaborate (and time consuming) protocol for eliciting expert judgments, including greater reliance on face-to-face interviews, also may help in better understanding of their views.

Another direction of future work might be applying the models developed here to address climate policy issues more extensively. For example, a power plant database could be used with the model to assess the feasibility of retrofitting amine-based systems to existing coal plants, the emission reductions that realistically could be achieved through such an effort, and the overall cost of such a program. Another application might be in the form of a case study of a prospective power plant sited in a developing country with site-specific cost data and regulatory framework. This work might also be extended in the direction of modeling other technological options for CO_2 capture at power plants,

126

including advanced combustion systems using pure oxygen. IECM-CS can provide a consistent framework for comprehensive comparisons of various technological options for carbon sequestration.

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APPENDIX A

POTENTIAL ENVIRONMENTAL IMPACTS OF AMINE SYSTEMS

Amine system is an "end-of-pipe" treatment. It captures CO_2 generated during combustion of a fossil fuel in a power plant. Although an end-of-pipe solution is less desirable than pollution prevention approaches, it is a common practice to reduce environmental impact of industrial activities (Rubin 2001). Often it is observed that the environmental control technologies, especially those based on chemical processes, transfer the pollutants (or their derivatives) from one phase (or part of the ecosystem) to another phase (or part of the ecosystem). Many times, this could result in "pollution transfer" rather than "pollution control." For example, a flue gas desulfurization (FGD) system that controls SO_2 emission from a power plant flue gas produces "FGD waste," a solid waste product that needs to be managed later. Many of the wastewater treatment plants separate out contaminants from the water in the form of a solid residue, which again has to be taken care of. In some cases, as in the case of FGD waste, it is possible to make use of this solid product in the manufacture of construction materials. This is the most benign strategy for the environmental protection, and is a good example of industrial ecology. However, this may not be always feasible and some of the solid wastes may have to be disposed of. Depending upon the chemical nature of such solid waste, it is either stored in a landfill or incinerated. Precautions must be taken while disposing the solid waste to avoid creating a new problem in the form of soil pollution, groundwater contamination or air pollution.

In case of MEA-based CO_2 capture systems, environmental problems may arise from the spent sorbent slurry discharged from the MEA reclaimer (also called *reclaimer bottoms*) and the emissions of MEA and ammonia (NH_3) carried by the treated flue gas. Here is a brief description of these issues. It may be noted that the large concentrated CO_2 stream generated as a "byproduct" of this process may have its own set of concerns, and is beyond the scope of this study.

A. Spent Sorbent or Reclaimer Bottoms

As mentioned before, MEA degrades under the real operating conditions in a plant. Typically, the degradation products are separated in a reclaimer and disposed of as hazardous waste (Barchas and Davis 1992). The waste is often picked up by a contactor and is incinerated at a permitted facility. This method of waste disposal is expensive and the CO_2 capture plant may have to spend substantial amount depending upon the waste quantity.

Recent study undertaken at the National Energy Technology Laboratory (NETL), Pittsburgh, has identified various chemical species that are found in the reclaimer waste samples from an operational CO_2 capture plant (Strazisar, Anderson et al. 2003). The major organic compounds which were found in these samples include monoethanolamine (C_2H_7NO, MEA), 3-hydroxyethylamino-N-hydroxy-ethyl propanamide ($C_7H_{16}N_2O_3$), 4-hydroxyethyl-2-piperizinone ($C_6H_{12}N_2O_2$), 2-hydroxyethylamino-N-hydroxyethyl acetamide ($C_6H_{14}N_2O_3$), Ammonia (NH_3), and N-acetylethanolamine ($C_4H_9NO_2$) with traces of several other compounds.

The analysis of inorganic species revealed the presence of seven metal cations at a concentration of 0.2 ppm or more. Since sodium carbonate is added to the reclaimer to regenerate MEA, sodium ions dominate all other metal ions (> 800 ppm). Other metals (potassium, selenium, arsenic, calcium, iron, aluminum, and zinc) are believed to originate mostly from the coal. Additionally, mercury was found to be present in the reclaimer waste at a concentration of 1 ppb. Anion concentrations (chloride, nitrate, fluoride, sulfate, phosphate, bromide) are found to be relatively higher (80-49000 ppm). The amounts of halide anions match the typical halogen concentrations found in coal. This might be the result of "heat-stable-salts" formed by reaction between MEA and mineral acids (HCl, HF, HBr) in the flue gas.

This analysis helps to understand why the spent sorbent (reclaimer bottoms) is treated as hazardous waste. From economic as well as environmental perspective, it is preferable for the CO_2 capture plant to cleanse the flue gas upstream, before entering the amine

system, so as to minimize sorbent degradation losses, corrosion problems, makeup sorbent requirement and cost of disposing the spent sorbent.

B. Environmental (Gaseous) Emissions

a) MEA entrainment with treated flue gas: As mentioned before, MEA is a primary amine with high pH. It is completely soluble in water and is readily biodegradable (Dow 2000). It is a reactive compound and is classified as a corrosive material. So, proper care needs to be taken while handling this compound. Toxic gases and vapors (such as oxides of nitrogen and carbon monoxide) may be released in a fire involving MEA. It can cause irritation and be harmful to gastrointestinal tract, nausea, vomiting and diarrhea when swallowed. It is an irritant to eyes and continued contamination of the eyes could cause permanent injury. MEA is also known to cause mild irritation to skin and repeated or prolonged contact may cause dermatitis. Inhalation of mist or aerosols can produce severe respiratory irritation and cause sore throat, coughing, headache, nausea and vomiting. In terms of chronic effects, lungs may be affected with repeated or prolonged exposure. MEA may have effects on the central nervous system, gastrointestinal tract and kidneys (Deltrex 2000). Several animal studies were conducted by exposing rats and rabbits to MEA vapors of 12-102 ppm for several weeks. Skin was found to be the significant target tissue at relatively high concentration of MEA vapor; other sensitive target tissues include the kidneys and livers (Knaak, Leung et al. 1997). Based on various laboratory tests, it is found to be lacking in genotoxicity.

MEA is not listed as a hazardous air pollutant under the Clean Air Act of 1990 (CAA 1990). The National Institute for Occupational Safety and Health (NIOSH) has established a recommended exposure limit (REL) for MEA of 3 ppm (8 mg/m3) as a time-weighted average for a normal 10-hour workday and a 40-hour workweek and a short-term exposure limit (STEL) of 6 ppm (15 mg/m3) for periods not to exceed 15 minutes (OSHA 1996). These limits are based on the risk of skin, eye and respiratory irritation and narcotic effects. However, no signs or symptoms of chronic exposure to ethanolamine have been reported in humans. MEA has been regarded as hazardous according to the criteria of Worksafe Australia (Deltrex 2000). Based on the LD_{50} value of 505 mg/ kg body weight (in rabbits exposed by dermal route), MEA is classified as a

130

"dangerous" chemical that falls within the European Risk Category 3 (Chemrest 2003). The European Toxicity Risk Code for this chemical is "XI = Irritant" which matches with the hazard category "Harmful/Irritant" assigned by Worksafe Australia (Deltrex 2000). It may be noted that MEA is widely used in various applications such as a dispersant for agricultural products; as a softening agent for hides; as an accelerator in the production of antibiotics, polishes and waving solutions for hair; as a rubber accelerator; an intermediate in the production of emulsifiers, soaps and detergents; and in some hair-care products. In case of MEA-based CO_2 capture systems, trace quantities (1-4 ppm) of MEA may be found in the exhaust flue gas at the stack. Under well-mixed atmospheric conditions, it is less likely to pose a risk of direct exposure to human beings. Also, only a small amount of MEA is expected to partition to the atmosphere. It may be removed by reactions with photochemically generated hydroxyl radicals or by precipitation. Thus, relatively low levels of MEA are expected to be present in the atmosphere; and owing to its short half-life, it is unlikely to adversely impact air quality (Davis and Carpenter 1997). However, MEA's complete solubility in water may facilitate its entry into surface and ground water.

According to the Dow Chemical Company (one of the leading manufacturers of MEA), MEA is "practically non-toxic" to aquatic organisms (Dow 1998). It is claimed that as MEA exhibits low (or no) aquatic toxicity, is biodegradable in soil, surface waters and wastewater treatment plants and does not show any tendency to bioaccumulate, the routine manufacture, use and disposal of this compound is not expected to adversely impact the environment (Davis and Carpenter 1997). However, U.S. Environmental Protection Agency has classified MEA as having "moderate" ecological toxicity, based on the effects on aquatic organisms, such as fish and algae (USEPA 2002). This aspect might need further careful investigation before MEA-based CO_2 capture systems are installed in large numbers.

It may be noted that the market cost of MEA sorbent lost via leakage or entrainment is likely to be trivial in the overall cost of running the plant. However the externalities and potential risks posed by the same might be significantly higher. In view of the above information, considering the potential health and environmental risks posed by MEA, it is

important to take special care to avoid MEA losses through entrainment in the absorber and leakage in the circulation piping.

b) Nitrosamines: Another potential problem that may arise from amine-based systems is in the form of "nitrosamines", which are known carcinogens that are formed by a reaction between an amine and a nitrogen oxide. These compounds were found in the samples of the lean sorbent (2.91 μmole/ ml). However, detectable amount of nitrosamines was not found in the reclaimer waste, which may be explained in terms of their low boiling point (Strazisar, Anderson et al. 2003). The trace quantities of MEA entrained by the flue gas may combine with nitrogen oxides in the atmosphere (or present in the flue gas itself) and may constitute to health hazards in the surrounding areas.

c) Ammonia: Ammonia (NH_3) is generated as a dissociation product of MEA. Loss of MEA (and emission of NH_3) via dissociation route is unavoidable under the normal operating conditions in the amine system. As seen in the case study of a new plant (Section 5.1 & *Appendix D*), the emission rate of NH_3 from a CO_2 capture plant is substantially higher than that from a power plant without CO_2 capture system. Emission of ammonia is not regulated under the current air pollution control programs, however, it is a known source of air (and water) pollution (Ashman, Sutton et al. 1998; Howarth, Sharpley et al. 2002). Especially in the polluted urban areas, changes in ammonia emissions have the most significant impact on the total particulate matter levels (Ansari and Pandis 1998). The treated flue gas coming from a capture plant is almost free of SO_2, but it contains a significant amount of NO_x. Gaseous emissions of ammonia, SO_2 and NO_x form secondary particulates (ammonium nitrate (NH_4NO_3) and ammonium sulfates (NH_4HSO_4 and $(NH_4)_2SO_4$)). These compounds are significant part of fine particulate matter ($PM_{2.5}$) in air and can play an important role in visibility impairment and regional haze (Battye, Aneja et al. 2003). Hence, the multi-fold increase in NH_3 emissions from a power plant owing to the amine-based CO_2 capture system has to be considered carefully in the light of local and regional air pollution issues. The contribution from all the industrial sources combined makes only a small fraction (0.2%-9.6%) of total ammonia emission inventory that is dominated by emissions from livestock waste and fertilizer application (Battye, Aneja et al. 2003). However, these

point sources of ammonia, especially in the vicinity of urban centers, can have substantial impact on the particulate matter levels and the air quality in general. So, the severity of the impacts of the higher ammonia emissions from the capture plant will significantly depend on the land-use pattern around the power plant.

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APPENDIX B

CHARACTERIZATION OF UNCERTAINTY AND VARIABILITY

The term "uncertainty" is a vast umbrella that covers a variety of concepts. Uncertainty often arises from various sources including lack of complete information, conflicting sources of information, variability in a process or an object, linguistic imprecision, and approximations incorporated in a model to simplify the real life situations (Morgan and Henrion 1990). Uncertainty in an empirical quantity is usually expressed using a probability distribution.

Any techno-economic analysis, and especially that of new energy and environmental control technologies that are still in the research phase, involves uncertainties regarding the performance and costs. These uncertainties come from incomplete data and numerous assumptions and approximations built into simulations. Some parameters, especially the cost parameters are influenced by a larger set of factors outside the scope of the particular study, and fluctuations in these quantities may be seen as "inherent randomness" when viewed within this limited focus area. In addition, there may be significant variability in plant or process design assumptions across different studies or organizations.

Uncertainty and variability are often ignored or treated in a limited way using sensitivity analysis. However sensitivity analysis suffers from shortcomings resulting from the difficulty in evaluating the effect of simultaneous variations in several parameters and the lack of insight into the likelihood of obtaining any particular result.

A more robust approach is to represent uncertainties and/or variability in model parameters using probability distributions. Using probabilistic simulations techniques, simultaneous uncertainties in any number of input parameters can be propagated through a model to determine their combined effect on model outputs. The result of a probabilistic simulation includes both the possible range of values for model output parameters and information about the likelihood of obtaining various results. The development of ranges and probability distributions for model input parameters can be

134

based on information available in published studies, statistical data analysis and/or the judgments of process engineers with relevant expertise.

One of the distinguishing features of this modeling effort is a probabilistic capability that allows model inputs to be represented by probability distributions rather than single deterministic values. Depending upon the parameter, these distributions reflect the ranges of values reported in the literature, modeling approximations, the evolving nature of the technology, practical considerations in running such plants and variety of plant or process design assumptions. Some of the distributions are also based on an expert elicitation exercise (explained in Chapter 6) in which experts were asked about the nominal values and possible ranges for several important parameters characterizing the performance of current commercial MEA-based systems capturing 90% CO_2 from the flue gas of a typical coal-fired power plant.

While designing an amine-based CO_2 capture system for a given flue gas (from a power plant application), there are certain parameters that could be specified independent of others. For example, the sorbent concentration, CO_2 capture efficiency target, lean sorbent loading, temperature and pressure of sorbent regeneration steam, CO_2 product pressure, *etc*. Distributions for such parameters reported in different studies essentially represent variability. Experts' technical judgments were useful in defining these distributions.

Probability distributions for parameters such as the efficiencies of fans, pumps or compressors represent the possibility of encountering fluctuations in the performance due to inherent characteristics of these devices in an operating plant. Uncertainties arising from real plant operating conditions and approximations in process simulations are also reflected in the distributions for parameters such as MEA makeup rate, removal efficiencies for other acid gases (SO_2, NO_2 and HCl), and equivalent energy penalty from extraction of sorbent regeneration steam from the steam cycle of the base plant.

In case of cost parameters such as capital costs, O&M costs, cost of reagents (including MEA) and cost of disposal, the distributions represent both variability and uncertainty

135

arising from disagreement in data sources and inherent characteristics of market mechanism.

Then there are certain process parameters that are interdependent. For example, the CO_2 capture efficiency (η) is a function of various operating variables of the system for a given column design.

$$\eta_{CO2} = f(y_{CO2}, C, L/G, \phi_{lean}, T_{fg},)$$

where, y_{CO2} = CO_2 concentration in the flue gas,

                C = sorbent concentration,

                L/G = sorbent circulation,

                ϕ_{lean} = lean sorbent loading, and

                T_{fg} = temperatures of the flue gas

In the process model that we have developed here, the CO_2 capture efficiency (η) is a user-defined parameter (treated as an independent parameter) and sorbent circulation (L/G) is estimated as:

$$(L/G) = f(y_{CO2}, C, \eta_{CO2}, \phi_{lean}, T_{fg})$$

Similarly, sorbent regeneration heat requirement (Q/L) is estimated as:

$$(Q/L) = f(L/G, \phi_{lean}, C)$$

Probability distributions for these calculated parameters are not explicitly defined. Instead, the probability distributions on the independent parameters are propagated to these parameters throughout the model.

Table 3.1 (in Chapter 3) lists the probability distributions developed for performance model parameters. Similarly, Table 4.1 (in Chapter 4) lists the probability distributions developed for some of the cost model parameters. These distributions reflect both uncertainty and variability in system designs. These tables have been reproduced here for convenience. *Appendix C* discusses the basis for these distributions.

Table 3.3. Amine System Performance Model Parameters and Uncertainties

Performance Parameter	Units	Data (Range)	Nominal Value	Unc. Representation (Distribution Function)
CO_2 removal efficiency	%	Mostly 90	90	-
SO_2 removal efficiency	%	Almost 100	99.5	Uniform(99,100)
NO_2 removal efficiency	%	20-30	25	Uniform(20,30)
HCl removal efficiency	%	90-95	95	Uniform(90,95)
Particulate removal eff.	%	50	50	Uniform(40,60)
MEA concentration	wt%	15-50	30	Triangular (20,30,40)
Lean sorbent CO_2 loading	mol CO_2/mol MEA	0.15-0.30	0.2	Triangular(0.1,0.2,0.25)
Nominal MEA make-up	kg MEA/tonne CO_2	0.5-3.1	1.5	Triangular(0.5,1.5,3.1)
MEA loss (SO_2)	mol MEA/mol SO_2	2	2	-
MEA loss (NO_2)	mol MEA/mol NO_2	2	2	-
MEA loss (HCl)	mol MEA/mol HCl	1	1	-
NH_3 generation	mol NH_3/mol MEA oxidized	1	1	-
Caustic consumption in MEA reclaimer	kg NaOH/tonneCO_2	0.13	0.13	-
Activated carbon use	kg C/tonne CO_2	0.075	0.075	-
Gas-phase pressure drop	kPa	4-37	14	Triangular(4,14,37)
Fan efficiency	%	70-80	75	Uniform (70,80)
Sorbent pumping head	kPa	200	200	Triangular(150,200,250)
Pump efficiency	%	70-80	75	Uniform (70,80)
Equiv. elec. requirement	% regeneration heat	9-19	14[a]	Uniform (9,19)
CO_2 product pressure	MPa	7.58-15.16	13.79	Triangular(7.58,13.79,15.16)
Compressor efficiency	%	75-88	80	Uniform (75,88)

[a] for retrofit applications, nominal value is 22.

Table 4.4. Amine System Cost Model Parameters and Uncertainties

Cost Parameter	Units	Nominal Value	Unc. Representation (Distribution Function)
Process facilities	M$	calc	*Normal(1.0,0.1)
Engineering and home office	% PFC	7	Triangular (5,7,10)
General facilities	% PFC	10	Triangular (5,10,15)
Project contingency	% PFC	15	Triangular (10,15,20)
Process contingency	% PFC	5	Triangular (2,5,10)
Royalty fees	% PFC	0.5	Triangular (0,0.5,0.5)
Startup cost	Month of TOM	1	Triangular(0.5,1,1)
Inventory cost	% TPC	0.5	Triangular(0.4,0.5,0.6)
Total maintenance cost	% TPC	2.5	Triangular(1,2.5,5)
Operating labor	Jobs/shift	2	Triangular(1,2,3)
MEA cost	$/ tonne MEA	1200	Uniform (1100,1300)
Waste disposal cost	$/ tonne waste	175	*Normal(1.0,0.1)
CO_2 transport cost	$/ tonne CO_2/ km	0.02	Triangular (0.004,0.02,0.08)
CO_2 storage/disposal cost	$/ tonne CO_2	5	Triangular (0,5,10)
Revenue from CO_2 usage in EOR or ECBM[b]	$/ tonne CO_2	-10[a]	Triangular (-20,-10,0)

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APPENDIX C

PROBABILITY DISTRIBUTIONS FOR AMINE SYSTEM MODEL PARAMETERS

Here we briefly explain the basis for the probability distributions for various model parameters (Table 3.3 and Table 4.3) used in the probabilistic analysis presented in Chapter 5. As mentioned in *Appendix B*, these distributions take into account the data reported in literature, modeling approximations, and experts' technical judgments (especially when sufficient data is not available).

1. **CO_2 capture efficiency (%)**

Almost all the studies report CO_2 capture efficiency of 90%. This seems to be the optimum capture level in the MEA-based CO_2 capture systems, especially for Fluor Daniel's process using 30% MEA sorbent. Few studies mention desired capture efficiency of 85% or less. Only the Kerr-McGee/ ABB Lummus amine process using 20% MEA sorbent is reported to capture as high as 96% CO_2. Here we use 90% as the default value for this parameter and do not specify any distribution.

CO_2 capture efficiency (%)	Reference(s)
80	[1]
85	[2], [3]
85-90	[4]
90	[5], [6], [7], [8], [9], [10], [11], [12], [13], [14],[15], [16], [17], [18], [19], [20], [21], [22], [23]
85-95	[24], [25]
93	[26]
96	[27], [28]

2. **Acid gas removal efficiency of MEA system (%)**

MEA system designed to remove CO_2 from the flue gas also removes other acid gases (SO_2, NO_2 and HCl) if they are present. Just like other wet scrubber technologies, it also removes sizable portion of the particulate matter in the flue gas. Unfortunately, no data points are available regarding the removal efficiencies of these species in the literature.

Hence these distributions are solely based on personal communication with technical experts working in this field for a long time [29-31].

- SO$_2$ removal efficiency of MEA system (%): Uniform(99,100)

- NO$_2$ removal efficiency of MEA system (%): Uniform(20,30)

- HCl removal efficiency of MEA system (%): Uniform(90,95)

- Particulate removal efficiency of MEA system (%): Uniform(40,60)

3. **MEA concentration (% w/w)**

Today the commercially available MEA-based technology supplied by Fluor Daniel uses 30% MEA sorbent with some inhibitors. Other suppliers who do not use this inhibitor, prefer to use lower MEA concentration in the range of 15-20%. The highest MEA concentration is reported to be 50% (an optimization study, not in a real plant). Since the model is based on Fluor Daniel's Econamine FG process, the nominal value of 30% for MEA concentration is used. Given the higher energy penalty of dilute sorbent systems, it is unlikely that systems with sorbent concentrations less than 20% will be built today. At the same time, in spite of ongoing R&D efforts, an optimized amine system with 50% MEA is far from reality today. Hence a triangular distribution (20,30,40) is used to convey the variability in current commercial system designs.

MEA concentration (%)	Reference(s)
12, 18	[24], [25]
15	[2]
15-20	[32], [19]
20	[27], [28], [33]
20-30	[1], [34], [35]
30	[6], [8], [9], [12], [14], [33], [13], [4], [36], [37], [17], [24], [26]
50	[17]

4. **Lean sorbent CO$_2$ loading (mole CO$_2$ / mole MEA)**

The regenerated (or lean) sorbent contains some "left-over" CO$_2$. The level of lean sorbent CO$_2$ loading mainly depends upon the initial CO$_2$ loading in the sorbent and the amount of regeneration heat supplied, or alternatively, the regeneration heat requirement

depends on the allowable level of lean sorbent loading. The range of values reported in the literature corresponds to variety of designs and operating conditions. Although a higher value translates into lower regeneration heat requirement (and hence lower energy penalty), experts in this technology believe that operating amine system at such conditions will lead to severe corrosion and maintenance problems [29, 30]. Similarly, a very low value like 0.05 implies very high regeneration energy requirement, which may not be economically viable due to the large energy penalty. So, the first (0.05) and the last (0.3) data points have been omitted while characterizing the distribution for this parameter. Here we use a nominal value of 0.2 and a triangular distribution (0.1, 0.2, 0.25) that is based on literature survey as well as experts' opinions.

Lean sorbent CO_2 loading (mole CO_2 / mole MEA)	Reference(s)
0.05-.2	[33]
0.1	[34]
0.16	[38]
0.2	[39], [40]
0.21	[38]
0.215	[27], [28]
0.24	[17]
0.25	[17]
0.3	[2]

5. **Nominal MEA makeup (kg MEA/ tonne CO_2)**

During the normal operating conditions, MEA is lost through polymerization and oxidation reactions. In order to keep the system continuously running, sorbent makeup is required. Typically this value is reported by various studies in the units of kg MEA per tonnes of CO_2 captured. The range of values indicate both variability due to differences in system design and operating conditions as well as uncertainty due to complex chemistry involved. Here we use a nominal value of 1.5 kg MEA per tonne CO_2 captured, with a triangular distribution (0.5, 1.5, 3.1).

6.

MEA makeup rate (kg MEA/ tonne CO₂ captured)	Reference(s)
0.5-2	[20]
0.7	[28], [14]
0.9	[41]
1.5	[38], [9], [17]
1.6	[42]
1.8	[8], [11], [41]
3.1	[36]

7. **Blower pressure head (kPa)**

Blower pressure head (ΔP_{fg}) is the pressure head that needs to be provided to the flue gas in the blower so that it can overcome the pressure drop in the absorber tower. Typically, it would depend on the absorber design. We find a range of values reported in the literature, as well as indicated by the experts. Based on these numbers, the nominal value for this parameter is taken as 14. The variability is represented by a triangular distribution covering the range (4, 14, 37) of all these values.

Blower pressure head (kPa)	Reference(s)
4	[2]
5	[3], [17]
12	[28]
14	[25], [19]
15	[26]
17	[6]
20	[42], [9]
37	[33]

8. **Sorbent pumping head (kPa)**

Sorbent pumping head ($\Delta P_{sorbent}$) is the pressure head to be provided to the sorbent using sorbent circulation pumps, so that it can overcome the pressure losses in the absorber and regenerator columns. A typical value is about 200 kPa [17], and a modest range around the same has been assumed to represent the uncertainty coming from lack of sufficient data, triangular(150,200,250).

9. **Blower and pump efficiency (%)**

Flue gas blower and sorbent circulation pump are common mechanical devices used in industrial operations. These devices have performance ratings that may vary depending upon the make/type and the operating conditions. Typically, the efficiencies would be around 70-80%. Hence we use a uniform distribution (uniform (70, 80)).

10. **Equivalent electricity generation penalty (% of regeneration heat energy)**

As explained before, this factor (F_{HE}) gives the equivalent loss of power generation capacity due to extraction of steam from the power plant steam cycle to meet the sorbent regeneration heat requirement. This factor mainly depends on the design issues such as the quality of steam used for sorbent regeneration, and the level of heat integration between the base plant and the amine system. Recent developments suggest that the energy penalty can be substantially reduced by better heat integration and in-house practices [43, 44]. Here we use a nominal value of 14 with a uniform distribution (9,19) for a new plant. Retrofit applications are likely to have some constraints on the level of heat integration, and hence have a higher value for this factor. The values obtained from the literature are in the range (20,25), hence we use a nominal value of 22.

Equivalent electricity loss (%)	Reference(s)
9	[17]
16	[14], [17]
17	[45]
19	[6]
20-25	[28], [27]
22	[2], [26]
25	[3]

11. **CO$_2$ product pressure (psig)**

Most of the data sources report the value of CO_2 product pressure to be around 2000 psig. It is believed that pressure of this magnitude would be sufficient to overcome pressure losses incurred during the transport of CO_2 product over a reasonable distance (100 miles or so) without any need for recompression stations to keep the CO_2 product in liquefied state. Depending upon the assumptions about the transportation distance and other details, this value may be different. The CO_2 product pressure has to be above 1070 psig,

the critical pressure of CO_2. Also, the product pressure of 2200 psig is sufficiently high for transport of CO_2 via pipelines. So, a triangular distribution has been adopted to reflect this range 1100-2200 with a nominal value of 2000.

CO_2 product pressure (psig)	Reference(s)
1164	[17]
1207	[6]
1451	[3], [46]
1595	[2]
2000	[47], [27], [28], [48], [16], [49]
2035	[8], [11], [9]
2180	[42], [26]
3200	[5]

12. **Compressor efficiency**

This is the effective efficiency of the compressors used to compress CO_2 product to the desirable pressure. As seen from the reported data, the compression efficiencies lie in the range of about 75% to 88%. Hence the nominal value of compressor efficiency (η_{comp}) is taken as 80% with a triangular distribution to cover the data range.

CO_2 compression efficiency (%)	Reference(s)
75	[50]
75-85	[3]
85	[17]
88	[28]

It may be noted that probability distributions have not been assigned to some performance parameters such as MEA losses due to acid gases (SO_2, NO_2, HCl), ammonia generation and consumption of caustic and activated carbon. These are the parameters that reflect stoichiometry (balance among chemical species).

Next we have discussion about the probability distributions for some cost parameters.

13. **Sorbent cost ($/ tonne sorbent)**

The cost of the sorbent depends upon various market forces including the cost of natural gas (which is the ultimate feedstock for its manufacture). Hence it is likely to be

fluctuating. Based on the data and experts' judgments, the nominal value was taken as $1200/ tonne sorbent with a uniform distribution (1000, 1300).

Sorbent cost ($/ tonne sorbent)	Reference(s)
970	[42]
1189	[11]
1300	[28]
1340	[17, 51]

14. **Total maintenance cost (% TPC)**

The total maintenance cost is generally specified as a fraction of total plant cost. This parameter depends on some design parameters (*e.g.* sorbent concentration, column design) as well as the operating conditions (*e.g.* flue gas characteristics, CO_2 loading levels). Hence there is likely to be some variability as well as performance uncertainty reflected in the range of data. Based on the data as well as experts' judgments, 2.5% was taken as the nominal value with a triangular distribution (1, 2.5, 5).

Total maintenance cost (% TPC)	Reference(s)
1.5	[42]
2	[11]
2.2	[28]
4	[2]
4	[17]

15. **CO_2 transport cost**

There is a wide range of numbers reported for the cost of transporting the concentrated stream of CO_2 product. Most of the variability may be explained in terms of assumptions about the location of the pipeline and design parameters (safety factors, spare capacity *etc.*). Few representative numbers are listed here. The nominal value is taken as $0.02/ km per tonne CO_2, with a triangular distribution (0.004,0.02,0.08).

145

CO$_2$ transport cost ($/ km per tonne CO$_2$)	Reference(s)
0.004-0.03	[52]
0.01-0.03	[53]
0.01-0.05	[54]
0.012	[55]
0.024-0.061	[34]
0.03-0.08	[56]

The distributions for other cost parameters (mainly the indirect capital costs) are based on those for other environmental control technologies.

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APPENDIX D

CASE STUDY RESULTS FOR NEW COAL PLANTS

<u>Assumptions</u>:

- Base plant (Super critical PC):

    o Coal: Wyoming powder river basin, 0.48% S, 8340 Btu/lb, 23.19/tonne

    o Heat Rate: Steam cycle HR 6750 Btu/kWh = Gross cycle HR 7923 Btu/kWh

- SO_2 control: FGD system using limestone

- CO_2 control:

    o MEA system using 30% w/w MEA-based sorbent

    o CO_2 product compression to 2000 psig

    o cost for CO_2 transport = $7/ tonne CO_2 (100 miles @ $0.0426/tonne CO_2 per km)

    o cost for CO_2 disposal = $5/ tonne CO_2

- Other details as mentioned in Tables 3.3, 4.2, 4.3 and 5.1.

Parameter	Reference Plant	Capture Plant (A)	% change	Capture Plant (B)	% change
Model Inputs:					
Gross capacity (MW)	500	500	0%	670	+34%
FGD efficiency (%)	95	99		99	
CO_2 capture efficiency (%)	-	90		90	
Energy Penalty:					
Base plant, PC (MW)	29.3	29.3	0%	39.2	+34%
FGD System (MW)	9.5	13.7	+43.4%	18.3	+92%
ESP (MW)	0.9	0.9	0%	0.9	0%
SCR (MW)	2.7	2.7	-0.4%	3.6	+33%
MEA: Regen. heat req. (equiv.)	-	60.8		81.5	
MEA: fans (MW)	-	10.4		14.0	
MEA: pumps (MW)	-	0.9		1.1	
MEA: CO_2 compression (MW)	-	40.3		54.0	

Parameter	Reference Plant	Capture Plant (A)	% change	Capture Plant (B)	% change
MEA: total (MW)	-	112.4		150.6	
Total energy penalty (MW)	42.4	158.4	+275%	212.6	+402%
7.5 Plant Performance					
Total energy penalty (%MW$_g$)	8.5%	31.8%	+275%	31.7%	+275%
Net power generation (MW)	457.6	341.2	-26%	457.6	0%
Net cycle heat rate (Btu/kWh)	8,657	11,560	+34%	11,550	+33%
Sorbent regen. heat (kJ/kgCO$_2$)	-	4575		4575	
Plant Consumption:					
Coal consumption (tonne/hr)	215.5	214.6	-0.4%	287.5	+33%
Limestone consumed (tonne/hr)	2.3	2.4	+4%	3.2	+39%
MEA consumed (kg/hr)	-	789		1057	
Emissions/ Discharges:					
CO$_2$ emission (tonne/ hr)	381.3	38.0	-90%	50.9	-87%
NO$_x$ emission (kg/ hr)	269.5	265.0	-2%	355.2	+32%
SO$_x$ emission (kg/ hr)	76.4	0.11	-99.9%	0.14	-99.8%
NH$_3$ emission (kg/ hr)	5.4	29.8	+457%	40.0	+648%
CO$_2$ emission (gCO$_2$/ kWh)	833.3	111.3	-87%	111.2	-87%
NO$_x$ emission (gNO$_x$/ kWh)	0.59	0.78	+32%	0.78	+32%
SO$_x$ emission (gNO$_x$/ kWh)	0.17	0.0003	-99.8%	0.0003	-99.8%
Bottom ash (tonne/hr)	3.5	3.5	-0.4%	4.6	+33%
Fly ash (tonne/hr)	8.0	8.0	-0.4%	10.7	+34%
FGD waste (tonne/hr)	4.2	4.3	+4%	5.8	+39%
Spent MEA sorbent (tonne/hr)	-	1.0		1.4	
CO$_2$ product (tonne/ hr)	-	342		458	
Capital costs (TCR, M$)					
PC	516.2	513.6	-0.5%	646.0	+25%
ESP	23.5	22.1	-6%	27.8	+18%
FGD	48.3	50.1	+4%	57.6	19%
SCR	27.6	27.7	+0.2%	34.8	26%

Parameter	Reference Plant	Capture Plant (A)	% change	Capture Plant (B)	% change
MEA	-	146.5		196.6	
Total - TCR (M$)	615.7	760.1	+24%	962.8	+56%
Normalized TCR ($/ kW)	1345	2228	+66%	2104	+56%
Parameter	**Reference Plant**	**Capture Plant (A)**	*% change*	**Capture Plant (B)**	*% change*
O&M costs (M$/yr)					
MEA – FOM	-	4.1		5.3	
MEA – reagent	-	6.5		8.7	
MEA – power	-	13.5		17.2	
MEA – steam (equiv.)	-	15.9		20.2	
MEA – CO_2 transport	-	7.2		9.7	
MEA – CO_2 disposal	-	11.2		15.1	
TOM – MEA	-	61.3		79.9	
TOM – PC	44.4	13.3	-70%	17.9	-60%
TOM – ESP	1.6	1.6	-1.4%	1.8	+16%
TOM – FGD	7.5	8.6	+16%	10.2	+36%
TOM – SCR	4.2	4.2	-0.5%	5.5	+30%
8. OVERALL PLANT COSTS					
Fuel cost	32.9	32.7	-0.4%	43.8	+34%
TOM – whole plant	57.6	89.1	+55%	115.2	+100%
TRR (M$/ yr), whole plant	148.7	201.5	+36%	257.7	+73%
COE ($/ MWh)	49.4	89.9	+82%	85.7	+73%
$/ tonne CO_2 avoided	-	56.0		50.2	
$/ tonne CO_2 delivered	-	40.3		36.2	

APPENDIX E

QUESTIONNAIRE SENT TO EXPERTS ON AMINE-BASED CO₂ CAPTURE TECHNOLOGY

Thank you for agreeing to assist us in our work on characterizing the uncertainty and variability associated with the performance of amine-based CO_2 capture technology. We plan to use your answers, and those of other experts as inputs to engineering-economic models we have developed to characterize the performance and cost of these systems. While we will acknowledge the experts who have assisted us in this effort, we will not identify any expert with any specific response. If you have questions or concerns please contact me:

By E-mail: abr@cmu.edu, or

By Phone: (412) 268-6826 or (412) 268-6115, or

By Fax: (412) 268-1089 (attn: Anand B. Rao)

Please also send your responses by email or fax, or by regular mail to:

Anand B. Rao
Department of Engineering & Public Policy
Carnegie Mellon University
Pittsburgh, PA 15213, USA.

Alternatively, if you prefer, I can give you a call and note down your responses.

In the pages that follows we:

1. provide some background on the problem

2. list the key assumptions we are using in our model and ask you to comment on their appropriateness *for current systems*

3. ask you to make judgments about the likely values of a number of key coefficients *for future systems*

4. ask you to provide a ranking of various research objectives to reduce the cost of CO_2 capture and sequestration from flue gas streams.

We estimate that you may need approximately 40-50 minutes to complete this questionnaire, and hope you will find that acceptable. We really appreciate your time and help, and will be happy to share our findings with you at the end of this study.

Part 1: Background

Development of improved technology to capture and sequester the CO_2 emitted by power plants using fossil fuels — especially coal — is the subject of major research efforts worldwide. The attraction of this option is that it would allow abundant world resources of fossil fuels to be used for power generation and other applications without contributing significantly to atmospheric emissions of greenhouse gases. The two key barriers to carbon capture and sequestration (CCS), however, are the high cost of current CO_2 capture technologies, and uncertainties regarding the technical, economic and political feasibility of CO_2 storage options.

As part of the USDOE's Carbon Sequestration Program, we have developed an integrated modeling framework to evaluate the performance and costs of alternative CO_2 capture and sequestration technologies for fossil-fueled power plants, in the context of multi-pollutant control requirements. This model (called the IECM-CS) allows for explicit characterization of the uncertainty or variability in any or all model input parameters. One of the purposes of this model is to improve the understanding in both the technical and policy communities about the magnitude of CCS cost and the various factors that affect it. We also want to explore the potential for reducing costs through targeted R&D.

At this stage, many of the model parameter values and uncertainty distributions have been based on information gathered from the literature. This approach has its limitations owing to the limited availability of data and possibility of inconsistent assumptions across different studies. An alternative method that can allow a more robust analysis of uncertainty and variability involves the development of expert judgments. Here, we want to understand how experts in this field would characterize some of the key parameters that affect the performance and cost of a particular CO_2 capture technology, namely, amine-based absorption of CO_2 from flue gas. We are interested both in current system designs, and improved future designs that you might envision.

Please briefly review the *Supplementary Information* on the next two pages to make sure that we use a consistent terminology during this exercise.

Overview of amine-based CO_2 capture systems

The idea of separating CO_2 from flue gas streams started in the 1970s, not with concern about the greenhouse effect, but as a potentially economic source of CO_2, mainly for enhanced oil recovery (EOR) operations. Several commercial CO_2 capture plants were constructed in the U.S. in the late 1970s and early 1980s. CO_2 was also produced for other industrial applications such as carbonation of brine and production of products like dry ice, urea and beverages. Some of these CO_2 capture plants are still in operation today, but all these plants are much smaller than a typical power plant. The first commercial CO_2 sequestration facility started in Norway in September 1996 in response to a Norwegian carbon tax. Since then, Statoil has been storing CO_2 from the Sleipner West gas field in a sandstone aquifer 1000 m beneath the North Sea. The international research community is closely monitoring this facility.

All these plants capture CO_2 with processes based on chemical absorption using a monoethanolamine (MEA)-based solvent. MEA is an organic chemical belonging to the family of compounds known as amines. It was developed over 60 years ago as a general, non-selective solvent to remove acidic gas impurities (e.g. H_2S, CO_2) from natural gas streams. The process was then adapted to treat flue gas streams for CO_2 capture. Fluor Daniel Inc., Dow Chemical Co., Kerr-McGee Chemical Corp. and ABB Lummus Crest Inc., were some of the initial developers of MEA-based technology for CO_2 capture. Typically, about 75% to 90% of the CO_2 is captured using this technology, producing a nearly pure (>99%) CO_2 product stream.

Process Description

A continuous scrubbing system is used to separate CO_2 from the flue gas stream. The system consists of two main elements: an absorber where CO_2 is removed, and a regenerator (or stripper) where CO_2 is released (in concentrated form) and the sorbent is recovered.

*Cross Heat -Exchanger
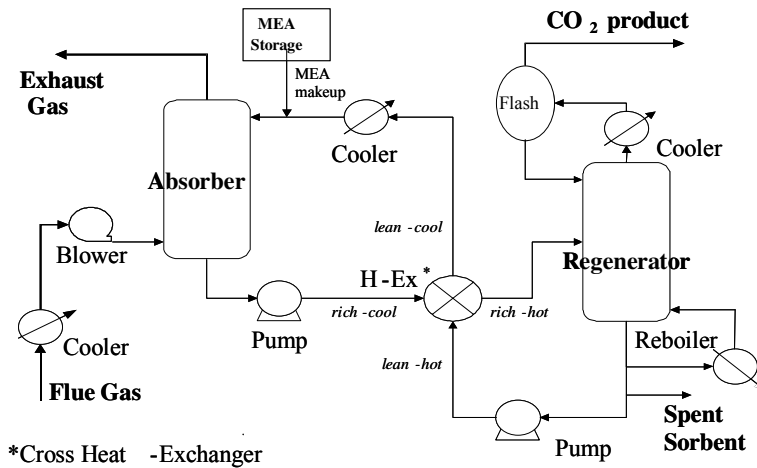
In a power plant application, cooled flue gases flow vertically upwards through the absorber countercurrent to the absorbent (consisting of MEA in a water solution, often with some additives to inhibit corrosion). The MEA reacts chemically with the CO_2 in the flue gases to form a weakly bonded compound called carbamate. The scrubbed gases are then washed and vented to the atmosphere. The CO_2-rich solution leaves the absorber and passes through a heat exchanger, then is further heated in a reboiler using low-pressure steam. The carbamate formed during absorption is broken down by the application of heat, regenerating the solvent, and producing a concentrated CO_2 stream. The hot CO_2-lean solvent is then returned to the heat exchanger, where it is cooled, then sent back to the absorber. Some fresh MEA is added to make up for losses incurred in the process. The process chemistry is complex, but the main reactions taking place are:

CO_2 Absorption: $2 \, R\text{-}NH_2 \, (MEA) + CO_2 \rightarrow R\text{-}NH_3^+ + R\text{-}NH\text{-}COO^-$ (Carbamate)   (1)

MEA Regeneration: $R\text{-}NH\text{-}COO^- + R\text{-}NH_3^+ + \text{Heat} \rightarrow CO_2 + 2 \, R\text{-}NH_2$ (2)
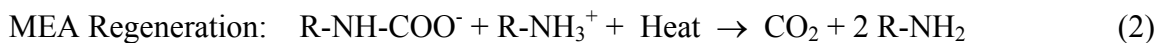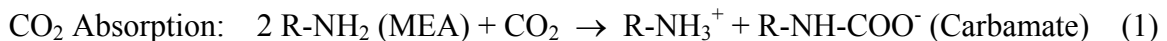
Pure MEA (with $R = HO\text{-}CH_2CH_2$) is an "unhindered" amine that forms stable carbamate; hence, only half a mole of CO_2 is absorbed per mole of amine, as shown in Reaction (1). For other "hindered" amines (where R is a bulky group), the carbamate formed is not stable, and an alternate reaction leads to a higher theoretical capacity of one mole of CO_2 per mole of amine. But the CO_2 uptake rate of hindered amines is very low. Efforts are underway to formulate better solvents by combining favorable properties of these two groups of amines.

157

Some of the solvent also is lost during the process because of physical losses, entrainment, vaporization and chemical degradation. All the solvent entering the stripper does not get regenerated. Flue gas impurities, especially oxygen, sulfur dioxide and nitrogen dioxide react with MEA to form heat-stable salts, thus reducing the CO_2-absorption capacity of the solvent. However, proprietary inhibitors are available that can render the solvent tolerant to oxygen. Flue gas NO_x is not a major problem since the predominant form ($\sim 95\%$) of total NO_x in the flue gas is nitric oxide (NO), which does not react with inhibited amines. But SO_2 and NO_2 do react to degenerate MEA solvent, so very low inlet concentrations of these gases (on the order of 10 ppm) are desirable to avoid excessive loss of solvent. Since the untreated flue gases of coal-fired power plants typically contain about 700 to 2500 ppm SO_2 (plus roughly 10-40 ppm NO_2), the interaction of SO_2 with the CO_2 control system is particularly important. The heat-stable salts that are formed in these reactions may be treated in a side-stream MEA reclaimer, which can regenerate some of the MEA. Technologies such as electrodialysis are also being proposed for this purpose.

Finally, corrosion control is very important in amine systems, especially when processing oxygen-containing gases. In order to reduce corrosion rates, corrosion inhibitors, low concentrations of MEA, appropriate materials of construction and mild operating conditions are required.

A key feature of amine systems is the large amount of heat required to regenerate the solvent. This heat is typically drawn from the steam cycle and significantly reduces the net efficiency of the power plant. Substantial electrical energy also is needed to compress the captured CO_2 for pipeline transport to a storage site. As shown later in this paper, the overall energy penalty of this process has a major impact on system performance as well as cost.

From a multi-pollutant perspective, there are also important interactions between the CO_2 capture system and the control of other air pollutants, especially SO_2 and NO_x emissions. Acid gases like SO_2 and NO_2 react with MEA to form heat-stable salts that reduce the CO_2 absorption capacity of the solvent. Thus, very low concentrations of these gases (on

the order of 10 ppm) are desirable to avoid excessive loss of (costly) solvent. The problem is especially acute for SO_2 because its concentration in flue gases is typically 700 to 2500 ppm at coal-fired plants. NO_x is less of a problem because most of the NO_x is nitric oxide (NO), whereas only NO_2 (typically about 5% of total NO_x) is reactive (see Supplementary Information for additional details).

Part 2: Current Amine Systems

To begin with, please consider a CO_2 capture system which:
- uses 30% (by weight) MEA-based sorbent,
- treats the flue gas stream from a coal-combustion source which has a CO_2 concentration of about 12% (by volume) and which has been pre-treated for removal of SO_x and NO_x and cooled to a desired absorber inlet temperature,
- and removes 90% of CO_2 from the flue gas stream.

In the table that follows we have summarized the base case key parameters that we ask you to comment upon. These parameters are intended to characterize the performance of a <u>current commercial system</u> as system described above and in the supplemental information given earlier.

Please indicate whether you find each of these nominal values and ranges to be reasonable. If not, please indicate the value you would prefer and provide us with a brief explanation. <u>If you prefer to use different units than the ones shown here, please indicate clearly the measure that you prefer.</u>

Parameter	Accept-ability	If not OK, New Value	Explanation of change
Absorber inlet flue gas pressure			
Nominal value = 26 kPa gauge = 3.8 psig	o OK o not OK		
Range = 14 - 30 kPa gauge = 2 - 4.4 psig	o OK o not OK		
Temperature of flue gas entering the absorber			
Nominal value = 60 deg C = 140 deg F	o OK o not OK		
Range = 50 - 62 deg C = 122 - 144 deg F	o OK o not OK		
Lean sorbent CO_2 loading (mole CO_2/ mole sorbent)			
Nominal value = 0.2 = 7.3 x10^{-3} SCF CO_2/ gal soln	o OK o not OK		
Range = 0.15 - 0.25 = 5.5 – 9.1 x10^{-3} SCF CO_2/ gal	o OK o not OK		

Parameter	Accept-ability	If not OK, New Value	Explanation of change
Heat required for sorbent regeneration (kJ / kg CO_2)			
Nominal value = 4350 = 2.2 lb steam/ lb CO_2	o OK o not OK		
Range = 3500 - 6000 = 1.75 – 3.00 lb steam/ lb CO_2	o OK o not OK		
Allowable levels of other components in flue gas			
SO_2 < 10 ppmv	o OK o not OK		
NO_2 < 10 ppmv	o OK o not OK		
O_2 ~ 3.5 % by volume	o OK o not OK		
Maximum train size (tonnes CO_2 per day)			
Nominal value = 5000	o OK o not OK		
Energy required for CO_2 compression to 2000 psig (kWh / tonne CO_2)			
Nominal value = 119	o OK o not OK		
Range = (112, 145)	o OK o not OK		

Part 3: Judgments About Future Amine Systems

In this section we would like to obtain your technically informed probabilistic judgments about several key parameters of a future amine-based CO_2 capture system built around the year 2015. We would like you to consider all of the parameters listed, but feel free to skip any parts that you are not comfortable with. <u>Also, if you prefer to use some different unit of measurement in your answer, please mention it clearly</u>.

In producing your answers please assume that:

- We are still talking about an amine-based plant that treats the flue gas stream from a coal-combustion source, which is about 12%, CO_2 and which has been pre-treated for removal of SO_x and NO_x, and removes 90% of CO_2 from the flue gas stream.

- The plant has been optimized for the lowest overall cost of CO_2 avoidance ($/ tonne CO_2 avoided), considering both capital and operating costs (including energy costs) over the life of the plant.

- R&D support for this technology continues to steadily grow at a modest rate through 2015, and includes several new large-scale applications to coal-fired power plants.

Parameter 1: Amine sorbent concentration (wt %)

First please give us your <u>highest</u> estimate of the value that you think that amine sorbent concentration might be in state-of-the-art operating plants by 2015.

wt%

Suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 1.15 times this value. Can you think of any plausible story of how that might have happened?

o No o Yes

If you answered yes, briefly what is the story:

Is there at least a 5% probability that this story could turn out to be true?

o No o Yes

Next we'd like your <u>lowest</u> estimate of the value that you think that sorbent concentration might be in state-of-the-art operating plants by 2015.

wt%

Again, suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 0.85 times this value. Can you think of any plausible story of how that might have happened?

o No o Yes

If you answered yes, briefly what is the story:

Is there at least a 5% probability that this story could turn out to be true?

o No o Yes

Finally we'd like your <u>best</u> estimate of the value that you think that average sorbent concentration might be in state-of-the-art operating plants by 2015.

wt%

Parameter 2: Unit heat requirement for sorbent regeneration

First please give us your <u>lowest</u> estimate of the value that you think that sorbent regeneration heat requirement might be in state-of-the-art operating plants by 2015.

kJ/ kg CO_2 captured (or   lb steam/ lb CO_2 captured)

Suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 0.85 times this value. Can you think of any plausible story of how that might have happened?

o No o Yes

If you answered yes, briefly what is the story:

Is there at least a 5% probability that this story could turn out to be true?

o No o Yes

Next we'd like your <u>highest</u> estimate of the value that you think that sorbent regeneration heat requirement might be in state-of-the-art operating plants by 2015.

kJ/ kg CO$_2$ captured (or   lb steam/ lb CO$_2$ captured)

Again, suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 1.15 times this value. Can you think of any plausible story of how that might have happened?

o No o Yes

If you answered yes, briefly what is the story:

Is there at least a 5% probability that this story could turn out to be true?

o No o Yes

Finally we'd like your <u>best</u> estimate of the value that you think that sorbent regeneration heat requirement might be in state-of-the-art operating plants by 2015.

kJ/ kg CO$_2$ captured (or   lb steam/ lb CO$_2$ captured)

Parameter 3: Nominal sorbent loss (kg sorbent / tonne CO$_2$ captured)

First please give us your <u>lowest</u> estimate of the value that you think that nominal sorbent loss might be in state-of-the-art operating plants by 2015.

kg/ tonne CO$_2$ captured

Suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 0.85 times this value. Can you think of any plausible story of how that might have happened?

o No o Yes

If you answered yes, briefly what is the story:

Is there at least a 5% probability that this story could turn out to be true?

Next we'd like your <u>highest</u> estimate of the value that you think that nominal sorbent loss might be in state-of-the-art operating plants by 2015.

$$\boxed{\textbf{kg/ tonne } CO_2 \textbf{ captured}}$$

Again, suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 1.15 times this value. Can you think of any plausible story of how that might have happened?

o No o Yes

If you answered yes, briefly what is the story:

_____

_____

_____

Is there at least a 5% probability that this story could turn out to be true?

o No o Yes

Finally we'd like your <u>best</u> estimate of the value that you think that average nominal sorbent loss might be in state-of-the-art operating plants by 2015.

$$\boxed{\textbf{kg/ tonne } CO_2 \textbf{ captured}}$$

Parameter 4: Cost of sorbent (US$ / tonne sorbent)

First please give us your <u>lowest</u> estimate of the value that you think that unit cost of sorbent might be in state-of-the-art operating plants by 2015.

$$\boxed{\textbf{US\$ / tonne sorbent}}$$

Suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 0.85 times this value. Can you think of any plausible story of how that might have happened?

o No o Yes

If you answered yes, briefly what is the story:

_____

_____

_____

Is there at least a 5% probability that this story could turn out to be true?

o No o Yes

Next we'd like your <u>highest</u> estimate of the value that you think that unit cost of sorbent might be in state-of-the-art operating plants by 2015.

$$\boxed{\textbf{US\$ / tonne sorbent}}$$

Again, suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 1.15 times this value. Can you think of any plausible story of how that might have happened?

<div align="center">o No o Yes</div>

If you answered yes, briefly what is the story:

_____

_____

_____

Is there at least a 5% probability that this story could turn out to be true?
<div align="center">o No o Yes</div>

Finally we'd like your <u>best</u> estimate of the value that you think that average unit cost of sorbent might be in state-of-the-art operating plants by 2015.

<div align="center">

US$ / tonne sorbent

</div>

Parameter 5: Other Sorbents

The preceding questions have all focused on amine-based sorbents. Today there is much research being directed at developing alternative sorbents for post-combustion CO_2 capture from flue gas. How likely do you think it is that by 2015 there will be some other commercially available sorbent (other than advanced amines) that significantly out-performs amine-based sorbents in CO_2 capture from flue gas and which is economically competitive? (please mark an <u>X</u> on the line)

<div align="center">

0.0   0.2   0.4   0.6   0.8   1.0
├────────┼────────┼────────┼────────┼────────┤

</div>
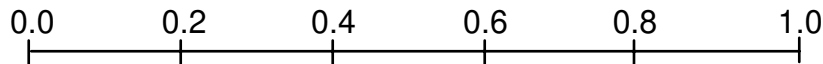
If your answer was less than 0.5, do you think that some other commercially available and economically competitive sorbent will become available some time after 2015?

      o No

      o Yes in approximately the year 20____

The next page addresses a parameter related to CO_2 compression. Please address this too if you can. You may assume that the product CO_2 flow rate is about 400 tonne CO_2 / hr (with 99.8% purity).

Parameter 6: Energy required for CO$_2$ Compression

First please give us your <u>highest</u> estimate of the value that you think that energy requirement for CO$_2$ compression might be in state-of-the-art operating plants by 2015.

> **kWh/ tonne CO$_2$**, or **compressor efficiency =**   **%**

Suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 1.15 times this value. Can you think of any plausible story of how that might have happened?

<div align="center">o No o Yes</div>

If you answered yes, briefly what is the story:

___

Is there at least a 5% probability that this story could turn out to be true?
<div align="center">o No o Yes</div>

Next we'd like your <u>lowest</u> estimate of the value that you think that energy requirement for CO$_2$ compression might be in state-of-the-art operating plants by 2015.

> **kWh/ tonne CO$_2$**, or **compressor efficiency =**   **%**

Again, suppose that we have a clairvoyant who can look ahead to 2015 and tells you that the actual number is 0.85 times this value. Can you think of any plausible story of how that might have happened?

<div align="center">o No o Yes</div>

If you answered yes, briefly what is the story:

___

Is there at least a 5% probability that this story could turn out to be true?
<div align="center">o No o Yes</div>

Finally we'd like your <u>best</u> estimate of the value that you think that average energy requirement for CO$_2$ compression might be in state-of-the-art operating plants by 2015.

> **kWh/ tonne CO$_2$**, or **compressor efficiency =**   **%**

Part 4: Judgments About Overall Plant Performance and Cost

In the following questions we want your comparative judgments about the overall performance and cost of a state-of-the-art operating coal-fired power plant in the year 2015, with and without amine-based CO$_2$ capture system. Please keep in mind that the terms "reference plant" and "capture plant" refer to the following:

Reference Plant:

- **New low-S coal-fired power plant with environmental control units (ESP, FGD and SCR)**
- Net generation = 500 MW

Capture Plant:

- **New low-S coal-fired power plant (similar to the reference plant) with environmental control units (ESP, FGD and SCR)**
- Amine-based CO_2 capture system to capture 90% CO_2 from the power plant flue gas stream
- The product CO_2 is compressed to 2000 psig (for transport to a disposal site)
- Net power generation = 500 MW
- Costs of CO_2 transport and storage are **not** included

Note: In questions about plant cost, you should also assume:

- **A mid-western US plant location**

- **Total capital requirement (TCR) includes interest during construction and other owner's costs**

- **The cost of fuel is US$1.2/GJ (HHV basis)**

- **Currency is current US dollars (US$)**

Again, feel free to skip any question you're not comfortable expressing a judgment about.

Parameter 7: Net Plant Efficiency

Consider the **reference plant** as described on the previous page.

First please give us your <u>highest</u> estimate of the value that you think that the net efficiency (HHV basis) of this reference plant might be in 2015:

%

Next we'd like your <u>lowest</u> estimate of the value that you think that the net efficiency (HHV basis) of this reference plant might be in 2015:

%

Finally we'd like your <u>best</u> estimate of the value that you think that average net efficiency (HHV basis) of this reference plant might be in 2015.

%

Now consider the **capture plant** as described on the previous page.

First please give us your <u>highest</u> estimate of the value that you think that the net efficiency (HHV basis) of this CO_2 capture plant might be in 2015:

% efficiency points lost, or	**% net efficiency**

Next we'd like your <u>lowest</u> estimate of the value that you think that the net efficiency (HHV basis) of this CO_2 capture plant might be in 2015:

% efficiency points lost, or	**% net efficiency**

Finally we'd like your <u>best</u> estimate of the value that you think that average net efficiency (HHV basis) of this CO_2 capture plant might be in 2015.

% efficiency points lost, or	**% net efficiency**

Parameter 8: Total Capital Requirement

Consider the **reference plant** as described on the previous page.

First please give us your <u>highest</u> estimate of the value that you think that the total capital requirement of this reference plant might be in 2015:

$$\boxed{\qquad \textbf{M\$ (or} \qquad \textbf{\$/kW}_{\textbf{net}}\textbf{)}}$$

Next we'd like your <u>lowest</u> estimate of the value that you think that the total capital requirement of this reference plant might be in 2015:

$$\boxed{\qquad \textbf{M\$ (or} \qquad \textbf{\$/kW}_{\textbf{net}}\textbf{)}}$$

Finally we'd like your <u>best</u> estimate of the value that you think that average total capital requirement of this reference plant might be in 2015.

$$\boxed{\qquad \textbf{M\$ (or} \qquad \textbf{\$/kW}_{\textbf{net}}\textbf{)}}$$

Now consider the **capture plant** as described on the previous page.

First please give us your <u>highest</u> estimate of the value that you think that the total capital requirement of this CO_2 capture plant might be in 2015:

$$\boxed{\qquad \textbf{M\$ (or} \qquad \textbf{\$/kW}_{\textbf{net}}\textbf{)}}$$

Next we'd like your <u>lowest</u> estimate of the value that you think that the total capital requirement of this CO_2 capture plant might be in 2015:

$$\boxed{\qquad \textbf{M\$ (or} \qquad \textbf{\$/kW}_{\textbf{net}}\textbf{)}}$$

Finally we'd like your <u>best</u> estimate of the value that you think that total capital requirement of this CO_2 capture plant might be in 2015.

$$\boxed{\qquad \textbf{M\$ (or} \qquad \textbf{\$/kW}_{\textbf{net}}\textbf{)}}$$

Parameter 9: Cost of Electricity

Consider the **reference plant** as described on the previous page.

First please give us your <u>highest</u> estimate of the value that you think that the cost of electricity generated from this reference plant might be in 2015:

$/MWh (or	**cents/kWh)**

Next we'd like your <u>lowest</u> estimate of the value that you think that the cost of electricity generated from this reference plant might be in 2015:

$/MWh (or	**cents/kWh)**

Finally we'd like your <u>best</u> estimate of the value that you think that average cost of electricity generated from this reference plant might be in 2015.

$/MWh (or	**cents/kWh)**

Did you have a particular capacity factor (load factor) and capital charge factor (fixed charge factor) in mind for these estimates? If so, what are they:

Capacity factor	**% (or hours/yr)**
Capital charge factor	**% (or plant life = yr & *i* = %)**

Now consider the **<u>capture plant</u>** as described on the previous page.

First please give us your <u>highest</u> estimate of the value that you think that the cost of electricity generated from this plant might be in 2015:

$/MWh (or	**cents/kWh)**

Next we'd like your <u>lowest</u> estimate of the value that you think that the cost of electricity generated from this CO_2 capture plant might be in 2015:

$/MWh (or	**cents/kWh)**

Finally we'd like your <u>best</u> estimate of the value that you think that cost of electricity generated from this CO_2 capture plant might be in 2015.

$/MWh (or	**cents/kWh)**

Did you have a particular capacity factor (load factor) and capital charge factor (fixed charge factor) in mind for these estimates? If so, what are they:

Capacity factor	**% (or hours/yr)**
Capital charge factor	**% (or plant life = yr & *i* = %)**

Part 5: Research Priorities

Today there is an ongoing effort worldwide to bring down the cost of CO_2 capture and sequestration from flue gas streams. The factors affecting this cost may be categorized as:

a) factors related to the "base" power plant (including other environmental control units)

b) factors related to the amine-based CO_2 capture technology

c) factors related to the post-capture processing of the concentrated CO_2 stream

On the following pages you will find a list of research objectives that may help reduce the overall cost of CO_2 capture and sequestration from flue gas streams. We would like to know how you would prioritize R&D efforts in these areas.

You may also add more items to this list (items D1, D2 etc.), and take them into consideration while going through the ranking exercise.

Initially, please indicate your priorities as:

H: <u>High</u> priority   **M**: <u>Medium</u> priority   **L**: <u>Low</u> priority

Finally, please further prioritize your preferences on the same page, by putting a rank/number against each **<u>High Priority</u>** item, taking into account the potential effectiveness of these factors. (You may give the same rank/number to two or more items if you think they are equally preferred). Please note that <u>rank 1 indicates the highest priority</u>.

H: <u>High</u> priority   **M**: <u>Medium</u> priority   **L**: <u>Low</u> priority

[H / M / L]   (RANK)

A1: [   ] To develop more efficient power plants (lower heat rate)   (   )

A2: [   ] To improve boiler designs so that fuel can be burned with lower excess air
      (typically for a coal plant, ~20% excess air is used)   (   )

A3: [   ] To develop more efficient technologies for SO_x and NO_x control so as to
      reduce the acidic gas impurities in the flue gas stream   (   )

A4: [   ] To improve heat integration within the power plants to reduce the energy
      penalty for CO_2 capture due to steam extraction for sorbent regeneration   (   )

B1: [   ] To develop more efficient fans for flue gas handling   (   )

B2: [   ] To develop CO_2 absorbers that can handle higher sorbent concentrations   (   )

B3: [   ] To develop sorbents with higher CO_2 loading capacity   (   )

B4: [   ] To develop sorbents with lower regeneration energy requirement   (   )

B5: [   ] To develop absorber columns offering lower pressure drops
(   )

B6: [   ] To develop absorber columns offering higher CO_2 capture efficiencies   (   )

B7: [   ] To develop more efficient pumps for sorbent circulation   (   )

B8: [   ] To develop more efficient heat exchanging devices
(   )

B9: [   ] To reduce the cost of sorbent manufacturing   (   )

B10:[   ] To develop sorbents with lower makeup requirements (less losses)   (   )

B11:[   ] To develop less expensive technologies for disposal of spent sorbents   (   )

B12:[   ] To develop better instrumentation/ automation in the CO_2 capture system
      so as to reduce the labor requirement   (   )

B13:[   ] To develop better construction materials so as to reduce the losses due to
      corrosion   (   )

C1: [   ] To develop more efficient compressors for CO_2 compression   (   )

C2: [   ] To develop a transport technology that can handle low-pressure
      CO_2 streams   (   )

C3: [   ] To develop less expensive technologies for CO_2 storage/ disposal   (   )

D1: [   ]   (   )

D2: [   ]   (   )

D3: [   ]   (   )

D4: [   ]   (   )

D5: [   ]   (   )

AN INTEGRATED MODELING FRAMEWORK
FOR CARBON MANAGEMENT TECHNOLOGIES

Volume 2 – IECM-*cs* User Manual:
Amine-Based CO₂ Capture and Storage Systems
for Fossil Fuel Power Plant

Final Report of

Work Performed Under Contract No.: DE-FC26-00NT40935
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Report Submitted, March 2004

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Disclaimer

Abstract

This Integrated Environmental Control Model (IECM) and Interface were developed for the U. S. Department of Energy's National Energy Technology Laboratory (NETL), formerly known as the Federal Energy Technology Center (FETC), under contracts No. DE-AC22-92PC91346, DE-AC21-92MC29094, and DE-FC26-00NT40935.

The purpose of the model is to calculate the performance, emissions and cost of employing alternative environmental control methods in a coal-fired power plant. The model consists of a base plant and various control technology modules; these modules may be implemented together in any desired combination.

A Graphical User Interface (GUI) facilitates the configuration of the technologies, entry of data, and retrieval of results. This *User Manual* gives information on both the interface and the underlying model. It provides detailed descriptions of plant configurations, parameter settings, and result screens. It also describes technical details behind the model's operation and includes an introduction to uncertainty analysis.

Contents

Hot-Side SCR   95

Mercury   113

Cold-Side ESP   131

Fabic Filter   145

Wet FGD   161

By Product Management 233

Stack 239

Units 243

Working with Graphs 245

Running a Probabilistic Analysis 247

Appendix A - Introduction to Uncertainty Analysis 253

Introduction

The Integrated Environmental Control Model

This Integrated Environmental Control Model (IECM) and Interface were developed for the U. S. Department of Energy's National Energy Technology Laboratory (NETL), formerly known as the Federal Energy Technology Center (FETC), under contracts No. DE-AC22-92PC91346, DE-AC21-92MC29094, and DE-FC26-00NT40935.

Purpose

The purpose of the model is to calculate the performance, emissions and cost of employing alternative environmental control methods in a coal-fired power plant. The model consists of a base plant and various control technology modules; these modules may be implemented together in any desired combination.

A Graphical User Interface (GUI) facilitates the configuration of the technologies, entry of data, and retrieval of results.

System Requirements

The current model requires the following configuration:

- Intel-based computer running Windows 95 (or better) or Windows NT 4.0 (or better) operating system

- Pentium Processor

- any SVGA (or better) display—at a resolution of 800x600 (or more) pixels[1]

- at least 40 Megabytes of free hard disk space

- at least 32 Megabytes of total memory

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[1] Smaller screen resolution results in the interface screens being scaled smaller. The taskbar, part of the Windows operating system, reduces the useable resolution of the screen if it is always visible. This may force the IECM interface to be scaled down slightly. To avoid this situation, select the "Auto Hide" option of the Taskbar properties in Windows.

Uncertainty Features

The ability to characterize uncertainties explicitly is a feature unique to this model. As many as one hundred input parameters can be assigned probability distributions. When input parameters are uncertain, an uncertainty distribution of results is returned. Such result distributions give the *likelihood* of a particular value, in contrast to conventional single-value estimates.

The model can run using single deterministic values or uncertainty distributions. The conventional deterministic form using single values for all input parameters and results may be used, or probabilistic analyses may be run—for instance, to analyze advanced technology costs.

Software Used in Development

The underlying engineering models are written in Digital Equipment Corporation's Fortran. Fortran runtime libraries are included with the IECM Interface software. This language provides the flexibility to configure many various power plant designs while also providing the power to conduct probabilistic analyses.

All databases are in Microsoft® Access format and may be viewed in Access, as long as they are not changed. This format is a software industry standard and facilitates sharing and updating of information.

To simplify the use of the model, a Graphical User Interface (GUI) has been added. The interface eliminates the need to master the underlying commands normally required for model operation. The interface is written in Microsoft® Visual C++, a standard software development tool for the Windows environment. Visual C++ runtime libraries are included with the IECM Model software and do not need to be licensed separately.

Wise InstallBuilder was used to generate full and upgrade installer programs. This product was chosen based on its flexibility and its support of Visual Basic runtime libraries and Microsoft Data Access Components (MDAC)[2]. The Visual Basic runtime libraries provide the support needed to run the database file compactor program provided with the IECM. MDAC provides the software support needed to link Microsoft® Access data files to the IECM interface program. Wise InstallBuilder provides the VB and MDAC installation as an option, rather than forcing the user to download it from Microsoft and install it prior to installing the IECM.

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[2] The current version of MDAC is 2.6. This is installed with the full installer for the IECM. Any update installers provided for upgrading the IECM from a previous version to the current version do not upgrade MDAC unless the user updates MDAC separately.

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User Documentation and Help

Getting Started

Getting Started gives step-by-step instructions for installing the model software and using the interface. It describes navigating the model, using the main program areas, working with sessions, and printing or exporting results.

User Manual

The *User Manual* gives further information on both the interface and the underlying model. It provides detailed descriptions of plant configurations, parameter settings, and result screens. It also describes technical details behind the model's operation and includes an introduction to uncertainty analysis.

Model Tutorial

The *Model Tutorial* is a pictorial introduction to the IECM. It presents a graphical tour of the interface, a case study to follow using the model, and an appendix, which reproduces every screen in the model. These tools help any user to quickly become more familiar with the interface and model.

Technical Manual

The *Technical manual* is a detailed engineering description of the technologies and costing assumptions used in the IECM. This manual is not provided by default with the IECM software; however, it can be downloaded with any web browser from http://www.iecm-online.com.

Online Help

Online help is provided via a Windows Help File containing the text of *Getting Started* and the *User Manual*.

Accessing the IECM Help file:

If you are not running the IECM interface, click the **Help** icon inside the IECM folder on the **Start** menu. This opens the help file to the table of contents.

If you are running the IECM interface, do any one of the following:

- Press the **F1** key. The IECM supports context-sensitive help and will open the help file to the topic associated with the item or screen you are viewing.

- Pull down the **Help** menu at the top of the IECM window. Select **Help Topics**. This opens the help file to the table of contents.

- Click the **Context-Sensitive Help** icon on the toolbar on the left side of the IECM window. The IECM supports context-sensitive help and will open the help file to the topic associated with the item or screen you are viewing.

- Click the **Help Topics** icon on the toolbar on the left side of the IECM window. This opens the help file to the table of contents. If this method does not work, try one of the other options above.

The IECM Help File Contents window will display.
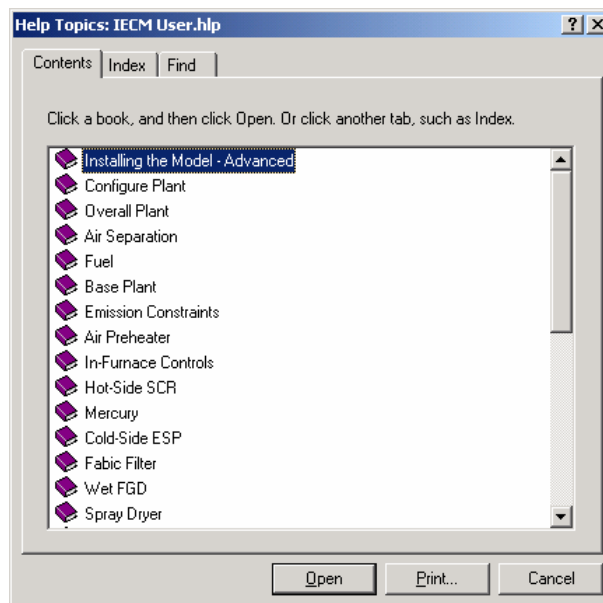
The IECM Help File Topics Window

Installing the Model - Advanced

Advanced Installation Options

Normal installation is described in *Getting Started*. This section addresses installation from a network drive or the worldwide web. This section also describes advanced features of the installation program and the files installed.

Local and Network Installation

The Setup program can be run from a local hard drive or a network server. Installing from a hard drive eases the burden of sharing one IECM compact disk (CD) between multiple users. Installing from a network server simplifies the process of installing the entire package on a series of personal computers connected to the network. However, both methods require some familiarity with creating and finding folders and sub-directories on a network hard drive.

NOTE:
You may also install the interface to a network server. All files will be loaded to the server except the shortcut in the start menu of the local personal computer. The interface will run from the server and all sessions will be saved to the network drive, meaning that others with access to the network drive may change or delete them. Installation to a network server is not currently supported.

Installing the IECM from a Local Hard Drive

To install from a local hard drive:

1. Copy the contents of the IECM compact disk (CD) disk into one sub-directory or folder on your personal hard drive.

2. On the personal computer, click the **Start** button.

3. Choose **Run…** from the Start menu.

4. Type "X:\XXX\Media\SETUP.EXE" where "X:\XXX\" is the drive and directory on your local hard drive to which you copied the files.

The Installation Program will begin. Follow the instructions on the screen.

If you receive an error message while running Setup, restart your computer and run the installation program again. If Setup still returns an error message, call Technical Support.

Installing the IECM from a Network

To install from a network hard drive:

1. Copy the contents of the IECM compact disk (CD) disk into one sub-directory or folder on a network hard drive.

2. On the personal computer, click the **Start** button.

3. Choose **<u>Run…</u>** from the Start menu.

4. Type "`X:\XXX\Media\SETUP.EXE`" where "`X:\XXX\`" is the drive and directory on the network hard drive to which you copied the files.

The Installation Program will begin. Follow the instructions on the screen.

If you receive an error message while running Setup, restart your computer and run the installation program again. If Setup still returns an error message, call Technical Support

Internet Installation

The contents of the IECM CD-ROM are also available on the worldwide web (www.iecm-online.com). The media, documentation and various text files can be downloaded to your local computer or network hard drive.

Downloading the IECM from the worldwide web.

To download the install software to your computer:

1. Open a web browser program (e.g., Internet Explorer or Netscape).

2. In the "Address" line of the browser, type the following http://www.iecm-online.com. You will see the iecm–online home page.
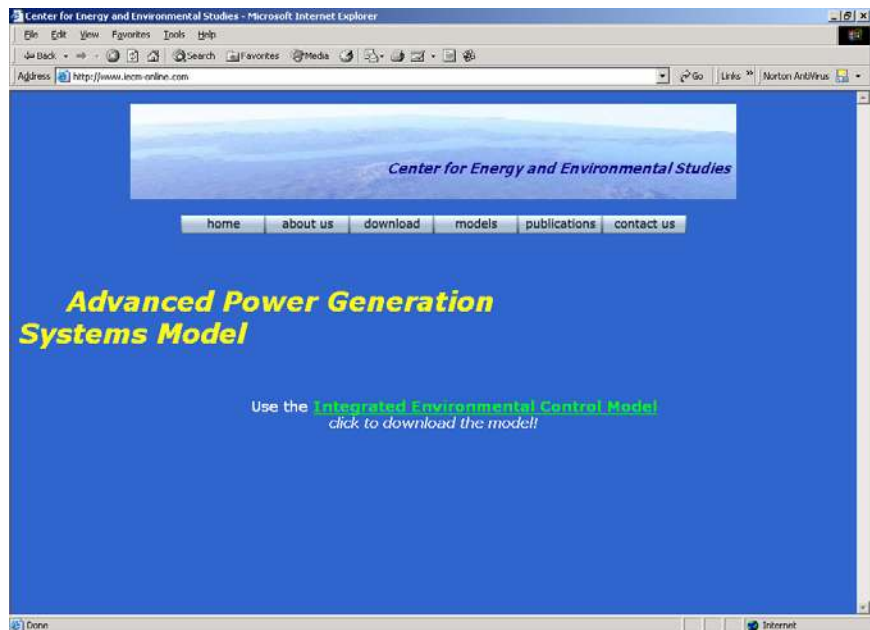
iecm–online Home Page

3. Click on either the button labeled **download** or the highlighted green text **Integrated Environmental Control Model**.
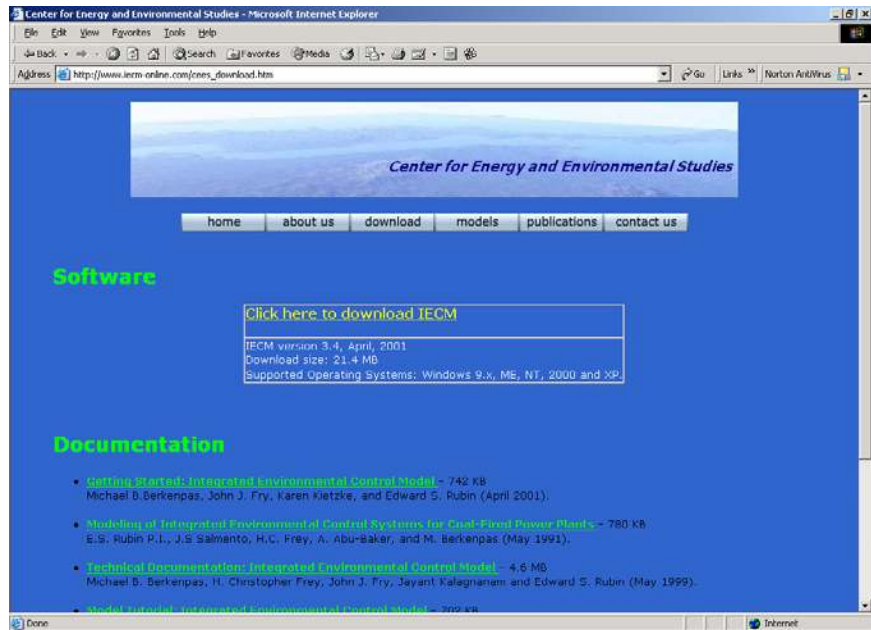
iecm–online download page

> 4. Click on the the yellow highlighted text **Click here to download IECM**. A dialog box will appear.
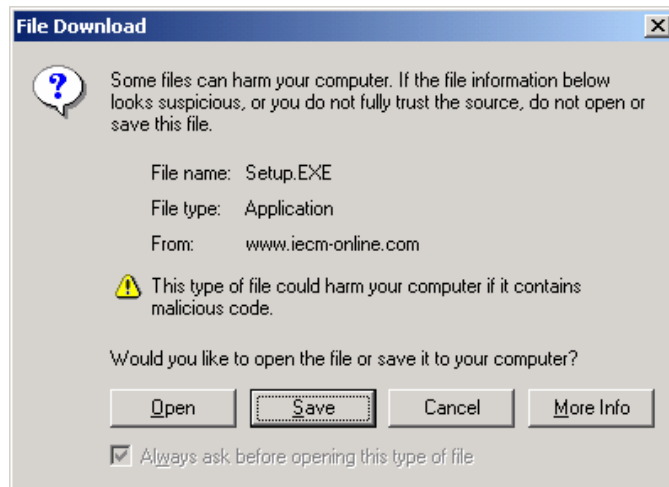
File download dialog box; save the program to disk

> 5. Click on the **Save** button..
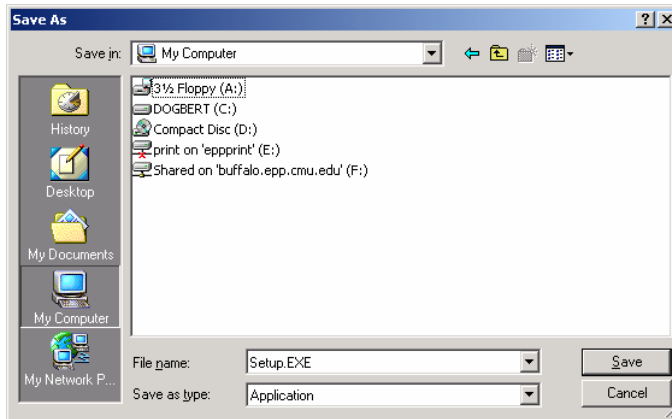
Save file dialog box; use this to select the location to save the program

> 6. Choose a location to save the setup file and click the "Save" button.
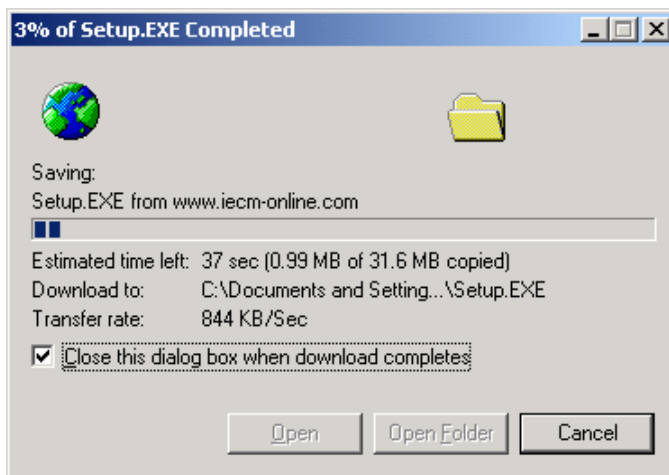
File download progress indicator

The download will begin. Once it is finished, you can proceed to install the IECM software. If you receive an error message while running Setup, restart your computer and run the installation program again. If Setup still returns an error message, call Technical Support

Changing the Destination Location

The destination location for the IECM software can be changed during the installation process. This is accomplished by clicking the **Browse…** button on the "Choose Destination Location" screen during the installation process (See the *Getting Started* manual for a description of the entire installation process). The **Browse…** button opens the "Select Destination Directory" window which can be used to locate or type the exact destination location for the IECM software.
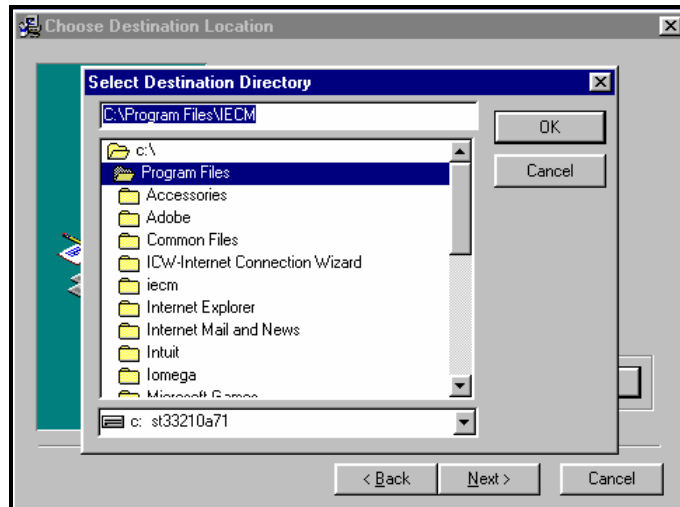
The "Select Destination Directory" window

Select a specific folder in which to install the IECM software by clicking on the folder name to highlight it. Then click the **OK** button to return to the "Choose Destination Location" screen.

Files Installed

This section provides a full list and short description of the files installed by the IECM installer software. The software is divided into three categories.

Help Files

The following help files are installed by default in the `C:\PROGRAM FILES\IECM-CS` directory by the installation program:

C:\PROGRAM FILES\IECM-CS\

This is the main program directory.

IECMINT.CNT: IECM "Getting Started" online help contents file.

IECMINT.HLP: IECM "Getting Started" online help file.

USER.CNT: IECM "User Manual" online help contents file.

USER.HLP: IECM "User Manual" online help file (linked to IECMINT.HLP).

Program Files

All applications and their support files specific to the IECM software itself are considered program files. These can be installed into any directory during installation. The folder can be changed from the default location suggested during installation.

C:\PROGRAM FILES\IECM-CS\

This is the main program directory. The following program files are installed by default in the "C:\Program Files\IECM" directory by the installation program:

COMPACT.EXE: Support application that compacts Microsoft Access 97 database files (e.g., the files in the "C:\Program Files\IECM\Sessdb" directory).

GSW32.EXE: Graphics Server for Windows 4.5 program file.

GSWAG32.DLL: Graphics Server for Windows 4.5 support file.

GSWDLL32.DLL: Graphics Server for Windows 4.5 support file.

[*Graphics Server: Graphing Toolkit for Windows*. Kent, Washington: Bits Per Second Ltd. And Pinnacle Publishing Co., 1996. http://www.pinpub.com

HISTORY.TXT: History of the IECM software, including features installed and planned.

IECMILIB.DLL: IECM interface support file. It handles all database, uncertainty and model access.

IECMINT.EXE: IECM program file for the interface.

IECMINT.MDB: Microsoft Access 97 template database file.

LHS.DLL: IECM interface support file. It handles all uncertainty sampling.

LICENSE.TXT: IECM license agreement.

MODEL.DLL: IECM interface model support file. It contains all the technology performance and cost modules.

SPR32D35.DLL: Spread 3.0 support file.

TAB32D30.DLL: Tab Pro 3.1 support file.

[*Spread and Tab Pro for Windows*. Morrisville, North Carolina: Far Point Technologies, 1996 and 2000. http://www.fpoint.com]

UNWISE32.EXE: Uninstaller program. This requires an installer log created during installation.

C:\PROGRAM FILES\IECM-CS\INTDB\

This directory contains the database files used by the IECM interface. These contain default data used in the interface program. The following files are installed by the installation program:

INTDESC.MDB: Microsoft Access database file. It contains all the descriptions for the IECM interface screens.

MODCOALS.MDB: Microsoft Access database file. It contains the model default coal information.

C:\PROGRAM FILES\IECM-CS\SESSDB\

The "C:\Program Files\IECM\Sessdb" directory contains the database files created by the IECM interface. All user data associated with sessions are stored here. These files are not created by the installation program; rather, they are created by the IECM Interface at runtime if they are not available. This means that user data cannot be overwritten by the installation program.

System Files

Several files are installed into the windows system directory. These system files are common to many Windows applications. All of these files are created and distributed freely through Microsoft ® Corporation using their installer packages. These system files are unique to the other IECM components listed above because they are hard-wired into the system registry file. In order to maintain consistency with the operating system and stability with the IECM interface, these special system files must be stored in the windows system directory and installed with software installers directly from Microsoft.

A full list of the Microsoft ® Corporation files installed is provided in the INSTALLR.TXT file located on the IECM compact disk (CD).

Microsoft Data Access Components

The use of Microsoft Access database files requires the installation of ODBC drivers and support files from Microsoft. ODBC is a programming interface that enables applications to access data in database management systems that use Structured Query Language (SQL) as a data access standard. The Microsoft MDAC package is included with the IECM installer program as delivered directly from Microsoft and delivers this important functionality. Files are installed into the "C:\Windows\System32" directory.

Microsoft Visual Basic 4.0 Runtime

The components of this package are installed from within the IECM installer as delivered by Microsoft. They provide Microsoft Visual Basic support files and are installed into the "C:\Windows\System32" directory and the "C:\Program Files\Common\Microsoft" directory.

Microsoft MFC 4.2

The components of this package are installed from within the IECM installer as delivered by Microsoft. They are Microsoft Visual C++ support files delivered under the Microsoft Foundation Class libraries. They are installed into the "C:\Windows\System32" directory.

Files Modified by Install

Currently no user files are modified when the IECM software is installed. All user files are stored in the "C:\Program Files\IECM\Sessdb" directory.

Uninstalling and Rolling Back Installations

The IECM Installation program will uninstall the software or roll back the installation to a previous version.

Uninstallation Steps

Uninstallation removes the IECM Interface completely from your computer.

Run the Uninstaller

1.   Click the **Start** button.

2. Choose **Settings**, and then **Control Panel**.

3. Double-click **Add/Remove Programs** in the **Control Panel** folder.

4. Highlight **IECM Interface** on the list of installed software.

5. Click the **Add/Remove…** button.

Select Uninstall Method

The first screen which displays when the uninstaller is run is the "Select Uninstall Method" screen. It asks you if you want it to remove files automatically or specify which files to delete.

The "Select Uninstall Method" screen.

Click the circle next to **Automatic** to make automatically uninstall the software, click the circle next to **Custom** to choose which files to delete. Click the **Next** button to continue to the next screen.

Select Files to Remove

If you have chosen **Custom** on the "Select Uninstall Method" screen, the "Select Private Files to Remove" screen will display.
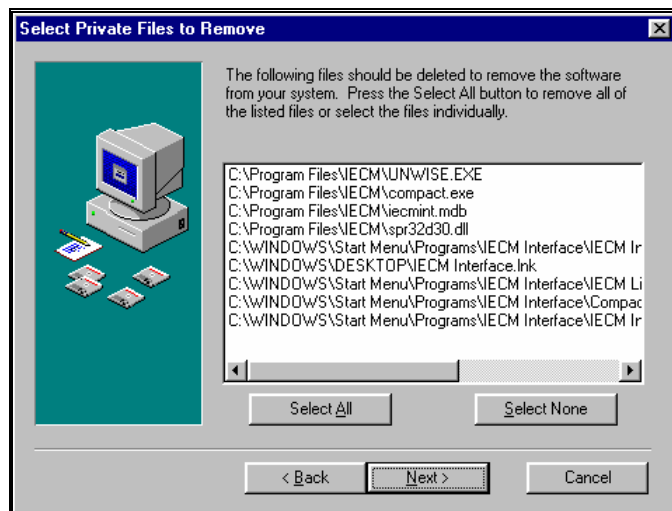
The "Select Private Files to Remove" screen

Select files to delete by clicking on their names in the scroll box to highlight them. You may also click the **Select All** button to select all the files in the scroll box. Click the **Next** button to continue to the next screen.

Perform Rollback

The "Perform Rollback" screen asks if you would like to uninstall the software completely, or just to roll back the installation to a previous version.
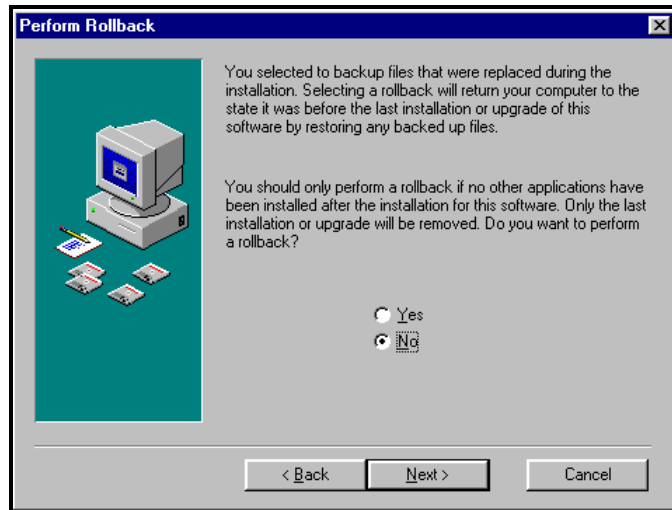
The "Perform Rollback" screen

Click the circle next to **No** to uninstall the software completely. Click the **Next** button to continue to the next screen.

Perform Uninstall

The uninstaller is now ready to perform the uninstall. The "Perform Uninstall" screen allows you to go back one last time to check the options you have chosen for uninstallation.
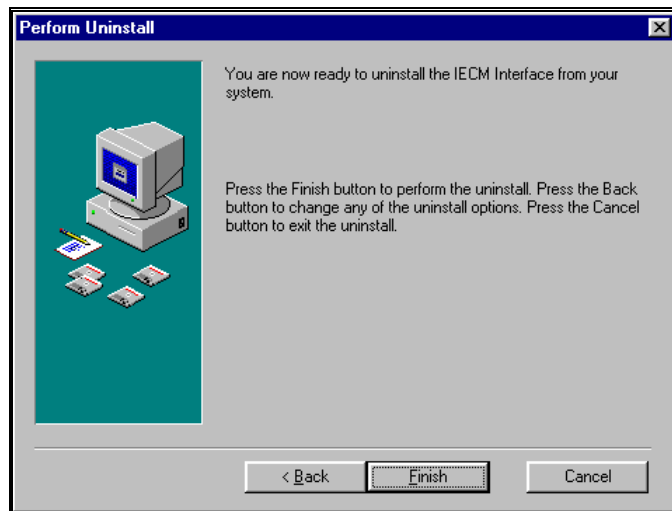
The "Perform Uninstall" screen

Click the **Back** button to return to any of the previous screens to check or change the uninstallation options. Click the **Next** button to continue to uninstall the software.

Rollback Steps

Instead of completely uninstalling the software, you may rollback the IECM Interface software to the previous installed version. You may only perform a rollback if:

- You have upgraded the IECM Interface software, not just performed a new installation or
- As part of that upgrade, you have backed up the files replaced. See *Getting Started* for how to backup replaced files as part of an installation.

If you have either not backed up replaced files, or have not upgraded, a rollback **will** return the software to its previous position, but that condition will be an empty folder.

Run the Uninstaller

1. Click the **Start** button.
2. Choose **Settings**, and then **Control Panel**.
3. Double-click **Add/Remove Programs** in the **Control Panel** folder.
4. Highlight **IECM Interface** on the list of installed software.
5. Click the **Add/Remove…** button.

Select Uninstall Method

The first screen which displays when the uninstaller is run is the "Select Uninstall Method" screen. It asks you if you want it to remove files automatically or specify which files to delete.

The "Select Uninstall Method" screen.

Click the circle next to **Automatic** to make automatically uninstall the software. Click the **Next** button to continue to the next screen.

Perform Rollback

The "Perform Rollback" screen asks if you would like to uninstall the software completely, or just to roll back the installation to a previous version.
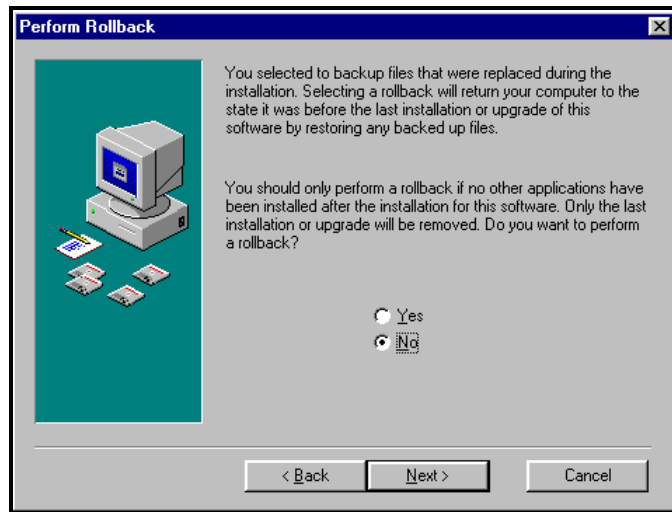
The "Perform Rollback" screen

Click the circle next to **Yes** to roll back the software to the previous version. Click the **Next** button to continue to the next screen.

Perform Uninstall

The uninstaller is now ready to perform the rollback. The "Perform Uninstall" screen allows you to go back one last time to check the options you have chosen for the rollback.
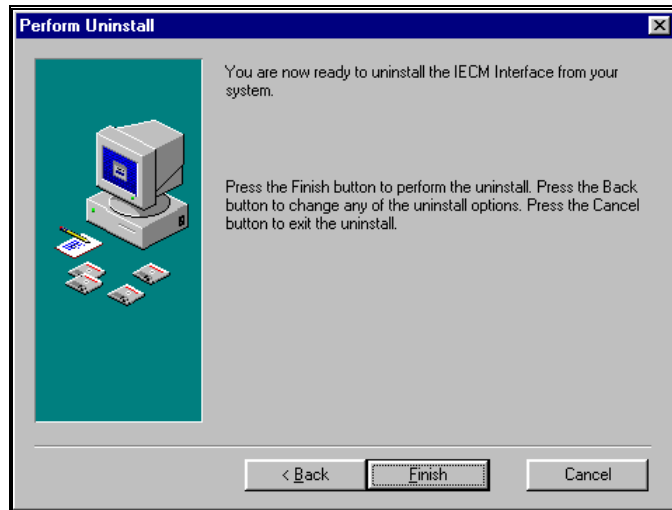
The "Perform Uninstall" screen

Click the **Back** button to return to any of the previous screens to check or change the rollback options. Click the **Next** button to continue to roll back the installation of the software to the previous version.

Configure Plant

Configuring the Combustion Turbine Plant

If the user has selected **Combustion (Turbine)** as the plant type from the **New Session** pull down menu the **NGCC Configuration** screen will appear in the **Configure Plant** program area.
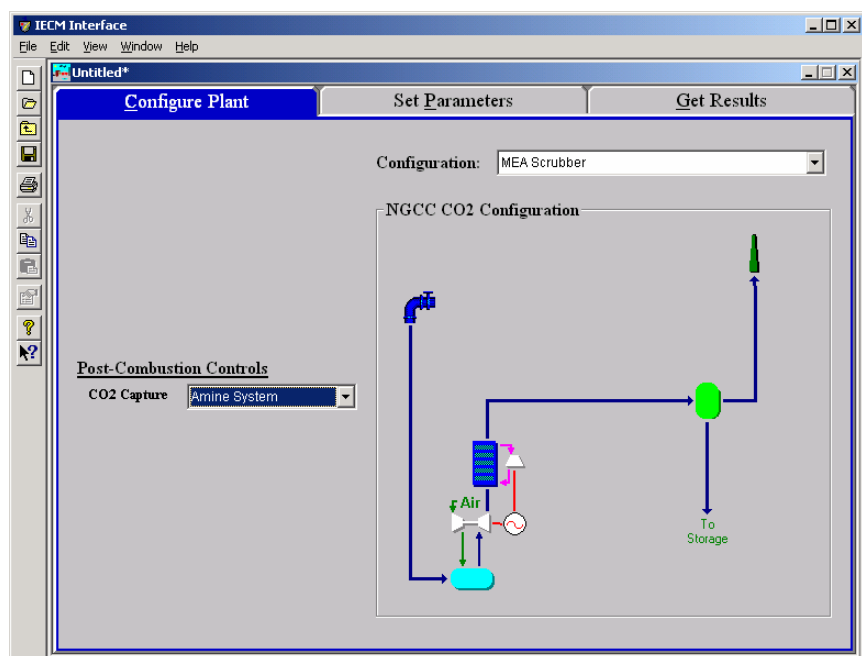
Configure Plant – Combustion (Turbine) input screen.

Post-Combustion Controls

CO_2 **Capture:** If CO_2 **Capture** is desired it may be added by selecting the **Amine System** option from the pull down menu. The default is **None**.

Configuring the Combustion Boiler Plant

If the user has selected **Combustion (Boiler)** as the plant type from the **New Session** pull down menu the **Configuration** screen will appear in the **Configure Plant** program area.
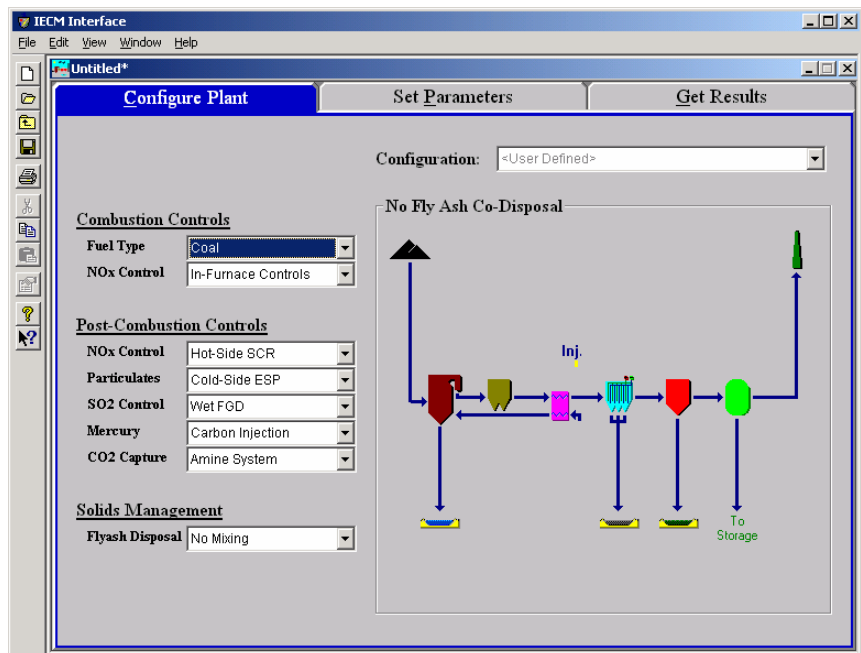
Configure Plant – Combustion (Boiler) input screen

Combustion Controls

These configuration options determine the type of furnace and any technologies for reducing NO_x emissions.

> **Fuel Type:** Coal is the fuel that is used by the model.
>
> **NO_x Control:** From this configuration screen, you may choose either **None** or **In-Furnace Controls**.
>
> > **In-Furnace NO_x:** Controls include an assortment of options which combine low NO_x burners (LNB) with overfire air (OFA), selective non-catalytic reduction (SNCR), and natural gas reburning. These options are selected from a pull-down menu in the Set Parameters program

Post-Combustion Controls

These configuration options determine the presence and type of post-combustion emissions controls.

> **NO_x Control:** The choices available are **None**, for no post-combustion NO_x control, or **Hot Side SCR** for a Hot-Side Selective Catalytic Reduction technology. The default setting is **None**. The only post-combustion NO_x control technology currently included with the IECM is a selective catalytic reduction (SCR) process. Although an SCR technology can be positioned at various points along the flue gas train, the IECM considers only the hot-side, high dust configuration. Hot-side SCR systems are capable of removing up to 80 or 90 percent of the NO_x emitted from a coal-fired power plant. Although they are not yet

prevalent in the United States, they are widely used in Europe and Japan. SCR systems affect other systems in the power plant, requiring some modifications to the boiler, air heater and induced draft fan. Other technologies affected but not requiring modifications are the ESP and FGD systems. If **In-Furnace Controls** is selected under Combustion Controls, a Hot Side SCR may also be selected.

Particulates: The choices available are **None** for no post-combustion Particulate control, **Cold Side ESP** for a Cold-Side Electrostatic Precipitator, and four different kinds of Fabric Filters (baghouses): **Reverse Gas Fabric Filter**, **Reverse Gas Sonic Fabric Filter**, **Shake & Deflate Fabric Filter**, and **Pulse-Jet Fabric Filter**. The default setting is **None**. The **None** setting is not available when the Mercury technology option is either **Carbon Injection** or **Carbon + Water Injection**. This assures the removal of the carbon being injected immediately downstream of the air preheater.

Fabric Filter Types: Fabric filter types are based on the bag cleaning techniques used. Various bag-cleaning techniques influence other process parameters. The choice of the bag cleaning method is usually based on the type of coal used—and therefore the filterability of the ash—and your experience with filtering the particular kind of ash. The particular option you select determines the air to cloth ratio, bag life, bag length, power requirements, pressure drop, capital costs and O&M costs. There are four available bag filter types:

Reverse Gas Fabric Filter: Uses an off-line bag cleaning technique in which an auxiliary fan forces a relatively gentle flow of filtered flue gas backwards through the bags causing them to partially collapse and dislodge the dustcake. Over 90% of baghouses in U. S. utilities use reverse-gas cleaning.

Reverse Gas Sonic Fabric Filter: Uses a variation of Reverse Gas cleaning in which low frequency pneumatic horns sound simultaneously with the flow of reverse gas to add energy to the dustcake removal process.

Shake & Deflate Fabric Filter: Uses a method for off-line cleaning in which the bags are mechanically shaken immediately after or while a small quantity of filtered gas is forced back to relax the bags. The amount of filtered gas used is smaller than that used in Reverse Gas cleaning.

Pulse-Jet Fabric Filter: Uses a method for on-line cleaning in which pulses of compressed air are blown down inside and through the bags to remove dustcake while the bags are filtering flue gas. Wire support cages are used to prevent bag collapse during filtration and ash is collected outside of the bags.

SO$_2$ Control: The choices available are **None** for no post-combustion SO$_2$ control, **Wet FGD** for a Wet Flue Gas Desulfurization technology (Lime or Limestone—this is selected in the **Set Parameters—SO2 control—1. Configuration** screen), or a **Lime Spray Dryer**. Choice of a Lime Spray Dryer places this technology before the Particulate control technology in the plant design and diagrams. The default setting is **None**.

Mercury: There are three choices available for Mercury control. The options provided are **None**, **Carbon Injection**, and **Carbon + Water Injection**. The default option is **None**. Although some mercury removal is accomplished naturally in a power plant, carbon injection is provided as a technology to supplement the natural removal to reach higher removals. It is believed that some mercury is captured or trapped in ash and is removed with bottom ash and fly ash. Mercury removal is accomplished by injecting fine particles of activated carbon into the flue gas after the air preheater. Because the removal increases with lower flue gas temperatures, water and carbon injection is added as a second technology option. The **Carbon Injection**, and **Carbon + Water Injection** options are only available when a cold-side ESP or fabric filter are selected. This is because a particulate device is required to remove the mercury-laden ash and activated carbon.

CO_2 Capture: If **CO_2 Capture** is desired it may be added by selecting the **Amine System** option from the pull down menu. The default is **None**.

Solids Management

Flyash Disposal: This configuration setting determines how flyash is disposed. Fly ash collected from a particulate removal system is typically combined with other solid waste streams if other waste streams exist. The waste disposal option has little effect on the rest of the IECM. The choices are **Mixed w/FGD Wastes** to dispose of flyash with FGD wastes, and **Mixed w/ Bottom Ash** to dispose of flyash with bottom ash (e.g. in the pond) or **No Mixing**.

Overall Plant

Overall Plant Diagram
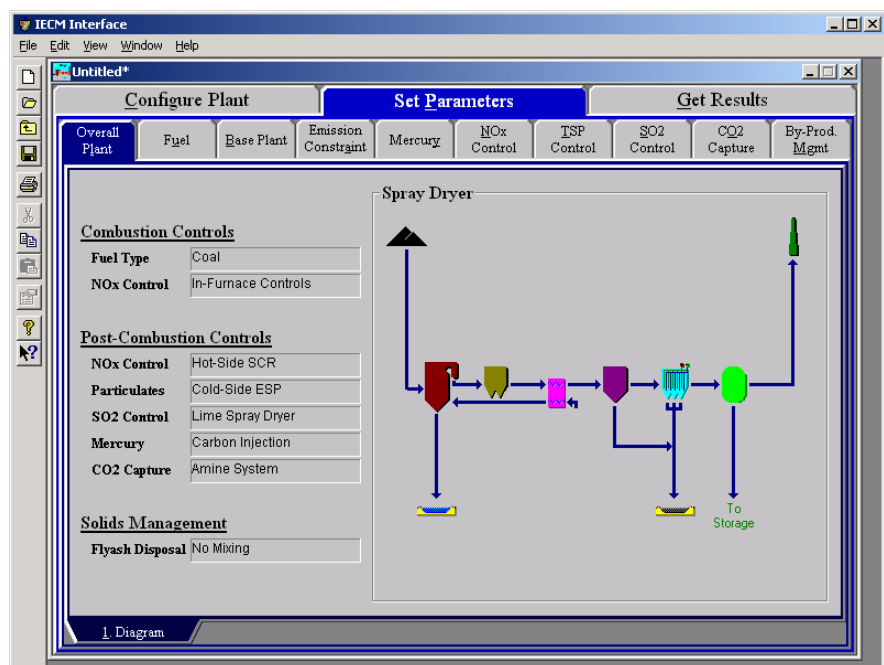
Overall Plant – Diagram result screen.

This **Diagram** appears in the <u>Set Parameters</u> and in the <u>Get Results</u> program area. The screen displays the plant configuration settings on the left side of the page and a diagram of the plant as configured at the right of the page. No results are displayed on this screen.

Overall Plant Performance

Overall Plant – Plant Perf. result screen.

The **Plant Perf.** result screen displays performance results for the plant as a whole. Values for the major input and outputs of the power plant are given. Each result is described briefly below.

> **Gross Electrical Output:** This is the gross output of the generator in megawatts (MWg). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates. The value is an input parameter.

> **Aux. Electrical Output:** If an auxiliary natural gas boiler is used to provide steam and power for the Amine System, this is the additional electricity that it produces.

> **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

> **Gross Cycle Heat Rate:** This is the heat rate of the gross cycle including the effects of the boiler efficiency. This is considered the gross heat rate.

> **Net Cycle Heat Rate:** This is the net heat rate, which includes the effect of plant equipment and pollution control equipment.

> **Fuel Energy Input:** This is the fuel energy input for the plant on an hourly basis (maximum capacity).

> **Annual Operating Hours:** This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.

> **Annual Power Generation:** This is the net annual MWh production of the plant. The capacity factor is used in determining its value.

Overall Plant Mass In/Out

Overall Plant – Mass In/Out result screen.

The **Mass In/Out** result screen displays the flow rates of fuels and chemicals into the plant and solid and liquid flow rates out of the plant. Each result is described briefly below.

Input Flow Rates

>**Coal:** Total mass of coal entering the boiler on a wet basis.

>**Oil:** Total mass of oil used in the power plant

>**Natural Gas: :** Total mass of natural gas used in the power plant

>**Total Fuels:** This is the total fuel mass entering the power plant. This result is highlighted in yellow.

>**Lime/Limestone:** Total mass of this reagent used in the power plant on a wet basis.

>**Sorbent:** Total mass of sorbent used in the power plant.

>**Ammonia: :** Total mass of ammonia used in the power plant.

>**Urea:** Total mass of urea used in the power plant. Urea is the reagent used to reduce NO_x in the SNCR technology.

>**Dibasic Acid:** Total mass of dibasic acid used in the power plant.

>**Activated Carbon:** Total mass of activated carbon injected in the power plant.

>**Total Chemicals:** This is the total reagent mass entering the power plant. This result is highlighted in yellow.

Output Flow Rates

>**Bottom Ash Disposed:** Total mass of bottom ash collected in the power plant on a dry basis.

Fly Ash Disposed: Total mass of fly ash collected in the power plant on a dry basis.

Scrubber Solids Disposed: Total mass of scrubber solid wastes collected in the power plant on a dry basis.

Particulate Emissions to Air: Total mass of particulates emitted to the air from the power plant.

Captured CO2:

Byproduct Ash Sold: : Total mass of ash (bottom and fly ash) sold in commerce as a by-product on a dry basis.

Byproduct Gypsum Sold: : Total mass of flue gas treatment solids sold in commerce as a by-product on a dry basis.

Byproduct Sulfur Sold: Total mass of elemental sulfur recovered from flue gas and sold in commerce as a by-product on a dry basis.

Byproduct Sulfuric Acid Sold: Total mass of sulfuric acid recovered from the flue gas and sold in commerce as a by-product.

Total: This is the total wet solid mass exiting the power plant. This result is highlighted in yellow.

Overall Plant Gas Emissions

Overall Plant – Gas Emissions result screen.

The **Gas Emissions** result screen displays values for the major flows of gas out of the power plant Each result is described briefly below.

StackGas Components

Nitrogen (N$_2$): Total mass of emitted nitrogen.

Oxygen (O$_2$): Total mass of emitted oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

Total Gases: Total flow rate of all gases. This result is highlighted in yellow.

Total SO_x (equivalent SO_2): Total mass of all sulfur oxides. This is the sum of the SO_2 and SO_3 above.

Total NO_x (equivalent NO_2): Total mass of all nitrogen oxides. This is the sum of the NO and NO_2 above.

Overall Plant Cost Summary

Overall Plant Cost Summary result screen.

The **Cost Summary** result screen displays costs associated with the power plant as a whole. Each technology (row) is described briefly below.

Combustion NO_x Control: The total cost of the In-Furnace NO_x controls used.

Post-Combustion NO_x Control: The total cost of all the Post-Combustion NO_x removal modules used.

Mercury Control: The total cost of all the mercury control modules used.

TSP Control: The total cost of all the conventional particulate removal modules used.

SO₂ Control: The total cost of all the SO_2 conventional removal modules used.

Combined SOₓ/NOₓ: The total cost of all the combined SO_x/NO_x advanced removal modules used.

Subtotal: This is the cost of the conventional and advanced abatement technology modules alone. This is the total abatement cost. The subtotal is highlighted in yellow.

Base Plant: The total cost of the base plant without consideration of any abatement technologies. This can be used to compare with other power plant types.

Total: This is the total cost of the entire power plant. This result is highlighted in yellow.

Each cost category (column) is described briefly below.

Capital Cost: The total capital requirement (TCR). This is the money that is placed (capitalized) on the books of the utility on the service date. The total cost includes the total plant investment plus capitalized plant startup. Escalation and allowance for funds used during construction (AFUDC) are also included. The capital cost is given on both a total and an annualized basis.

Revenue Required: Amount of money that must be collected from customers to compensate a utility for all expenditures in capital, goods, and services. The revenue requirement is equal to the carrying charges plus expenses. The revenue required is given on both an annualized and a net energy output basis.

Overall NGCC Plant

Overall NGCC Plant Diagram
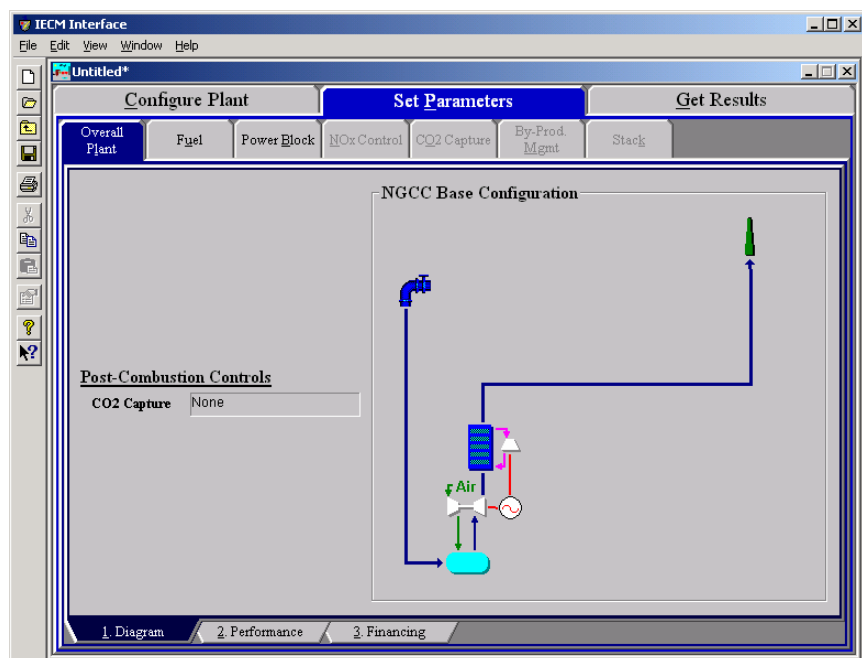
Overall NGCC Plant – Diagram input screen

The **Overall NGCC Plant Diagram** appears in the **Set Parameters** and in the **Get Results** program area. The screen displays the plant configuration settings on the left side of the page and a diagram of the plant as configured at the right of the page. No results are displayed on this screen.

Overall NGCC Plant Performance Inputs
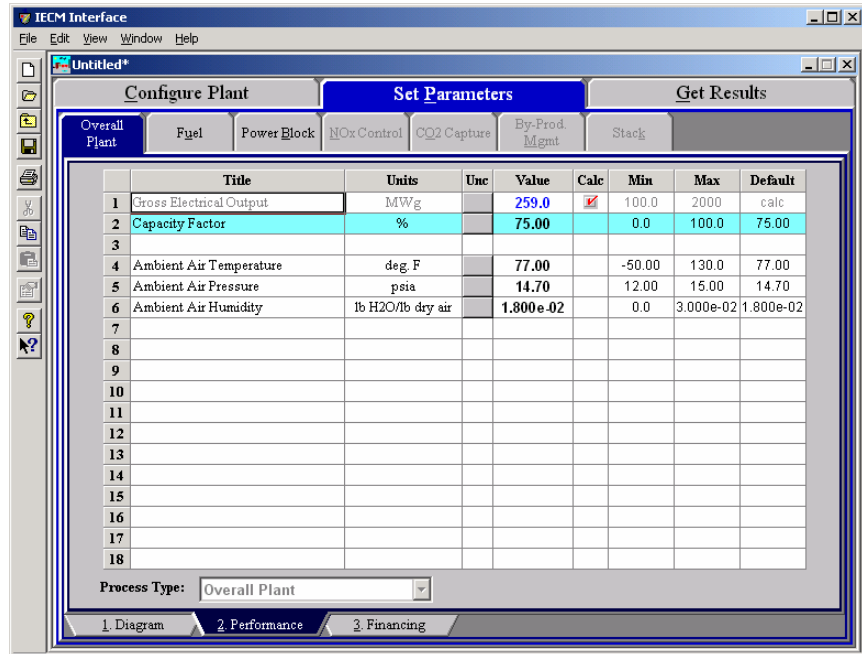
Overall NGCC Plant – Performance input screen.

The Natural Gas Combined Cycle input performance parameters are described below:

> **Gross Electrical Output:** This is the gross output of the generator in megawatts (MW_g). The value does not include auxiliary power requirements. The model uses this information to calculate key mass flow rates.

> **Capacity Factor:** This is an annual average value, representing the percent of equivalent full load operation during a year. The capacity factor is used to calculate annual average emissions and materials flows.

> **Ambient Air Temperature:** This is the temperature of the ambient plant air.

> **Ambient Air Pressure:** This is the pressure of the ambient plant air.

> **Ambient Air Humidity:** This is the humidity of the ambient plant air.

Overall NGCC Plant Financing Inputs

Overall NGCC Plant – Financing input screen.

This screen describes the factors required to determine the carrying charge for all capital investments. The carrying charge is defined as the revenue required to pay for any capital investment. The total charge can also be expressed as a levelized cost factor or fixed charge factor. The fixed charge factor is a function of many items. You have the option of specifying the fixed charge factor directly, or allowing it to be calculated from the other input quantities below it on the financial input screen.

The first four inputs are highlighted in blue. Each parameter is described briefly below.

> **Year Costs Reported:** This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used by the IECM to scale all costs to the cost year specified by this parameter.

> **Constant or Current Dollars:** Constant dollar analysis does not include the affect of inflation, although real escalation is included. Current dollar analysis includes inflation and real escalation. This choice allows you to choose the mode of analysis for the entire IECM economics.

> **Fixed Charge Factor (FCF):** The fixed charge factor is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.

> One may specify a Fixed Charge Factor, or fill in the following inputs and the model will calculate the FCF based on them:

Inflation Rate: This is the rise in price levels caused by an increase in the available currency and credit without a proportionate increase in available goods or services. It does not include real escalation.

Plant or Project Book Life: This is the years of service expected from a capital investment. It is also the period over which an investment is recovered through book depreciation.

Real Bond Interest Rate: This is a debt security associated with a loan or mortgage. It is the most secure form of security but the lowest in its return.

Real Preferred Stock Return: This equity security is the second most speculative type and pays the second highest rate of return. The holder of the stock is a part owner of the company.

Real Common Stock Return: This is the most speculative type of equity security sold by a utility and pays the highest relative return. The holder of the stock is a part owner of the company.

Percent Debt: This is the percent of the total capitalization that is associated with debt money. This includes loans and mortgage bonds.

Percent Equity (Preferred Stock): This is the percent of the total capitalization that is associated with the sale of preferred stock.

Percent Equity (Common Stock): This value is the remainder of the capitalization, calculated as 100% minus the percent debt, minus the percent equity in preferred stock.

Federal Tax Rate: This is the federal tax rate. It is used to calculate the amount of taxes paid and deferred.

State Tax Rate: This is the state tax rate. It is used to calculate the amount of taxes paid and deferred.

Property Tax Rate: The property tax rate, or ad valorem, is used to calculate the carrying charge.

Investment Tax Credit: This is an immediate reduction in income taxes equal to a percentage of the installed cost of a new capital investment. It is zero by default. It is used to set the initial balance and the book depreciation.

Overall NGCC Plant Performance Results

Overall NGCC Plant – Performance results screen.

Performance Parameter

> **Net Electrical Output:** This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

> **Total Plant Energy Input:** The fuel energy input to the plant on an hourly basis (maximum capacity).

> **Gross Plant Heat Rate, HHV:** This is the gross heat rate of the entire plant.

> **Net Plant Heat Rate, HHV:** This is the net heat rate of the entire plant (including aux power produced) which includes the effect of plant equipment and pollution control equipment.

> **Annual Operating Hours:** This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.

> **Annual Power Generation:** This is the net annual MWh production of the plant. The capacity factor is used in determining its value.

> **Net Plant Efficiency, HHV:** This is the net efficiency of the entire plant.

Plant Energy Requirements

> **Turbine Generator Output:** This is the energy generated by the turbine.

> **Air Compressor Use:** The energy required to operate the air compressor.

> **Misc. Losses:** This variable accounts for any turbine electricity losses that are not incorporated into the lossed due to air compressor use.

Net Turbine Output: This if the net energy generated by the turbine. This is the gross output of the turbine minus the energy required by the air compressor and any miscellaneous losses.

*Absorption CO_2 Capture Use: If a **CO_2 Capture** system is in use, this is the energy required to operate the system.

*Aux. Electrical Output: If an auxiliary natural gas boiler is used to provide steam and power for the Amine System, this is the additional electricity that it produces

Net Electrical Output: This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

Overall NGCC Plant Mass In/Out Results

Overall NGCC Plant – Mass In/Out results screen.

Chemical Inputs

Coal: Flow rate of coal used in the power plant.

Oil: Flow rate of oil used in the power plant

Natural Gas: : Flow rate of natural gas used in the power plant

Petroleum Coke: Total mass of petroleum coke used in the power plant

Other Fuels: Flow rate of other fuels used in the power plant

Total Fuels: This is theFlow rate of fuel entering the power plant. This result is highlighted in yellow.

Lime/Limestone: Total mass of this reagent used in the power plant on a wet basis.

Selexol: Total mass of selexol sorbent used in the power plant

Ammonia: : Total mass of ammonia used in the power plant.

Activated Carbon: Flow rate of activated carbon injected in the power plant.

Other Chemicals, Solvents & Catalyst: Flow rate of other chemicals, solvents and catalysts used in the power plant.

Total Chemicals: Flow rate of reagent entering the power plant. This result is highlighted in yellow.

Water: Flow rate of water used in the power plant.

Solid & Liquid Outputs

Slag: Flow rate of slag from the power plant on a dry basis.

Ash Disposed: Flow rate of ash from the power plant on a dry basis.

Scrubber Solids Disposed: Flow rate of scrubber treatment solid wastes from the power plant on a dry basis.

Solids Emitted: Flow rate of solids emitted from the plant.

Captured CO_2: Flow rate of the captured CO_2.

Byproduct Ash Sold: : Flow rate of ash (bottom and fly ash) sold in commerce as a by-product on a dry basis.

Byproduct Gypsum Sold: : Flow rate of flue gas treatment solids sold in commerce as a by-product on a dry basis.

Byproduct Sulfur Sold: Flow rate of elemental sulfur recovered from flue gas and sold in commerce as a by-product on a dry basis.

Byproduct Sulfuric Acid Sold: Total mass of sulfuric acid recovered from the flue gas and sold in commerce as a by-product.

Total: This is the total wet solid mass exiting the power plant. This result is highlighted in yellow.

Overall NGCC Plant Gas Emissions Results

Overall NGCC Plant – Gas Emissions result screen.

Stack Gas Component

Each result is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Total Gases: Total of the individual components listed above. This item is highlighted in yellow.

Total SOₓ (equivalent SO₂): Total mass of SOₓ as equivalent SO₂.

Total NOₓ (equivalent NO₂): Total mass of NOₓ as equivalent NO₂.

Overall NGCC Plant Cost Summary Results

Overall NGCC Plant – Cost Summary results screen.

Technology

> **Air Separation Unit:** This is the capital cost for the Air Separation process area of the plant.

> **Gasifier Area:**This is the capital cost for the **Gasifier** process area of the plant.

> **Particulate Control:** This is the capital cost for the equipment that performs **Particulate Capture** in the plant.

> **Sulfur Control:** This is the capital cost for the equipment that performs **Sulfur Capture** in the plant.

> **CO$_2$ Capture:** This is the capital cost for the equipment that performs **CO$_2$ Capture** in the plant.

> **Mercury Control:**This is the capital cost for the Air Separation process area of the plant.

> **Power Block:** This is the capital cost for the **Power Block** process area of the plant.

> **Post-Combustion NO$_x$ Control:**This is the capital cost for the equipment that performs **Post-Combustion NO$_x$ Control** in the plant.

> **Total:**This is the **Sum** of all of the above capital costs for all of the process areas in the plant.

Fuel

The screens associated with the **Fuel** Technology Navigation Tab display and define the composition and cost of the fuels used in the plant

Fuel Properties Input

The selection of the particular coal model default, cleaned, saved externally, or user-specified and its ultimate and ash properties are selected and editable on the **Properties** input screen.
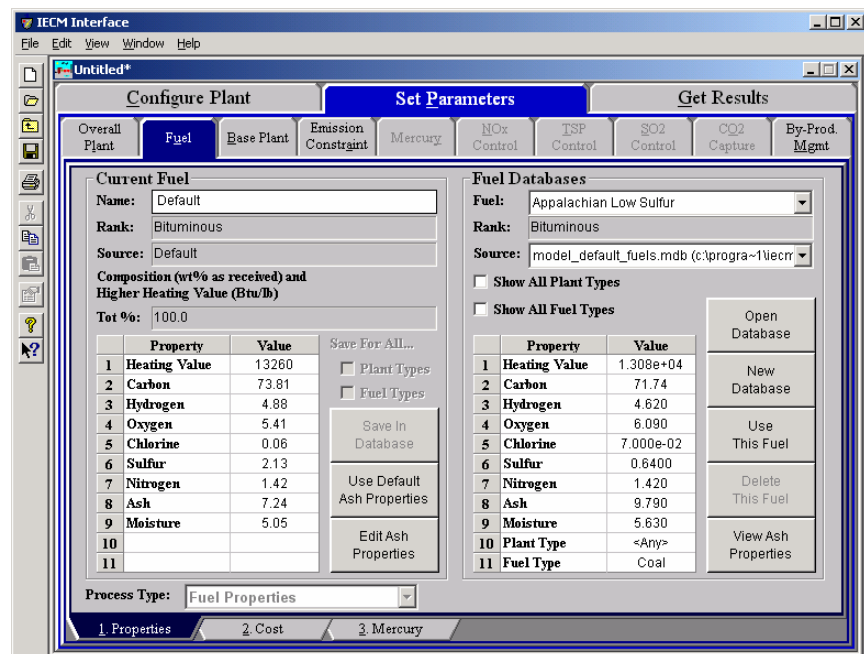
Fuel – Properties input screen.

There are two panes on the Fuel Properties input screen: one for the composition and higher heating value properties of the **Current Fuel**, the other for properites of the fuels in the **Fuel Databases**. The **Current Fuel** is the fuel for which the model will conduct its calculations. The IECM interface currently supports only one fuel selection per session. The **Fuel Databases** pane displays the properties for other selectable fuels. From this screen, you may choose a fuel from the model defaults, enter a user-defined fuel, or choose a previously saved user-defined fuel. Properties

of existing fuels may be modified and new fuels may be created and saved to user specified databases. A full suite of buttons have been provided to make the selection and management of the fuel properties easier.

Both the **Current Fuel** pane and the **Fuel Databases** pane display the following information: for a fuel.

Name This is the name of the fuel, it may be the trade name or a unique identifier supplied by the user.

Rank: The rank of a coal refers to the degree of coalification endured by the organic matter. It is estimated by measuring the moisture content, specific energy, reflectance of vitrinite or volatile matter (these are known as rank parameters

Source: The model provides the values for default fuel properties, these can be used "as is" or modified and used. Modified fuels maybe stored in a new database or an existing database. Source displays the database file from which the data was retrieved, or indicates that the data has been enetered by the user.

Fuel Properties: The property value spreadsheet is used to display the heating value and content of carbon, hydrogen, oxygen, chlorine, sulfur, nitrogen, ash, and moisture are specified on a weight percent basis for coal fuels. The data can be edited only in the **Current Coal** pane. The fuel composition is used in a combustion equation to calculate the flue gas composition in the furnace. The heating value is used to calculate the mass flow rate of fuel. Property data also determines the fuel rank (bituminous, subbituminous, or lignite). This, in turn, determines the default values of several boiler parameters. The editable fuel properties are:

Heating Value: This is the higher heating value of the fuel in Btu/lb.

Carbon: The weight percent of carbon in the fuel on a wet basis.

Hydrogen: This is the weight percent of hydrogen in the fuel on a wet basis.

Oxygen: This is the weight percent of oxygen in the fuel on a wet basis.

Chlorine: This is the weight percent of chlorine in the fuel on a wet basis.

Sulfur: This is the weight percent of sulfur in the fuel on a wet basis.

Nitrogen: This is the weight percent of nitrogen in the fuel on a wet basis.

Ash: This is the weight percent of ash in the fuel on a wet basis.

Moisture: This is the weight percent of moisture in the fuel on a wet basis.

Ash Properties: The property value spreadsheet is also used to display the oxide content of the ash in coal on a percent of total ash basis. The data can be edited only in the **Current Fuel** pane. The ash content is used to determine the resistivity of the ash. This, in turn, determines the specific collection area (SCA) of the cold-side ESP. The editable ash properties are:

SiO_2: The percent by wieght of silicon dioxide in the ash.

Al_2O_3**:** The percent by wieght of Aluminum Oxide in the ash.

Fe_2O_3**:** The percent by wieght of ferric oxide in the ash.

CaO: The percent by wieght of calcium oxide in the ash.

MgO: The percent by wieght of magnesium oxide in the ash.

Na_2O**:** The percent by wieght of sodium oxide in the ash.

K_2O**:** The percent by wieght of potassium oxide in the ash.

TiO_2**:** The percent by wieght of titanium dioxide in the ash.

MnO_2**:** The percent by wieght of manganese dioxide in the ash.

P_2O_5**:** The percent by wieght of phosphorus pentoxide in the ash.

SO_3**:** The percent by wieght of sulfur trioxide in the ash.

Selecting a Fuel

The **Current Fuel** pane displays the fuel that is in use by the model. The **Fuel Databases** pane initially displays the first default fuel in the model's default database. To make the fuel that is displayed in the **Fuel Database** pane the fuel to be used by the model, press the **Use this Fuel** button. The fuel will then be displayed in the **Current Fuel** pane. To view the ash properties, press the **View Ash Properties** button in the **Fuels Database** , the ash properties are displayed and the button that was pressed, labeled **View Ash Properties** has changed to **View Fuel Properties.** This button toggles between **View Ash Properties** and **View Fuel Properties.** To find other fuels:

Select a Different Fuel in the Open Database: Select the pull down menu on the text box labeled **Fuel:**. The list of fuels in the database is displayed another fuel can be chosen.

Select a Different Open Database: Select the pull down menu on the text box labeled **Source:**. The list of other open databases is displayed.

Open Another Fuel Database: When pressed the button labeled **Open Database** will display the Windows **Open** screen. All files with **.fdb** extension will be displayed. **.fdb** is the default extension for the **Fuel Databases** files. Select a file and press the **Open** button.

Modifiying a Fuel

The fuel values that are displayed in the **Current Fuel** pane may be modified. Put the cursor into the cell containing the value of the property to be edited and enter the new value. To edit the ash properties of the current fuel; press the **Edit Ash Properties** button in the **Current Fuel** pane, the ash properties are displayed and the button that was pressed, labeled **Edit Ash Properties** has changed to **Edit Fuel Properties.** This button toggles between **Edit Ash Properties** and **Edit Fuel Properties.** . The ash properties may be edited in the same way as the fuel properties. Place the cursor in the value of the property to be modified and enter the new value. The model will run using the fuel that is displayed in the **Current Fuel** pane.

Saving a Modified Fuel

A fuel that has been modified may be saved to any user specified fuel database except the default database, **model_default_fuels.mdb**. Use the **Save in Database** button to save the modified fuel, displayed in the **Current Fuel** pane to the database that is displayed in the **Source** text box. If the default database, **model_default_fuels.mdb** is displayed in the text box titled **Source**, the **Save**

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in Database button will be grayed out, not active. Activate the **Save in Database,** by opening another database or creating a new database**.**

Deleting a Fuel

A fuel that is displayed in the **Fuel Databases** pane, may be deleted using the **Delete this Fuel** button, if it is not a model default fuel. Fuels in the model default database, **model_default_fuels.mdb,** cannot be deleted.

Open Database

Press the **Open Database** button on the **Fuels Database** pane and the **Windows Open Screen** will appear. A valid fuel database file as an **.fdb** extension. Click on the database file to open and press the **Open** button. The **Fuels Database** displays the first fuel in the selected database and the **Source**: text box displays the full path and file name of the database that has just been opened.
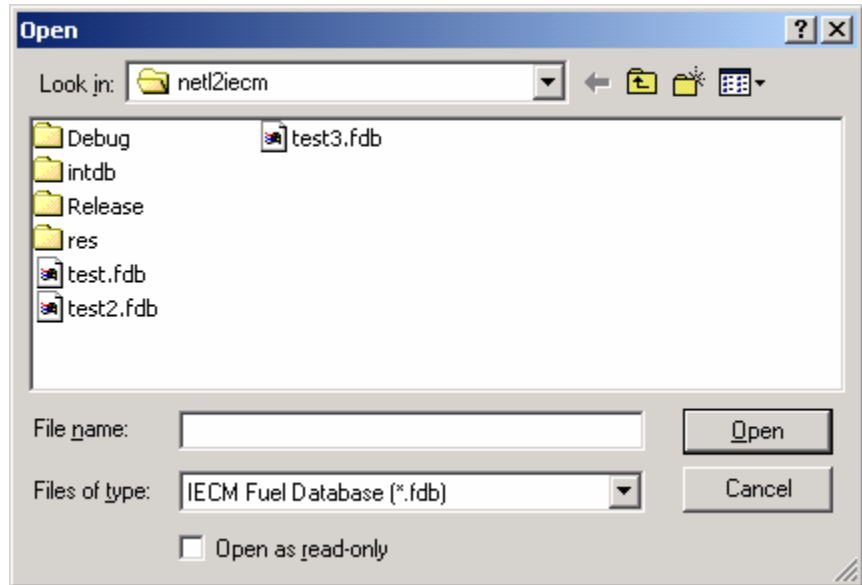
Fuels – Windows Open screen.

New Database

Press the **New Database** button on the **Fuels Database** pane and the **Windows Save As Screen** will appear. Type in the name of the new database file into the **File name:** text box. All fuel database files have an **.fdb** extension. Press the **Save** button. The **Source**: text box displays the full path and file name of the new database and all other fuel values in the **Fuels Database** pane will be blank
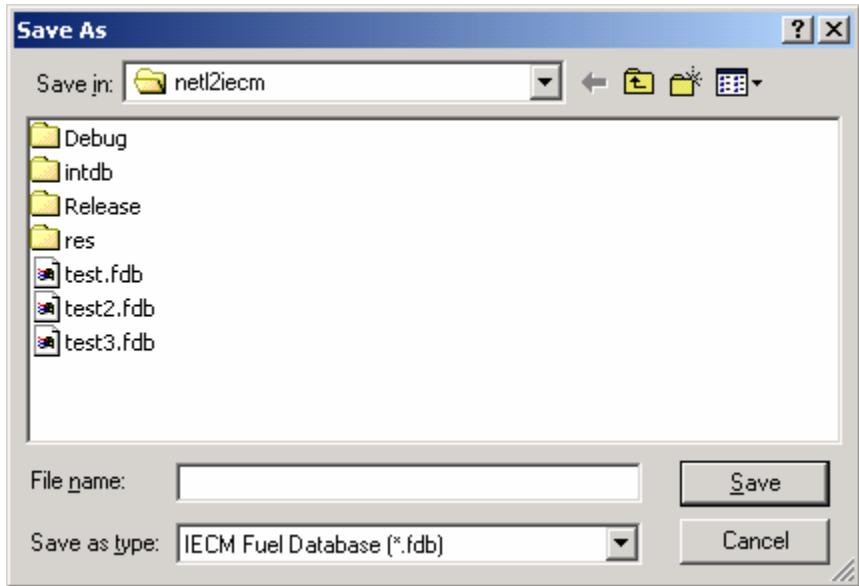
Fuels – Windows Save As screen.

Fuel Coal Cost Input

The cost of the cleaned coal, transportation costs, and other miscellaneous coal costs are accessed on the **Cost** input screen.
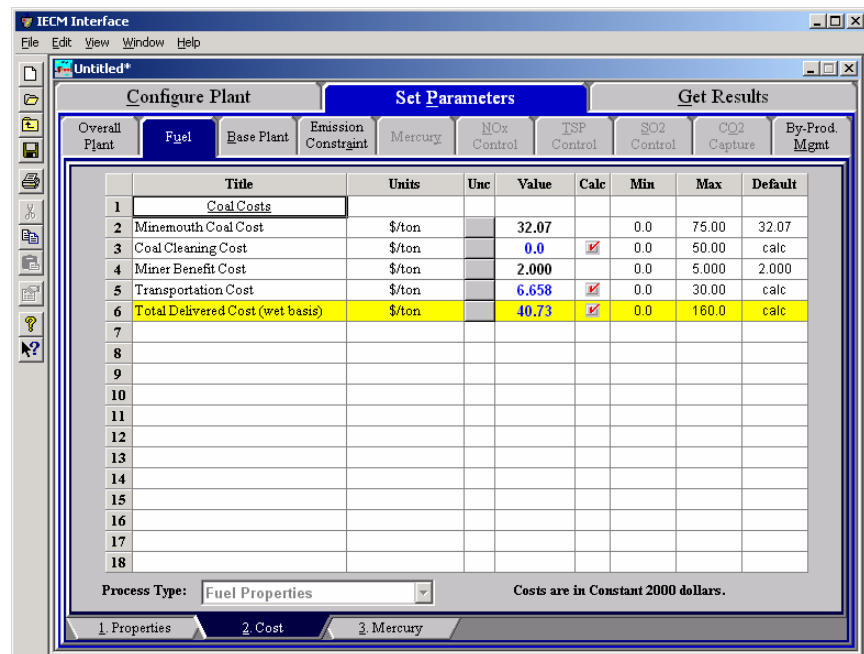
Fuel – Coal Cost input screen.

Each parameter is described briefly below.

Minemouth Coal Cost: This is the cost of the delivered coal in dollars per wet ton. It does not include any cleaning costs.

Coal Cleaning Cost: This is the cost of cleaning the coal. The default value is calculated. It is zero if the coal was not cleaned.

Miner Benefit Cost: This is the cost associated with the miner pension and benefit fund. It is expressed on a wet ton basis.

Transportation Cost: This is the transportation cost associated with the coal used by the power plant. It is scaled by the cost index and expressed on a wet basis.

Total Delivered Cost (as-fired): This is the total cost of delivered coal on a wet ton basis. It is simply the sum of all the quantities listed above. This input is highlighted in yellow.

Fuel Natural Gas Cost Input

If the user has configured the plant to use a Natural Gas fueled turbine the **Natural Gas Cost** input screen will be displayed.

Fuel – Natural Gas Cost Input Screen

Each parameter is described briefly below.

Natural Gas Cost: This is the cost of the delivered natural gas in millions of dollars per cubic foot.

Natural Gas Density: This the density of the natural gas in pounds per cubic foot.

Fuel Mercury Input

The concentration of mercury in the as-fired coal and speciation of mercury after combustion are entered on the **Mercury** input screen
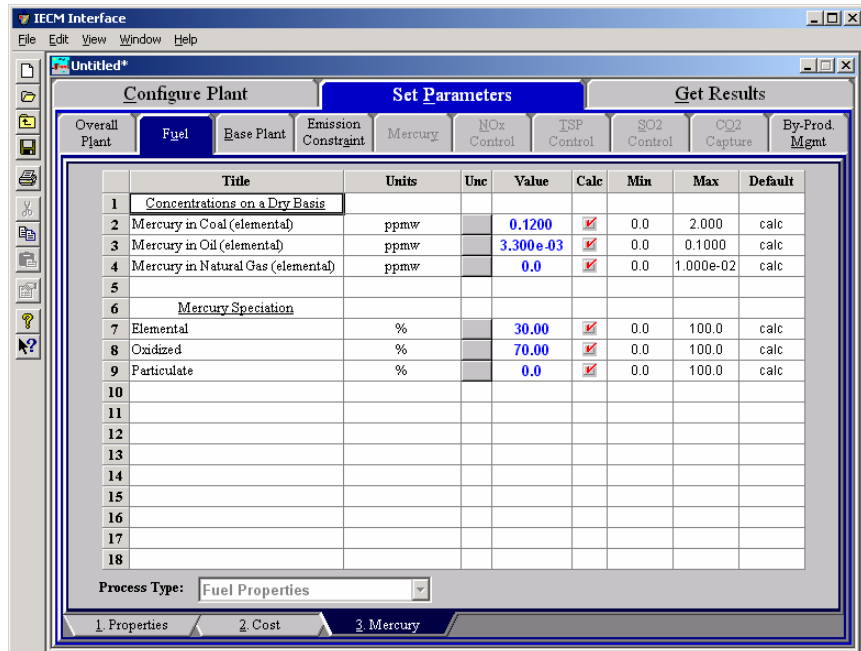
Fuel – Mercury input screen.

Each parameter is described briefly below:

Concentration on a Dry Basis

Trace elements found in fuels are typically measured and reported as a mass concentration given on a dry basis. The IECM uses this concentration in conjunction with the fuel flow rate and fuel moisture to determine the mass flow rate. Currently Mercury is the only trace species tracked in the IECM.

> **Mercury in Coal (elemental):** This input parameter specifies the mass concentration of total mercury in the coal given on a dry basis. The mercury concentration should be given on an elemental basis, not on a mercury compound basis. The default value is a function of the coal rank.

> **Mercury in Oil (elemental):** This input parameter specifies the mass concentration of total mercury in the oil. The mercury concentration should be given on an elemental basis, not on a mercury compound basis.

> **Mercury in Natural Gas (elemental):** This input parameter specifies the mass concentration of total mercury in the natural gas. The mercury concentration should be given on an elemental basis, not on a mercury compound basis.

Mercury Speciation

Once the fuel is combusted, the mercury can be identified in primarily two chemical states: elemental (Hg^0) and oxidized (Hg^{+2}). Although mercury can alternatively be reported as particulate or gas phase, the IECM assumes Mercury is reported on an elemental and oxidized basis.

> **Elemental:** This is the percent of total mercury that is in an elemental state (Hg^0) after combustion. Elemental mercury is typically unreactive and passes through a power plant. The default value is a function of the coal rank.

Oxidized: This is the percent of total mercury that is in an oxidized state (Hg^{+2}) after combustion. Oxidized mercury is very reactive and typically forms mercury compounds. The default value is a function of the coal rank.

Particulate: This parameter is not currently used in the IECM. It's value is set to force the sum of the speciation types to be 100%.

Fuel Natural Gas Properties Input

If the user has configured the plant to have **CO2 Capture** and added an Auxiliary Natural Gas Boiler, or if the user has configured the plant to use a Natural Gas fueled turbine then the **Natural Gas Properties** input screen will also be available.

Fuel – Natural Gas input screen.

The **Natural Gas Properties** input screen displays and allows the user to update the fuel properties of Natural Gas.

Natural Gas Properties

Higher Heating Value: Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel (wet) from completely burning the fuel to produce carbon dioxide and liquid water. The latent heat of condensation is included in the value.

Ethane (C$_2$H$_6$): The volume, by percent, of ethane in the natural gas.

Methane (CH$_4$): The volume, by percent, of methane in the natural gas.

Carbon Dioxide (CO$_2$): The volume, by percent, of carbon dioxide in the natural gas.

Oxygen (O$_2$): The volume, by percent, of oxygen in the natural gas.

Nitrogen (N$_2$): The volume, by percent, of nitrogen in the natural gas.

Fuel Coal Diagram

The **Fuel** Technology Navigation Tab in the **Get Results** program area contains the **Diagram** result screen. It displays the properties set up in the Fuel Properties input screens of the of the **Set Parameters** program area.
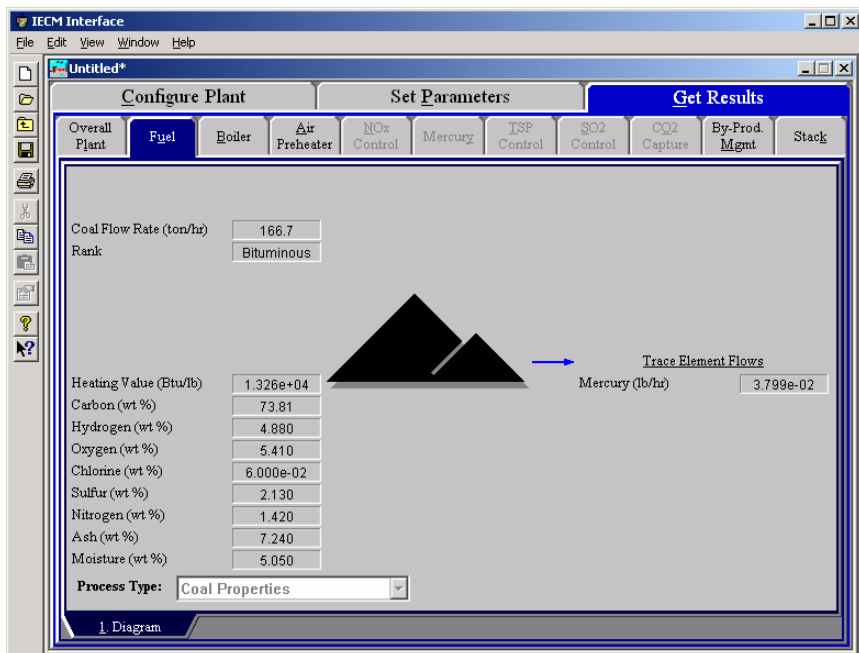
Fuel — Diagram result screen for coal.

The **Coal Diagram** result screen displays fuel composition and flow rate information, which is described briefly below.

> **Coal Flow Rate:** Coal flow rate into the boiler on a wet basis. Waste products removed prior to the burners are not considered here.

> **Rank:** The rank of the coal based on the higher heating value. This is primarily determined by the higher heating value and to a lesser degree by the sulfur and ash content.

> **Heating Value:** Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel (wet) from completely burning the fuel to produce carbon dioxide and liquid water. The latent heat of condensation is included in the value.

> **Carbon:** The carbon content of the coal by weight on an elemental and wet basis.

> **Hydrogen:** The hydrogen content of the coal by weight on an elemental (H) and wet basis.

> **Oxygen:** The oxygen content of the coal by weight on an elemental (O) and wet basis.

> **Chlorine:** The chlorine content of the coal by weight on an elemental (Cl) and wet basis.

> **Sulfur:** The sulfur content of the coal by weight on an elemental (S) and wet basis.

Nitrogen: The nitrogen content of the coal by weight on an elemental (N) and wet basis.

Ash: The ash content of the coal by weight on a wet basis.

Moisture: The inherent moisture content of the coal by weight.

Trace Element Flows

Trace elements are now supported in the IECM. The mass flow rate is reported in units of pounds per unit of time. All values reflect the elemental mass flow rate.

Mercury: This is the elemental mercury flow rate in coal.

Fuel Natural Gas Diagram
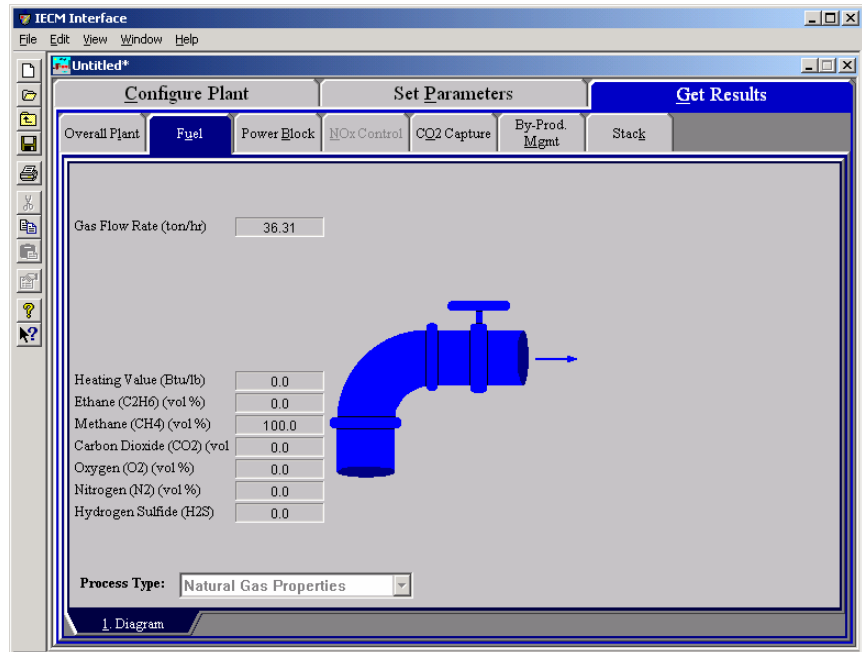
Fuel – Diagram result screen for natural gas.

The **Natural Gas Diagram** result screen displays fuel composition and flow rate information, which is described briefly below.

Gas Flow Rate: The natural gas flow rate to the turbine.

Heating Value: Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel.

Ethane (C$_2$H$_6$): The volume, by percent, of ethane in the natural gas.

Methane (CH$_4$): The volume, by percent, of methane in the natural gas.

Carbon Dioxide (CO$_2$): The volume, by percent, of carbon dioxide in the natural gas.

Oxygen (O$_2$): The volume, by percent, of oxygen in the natural gas.

Nitrogen (N$_2$): The volume, by percent, of nitrogen in the natural gas.

Hydrogen Sulfide (H$_2$S): The volume, by percent, of hydrogen sulfide in the natural gas.

Base Plant

The **<u>Base</u> Plant** Technology Navigation Tab screens display and define the performance and costs directly associated with the power plant, particularly the boiler. Pre-combustion and post-combustion control technologies are not considered part of the Base Plant.

Base Plant Furnace Factors Inputs

Inputs for the furnace factors that effect the major flow rates and concentrations of the gas and solids streams are entered on the **Furnace Factors** input screen.

This screen accepts inputs for the flue gas and ash products emitted from the boiler into the flue gas and ash streams. Factors in emissions include: incomplete combustion and thermodynamic equilibrium between gas species associated with the combustion products.

This screen's inputs are needed to calculate boiler efficiency and air pollutant emissions. The emission of carbon, ash, sulfur and nitrogen are specified by the United States Government's Environmental Protection Agency's (EPA) compilation of emission factors. Also included from the compilation are the incomplete transfer percentages of solid and gaseous forms of these substances.

This screen is available for all plant configurations.
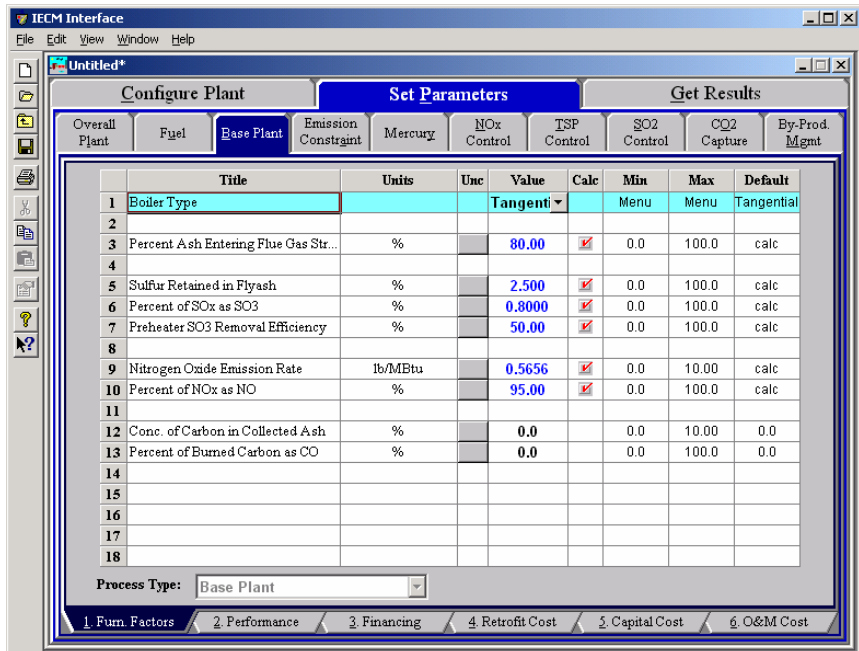
Base Plant – Furn. Factors input screen.

Each parameter is described briefly below:

Boiler Type: The choices available are **Tangential**, **Wall**, and **Cyclone**. The default setting is **Tangential**. The firing method affects model default parameters for nitrogen oxide emissions and the partitioning of fly ash and bottom ash in the furnace.

Percent Ash Entering Flue Gas Stream: The default values for this parameter are a function of the fuel and boiler types and are based on the AP-42 EPA emission factors. Ash not entering the flue gas stream is assumed to be removed as bottom ash. This is also referred to as the overhead ash fraction.

Sulfur Retained in Flyash: This parameter gives the percent of total sulfur input to the boiler that is retained in the flyash stream of a coal-fired power plant. The default values are a function of the selected boiler type and the coal rank as specified by the AP-42 EPA compilation of emission factors.

Percent of SO$_x$ as SO$_3$: This parameter quantifies the sulfur species in the flue gas stream. Sulfur not converted to SO$_2$ is assumed to be converted to SO$_3$. The default value is based on emission factors derived by Southern Company[3] and are a function of the selected coal.

Preheater SO$_3$ Removal Efficiency: Sulfuric acid (H$_2$SO$_4$) is created downstream of the boiler by the reaction of SO$_3$ with H$_2$O. A percent of the sulfuric acid is condensed on particulates in the preheater and removed from the flue gas. This parameter specifies the amount of SO$_3$ removed from the flue gas in the preheater as a function of the coal rank. The default value is based on data provided by Southern Company Services.[4]

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[3] Hardman, R., R. Stacy, et al. (1998). Estimating Total Sulfuric Acid Emissions from Coal-FIred Power Plants, Southern Company Services.
[4] Ibid.

Nitrogen Oxide Emission Rate: This parameter establishes the level of NO_x emissions from the boiler. The default values reflect the AP-42 EPA emission factors. It is a function of boiler firing method and the coal rank. The model calculates this value and expresses it in pounds of equivalent NO_2 per ton of coal.

Percent of NOₓ as NO: This parameter establishes the level of nitric oxide (NO) in the flue gas stream. The remainder of the total NO_x emissions is assumed to be nitrogen dioxide (NO_2). The default parameters reflect the AP-42 EPA emission factors and are dependent on the fuel type.

Conc. of Carbon in Collected Ash: This parameter accounts for retention of carbon in the fly ash and bottom ash. The amount of carbon in the collected ash streams is typically known. It is used to calculate the total unburned carbon in coal, boiler efficiency and flue gas composition.

Percent of Burned Carbon as CO: This parameter accounts for any incomplete combustion in the furnace, and is used to calculate boiler efficiency and flue gas composition. The remainder is assumed to be CO_2 or unburned carbon.

Base Plant Performance Inputs

Inputs for the major flow rates and concentrations of the gas and solids streams are entered on the **Performance** input screen

Base Plant—Performance input screen.

The first six inputs are highlighted in blue. Each parameter is described briefly below.

Gross Electrical Output: This is the gross output of the generator in megawatts (MW_g). The value does not include auxiliary power

requirements. The model uses this information to calculate key mass flow rates.

Steam Cycle Heat Rate: This is the gross amount of energy in steam needed to produce a kilowatt-hour (kWh) of electricity at the generator. This variable does not consider auxiliary power requirements. This heat rate, plus the boiler efficiency, is used to figure out the overall plant performance (i.e., the gross cycle heat rate).

Boiler Efficiency: This is the percentage of fuel input energy transferred to steam in the boiler. The model default is to calculate the boiler efficiency using standard algorithms described in the literature. The efficiency is a function of energy losses due to inefficient heat transfer across the preheater, latent heat of evaporation, incomplete combustion, radiation losses, and unaccounted losses.

Capacity Factor: This is an annual average value, representing the percent of equivalent full load operation during a year. The capacity factor is used to calculate annual average emissions and materials flows.

Excess Air for Furnace: This is the excess theoretical air used for combustion. It is added to the stoichiometric air requirement calculated by the model. The value is calculated and based on the fuel type and boiler type.

Leakage Air at Preheater: This is the additional excess air introduced because of leakage into the system at or beyond the air preheater. It is based on the stoichiometric air required for combustion. The leakage air increases the total gas volume downstream of the air preheater.

Gas Temperature Exiting Economizer: This is the temperature of the flue gas exiting the economizer. The temperature is used in the calculation of the flue gas volume and air preheater performance.

Gas Temperature Exiting Air Preheater: This is the temperature of the flue gas exiting the air preheater. The temperature is used in the calculation of the flue gas volume and air preheater performance.

Ambient Air Temperature: This is the inlet temperature of the ambient combustion air prior to entering the preheater. The model presumes an **annual average** temperature. Inlet air temperature affects the boiler energy balance and efficiency. It provides a reference point for the calculation of pressure throughout the system. Currently, the model cannot have temperatures below 77°F.

Ambient Air Pressure: This is the absolute pressure of the air inlet stream to the boiler. The air pressure is used to convert flue gas molar flow rates to volume flow rates.

Ambient Air Humidity: This is the water content of the inlet combustion air. This value is used in calculating the total water vapor content of the flue gas stream. The value is referred to as the specific humidity ratio, expressed as a ratio of the water mass to the dry air mass.

Percent Water in Bottom Ash Sluice: : This is the water content of the collected bottom ash. Bottom ash is assumed to be sluiced with water and dry otherwise, it may be combined with fly ash and then disposed.

Base Plant Power Requirements

These parameters specify the electrical energy requirements of pulverizers, steam pumps, forced draft fans, cooling system equipment (fans and pumps), and other miscellaneous equipment excluding gas cleanup systems. These energy requirements or penalties are expressed as a percent of a gross plant capacity and are used to calculate the net plant performance.

Coal Pulverizer: This is the energy needed to run the coal pulverizers prior to the coal being blown into the boiler. It is also referred to as an energy penalty to the base plant. The value is calculated and based on the fuel type. It is expressed as a percentage of the gross plant capacity.

Steam Cycle Pumps: This is the energy needed to operate the pumps in the steam cycle. It is also referred to as an energy penalty to the base plant. It is expressed as a percentage of the gross plant capacity.

Forced Draft Fans: This is the energy required for the forced draft fans and primary air fan expressed as a percentage of the gross plant capacity. It is also referred to as an energy penalty for the base plant.

Cooling System: This is the energy needed to run the pumps and other equipment for the water cooling system. It is expressed as a percentage of the gross plant capacity. It is also referred to as a base plant energy penalty.

Miscellaneous: This is the energy used by any other miscellaneous equipment in the base plant, not including equipment used for pollution control equipment. It is expressed as a percentage of the gross plant capacity. It is also referred to as a base plant energy penalty.

Base Plant Financing Inputs

Inputs for the financing costs of the base plant itself are entered on the **Financing** input screen.

Base Plant—Financing input screen.

This screen describes the factors required to determine the carrying charge for all capital investments. The carrying charge is defined as the revenue required to pay for any capital investment. The total charge can also be expressed as a levelized cost factor or fixed charge factor. The fixed charge factor is a function of many items. You have the option of specifying the fixed charge factor directly, or allowing it to be calculated from the other input quantities below it on the financial input screen.

The first four inputs are highlighted in blue. Each parameter is described briefly below.

Year Costs Reported: This is the year in which all costs are given or displayed, both in the input screens and the results. A cost index is used by the IECM to scale all costs to the cost year specified by this parameter.

Constant or Current Dollars: Constant dollar analysis does not include the affect of inflation, although real escalation is included. Current dollar analysis includes inflation and real escalation. This choice allows you to choose the mode of analysis for the entire IECM economics.

Fixed Charge Factor (FCF): The fixed charge factor is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.

Discount Rate (Before Taxes):

One may specify a Fixed Charge Factor, or fill in the following inputs and the model will calculate the FCF based on them:

Inflation Rate: This is the rise in price levels caused by an increase in the available currency and credit without a proportionate increase in available goods or services. It does not include real escalation.

Plant or Project Book Life: This is the years of service expected from a capital investment. It is also the period over which an investment is recovered through book depreciation.

Real Bond Interest Rate: This is a debt security associated with a loan or mortgage. It is the most secure form of security but the lowest in its return.

Real Preferred Stock Return: This equity security is the second most speculative type and pays the second highest rate of return. The holder of the stock is a part owner of the company.

Real Common Stock Return: This is the most speculative type of equity security sold by a utility and pays the highest relative return. The holder of the stock is a part owner of the company.

Percent Debt: This is the percent of the total capitalization that is associated with debt money. This includes loans and mortgage bonds.

Percent Equity (Preferred Stock): This is the percent of the total capitalization that is associated with the sale of preferred stock.

Percent Equity (Common Stock): This value is the remainder of the capitalization, calculated as 100% minus the percent debt, minus the percent equity in preferred stock.

Federal Tax Rate: This is the federal tax rate. It is used to calculate the amount of taxes paid and deferred.

State Tax Rate: This is the state tax rate. It is used to calculate the amount of taxes paid and deferred.

Property Tax Rate: The property tax rate, or ad valorem, is used to calculate the carrying charge.

Investment Tax Credit: This is an immediate reduction in income taxes equal to a percentage of the installed cost of a new capital investment. It is zero by default. It is used to set the initial balance and the book depreciation.

Base Plant Retrofit Cost Inputs

Inputs for the capital costs of modifications to process areas of the base plant itself are entered on the **Retrofit Cost** input screen

Base Plant—Retrofit Cost input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital

or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Each **Capital Cost Process Area** is described briefly below.

Steam Generator: This area accounts for the steam cycle equipment and pumps.

Turbine Island: This area accounts for the turbine island and associated pumps.

Coal Handling: This area accounts for the mechanical collection and transport equipment of coal in the plant.

Ash Handling: This area accounts for the mechanical collection and transport of ash in the plant.

Water Treatment: This area accounts for the pumps, tanks, and transport equipment used for water treatment.

Auxiliaries: Any miscellaneous auxiliary equipment is treated in this process area.

Base Plant Capital Cost Inputs

Inputs for the capital costs of the base plant itself are entered on the **Capital Cost** input screen.

Base Plant—Capital Cost input screen

The necessary capital cost input parameters associated with the base plant are on this input screen. The capital cost parameters and terminology used in the IECM are based on the methodologies developed by the Electric Power Research Institute (EPRI). They have prepared a Technical Assessment Guide (TAG) in order to provide a consistent basis for reporting cost and revenues associated with the electric power industry. This system of reporting is used by a wide audience, including

energy engineers, researchers, planners, and managers. The IECM has been developed around this TAG system so that costs associated with various technologies can be compared directly on a consistent basis and communicated in the language used by the audience listed above.

Total Plant Cost (TPC): Total Plant Cost is the sum of the process facilities capital, general facilities capital, engineering and home office fees, and the contingencies (project and process). This is considered the cost on an instantaneous basis (overnight), and expressed in December dollars of a reference year.

Direct Capital Costs: Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). This is the basis for all other capital cost parameters.

Process Facilities Capital: The process facilities capital for the technology is the total constructed cost of all on-site processing and generating units, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. These direct capital costs are generally calculated by the IECM and not presented directly on input screens. However, when important input variables are required for these calculations, they are listed at the top of the input screen.

Indirect Capital Costs

Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

Process Contingency Cost: This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Pre-Production Costs

These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to O&M costs over a specified period of time (months).

Fixed Operating Cost: Time period of fixed operating costs (operating and maintenance labor, administrative and support labor, and maintenance materials) used for plant startup.

Variable Operating Cost: Time period of variable operating costs at full capacity (chemicals, water, and other consumables, and waste disposal changes) used for plant startup. Full capacity estimates of the variable operating costs will assume operations at 100% load.

Misc. Capital Cost: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) to finance the base plant as a percent of the TCR of a new power plant. This value is 100% for a new plant and may be set as low as 0% for a base plant that has been paid off.

Base Plant O&M Cost Inputs

Inputs for the operation and maintenance costs of the base plant itself are entered on the **O&M Cost** input screen.

Base Plant—O&M Cost input screen

The EPRI TAG method of categorization has been used for operating and maintenance costs screens. It provides a consistent basis of reporting for a wider audience of users.

O&M costs are expressed on an average annual basis. The costs are broken down into two categories: variable and fixed. Variable costs include the costs of reagents, chemicals, water, and other materials consumed during plant operation. Fixed costs are associated with labor and overhead charges. All operating costs are subject to inflation.

The base plant considers a more detailed breakdown for the costs associated with the fuel. Together they characterize the fuel costs. Each parameter is described briefly below.

> **Delivered Coal Cost (as-fired):** This is the cost of the delivered coal in dollars per wet ton. The value is calculated by the IECM from the particular regional coal selected. It does not include any cleaning costs.

> **Waste Disposal Cost:** This is the bottom ash disposal cost for the base plant.

> **Water Use:** This is the water used by the base plant.

> **Water Cost:** This is the water cost as used for the base plant.

> **Base Plant Electricity Cost:** This is the unit cost of electricity for the base plant alone, without utility considerations.

Operating Labor

Operating labor is based on the number of personnel required to operate the plant per shift. The number of shifts should be specified.

> **Number of Operating Jobs:** This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

> **Number of Operating Shifts:** This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

> **Operating Labor Cost:** The hourly cost of labor is specified in the base plant O&M cost screen. The same value is used throughout the other technologies.

Total Maintenance Costs

The annual maintenance costs are tied to the capital cost of the technology and the maintenance labor. The parameters below provide the necessary information to determine the total maintenance cost as broken down by the material and labor components.

> **Total Maintenance Cost:** This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

> **Maint. Cost Allocated to Labor:** Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Overhead Charges

The only overhead charge in the EPRI TAG is associated with a charge for administrative and support. General materials are not included in this.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Other Factors

Real escalation rates are typically applied to variable O&M costs that do not change at the same rate as those provided by cost indices used in the IECM. Real escalation rates adjust the costs relative to the cost index adjustments from year to year.

Real Escalation Rate: This is the annual rate of increase of an expenditure due to factors such as resource depletion, increased demand, and improvements in design, manufacturing or construction techniques (negative rate). The real escalation rate does not include inflation.

Boiler Diagram

The **Diagram** result screen displays an icon for the Boiler and values for major flows in and out of it.
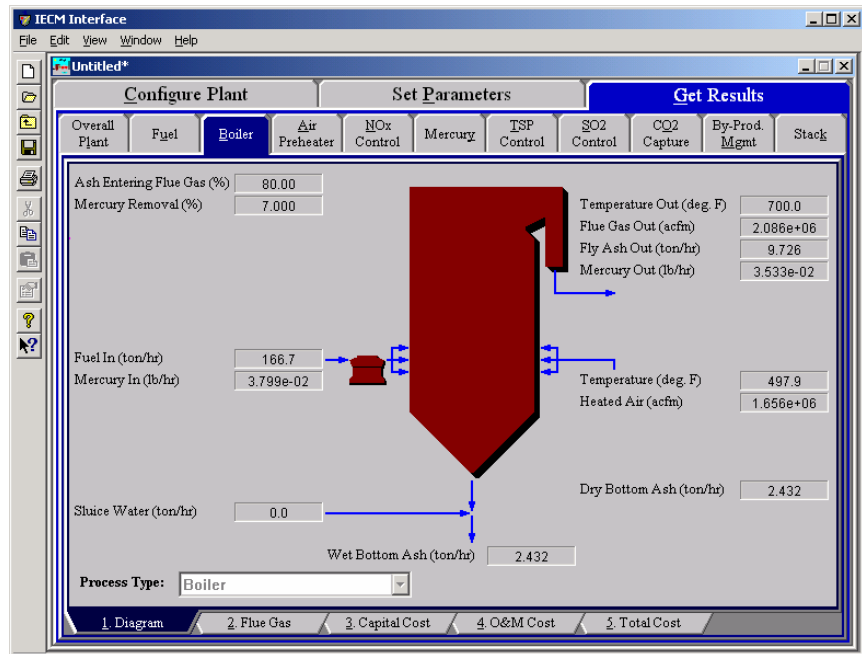
Boiler—Diagram result screen

Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

Fuel Entering Boiler

Wet Fuel: Fuel flow rate into the boiler on a wet basis. Waste products removed prior to the burners are not considered here.

Mercury In: This is the mass flow rate of total mercury entering the boiler. The mass reflects the molecular weight of elemental mercury.

Boiler Performance

Ash Entering Flue Gas: Percent of the ash in coal exiting the boiler in the flue gas.

Mercury Removal: Percent of the total mercury in coal removed from the boiler in the bottom ash.

Air Entering Boiler

Temperature: Heated air temperature measured at the burners. This is generally determined by the combustion air temperature exiting the air preheater.

Heated Air: Volumetric flow rate of the air at the burners, based on the air temperature at the burners and atmospheric pressure.

Flue Gas Exiting the Economizer

Temperature Out: Temperature of the flue gas at the exit of the economizer.

Flue Gas Out: Volumetric flow rate of the flue gas at the exit of the economizer, based on the temperature at the exit of the economizer and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas at the exit of the economizer. This includes ash, unburned carbon and unburned sulfur.

Mercury Out: Total mass of mercury exiting the economizer. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Bottom Ash

Sluice Water: Water added to the dry bottom ash. This water is added for transportation purposes.

Dry Bottom Ash: Total solids mass flow rate of the bottom ash. This includes ash, unburned carbon and unburned sulfur. The value is given on a dry basis.

Wet Bottom Ash: Total solids mass flow rate of the bottom ash for waste management. This includes dry bottom ash and sluice water. The value is given on a wet basis.

Boiler Flue Gas Results

The **Flue Gas** result screen displays a table of quantities of flue gas components entering the boiler in heated air and exiting the boiler in the flue gas. For each component, quantities are given in both moles and mass per hour.

Boiler— Flue Gas result screen

Each result is described briefly below.

> **Nitrogen (N$_2$):** Total mass of nitrogen.
>
> **Oxygen (O$_2$):** Total mass of oxygen.
>
> **Water Vapor (H$_2$O):** Total mass of water vapor.
>
> **Carbon Dioxide (CO$_2$):** Total mass of carbon dioxide.
>
> **Carbon Monoxide (CO):** Total mass of carbon monoxide.
>
> **Hydrochloric Acid (HCl):** Total mass of hydrochloric acid.
>
> **Sulfur Dioxide (SO$_2$):** Total mass of sulfur dioxide.
>
> **Sulfuric Acid (equivalent SO$_3$):** Total mass of sulfuric acid.
>
> **Nitric Oxide (NO):** Total mass of nitric oxide.
>
> **Nitrogen Dioxide (NO$_2$):** Total mass of nitrogen dioxide.
>
> **Ammonia (NH$_3$):** Total mass of ammonia.
>
> **Argon (Ar):** Total mass of argon.
>
> **Total:** Total of the individual components listed above. This item is highlighted in yellow.

Boiler Capital Cost Results

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the Boiler

Boiler—Capital Cost result screen

Each result is described briefly below.

Direct Capital Costs

The direct capital costs described here apply to the "base power plant" without any of the environmental control options that are separately modeled in the IECM. While the purpose of the IECM is to model the cost and performance of emission control systems, costs for the base plant are also needed to properly account for pre-combustion control options that increase the cost of fuel, and affect the characteristics or performance of the base plant. Base plant costs are also needed to calculate the internal cost of electricity which determines pollution control energy costs.

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses. They are described in general below. The primary factors in the model that effect the capital cost of the base plant are the plant size, the coal rank, and the geographic location of the plant.

> **Steam Generator:** This area accounts for the steam cycle equipment and pumps.
>
> **Turbine Island:** This area accounts for the turbine island and associated pumps.
>
> **Coal Handling:** This area accounts for the mechanical collection and transport equipment of coal in the plant.
>
> **Ash Handling:** This area accounts for the mechanical collection and transport of ash in the plant.
>
> **Water Treatment:** This area accounts for the pumps, tanks, and transport equipment used for water treatment.
>
> **Auxiliaries:** Any miscellaneous auxiliary equipment is treated in this process area.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: See definition above. This result is highlighted in yellow.

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the base plant that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the base plant.

Boiler O&M Cost Results

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the base plant. The variable O&M costs are calculated from the variable costs for fuel, water consumption and bottom ash

disposal (from the furnace). The fixed O&M costs are based on maintenance and labor costs.

The Boiler—O&M Cost result screen

Each result is described briefly below.

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

> **Fuel:** The total cost of as-fired fuel. Minemouth cost, coal cleaning costs and transportation costs are all included.

> **Water:** The total cost of water consumed by the base plant for direct or reheat use.

> **Disposal:** The total cost of bottom ash disposal. The value is given on a wet ash basis. This does not consider by-product ash sold in commerce.

> **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

> **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

> **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Boiler Total Cost Results

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the boiler.

Boiler—Total Cost result screen

Each result is described briefly below.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Emission Constraints

Emission Constraints Performance Inputs

The **Emission Constraints** Technology Navigation Tab in the **<u>Set</u> Parameters** program area contains the **Performance** input screen.

This screen accepts input for the allowable emission limits for sulfur dioxide, nitrogen oxides and particulate matter. The default values reflect current United States New Source Performance Standards (NSPS), which are applicable to all units constructed since 1978.

You may override the default values for any of these parameters. SO_2 emission limits are calculated by the model based on the NSPS limits that are a function of the sulfur content of the coal.

The emission constraints are used to calculate the removal efficiencies of control systems for SO_2, NO_x, and particulate matter needed to comply with the specified emission constraints. As discussed later, however, user-specified values for control technology performance may cause the plant to over-comply or under-comply with the emission constraints specified in this screen.

This screen is available for all plant configurations.
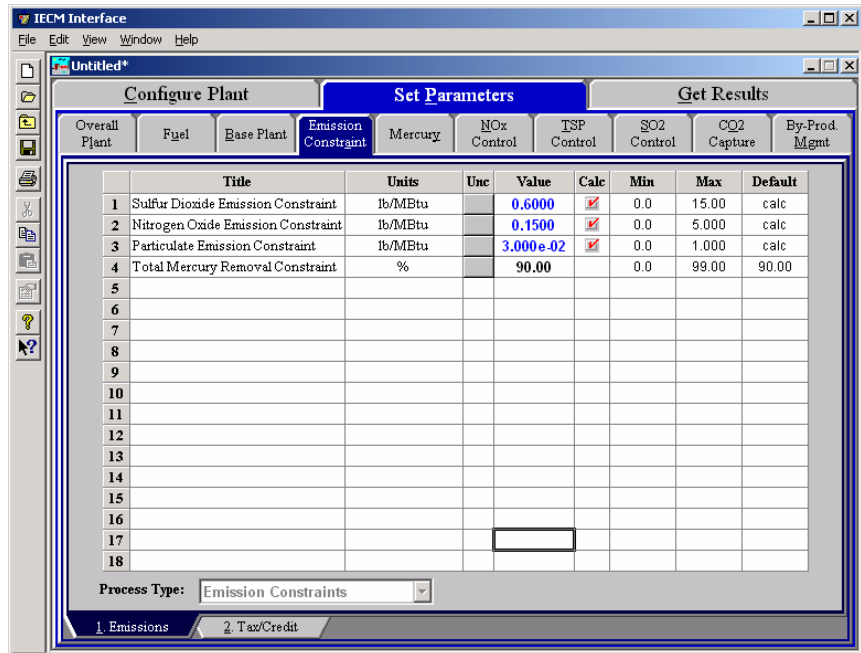
Emission Constraints – Performance input screen.

Each parameter is described briefly below.

Sulfur Dioxide Emission Limit: The emission constraint is defined by the 1979 revised NSPS. The calculated value is determined by the potential emission of the raw coal, minus the amount of sulfur retained in the ash streams. The emission limit is dependent on the fuel type and is used to determine the removal efficiency of SO_x control systems.

Nitrogen Oxide Emission Constraint: The combined emissions of NO_2 and NO_3 of present power plants are constrained by NSPS standards. The limit is a function of the coal rank and fuel type and is used to determine the removal efficiency of NO_x control systems.

Particulate Emission Constraint: The emission constraint of the total suspended particulates is defined by the NSPS standards of 1978. The limit is a function of the fuel type and is used to determine the removal efficiency of particulate control systems.

Total Mercury Removal Constraint: The emission constraint of total after the economizer. Mercury removed in the furnace due to bottom ash removal is not considered in this constraint. The limit determines the removal efficiency of the particulate control systems.

Emission Constraints Tax/Credit Inputs
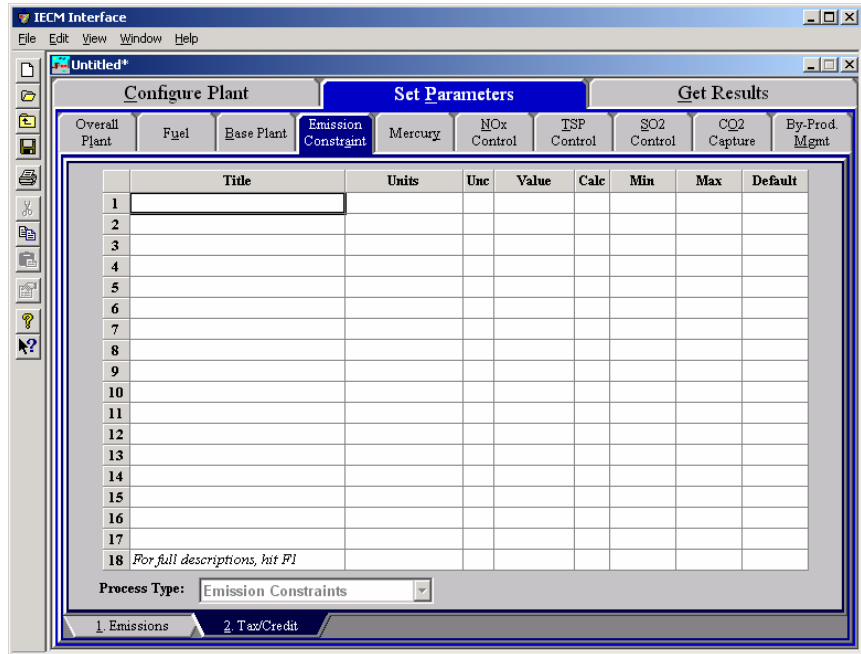
Emission Constraints Tax/Credit input screen.

Auxiliary Boiler

The **CO$_2$** Technology Navigation Tab in the **Get Results** program area contains result screens that display the flow rates and temperatures of substances through an **Auxiliary Boiler**.

If you have added an **Auxiliary Boiler** from the **Set Parameters** program area of the **CO$_2$ Capture** Configuration Input Screen then you may view either the **Amine System** or the **Aux. Boiler** using the pull down menu labeled **Proces Type**. Switch between the two sets of screens by using the **Process Type** pull-down menu at the bottom of the screen.
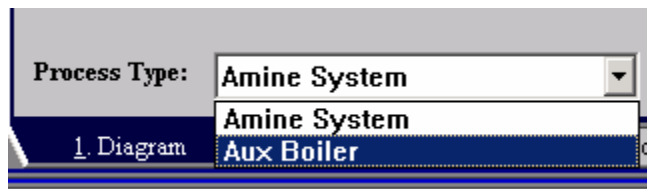
Auxiliary Boiler – Process Type

Auxiliary Boiler Diagram

The **Diagram** result screen displays an icon for the Boiler and values for major flows in and out of it.
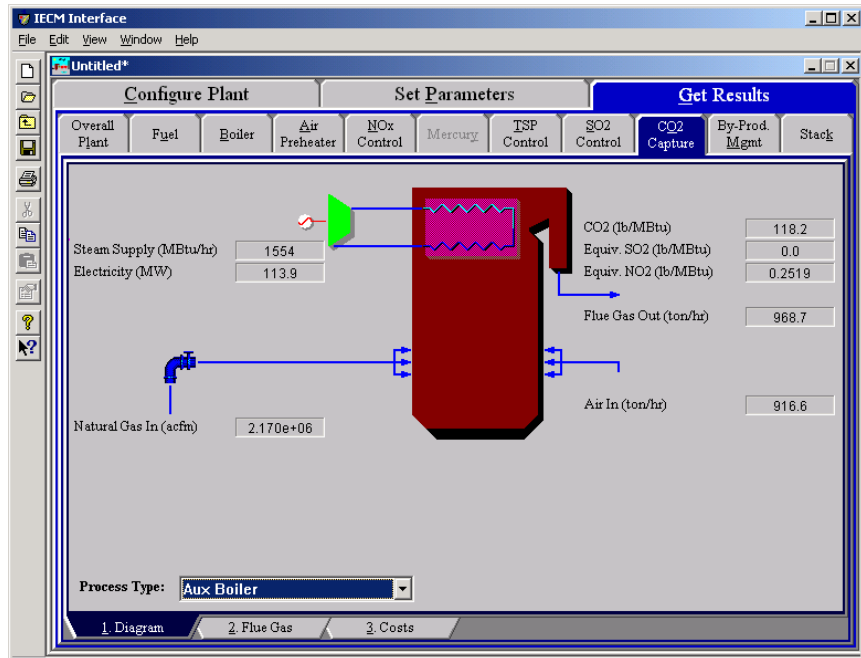
Auxiliary Boiler – Diagram.

Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

Fuel Entering Auxiliary Boiler

Natural Gas In: Natural gas flow rate into the boiler.

Air Entering Auxiliary Boiler

Air In: Volumetric flow rate of the air at the burners, based on the air temperature at the burners and atmospheric pressure.

Auxiliary Boiler Performance

Steam Supply: The flow rate of steam produced by the auxiliary boiler.

Electricity: Electricity produced by the steam turbine that is powered by the auxiliary boiler.

Flue Gas Exiting the Auxiliary Boiler

Flue Gas Out: Volumetric flow rate of the flue gas at the exit of the auxiliary boiler.

CO$_2$: This is the amount of CO$_2$ produced by the auxiliary boiler.

Equiv. SO$_2$: This is the amount of equivalent SO$_2$ produced by the auxiliary boiler.

Equiv. NO$_2$: This is the amount of equivalent NO2 produced by the auxiliary boiler.

Auxiliary Boiler Flue Gas Results

Auxiliary Boiler – Flue Gas result screen

Major Flue Gas Components

Each result is described briefly below:

> **Nitrogen (N$_2$):** Total mass of nitrogen.
>
> **Oxygen (O$_2$):** Total mass of oxygen.
>
> **Water Vapor (H$_2$O):** Total mass of water vapor.
>
> **Carbon Dioxide (CO$_2$):** Total mass of carbon dioxide.
>
> **Carbon Monoxide (CO):** Total mass of carbon monoxide.
>
> **Hydrochloric Acid (HCl):** Total mass of hydrochloric acid.
>
> **Sulfur Dioxide (SO$_2$):** Total mass of sulfur dioxide.
>
> **Sulfuric Acid (equivalent SO$_3$):** Total mass of sulfuric acid.
>
> **Nitric Oxide (NO):** Total mass of nitric oxide.
>
> **Nitrogen Dioxide (NO$_2$):** Total mass of nitrogen dioxide.
>
> **Ammonia (NH$_3$):** Total mass of ammonia.
>
> **Argon (Ar):** Total mass of argon.
>
> **Total:** Total of the individual components listed above. This item is highlighted in yellow.

Auxiliary Boiler Costs Results
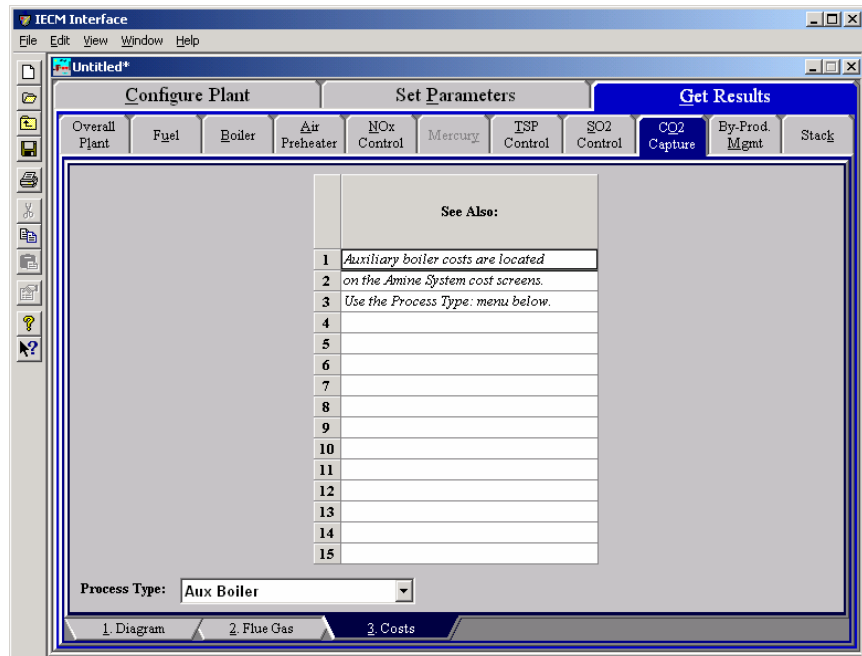
Aux. Boiler – Costs result screen.

Auxiliary Boiler costs are displayed by the **Amine System** cost screens. View these by selecting the **Amine System** from the **Process Type** menu on the bottom of the screen.

Air Preheater

The **Air Preheater** Technology Navigation Tab in the **Get Results** program area contains result screens that display the flow rates and temperatures of substances through the air preheater.

Air Preheater Diagram
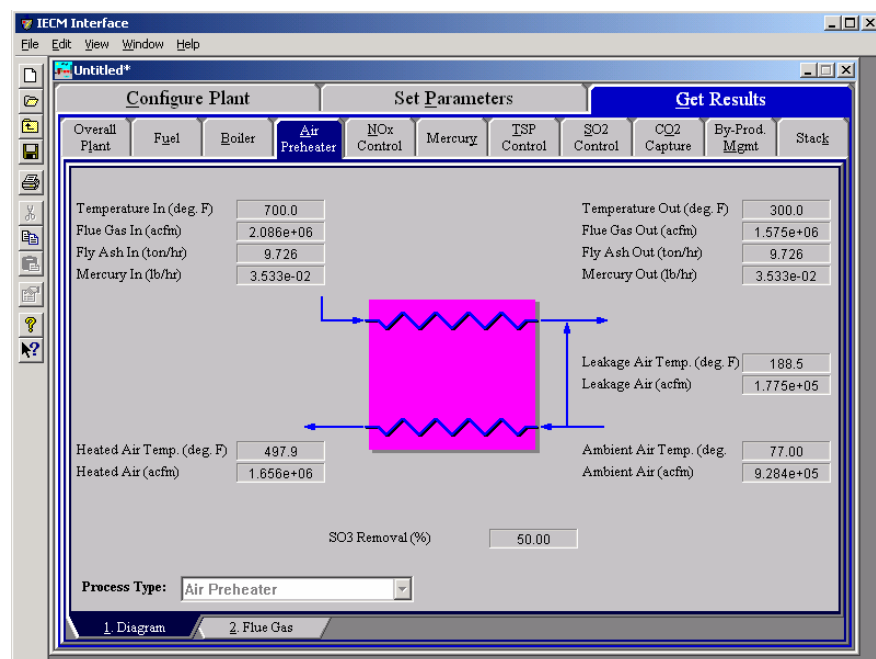
Air Preheater – Diagram.

The **Diagram** result screen displays an icon for the Air Preheater and values for major flows in and out of it. Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

Atmospheric Air Entering Preheater

Ambient Air Temp: Temperature of the atmospheric air entering the induced-draft fan.

Ambient Air: Volumetric flow rate of air entering the induced-draft fan, based on the atmospheric air temperature and atmospheric pressure.

Heated Air Exiting Preheater

Heated Air Temp: Heated combustion air temperature exiting the air preheater. This is a complicated function of the heat content and temperatures of the flue gas.

Heated Air: Volumetric flow rate of the combustion air exiting the air preheater, based on the combustion air temperature and atmospheric pressure.

Leakage Air

Leakage Air Temp: Temperature of the atmospheric air leaking across the air preheater into the flue gas. This is determined by the leakage parameter on the base plant performance input screen.

Leakage Air: Volumetric flow rate of the atmospheric air leaking across the air preheater into the flue gas. This is based on the leakage temperature and atmospheric pressure.

Flue Gas Entering Preheater

Temperature In: Temperature of the flue gas entering the air preheater. This is determined by the flue gas outlet temperature of the module upstream of the air preheater (e.g., the boiler economizer).

Flue Gas In: Volumetric flow rate of the flue gas entering the air preheater, based on the flue gas inlet temperature and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the air preheater. This is determined by the solids exiting the module upstream of the air preheater (e.g., the boiler economizer).

Mercury In: Total mass of mercury entering the air preheater in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Air Preheater Performance

SO_3 Removal: Percent of the SO_3 removed from the flue gas.

Cooled Flue Gas Exiting Preheater

Temperature Out: Temperature of the flue gas exiting the air preheater. This is determined by the parameter on the base plant performance input screen.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the air preheater, based on the flue gas exit temperature and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the air preheater. This is a function of the percent ash entering the flue gas (furnace emissions input parameter) and the ash content of the fuel.

Mercury Out: Total mass of mercury exiting the air preheater in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Air Preheater Flue Gas Results

Air Preheater – Flue Gas result screen.

Major Flue Gas Components

The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the air preheater. For each component entering and exiting in flue gas, values are given in both moles and mass per hour. For each component entering in atmospheric air, values are given in moles per hour. Each result is described briefly below.

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

In-Furnace Controls

The **NO_x Control** Technology Navigation Tab contains screens that address combustion or post-combustion air pollution technologies for Nitrogen Oxides.

These screens are available if the In-Furnace Controls has been selected for NO_x control under Combustion Controls. If you have selected both In-Furnace Controls and a Hot-Side SCR for NO_x control, you may switch between the two sets of screens that configure these technologies by using the Process Type pull-down menu at the bottom of the screen

The Process Type pull-down menu

In-Furnace Controls Configuration

Inputs for configuring the NO_x Control technology are entered on the **Config** input screen. Each parameter is described briefly below.
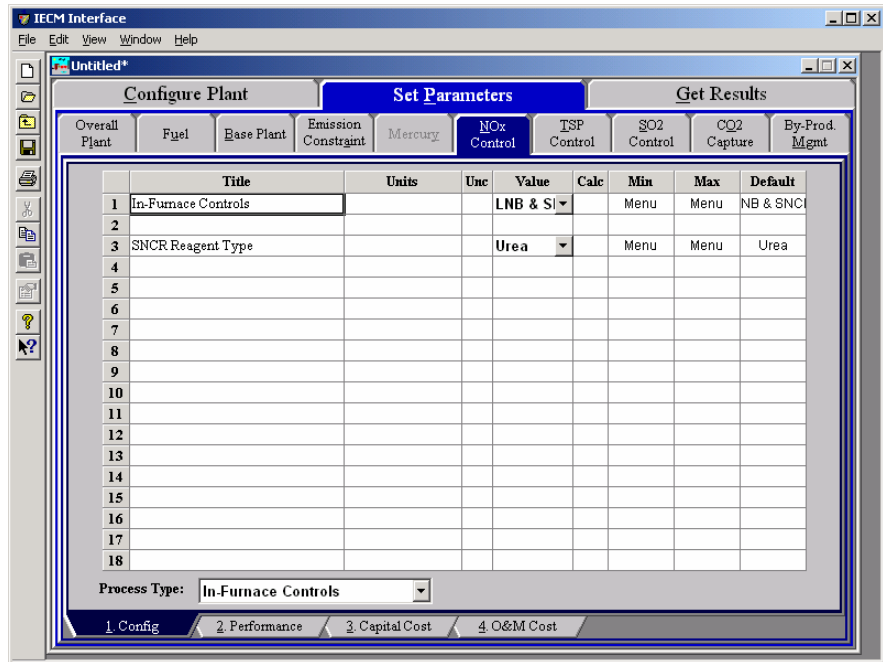
In – Furnace Controls – Config input screen.

In – Furnace Controls

This pull-down menu chooses what type of in-furnace NO_x controls are used. These technologies reduce NO_x between the primary fuel injection into the furnace and the economizer. These can be used in the combinations given in addition to the SCR. The low NO_x burner options are not displayed when a cyclone boiler is configured. The full list of choices is:

LNB – Low NO_x burners are a combustion NO_x control. These burners replace the upper coal nozzle of the standard two-nozzle cell burner with a secondary air port. The lower burner coal nozzle is enlarged to the same fuel input capacity as the two standard coal nozzles. The LNB operates on the principle of staged combustion to reduce NO_x emissions. Approximately 70% of the total air (primary, secondary, and excess air) is supplied through or around the coal-feed nozzle. The remainder of the air is directed to the upper port of each cell to complete the combustion process. The fuel-bound nitrogen compounds are converted to nitrogen gas, and the reduced flame temperature minimizes the formation of thermal NO_x. The net effect of this technology is greater than 50% reduction in NO_x formation with no boiler pressure part changes and no impact on boiler operation or performance. Low NO_x burners are not available for cyclone boilers.

LNB & OFA – Low NO_x burners (see above) with overfire air is another combustion NO_x reduction method. Overfire air is an enhancement to LNB to reduce NO_x formation by further separating the air injection locations. An addition of approximately 10% NO_x is reduced by the addition of OFA. A portion of the secondary air used by LNB is diverted to injection ports located above the primary combustion zone, reducing available oxygen in the primary combustion zone. Overfire air in the IECM refers to separated OFA for both wall and tangential-fired boilers. This option is not supported for cyclone boilers.

Gas Reburn – Gas reburn is a post-combustion NO_x reduction method. Gas reburn substitutes up to one-fourth of the heat input of coal with natural gas, reducing the NO_x up to 60% as a function of the amount of reburn. The natural gas is injected above the primary combustion zone to create a reducing zone. Reburn has been shown to be effective for wall and tangential-fired boilers and more recently for cyclone boilers.

SNCR – Selective non-catalytic reduction is a post-combustion NO_x reduction method. This process removes NO_x from flue gas by injecting one of two nitrogen-based reagents, ammonia or urea, in the presence of oxygen to form nitrogen and water vapor. Optimum removal is achieved in a temperature window of 1600-2000 F. Although the technology is very simple, the narrow temperature window provides the primary challenge. Ammonia slip and ash contamination are additional concerns that must be considered with SNCR.

LNB & SNCR – Low NO_x burners can be used in conjunction with SNCR to achieve very high NO_x removals. Both technologies are described in detail above.

If a Tangential or Wall Furnace Type have been selected in **Configure Plant**, then all five options will display. If you have selected a Cyclone Furnace type, then only **Gas Reburn** and **SNCR** will display.

The default for Tangential and Wall furnaces is **LNB & SNCR**. The default for a Cyclone furnace is **Gas Reburn**.

SNCR Reagent Type

Only displayed when **SNCR** or **LNB & SNCR** have been selected in the In-Furnace Controls pull-down menu. Nitrogen-based reagent injection is used in an SNCR to reduce NO_x in the presence of oxygen to form nitrogen and water vapor. The reagent choices are:

Urea – Urea ($CO(NH_2)_2$) is typically diluted to a 15-20% concentration with water. Urea has the advantage of safety and ease of storage and handling. Urea is the default reagent used in the IECM.

Ammonia – Ammonia can be supplied in two forms: anhydrous (NH_3) and aqueous(NH_4OH). The IECM considers only anhydrous ammonia. Ammonia may be an advantage when using an SNCR in conjunction with an SCR system.

In-Furnace Controls Performance Input
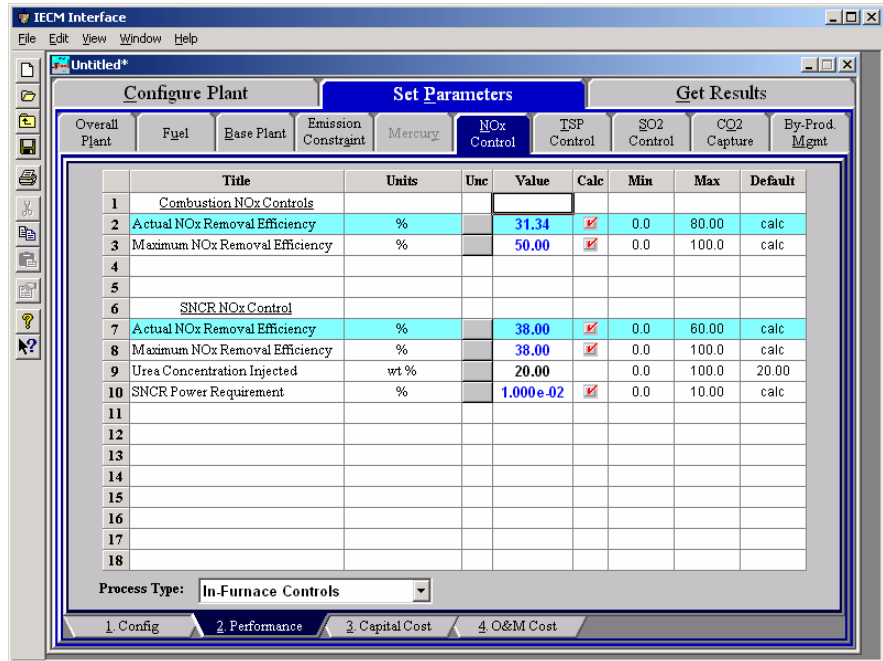
In – Furnace Controls – Performance input screen.

Inputs for the performance of the **In-Furnace Controls** NO$_x$ control technology are entered on the on the **Performance** input screen. Combustion NOx Controls These inputs will display if any combustion technology is used in the option selected in the **In-Furnace Controls** pull-down menu. This includes the **LNB, LNB + OFA, Gas Reburn**, and the **LNB + SNCR** options.

> **Actual NOx Removal Efficiency:** This is the NO$_x$ removal efficiency of the **LNB**, **LNB + OFA**, and **Gas Reburn** options, and the **LNB** removal portion of the **LNB + SNCR** option. The percent reduction of NO$_x$ is calculated by comparing the actual NO$_x$ emission to the uncontrolled NO$_x$ emission. The removal is a function of the **In-Furnace Control** type selected in the pull-down menu, the boiler type, and the maximum removal efficiency (below). **Note:** that the removal is not a function of the NO$_x$ emission constraint. This input is highlighted in blue.

> **Maximum NOx Removal Efficiency:** The maximum removal efficiency of NO$_x$ sets the upper bound for the actual NO$_x$ removal efficiency (above). The maximum removal is a function of the In-Furnace control type and the boiler type.

> **Natural Gas Heat Input:** This input will only display if **Gas Reburn** is selected in the **In-Furnace Controls** pull-down menu. The flow rate of natural gas injected is determined by this input on a Btu heat input basis.

SNCR NOx Control

These inputs will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu.

Actual NOx Removal Efficiency: The actual NO_x removal efficiency is a function of the maximum NO_x removal efficiency (below) and the NO_x emission constraint. This input is highlighted in blue.

Maximum NOx Removal Efficiency: The maximum removal efficiency is calculated as a function of the gross electrical output. Because of difficulty mixing the reagent in the flue gas for larger boilers, the maximum efficiency decreases with increasing plant size.

Urea Concentration Injected: Urea is typically injected as a liquid diluted by water. This parameter defines the amount of water used to dilute the urea prior to injection.

SNCR Power Requirement: As mentioned above, the power requirement for the SNCR is a function of gross electrical output of the power plant. The value is determined by the need for tank heaters when urea reagent is used.

In-Furnace Controls Capital Cost

In–Furnace Controls – Capital Cost input screen.

The **Combustion Modifications** inputs will not display if **SNCR** is selected in the In-Furnace Controls pull-down menu. The **SNCR Boiler Modifications** inputs will only display if **SNCR** or **LNB & SNCR** is selected

Base Capital Costs

The base capital costs (excluding retrofit, using gross KW) specify the total base capital costs, not considering any retrofit factors. No detailed information about direct or indirect costs is given. The costs are given as a total in units of dollars per gross kilowatt.

Combustion Modifications: This is the base capital cost of the **LNB**, **LNB + OFA**, and **Gas Reburn** options, and the LNB removal portion

of the **LNB + SNCR** option. This parameter is not shown when one of these options is not selected.

SNCR Boiler Modifications: This specifies the total base capital cost for the **SNCR** boiler NO_x removal equipment alone. This parameter is not shown when one of the SNCR options is not selected.

Retrofit Capital Cost Factors

Retrofit cost factors allow you to differentiate between the base cost of purchasing the capital equipment and the actual cost incurred. These factors vary from unit to unit.

Combustion Modifications: This is the retrofit cost factor for the **LNB**, **LNB + OFA**, and **Gas Reburn** options, and the LNB removal portion of the **LNB + SNCR** option. This parameter is not shown when one of these options is not selected

SNCR Boiler Modifications: This is the retrofit cost factor for the **SNCR** option alone. This parameter is not shown when one of the SNCR options is not selected

Total Capital Costs (including retrofit, using gross KW):

Combustion Modifications: This is the total capital cost of the **LNB, LNB + OFA,** and **Gas Reburn** options, and the LNB removal portion of the **LNB + SNCR** option. This combines the base capital cost with the retrofit cost factor. This parameter is not shown when one of these options is not selected.

SNCR Boiler Modifications: This specifies the total capital cost for the **SNCR** boiler NO_x removal equipment alone. This parameter is not shown when one of the SNCR options is not selected

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for in-furnace controls that has been paid off.

In-Furnace Controls O&M Cost

Inputs for the operation and maintenance costs of the In-Furnace Controls O&M $CosNO_x$ control technology are entered on the <u>6</u>. O&M Cost input screen for the Hot-Side SCR, and the <u>4</u>. O&M Cost input screen for In-Furnace Controls. Each parameter is described briefly below.
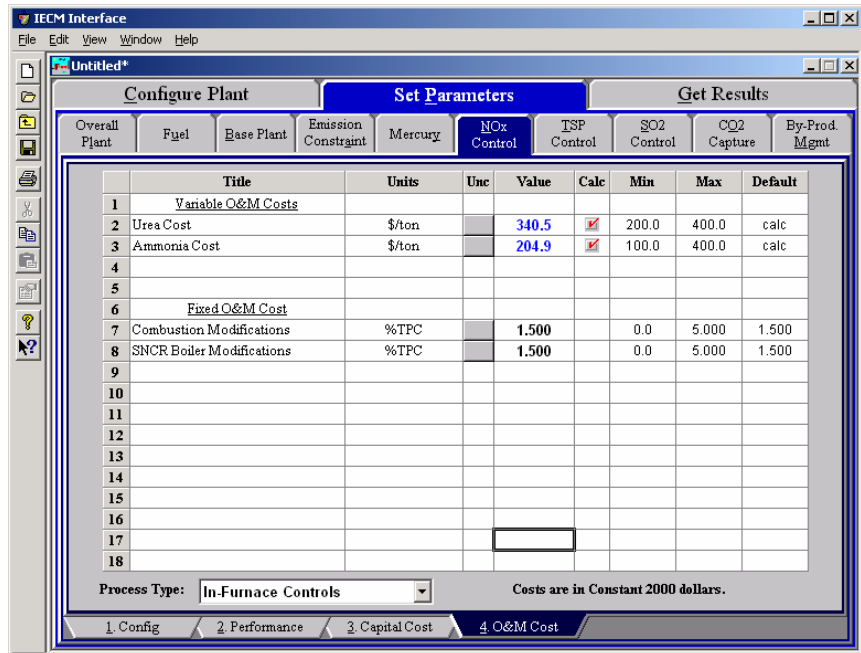
In-Furnace Controls – O&M Cost input screen.

Each parameter is described briefly below.

Variable O&M Costs

> **Urea Cost:** This is the cost of urea used for any of the SNCR options. This input will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu

> **Ammonia Cost:** This is the cost of ammonia used for any of the SNCR options. This input will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu

> **Natural Gas Cost:** This is the cost of natural gas used for the Gas Reburn option. This input will only display if **Gas Reburn** is selected

Fixed O&M Cost

Fixed O&M costs are given as a total cost, rather than itemized costs broken down by individual maintenance and labor costs. The results are given as a percent of the total capital cost.

> **Combustion Modifications:** This is the total fixed operating and maintenance cost for boiler NO_x modifications made in the combustion zone (LNB, OFA, natural gas reburn). This parameter is not shown if one of these options is not selected.

> **SNCR Boiler ModificationsVariable O&M Costs:** This is the total fixed O&M cost for the **SNCR** equipment alone. This input is not shown if one of the SNCR options is not selected.

In-Furnace Controls Diagram
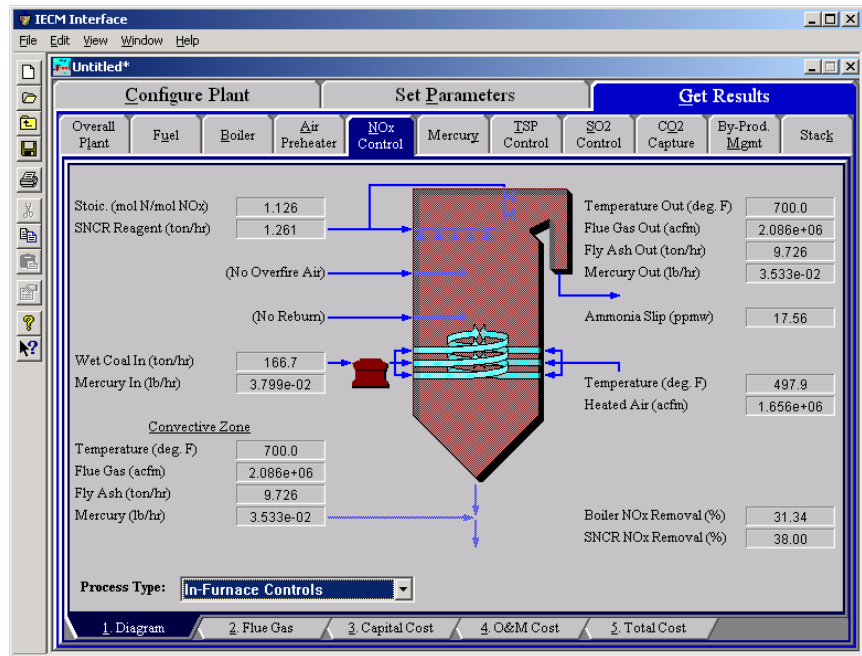
In-Furnace Controls – Diagram

The **Diagram** result screen displays an icon for the **In-Furnace Controls** NO_x technology selected and values for major flows in and out of it.

Fuel Entering Boiler

> **Wet Coal In:** Fuel flow rate into the boiler on a wet basis. Waste products removed prior to the burners are not considered here.

> **Mercury In:** This is the mass flow rate of total mercury entering the boiler. The mass reflects the molecular weight of elemental mercury.

Air Entering Boiler

> **Temperature:** Heated air temperature measured at the burners. This is generally determined by the combustion air temperature exiting the air preheater.

> **Heated Air:** Volumetric flow rate of the air at the burners, based on the air temperature at the burners and atmospheric pressure.

Flue Gas Exiting Convective Zone

This the area of the furnace between the combustion zone and the SNCR (if present). Changes in the flue gas after combustion due to in-furnace combustion NO_x controls are reflected here.

> **Temperature:** Temperature of the flue gas exiting the convective zone.

> **Flue Gas:** Volumetric flow rate of the flue gas exiting the convective zone, based on the temperature exiting the convective zone and atmospheric pressure.

> **Fly Ash:** Total solids mass flow rate in the flue gas exiting the convective zone. This includes ash, unburned carbon and unburned sulfur.

Mercury: Total mass of mercury in the flue gas exiting the convective zone. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting the Economizer

Temperature Out: Temperature of the flue gas at the exit of the economizer.

Flue Gas Out: Volumetric flow rate of the flue gas at the exit of the economizer, based on the temperature at the exit of the economizer and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas at the exit of the economizer. This includes ash, unburned carbon and unburned sulfur.

Mercury Out: Total mass of mercury in the flue gas exiting the economizer. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Gas Reburn

Reburn Gas: This is the flow rate of natural gas into the boiler. This result will only display if **Gas Reburn** is selected in the In-Furnace Controls pull-down menu

SNCR

The SNCR is located in the upper portion of the boiler. Several parameters are reported as a summary. These results will only display if **SNCR** or **LNB & SNCR** is selected in the In-Furnace Controls pull-down menu.

Stoic.: This is the actual reagent stoichiometry used in the SNCR. Note that urea has double the moles of nitrogen relative to that of ammonia.

SNCR Reagent: This is the mass flow rate of reagent (urea or ammonia) injected by the SNCR into the boiler. Note that water used to dilute the urea is included in this flow rate.

Ammonia Slip: This is the concentration of ammonia leaving the SNCR technology in the flue gas.

In-Furnace Controls Flue Gas Results

In-Furnace Controls – Flue Gas result screen.

The **Flue Gas** result screen for **In-Furnace Controls** displays a table of quantities of gas components entering and exiting the combustion zone. For each component, quantities are given in both moles and mass per hour. It also displays quantities of gas components exiting the convective zone in moles per hour. Each result is described briefly below.

Major Flue Gas Components

      Nitrogen (N$_2$): Total mass of nitrogen.

      Oxygen (O$_2$): Total mass of oxygen.

      Water Vapor (H$_2$O): Total mass of water vapor.

      Carbon Dioxide (CO$_2$): Total mass of carbon dioxide.

      Carbon Monoxide (CO): Total mass of carbon monoxide.

      Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

      Sulfur Dioxide (SO$_2$): Total mass of sulfur dioxide.

      Sulfuric Acid (equivalent SO$_3$): Total mass of sulfuric acid.

      Nitric Oxide (NO): Total mass of nitric oxide.

      Nitrogen Dioxide (NO$_2$): Total mass of nitrogen dioxide.

      Ammonia (NH$_3$): Total mass of ammonia.

      Argon (Ar): Total mass of argon

      Total: Total of the individual components listed above. This item is highlighted in yellow.

In-Furnace Controls Capital Cost Results

In-Furnace Controls – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the **In-Furnace Controls** NO$_x$ control technology.

Total Capital Costs

> **Combustion NO$_x$ Capital Requirement:** The total capital costs, including retrofit costs, for the LNB, OFA, and gas reburn technologies are included here. A zero is displayed when none of these technologies are installed.

> **SNCR Capital Requirement:** The total capital costs, including retrofit costs, for the SNCR technology is included here. A zero is displayed when an SNCR is not installed.

> **Total Capital Requirement:** Sum of the above**.**

Effective TCR: The TCR of the retrofit NO$_x$ controls that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the hot-side SCR.

In-Furnace Controls O&M Cost Results

In-Furnace Controls– O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **In-Furnace Controls** NO$_x$ control technology. Each result is described briefly below

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

> **Reagent:** The total reagent costs (urea and ammonia) are included here.

> **Water:** This is the cost of the water used to dilute the urea for the SNCR.

> **Power:** This is the power used for the pumps to move reagents and water in the SNCR.

> **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

> **Combustion NO$_x$ Costs:** This is the fixed O&M costs associated with the LNB, OFA, and gas reburn systems.

> **SNCR Boiler Costs:** This is the fixed O&M costs associated with the SNCR system.

> **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

In-Furnace Controls Total Cost Results

In-Furnace Controls – Total Cost result screen

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **In-Furnace Controls** NO_x Control technology. Each result is described briefly below. Note that all costs expressed in $/ton of NO_2 removed assume tons of equivalent NO_2.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Hot-Side SCR

The **NO$_x$ Control** Technology Navigation Tab contains screens that address combustion or post-combustion air pollution technologies for Nitrogen Oxides.

If you have selected a Hot-Side SCR, there will be six input screens and therefore six Input Navigation Tabs. If you have selected In-Furnace Controls, there will be four input screens and therefore four Input Navigation Tabs.

These input screens are only available if a Hot-Side SCR has been selected under Post-Combustion Controls in the **Configure Plant** program area.

If you have selected both In-Furnace Controls and a Hot-Side SCR for NO$_x$ control, you may switch between the two sets of screens that configure these technologies by using the Process Type pull-down menu at the bottom of the screen.

The Process Type pull-down menu

Hot-Side SCR Configuration
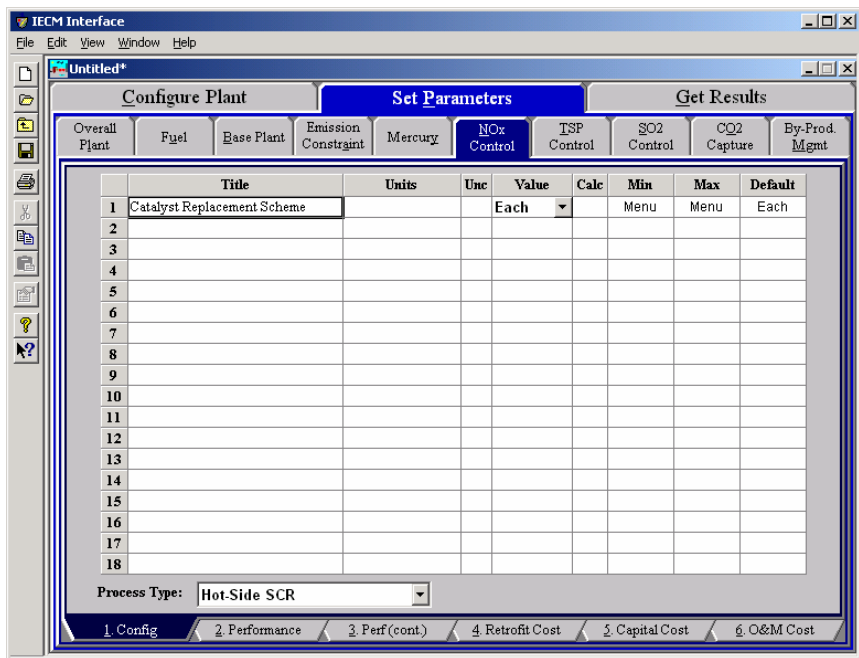
Hot–Side SCR – Config. input screen.

Inputs for configuring the **Hot–Side SCR** NO$_x$ Control technology are entered on the **Config** input screen. Each parameter is described briefly below.

> **Catalyst Replacement Scheme:** Catalyst is installed in the SCR as a series of layers. These activity or effectiveness of these layers decreases with time due to fouling and poisoning. The layers are replaced with clean layers on a regular basis in one of two ways: all at once or one layer at time (staggered). The selection of the replacement scheme involves trade-offs between capital and annual costs via the initial catalyst requirement and the replacement interval. More specifically:
>
> **Each** – Individual Layers. Replacing individual layers sequentially, rather than simultaneously, increases the effective catalyst life for a given volume of catalyst, decreasing the replacement interval. This reduces the O&M cost relative to simultaneous replacement. The default setting is **Each.**
>
> **All** – All Layers: Simultaneous replacement may lead to a smaller initial catalyst volume to achieve the same design activity as a sequential replacement scheme. This reduces the capital cost but increases the O&M cost.

Hot-Side SCR Performance Inputs
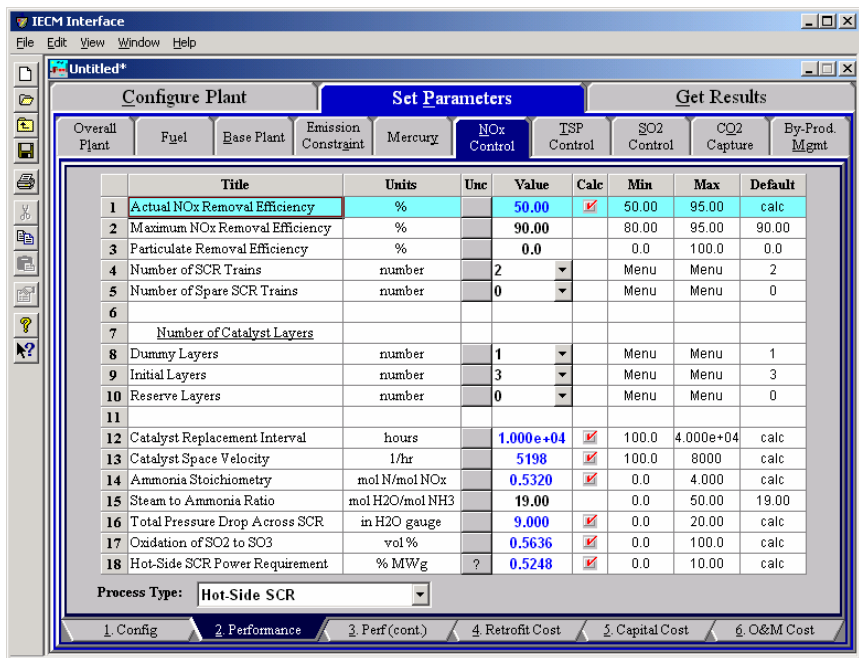
Hot–Side SCR – Performance input screen.

Inputs for the performance of the **Hot–Side SCR** NO_x control technology are entered on the on the **Performance** input screen. Each parameter is described briefly below.

Actual NO_x Removal Efficiency: The actual removal efficiency is dependent on the minimum and maximum removal efficiencies of the SCR and the emission constraint for NO_x. The model assumes a minimum removal of 50%. The actual removal is set to match the constraint, if feasible. It is possible that the SCR may under or over comply with the emission constraint. This input is highlighted in blue.

Maximum NO_x Removal Efficiency: This parameter specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual NO_x removal efficiency for compliance.

Particulate Removal Efficiency: The ash in the high dust gas entering the SCR collects on the catalyst layers and causes fouling. Ash removal is not a design goal; rather, it is a reality which is taken into consideration by this parameter.

Number of SCR Trains: This is the total number of SCR equipment trains. It is used primarily to calculate the capital costs. The value must be an integer.

Number of Spare SCR Trains: This is the total number of spare SCR equipment trains. It is used primarily to calculate capital costs. The value must be an integer.

Number of Catalyst Layers: The total number of catalyst layers is a sum of the dummy, initial and spares used. All catalyst layer types are of equal dimensions, geometry, and catalyst formulation. You specify each value; the value must be an integer. The catalyst layer types and

quantities are combined with pressure drop information to determine the auxiliary power requirements and the capital cost of the SCR technology. A layer may be interpreted as either a full layer (e.g., typically 1 meter deep), or a half layer (e.g., typically 0.5 meters deep) to represent alternative SCR catalyst replacement schemes. There is a limit of 8 total initial and reserve layers.

Dummy Layers: This is the number of dummy catalyst layers. The value must be an integer. A dummy layer corrects the flow distribution. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.

Initial Layers: This is the number of initial active catalyst layers. The value must be an integer. Three layers are installed initially. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.

Reserve Layers: This is the number of reserve or extra catalyst layers. These are available for later catalyst additions. The value must be an integer. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.

Catalyst Replacement Interval: This parameter calculates the operating hour interval between catalyst replacements. The interval is determined by the decision to replace all at once or each of them separately after each interval. Currently, the model is not set up to replace two half layers simultaneously.

Catalyst Space Velocity: The calculated space velocity is determined by several factors, including many of the reference parameters in the next Section. The space velocity is used to determine the catalyst volume required.

Ammonia Stoichiometry: This is the molar stoichiometry ratio of ammonia to NO_x entering the SCR device. The calculated quantity is based on an assumed NO_x removal reaction stoichiometry of 1:1 for both NO and NO_2, and a specified ammonia slip. It affects the amount of ammonia used and the amount of NO_x converted to moisture.

Steam to Ammonia Ratio: The molar ratio of steam to ammonia is used to determine the amount of steam injected to vaporize the ammonia. The value assumes the steam is saturated at 450 degrees Fahrenheit and the ammonia is diluted to 5 volume percent of the injected gas.

Total Pressure Drop Across SCR: The total is determined from the individual pressure drops due to air preheater deposits, the active catalyst layers, the dummy catalyst layers, the ammonia injection system and the duct work. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements.

Oxidation of SO_2 to SO_3: The oxidation rate is calculated for a high sulfur catalyst and affects the flue gas composition. It uses the space velocity and the inlet temperature. The SO_3 produced acts as an ash-conditioning agent if an ESP is used downstream.

SCR Energy Penalty: The default calculation of auxiliary power is based on the additional pressure drop, electricity to operate pumps and compressors, and equivalent energy for steam consumed. It is expressed as a percent of the gross plant capacity.

Hot-Side SCR Performance (Continued)
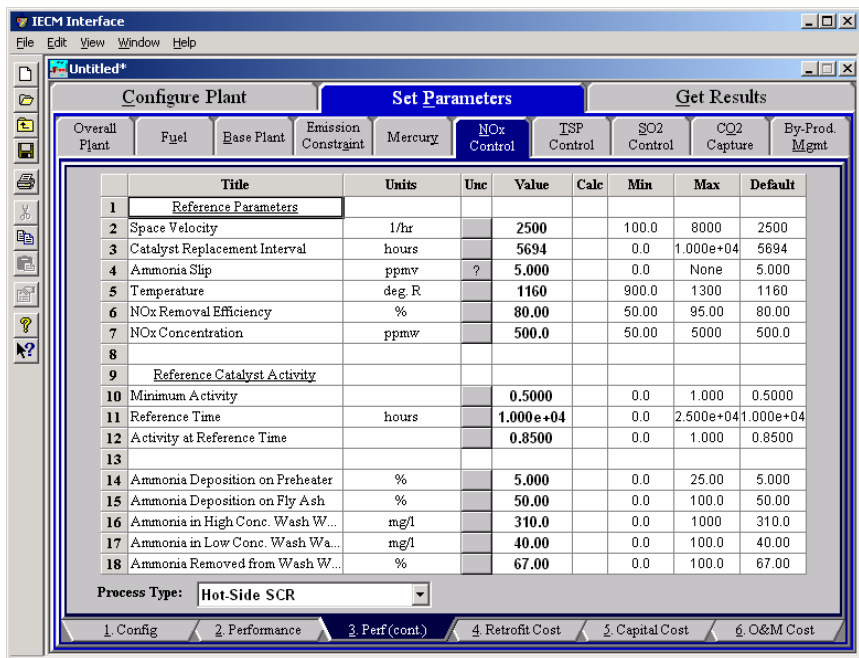
Hot–Side SCR – Perf.(cont.) input screen

The Hot-Side SCR system has additional inputs for performance entered on the **Perf (Cont.)** input screen. Many of the calculated quantities on the **Performance** screen are determined by the reference parameters described below.

Reference Parameters

The first set of reference parameters is primarily used to determine the actual space velocity. The values are used with actual operating conditions through a series of correction factors in the IECM. If you set the actual space velocity displayed on the **Performance** screen, this set of input parameters is not used by the IECM and does not have to be set.

> **Space Velocity:** This is the reference space velocity for a high dust system. It is used to calculate the actual space velocity.

> **Catalyst Replacement Interval:** This is the reference operating life in hours associated with the reference space velocity for the high dust catalyst. It is used to calculate the actual space velocity.

> **Ammonia Slip:** Ammonia slip accounts for the ammonia passing through the reactor unchanged and further downstream. The value is based on an 80 percent or lower NO_x removal efficiency. It is used in calculating the ammonia stoichiometry and actual space velocity.

> **Temperature:** This is the operating temperature associated with the reference space velocity. It is used to determine the actual space velocity.

> **NO_x Removal Efficiency:** This is the NO_x removal efficiency associated with the reference design specifications for the SCR system. It is used to determine the actual space velocity.

NO$_x$ Concentration: This is the inlet NO$_x$ concentration associated with the reference design specifications for the SCR system. It is used to determine the actual space velocity

Reference Catalyst Activity

Catalyst activity decreases with operating time due to plugging and catalyst poisoning. The loss is a complex function of the catalyst formulation and geometry, the operating conditions associated with the flue gas, including temperature and composition, and the loading and composition of the fly ash. This complex function is represented by an exponential decay formula in the IECM. The following parameters are used to determine the reference catalyst activity, assuming the initial activity has a value of unity:

Minimum Activity: The minimum activity is a lower limit for catalyst activity decay. The actual activity approaches this value over a long period of time.

Reference Time: This is the time that corresponds to a particular activity known for the catalyst. It is used to determine a decay rate constant.

Activity at Reference Time: A second activity reference point is needed to determine the activity decay rate. The activity should correspond to the reference time specified. It is used to determine a decay rate constant.

Ammonia Deposition on Preheater: This is the percent of the ammonia slip that is deposited as ammonium salts in the air preheater. It is treated like a partition coefficient.

Ammonia Parameters

Ammonia Deposition on Fly Ash: This is the percent of the ammonia slip that is absorbed onto the fly ash. It is treated like a partition coefficient. This is important for high dust systems.

Ammonia in High Conc. Wash Water: The ammonia that deposits in the air preheater is periodically removed by washing. It is initially highly concentrated and requires denitrification pretreatment prior to regular treatment. This is the average concentration in that stream.

Ammonia in Low Conc. Wash Water: The ammonia that deposits in the air preheater is periodically removed by washing. The concentration is initially high, but gradually decreases. This is the average concentration of the low concentration stream.

Ammonia Removed from Wash Water: The ammonia that deposits in the air preheater is periodically removed by washing. This is the average amount of ammonia removed from the high and low concentrated streams.

Hot-Side SCR Retrofit Cost
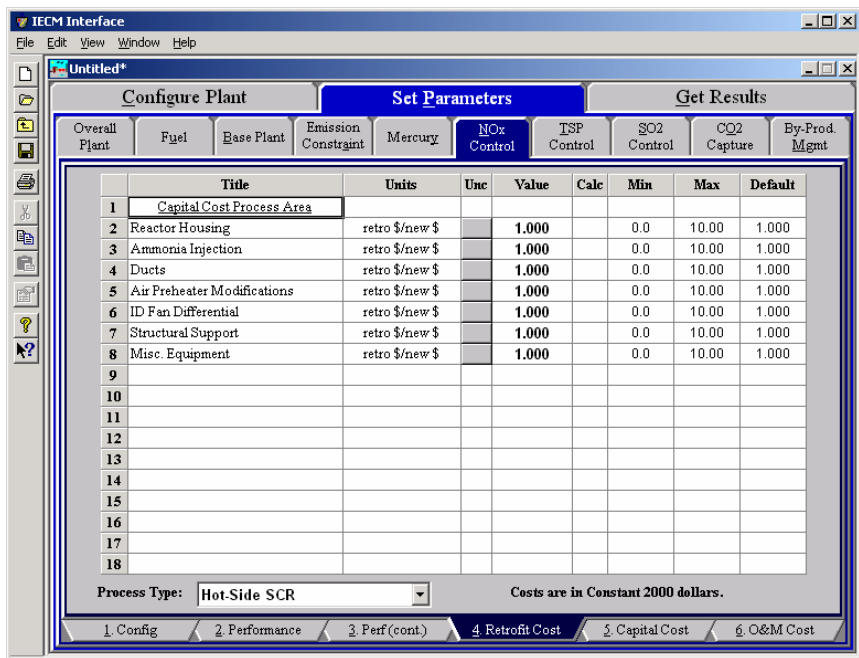
Hot–Side SCR – Retrofit Cost input screen.

The **Hot-Side SCR** system has inputs for the capital costs of modifications to process areas necessary to implement the technology entered on the **Retrofit Cost** input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens. Each parameter is described briefly below.

Capital Cost Process Area

> **Reactor Housing:** The reactor housing costs include carbon steel reactor vessel with six inches of mineral wool insulation, vessel internals and supports, steam sootblowers, reactor crane and hoist, installation, labor, foundations, structures, piping, and electrical equipment.

> **Ammonia Injection:** The ammonia unloading, storage, and supply system includes a storage vessel with a seven day capacity, an ammonia

vaporizer, mixer, injection grid, ductwork, dampers, and a truck unloading station.

Ducts: The ductwork includes economizer bypass and outlet ducts, SCR inlet and outlet ducts, SCR and economizer control dampers, air preheater inlet plenum, various expansion joints in the ductwork, and air preheater cross-over ducting.

Air Preheater Modifications: Thicker and smoother material is used for the heat transfer surfaces in the preheater. A larger motor is provided for the heat exchanger. High pressure steam soot blowers and water wash spray nozzles are also added.

ID Fan Differential: The ID fans must be sized to deal with the increased flue gas pressure drop resulting from the additional ductwork and the SCR reactor.

Structural Support: The costs of this area are related primarily to the structural support required for the SCR reactor housing, ductwork, and air preheater.

Misc. Equipment: This area includes the capital costs incurred for ash handling addition, water treatment addition, and flow modeling for a hot-side SCR system.

Hot-Side SCR Capital Cost Inputs

Hot–Side SCR – Capital Cost input screen.

Inputs for the capital costs of the **Hot–Side SCR** NO_x control technology are entered on the **Capital Cost** screen for the Hot-Side SCR, and the **Capital Cost** input screen for In-Furnace Controls. Each parameter is described briefly below.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

Process Contingency Cost: This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Pre-Production Costs: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

> **Months of Fixed O&M:** Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

> **Months of Variable O&M:** Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

> **Misc. Capital Costs:** This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a hot-side SCR that has been paid off.

Hot-Side SCR O&M Cost Inputs
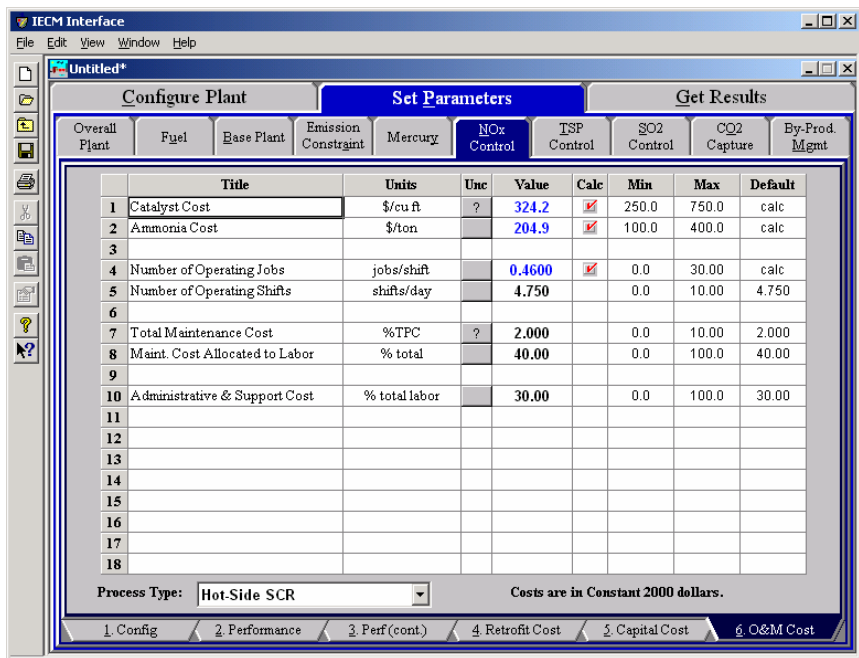
Hot–Side SCR – O&M Cost input screen.

Inputs for the operation and maintenance costs of the **Hot–Side SCR** NO$_x$ control technology are entered on the **O&M Cost** input screen. Each parameter is described briefly below.

Catalyst Cost: This is the cost of the catalyst used for the SCR technology.

Ammonia Cost: This is the cost of the ammonia used for the SCR technology.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Hot-Side SCR Diagram
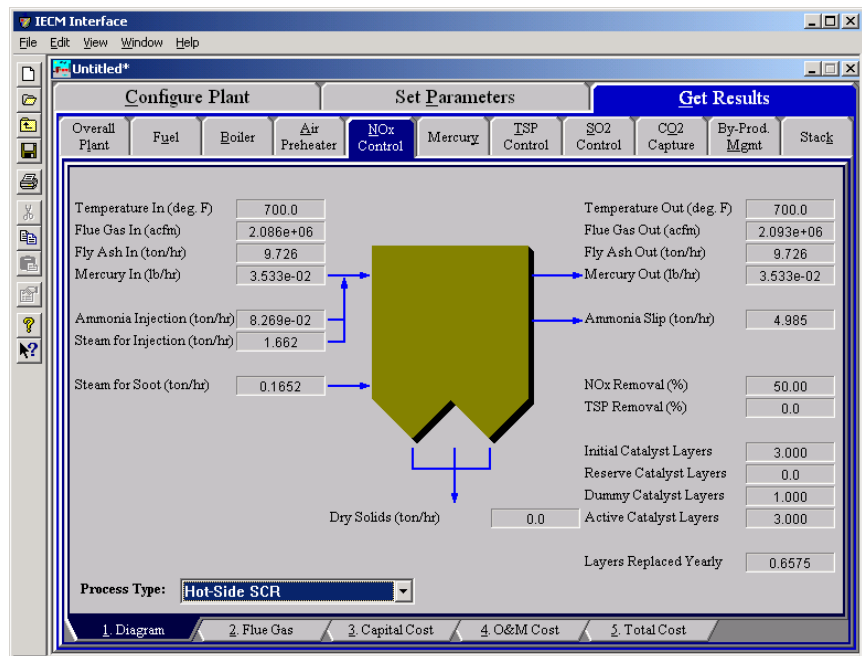
Hot–Side SCR – Diagram result screen.

The **Diagram** result screen displays an icon for the **Hot–Side SCR** NO_x technology selected and values for major flows in and out of it.

Reagent

Ammonia Injection: The total mass flow rate of ammonia injected into the SCR. This is a function of the NO_x concentration in the flue gas and the ammonia stoichiometric performance input value.

Steam for Injection: The total mass flow rate of steam into the SCR. This is the amount of steam added to the SCR to vaporize and transport ammonia into the inlet gas stream. This is determined by the steam to ammonia ratio input value and the ammonia injection.

Catalyst

Steam for Soot: This is the amount of steam blown into the hot-side SCR to remove soot buildup on the catalyst layers. The soot blowing steam is assumed to be directly proportional to catalyst volume.

Initial Catalyst Layers: This is the number of initial active catalyst layers. Three layers are installed initially. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. This is set by the input parameter.

Reserve Catalyst Layers: This is the number of reserve or extra catalyst layers. These are available for later catalyst additions. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. This is set by the input parameter.

Dummy Catalyst Layers: This is the number of dummy catalyst layers. A dummy layer corrects the flow distribution. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. This is set by the input parameter.

Active Catalyst Layers: This is the number of initial active catalyst layers. Three layers are installed initially. It is used to calculate the total pressure drop across the SCR and the auxiliary power requirements. It is equal to the number of initial and reserve catalyst layers.

Layers Replaced Yearly: Average catalyst layer replacement rate per year. This assumes that all catalyst layers are of equal depth.

Flue Gas Entering SCR

Temperature In: Temperature of the flue gas entering the SCR. This is determined by the flue gas outlet temperature of the module upstream of the SCR (e.g., the boiler economizer)

Flue Gas In: Volumetric flow rate of flue gas entering the SCR, based on the flue gas temperature entering the SCR and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the SCR. This is determined by the solids exiting from the module upstream of the SCR (e.g., the boiler economizer).

Mercury In: Total mass of mercury entering the hot-side SCR in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting SCR

Temperature Out: Temperature of the flue gas exiting the SCR. The model currently does not alter this temperature through the SCR.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the SCR, based on the flue gas temperature exiting the SCR and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the SCR. This is a function of the ash removal parameter on the SCR performance input screen.

Ammonia Slip: Total mass flow rate of ammonia that is unreacted and exits the SCR in the flue gas stream. This is a function if the ammonia injection flow rate, NO_x concentration in the flue gas, and NO_x removal efficiency.

Mercury Out: Total mass of mercury exiting the hot-side SCR in the flue gas. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

SCR Performance

NO_x Removal: Actual removal efficiency of NO_x in the SCR. This is a function of the minimum (50%) and maximum removal efficiencies (SCR performance input parameter) and the emission constraint for NO_x (emission constraints input parameter). It is possible that the SCR may over or under-comply with the emission constraint.

TSP Removal: Actual particulate removal efficiency in the SCR. This is set by the SCR input parameter.

Collected Solids

Dry Solids: Total solids mass flow rate of solids removed from the SCR. This is a function of the solids content in the flue gas and the particulate removal efficiency of the SCR.

Hot-Side SCR Flue Gas Results

Hot–Side SCR – Flue Gas result screen.

Major Flue Gas Components

The **Flue Gas** result screen for the **Hot-Side SCR** displays a table of quantities of flue gas components entering and exiting the SCR. For each component, quantities are given in both moles and mass per hour. Each result is described briefly below.

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH_3): Total mass of ammonia.

Argon (Ar): Total mass of argon

Total: Total of the individual components listed above. This item is highlighted in yellow.

Hot-Side SCR Capital Cost Results

Hot-Side SCR – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the **Hot–Side SCR** NO$_x$ control technology. Each result is described briefly below:

Direct Capital Costs

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of hot-side SCR units. They are described in general with specific model parameters that effect them described in particular.

Reactor Housing: The reactor housing costs include carbon steel reactor vessel with six inches of mineral wool insulation, vessel internals and supports, steam soot blowers, reactor crane and hoist, installation labor, foundations, structures, piping, and electrical equipment. The costs are a function of the number of vessels, including spares, and the volume of catalyst required. Catalyst costs are excluded.

Ammonia Injection: The ammonia unloading, storage, and supply system includes a storage vessel with a seven day capacity, an ammonia vaporizer, mixer, injection grid, ductwork, dampers, and a truck unloading station. The costs are a function of the ammonia injected.

Ducts: The ductwork includes economizer bypass and outlet ducts, SCR inlet and outlet ducts, SCR and economizer control dampers, air preheater inlet plenum, various expansion joints in the ductwork, and air preheater cross-over ducting. The costs are a function of the flue gas flow rate through the SCR.

Air Preheater Modifications: Thicker and smoother material is used for the heat transfer surfaces in the preheater. A larger motor is provided for the heat exchanger. High pressure steam soot blowers and water wash spray nozzles are also added. The costs are a function of the

number of operating vessels, and the heat transfer efficiency of the air preheater (UA product).

ID Fan Differential: The ID fans must be sized to deal with the increased flue gas pressure drop resulting from the additional ductwork and the SCR reactor. The costs are a function of the flue gas flow rate and pressure drop across the SCR.

Structural Support: The costs of this area are related primarily to the structural support required for the SCR reactor housing, ductwork, and air preheater. The costs are a function of the reactor housing costs, duct costs and air preheater modification costs above.

Misc. Equipment: This area includes the capital costs incurred for ash handling addition, water treatment addition, and flow modeling for a hot-side SCR system. The costs are a function of the gross plant capacity.

Initial Catalyst: The cost of the initial catalyst charge is included in the total direct cost, because it is such a large and integral part of the SCR system. The costs are a function of the initial catalyst charge.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the hot-side SCR that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the hot-side SCR.

Hot-Side SCR O&M Cost Results

Hot-Side SCR – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **Hot Side SCR** NO$_x$ control technology. Each result is described briefly below:

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Catalyst: Replacement catalyst cost per year for the hot-side SCR. This is a function of the number of catalyst layers, the number of layers replaced each year, and the catalyst space velocity (all three are performance input parameters).

Ammonia: Ammonia reagent cost per year for the hot-side SCR. This is a function of the concentration of NO$_x$ in the flue gas and the ammonia mass flow rate.

Steam: Annual cost of steam used for ammonia vaporization and ammonia injection. This is a function of the steam to ammonia ratio (performance input parameter) and the ammonia mass flow rate.

Water: Cost of water used to wash ammonia that deposits in the air preheater. This is a function of the efficiency and concentration of ammonia removed by wash water performance input parameters and the amount of ammonia salts deposited on the air preheater.

Electricity: Cost of electricity consumption of the hot-side SCR. This is a function of the gross plant capacity and the SCR energy penalty performance input parameter.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Hot-Side SCR Total Cost Results

Hot-Side SCR – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Hot–Side SCR** NO$_x$ Control technology. **Note:** that all costs expressed in $/ton of NO$_2$ removed assume tons of equivalent NO$_2$.Each result is described briefly below.

Cost Component

> **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

> **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

> **Total Annual O&M Cost:** This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

> **Annualized Capital Cost:** This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

> **Total Levelized Annual Cost:** The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Mercury

Mercury Control is a Technology Navigation Tab in the **Set Parameters** and in the **Get Results** program area. These screens define and display results for the performance and costs directly associated with the removal of mercury from each technology in the power plant Pre-combustion and post-combustion control technologies are all considered. Special consideration is given to flue gas conditioning used to enhance mercury removal. Water and activated carbon injection are currently considered as conditioning agents.

Mercury Removal Efficiency Inputs

Inputs for the removal of the speciated mercury from the flue gas stream are entered on the **Removal Eff.** input screen.

Mercury – Removal Efficiency input screen.

Each parameter is described briefly below.

Removal Efficiency of Mercury

The removal of mercury for each control technology configured is given as a percent of the total entering the control technology. The user is given the opportunity to specify the removal separately for each speciation type. Control technologies not currently configured are hidden.

Furnace Removal (total): Mercury present in ash is removed from the furnace through the removal of bottom ash. The speciation is not known, so the removal is specified as a total removal. The mercury removed in bottom ash is not credited toward the required removal to meet the mercury emission constraint.

Fabric Filter

Fabric Filter (total w/o control): Mercury present in ash is removed from the fabric filter through the removal of captured fly ash. The speciation is not known, so the removal is specified as a total removal. The value shown is determined without regard to particular mercury control methods. It has a substantial effect on the amount of activated carbon needed to meet the required removal of mercury.

Fabric Filter (oxidized): The fabric filter typically removes some mercury without adding a specific mercury control technology. This mercury is present in the ash and is removed with the collected ash. When a mercury control technology is added, the removal is enhanced. The default value is set to meet the overall removal efficiency constraint, with consideration given to the mercury removed by flue gas desulfurization and elemental mercury oxidized in a NO_x control technology. The lower limit is set by the removal efficiency of ash alone as specified by "Fabric Filter (total w/o control)" specified above.

Fabric Filter (elemental): Elemental mercury is assumed to be removed with the same efficiency as the removal of oxidized mercury specified above.

Cold – Side ESP

Cold-Side ESP (total w/o control): Mercury present in ash is removed from the cold-side ESP through the removal of captured fly ash. The speciation is not known, so the removal is specified as a total removal. The value shown is determined without regard to particular mercury control methods. It has a substantial effect on the amount of activated carbon needed to meet the required removal of mercury.

Cold-Side ESP (oxidized): The cold-side ESP typically removes some mercury without adding a specific mercury control technology. This mercury is present in the ash and is removed with the collected ash. When a mercury control technology is added, the removal is enhanced. The default value is set to meet the overall removal efficiency constraint, with consideration given to the mercury removed by flue gas desulfurization and elemental mercury oxidized in a NO_x control technology. The lower limit is set by the removal efficiency of ash alone as specified by "Cold-Side ESP (total w/o control)" specified above.

Cold-Side ESP (elemental): Elemental mercury is assumed to be removed with the same efficiency as the removal of oxidized mercury specified above.

Wet FGD

Wet FGD (oxidized): The wet lime/limestone FGD typically removes all the oxidized mercury due to its' high solubility in water.

Wet FGD (elemental): Elemental mercury is assumed to pass through the wet lime/limestone FGD. It is assumed that elemental mercury is present in the flue gas and is unreactive.

Spray Dryer

Spray Dryer (oxidized): Oxidized mercury is assumed to pass through the lime spray dryer. Although soluble in water, moisture injected into the spray dryer evaporates, resulting in the mercury remaining in the flue gas. The default value is zero.

Spray Dryer (elemental): Elemental mercury is assumed to pass through the lime spray dryer. It is assumed that elemental mercury is present in the flue gas and is unreactive.

Percent Increase in Speciation

Although NO_x control technologies do not remove mercury from the flue gas, they can change the mercury from one form to another. This is particularly true when catalysts are present. In this case, elemental mercury is converted to oxidized mercury. The parameters in this section define the percent increase in oxidized mercury across the control technology.

In-furnace NO_x (oxidized): Low NO_x burners with or without overfire air and gas reburn can effect the amount of oxidized mercury. At present, there is insufficient information available to specify a default value. The default is set to zero.

SNCR (oxidized): An SNCR can effect the amount of oxidized mercury. However, there is insufficient information available to specify a default value. The default is set to zero.

Hot-Side SCR (oxidized): Hot-side SCR as a control technology chances elemental mercury to oxidized mercury. It is believed that the catalyst is responsible for this shift in speciation. The default value is a function of the coal rank. .

Mercury Carbon (and Water) Injection Inputs

Inputs for activated carbon and water injected into the flue gas are entered on the **Carbon Inj.** input screen. Water can be optionally added to reduce the flue gas temperature and enhance the effect of the carbon on removing mercury. Note that the actual removal of the carbon and mercury are accomplished in particulate and flue gas desulfurization control technologies downstream
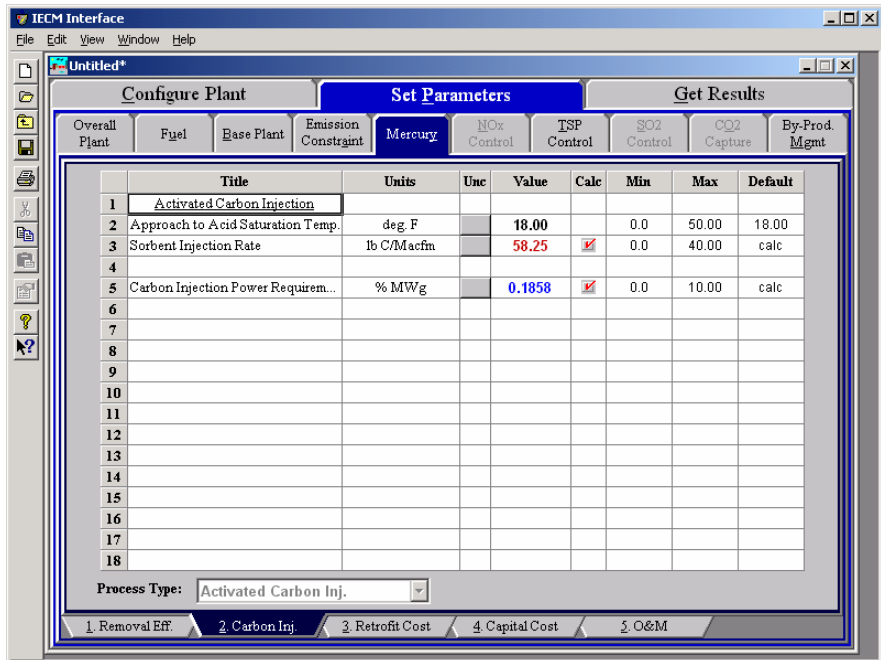
Mercury – Removal Efficiency input screen.

Each parameter is described briefly below.

Activated Carbon Injection

Injection of water to reduce the flue gas temperature and activated carbon to enhance mercury removal are the only control technologies presently incorporated into the IECM.

> **Approach to Acid Saturation Temperature:** When water is selected to be injected with the activated carbon this parameter appears on the **Removal Efficiency** input screen. It is important to keep the flue gas temperature above the sulfuric acid dew point temperature. This avoids condensation of acid on equipment. This parameter determines the amount of water injected into the flue gas. If the approach is above the actual temperature, the temperature is dropped to be the approach above the dew point. The dew point is a function of the SO_3 and H_2O content in the flue gas and the pressure of the flue gas.

> **Sorbent Injection Rate:** The flue gas temperature, the mercury removal efficiency in the particulate device, the coal rank, and the mercury removal efficiency without control, determines the injection rate of activated carbon into the flue gas. Mercury removal due to the ash removed in a cold-side ESP or fabric filter in the absence of enhanced mercury control methods is specified in the input screen. The default value is most sensitive to the flue gas temperature and the mercury removal efficiency without control.

> **Carbon Injection Power Requirement:** The power required for the water and carbon injection system is a function of carbon injection rate, the water injection rate, and the flue gas flow rate. This assumes the addition of a fan in the flue gas to balance the pressure drop. The default value is calculated as the ratio of the actual energy consumption by the gross electrical output of the power plant.

Mercury Retrofit Cost Inputs

Inputs for the capital costs of modifications to process areas of the activated carbon and water injection system are entered on the **Retrofit Cost** input screen.

Mercury – Retrofit Cost input screen.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Each parameter is described briefly below. Although the user cannot set the capital cost directly, the descriptions below include the key parameters used to determine the capital cost itself. The input parameters on this screen adjust this capital cost as calculated in the IECM.

Capital Cost Process Area

Spray Cooling Water: This capital cost area represents the materials and equipment necessary to inject water into the flue gas duct for the purpose of cooling the flue gas to a prerequisite temperature.

Equipment includes water storage tanks, pumps, transport piping, injection grid with nozzles, and a control system. The direct capital cost is a function of the water flow rate.

Sorbent Injection: This capital cost area represents the materials and equipment necessary to deliver the activated carbon into the flue gas. Equipment includes silo pneumatic loading system, storage silos, hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the sorbent flow rate.

Sorbent Recycle: This capital cost area represents the materials and equipment necessary to recycle ash and activated carbon from the particulate collector back into the duct injection point. The purpose is to create a equilibrium state where the carbon is reintroduced to improve performance. Equipment includes hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the recycle rate of ash and spent sorbent.

NOTE: Sorbent recycling is a feature to be added in a future version of the IECM.

Additional Ductwork: This capital cost area represents materials and equipment for ductwork necessary beyond the other process areas. Extra ductwork may be required for difficult retrofit installations.

NOTE: Future versions of the IECM will include parameters to determine a capital cost for this area. The current version assumes no additional ductwork.

Sorbent Disposal: This capital cost area represents materials and equipment required to house and dispose the collected sorbent. Equipment includes hoppers, blowers, transport piping, and a control system. This is in excess of existing hoppers, tanks, and piping used for existing particulate collectors. The direct capital cost is determined by the incremental increase in collected solids in the particulate collector.

CEMS Upgrade: This capital cost area represents materials and equipment required to install a continuous emissions monitoring system (CEMS) upgrade. The direct capital cost is determined by the net electrical output of the power plant.

Pulse-Jet Fabric Filter: This capital costs area represents an upgrade to an existing cold-side ESP, where one section at the back end of the unit is replaced with a pulse-jet fabric filter. This can be considered a pseudo-COHPAC. Equipment includes pulse-jet FF, filter bags, ductwork, dampers, and MCCs, instrumentation and PLC controls for baghouse operation. Equipment excludes ash removal system, power distribution and power supply, and distributed control system. The direct capital cost is a function of the flue gas flow rate and the air to cloth ratio of the fabric filter.

NOTE: The IECM currently does not support multiple particulate devices in the same configuration nor a modified cold-side ESP.

Mercury Capital Cost Inputs

Inputs for the capital costs of the activated carbon and water injection system are entered on the **Capital Cost** input screen.

Mercury – Capital Cost input screen.

The necessary capital cost input parameters associated with the base plant are on this input screen. The capital cost parameters and terminology used in the IECM are based on the methodologies developed by the Electric Power Research Institute (EPRI). They have prepared a Technical Assessment Guide (TAG) in order to provide a consistent basis for reporting cost and revenues associated with the electric power industry. This system of reporting is used by a wide audience, including energy engineers, researchers, planners, and managers. The IECM has been developed around this TAG system so that costs associated with various technologies can be compared directly on a consistent basis and communicated in the language used by the audience listed above.

Total Plant Cost (TPC) is the sum of the process facilities capital, general facilities capital, engineering and home office fees, and the contingencies (project and process). This is considered the cost on an instantaneous basis (overnight), and expressed in December dollars of a reference year.

Direct Capital Costs: Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). This is the basis for all other capital cost parameters.

The process facilities capital for the technology is the total constructed cost of all on-site processing and generating units, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. These direct capital costs are generally calculated by the IECM and not presented directly on input screens. However, when important input variables are required for these calculations, they are listed at the top of the input screen.

Indirect Capital Costs: Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

Process Contingency Cost: This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Pre-Production Costs

These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to O&M costs over a specified period of time (months).

Fixed Operating Cost: Time period of fixed operating costs (operating and maintenance labor, administrative and support labor, and maintenance materials) used for plant startup.

Variable Operating Cost: Time period of variable operating costs at full capacity (chemicals, water, and other consumables, and waste disposal changes) used for plant startup. Full capacity estimates of the variable operating costs will assume operations at 100% load.

Misc. Capital Cost: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for an activated carbon and water injection system that has been paid off.

Mercury O&M Cost Inputs

Inputs for the operation and maintenance costs of the mercury control technology are entered on the **O&M** cost input screen.

Activated Carbon Cost (w. shipping): This is the cost for the activated carbon, including the cost of shipping.

Disposal Cost: This is the disposal cost for the particulate control system. It is assumed that the ash is not hazardous, therefore can be disposed with the collected fly ash.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Mercury Diagram

The **Diagram** result screen displays an icon for the water and carbon injection systems, both part of the overall mercury control option and values for major flows in and out of it
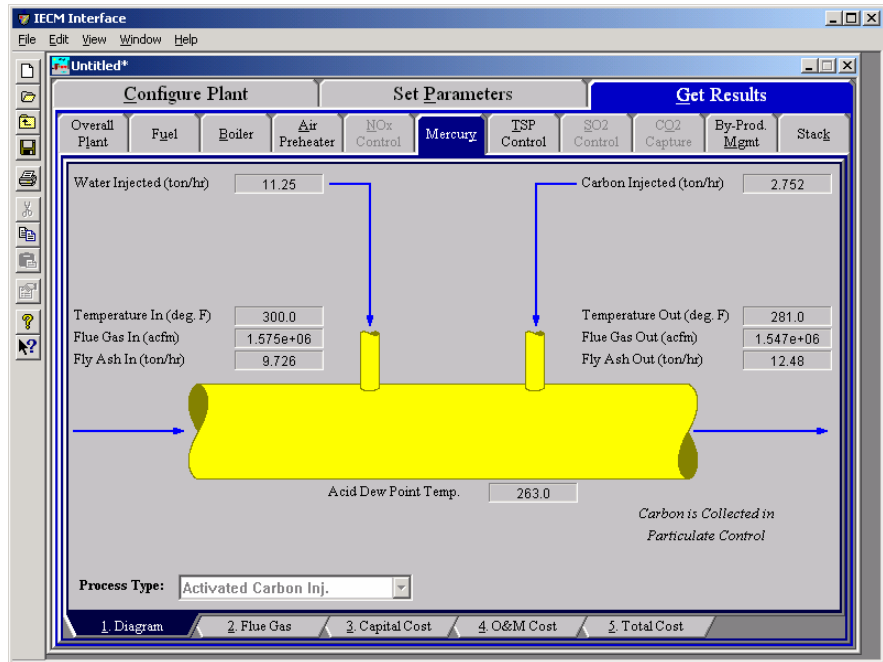
Mercury— Diagram result screen

Each result is described briefly below in flow order (not from top to bottom and left to right as they display on the screen).

Flue Gas Prior to Injection

> **Temperature In:** Temperature of the flue gas prior to flue gas conditioning.

> **Flue Gas In:** Volumetric flow rate of the flue gas prior to flue gas conditioning, based on the temperature prior to flue gas conditioning and atmospheric pressure.

> **Fly Ash In:** Total solids mass flow rate in the flue gas prior to flue gas conditioning. This includes ash, unburned carbon and unburned sulfur.

Flue Gas After Injection

> **Temperature Out:** Temperature of the flue gas after flue gas conditioning. This should be above the acid dew point temperature at the bottom of the screen.

> **Flue Gas Out:** Volumetric flow rate of the flue gas after flue gas conditioning, based on the temperature after flue gas conditioning and atmospheric pressure.

> **Fly Ash Out:** Total solids mass flow rate in the flue gas after flue gas conditioning. This includes ash, unburned carbon, activated carbon, and unburned sulfur.

> **Acid Dew Point:** This is the temperature that H_2SO_4 vapor condenses into the liquid phase. .

Flue Gas Conditioning

> **Water Injected:** Water added to the flue gas to reduce the temperature No water is injected if water injection is not specified in the configuration

or the inlet temperature is within the approach to saturation relative to the acid dew point.

Carbon Injected: Total activated carbon mass flow rate injected into the flue gas.

NOTE: Carbon injected into the flue gas is collected downstream in the particulate control device (e.g., the cold-side ESP).

Mercury Flue Gas Results

The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the flue gas conditioning area. For each component, quantities are given in both moles and mass per hour.

Mercury – Flue Gas result screen.

Major Flue Gas Components

Each result is described briefly below.

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Mercury Capital Cost Results

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the water and carbon injection systems, both part of the overall mercury control option.

Mercury – Capital Cost result screen.

Each result is described briefly below.

Direct Capital Costs

The direct capital costs described here apply to the various mercury control equipment added to the power plant. These controls may physically be part of other control technologies, but have their particular capital costs considered here.

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses. They are described in general below. The primary factors in the model that effect the capital cost of the base plant are the plant size, the amount of water injected, the amount of activated carbon injected, and the sulfur and moisture content of the coal.

Spray Cooling Water: This capital cost area represents the materials and equipment necessary to inject water into the flue gas duct for the purpose of cooling the flue gas to a prerequisite temperature. Equipment includes water storage tanks, pumps, transport piping, injection grid with nozzles, and a control system. The direct capital cost is a function of the water flow rate.

Sorbent Injection: This capital cost area represents the materials and equipment necessary to deliver the activated carbon into the flue gas. Equipment includes silo pneumatic loading system, storage silos, hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the sorbent flow rate.

Sorbent Recycle: This capital cost area represents the materials and equipment necessary to recycle ash and activated carbon from the particulate collector back into the duct injection point. The purpose is to create a equilibrium state where the carbon is reintroduced to improve performance. Equipment includes hoppers, blowers, transport piping, and a control system. The direct capital cost is a function of the recycle rate of ash and spent sorbent.

NOTE: Sorbent recycling is a feature to be added in a future version of the IECM.

Additional Ductwork: This capital cost area represents materials and equipment for ductwork necessary beyond the other process areas. Extra ductwork may be required for difficult retrofit installations.

NOTE: Future versions of the IECM will include parameters to determine a capital cost for this area. The current version assumes no additional ductwork.

Sorbent Disposal: This capital cost area represents materials and equipment required to house and dispose the collected sorbent. Equipment includes hoppers, blowers, transport piping, and a control system. This is in excess of existing hoppers, tanks, and piping used for existing particulate collectors. The direct capital cost is determined by the incremental increase in collected solids in the particulate collector.

CEMS Upgrade: This capital cost area represents materials and equipment required to install a continuous emissions monitoring system (CEMS) upgrade. The direct capital cost is determined by the net electrical output of the power plant.

Pulse-Jet Fabric Filter: This capital costs area represents an upgrade to an existing cold-side ESP, where one section at the back end of the unit is replaced with a pulse-jet fabric filter. This can be considered a pseudo-COHPAC. Equipment includes pulse-jet FF, filter bags, ductwork, dampers, and MCCs, instrumentation and PLC controls for baghouse operation. Equipment excludes ash removal system, power distribution and power supply, and distributed control system. The direct capital cost is a function of the flue gas flow rate and the air to cloth ratio of the fabric filter.

NOTE: The IECM currently does not support multiple particulate devices in the same configuration nor a modified cold-side ESP.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: See definition above. This result is highlighted in yellow.

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the water and carbon injection controls that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the water and carbon injection system.

Mercury O&M Cost Results

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs related to the water and carbon injection systems, both part of the overall mercury control option. The variable O&M costs are calculated from the variable costs for carbon, water consumption and fly ash disposal (from the particulate control device). The fixed O&M costs are based on maintenance and labor costs

Mercury – O&M Cost result screen.

Each result is described briefly below.

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

> **Activated Carbon:** This is the activated carbon cost for flue gas conditioning.

> **Water:** This is the water cost for flue gas conditioning.

> **Additional Waste Disposal:** This is the solid disposal cost per year for the flue gas conditioning. Only the removal of carbon from the particulate device is considered here.

> **Electricity:** This is the power utilization cost per year for the flue gas conditioning.

> **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

> **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

> **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Mercury Total Cost Results

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs related to the water and carbon injection systems, both part of the overall mercury control option.

Mercury – Total Cost result screen.

Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Cold-Side ESP

The **TSP Control**. Technology Navigation screens define and display flows and costs related to the particulate control technology. These screens are available only if the **Cold–Side ESP** TSP control technology is selected.

Cold-Side ESP Performance Inputs

Inputs for the performance of the Cold–Side ESP TSP control technology are entered on the **Performance** input screen. Many of the parameters are calculated by the IECM. Each parameter is described briefly below.

Cold–Side ESP – Performance input screen.

ESPs consist of a series of parallel plates with rows of electrodes in between them and carry a high voltage of opposite polarity. As the particle laden flue gas enters the unit, the particles are charged by the electrodes and is attracted to the plates. At controlled intervals the plates are rapped which shakes the dust to a hopper below. However, some of the dust is re-entrained and carried to the next zone or out of the

stack. Most ESPs use rigid collecting plates with shielded air pockets (baffles) through which ash falls into the hoppers after rapping.

The major design parameters which can significantly impact the total system capital cost are *gas flow volume* (which depends on the generating unit size), *SCA*, the collecting plate area per transformer-rectifier (T-R) set and the spacing between collector plates.

Particulate Removal Efficiency: The calculated value determines the removal efficiency needed to comply with the specified particulate emission limit set earlier. This efficiency then determines the mass of particulate matter removed in the collector.

Actual SO$_3$ Removal Efficiency: The default value is taken from the removal efficiency reported by Southern Company.[5] This efficiency then determines the mass of SO$_3$ removed from the flue gas in the collector.

Collector Plate Spacing: The collector plate spacing is typically 12 inches. The spacing is used to determine the specific collection area.

Specific Collection Area: The specific collection area (SCA) is the ratio of the total plate area and flue gas volume. It sizes the ESP. The value is calculated from the removal efficiency, plate spacing, and the drift velocity. It is used to determine the capital cost and the total collection area required.

Plate Area per T-R Set: This is the total surface area of one T-R set of plates. It is used to determine the total number of T-R sets needed and the capital costs.

Percent Water in ESP Discharge: This is the water content of the collected fly ash. Fly ash disposed with bottom ash is assumed to be sluiced with water and dry otherwise. The occluded water in wet fly ash is difficult to remove, resulting in a rather high water content when the fly ash is mixed with bottom ash.

Cold-Side ESP Power Requirement: The default calculation is based on the T-R set power consumption with estimates for auxiliary energy requirements and electro-mechanical efficiencies of fan motors. The T-R set power consumption is a function of removal efficiency.

Cold-Side ESP Retrofit Cost Inputs

Inputs for the capital costs of modifications to process areas to implement the Particulate control technology are entered on the **Retrofit Cost** input screen. All costs are in constant 1996 dollars.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for

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[5] Ibid.

each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Cold–Side ESP – Retrofit Cost input screen.

Each parameter is described briefly below.

Capital Cost Process Area

> **Particulate Collector:** This area covers the material and labor, flange to flange, for the equipment and labor cost for installation of the entire collection system.

> **Ductwork:** This area includes the material and labor for the ductwork needed to distribute flue gas to the inlet flange, and from the outlet flange to a common duct leading to the suction side of the ID fan.

> **Fly Ash Handling:** The complete fly ash handling cost includes the conveyor system and ash storage silos.

> **Differential ID Fan:** The complete cost of the ID fan and motor due to the pressure loss that results from particulate collectors.

Cold-Side ESP Capital Cost Inputs

Inputs for the capital costs of particulate control technology are entered on the **Capital Cost** input screen.
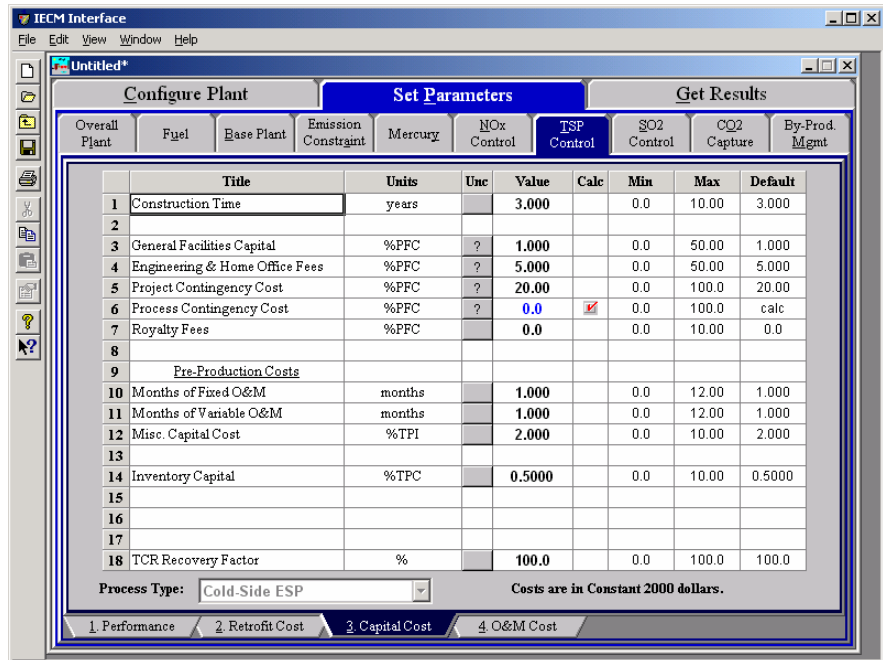
Cold–Side ESP – Capital Cost input screen.

The necessary capital cost input parameters associated with the electrostatic precipitator control technology are shown on this input screen.

Indirect Capital Costs: Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

> **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

> **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

> **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

> **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

> **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

> **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Pre-Production Costs

These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months)The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

Months of Variable O&M: Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

Misc. Capital Cost: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a cold-side ESP that has been paid off.

Cold-Side ESP O&M Cost Inputs

Cold–Side ESP – O&M Cost screen input.

Inputs for the operation and maintenance costs of the particulate control technology are entered on this screen.

Waste Disposal Cost: This is the disposal cost for the particulate control system.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Cold-Side ESP Diagram

The **Diagram** result screen displays an icon for the particulate control technology selected and values for major flows in and out of it.
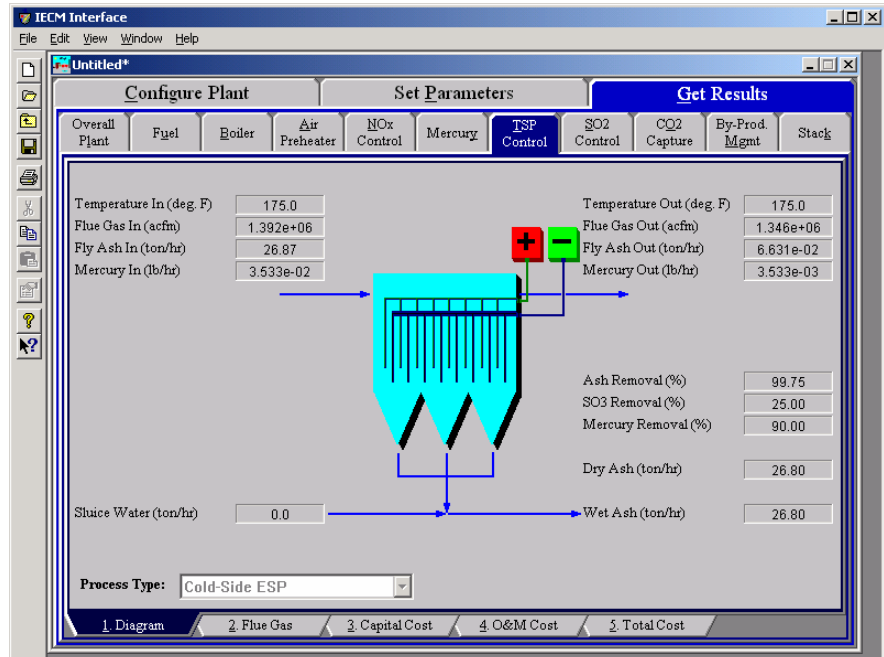
Cold–Side ESP – Diagram

Each result is described briefly below:

Flue Gas Entering ESP

Temperature In: Temperature of the flue gas entering the particulate control technology. This is determined by the flue gas outlet temperature of the module upstream of the air preheater (e.g., the air preheater).

Flue Gas In: Volumetric flow rate of the flue gas entering the particulate control technology, based on the flue gas inlet temperature and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the air preheater. This is determined by the solids exiting the module upstream of the particulate control technology (e.g., the air preheater).

Mercury In: Total mass of mercury entering the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting ESP

Temperature Out: Temperature of the flue gas exiting the particulate control technology. The model currently does not alter this temperature through the particulate control technology.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the particulate control technology, based on the flue gas exit temperature and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the particulate control technology. This is a function of the ash content of the inlet flue gas and the ash removal efficiency performance input parameter.

Mercury Out: Total mass of mercury exiting the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

ESP Performance

Ash Removal: Ash removal efficiency of the particulate control technology. This is a function of the ash emission constraint and the inlet ash mass flow rate.

SO$_3$ Removal: Percent of SO$_3$ in the flue gas removed from the particulate control technology. The SO$_3$ is assumed to combine with H$_2$O and leave with the ash solids as a sulfate (in the form of H$_2$SO$_4$).

Mercury Removal: Percent of the total mercury removed from the particulate control technology. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

Collected Fly Ash

Dry Ash: Total mass flow rate of the solids removed from the ESP. This is a function of the solids content in the flue gas and the particulate removal efficiency of the ESP. The value is given on a dry basis.

Sluice Water: Water added to the dry fly ash. This water is added for transportation purposes.

Wet Ash: Total mass flow rate of the solids removed for waste management. This includes dry fly ash and sluice water. The value is given on a wet basis.

Cold-Side ESP Flue Gas Results

The Flue **Gas** result screen displays a table of quantities of flue gas components entering and exiting the Particulate Control Technology. For each component, quantities are given in both moles and mass per hour.

Cold–Side ESP – Flue Gas results screen.

Each result is described briefly below**:**

Major Flue Gas Components

> **Nitrogen (N$_2$):** Total mass of nitrogen.
>
> **Oxygen (O$_2$):** Total mass of oxygen.
>
> **Water Vapor (H$_2$O):** Total mass of water vapor.
>
> **Carbon Dioxide (CO$_2$):** Total mass of carbon dioxide.
>
> **Carbon Monoxide (CO):** Total mass of carbon monoxide.
>
> **Hydrochloric Acid (HCl):** Total mass of hydrochloric acid.
>
> **Sulfur Dioxide (SO$_2$):** Total mass of sulfur dioxide.
>
> **Sulfuric Acid (equivalent SO$_3$):** Total mass of sulfuric acid.
>
> **Nitric Oxide (NO):** Total mass of nitric oxide.
>
> **Nitrogen Dioxide (NO$_2$):** Total mass of nitrogen dioxide.
>
> **Ammonia (NH3):** Total mass of Ammonia.
>
> **Argon (Ar):** Total mass of Argon.
>
> **Total:** Total of the individual components listed above. This item is highlighted in yellow.

Cold–Side ESP Capital Cost Results

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the particulate control technology.

Cold-Side ESP — Capital Costs results screen.

Direct Capital Costs

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the cold-side ESP are the specific and total collection areas of the T-R plate sets, and the flue gas flow rate through the ESP. The primary model factors that effect the capital costs of the fabric filter are the fabric filter type, the air to cloth ratio, the number of bags and compartments, and the flue gas flow rate through the fabric filter.

Collector: This area covers the material and labor, flange to flange, for the equipment and labor cost for installation of the entire collection system.

Ductwork: This area includes the material and labor for the ductwork needed to distribute flue gas to the inlet flange, and from the outlet flange to a common duct leading to the suction side of the ID fan.

Fly Ash Handling: The complete fly ash handling cost includes the conveyor system and ash storage silos.

Differential ID Fan: The complete cost of the ID fan and motor due to the pressure loss that results from particulate collectors.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the cold-side ESP that is used in determining the total power plant cost. The effective TCR is determined by the **TCR Recovery Factor** for the cold-side ESP.

Cold–Side ESP O&M Cost Results

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the Cold–Side ESP TSP particulate control technology.

Cold–Side ESP – O&M Cost result screen.

Each result is described briefly below

Variable Cost Component

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

> **Solid Waste Disposal:** Total cost to dispose the collected fly ash. This does not consider by-product ash sold in commerce.

> **Power:** Cost of power consumption of the particulate control technology. This is a function of the flue gas flow rate, ash removal efficiency and the type of coal (ash properties).

> **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

> **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

> **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.

> **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Cold-Side ESP Total Cost Results

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Cold–Side ESP TSP Control technology.

Cold–Side ESP – Total Cost result screen.

Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Fabic Filter

The **TSPControl** Technology Navigation Tab contains screens that design and display flows and costs related to the particulate control technology.

Fabric Filter Configuration
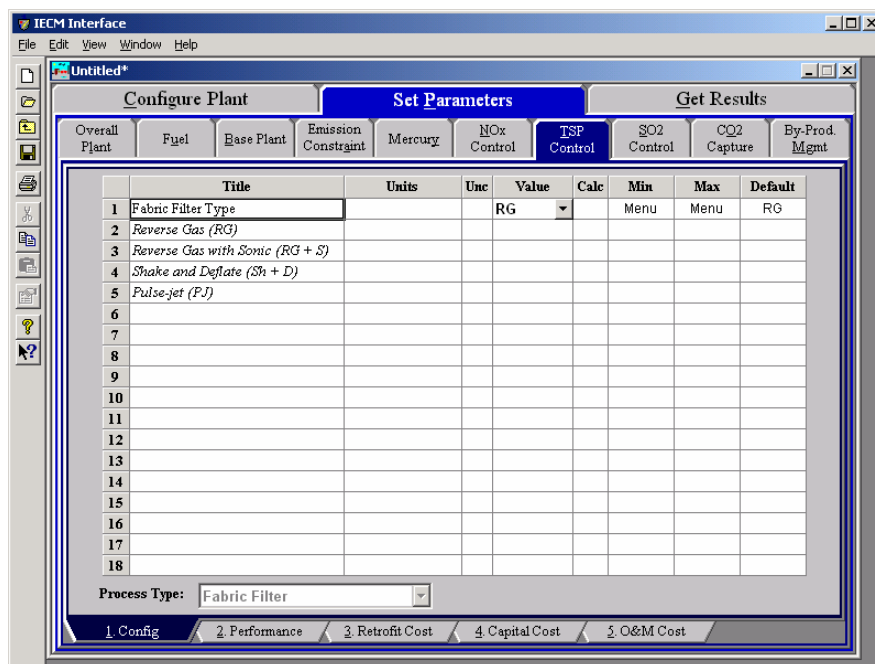
Fabric Filter – Configuration input screen.

Fabric Filter Type

Fabric filters consist of a large number of long tubular filter bags arranged in parallel flow paths. As the ash-laden flue gas passes through these filters, much of the particulate matter is removed. Ash accumulated on the bags is removed periodically by various methods of cleaning. Choose the cleaning method in the **Config.** input screen. The available methods are:

- Reverse Gas (RG)

- Reverse Gas with Sonic (RG + S)

- Shake and Deflate (Sh + D)

- Pulse-jet (PJ)

Fabric Filter Performance Inputs

Fabric Filter – Performance input screen.

The baghouse system is very efficient in removing particulate matter from the flue gas. It's model design is simple, requiring few parameters to characterize its effects on the overall performance of the plant. For properly designed fabric filters, the size of the system is independent of the removal efficiency.

Although the performance is determined by very few parameters, there are several design parameters necessary to determine the cost. These factors are also determined in this section. The major design parameters that can significantly impact the total system cost of the fabric filter are *gas flow volume* (which depends on the generating unit size), *A/C ratio*, the *flange-to-flange pressure drop* in the baghouse and the *bag life*.

Particulate Removal Efficiency: The calculated removal is set to comply with the particulate emission limit set earlier. The mass removed is then determined. If you select a spray dryer, the particulate removal efficiency applies to the combined mass of flyash and sulfur-laden wastes. This input is highlighted in blue.

Actual SO$_3$ Removal Efficiency: The default value is taken from the removal efficiency reported by Southern Company.[6] This efficiency then determines the mass of SO$_3$ removed from the flue gas in the collector.

Solids Loading Out: This is the fabric filter output loading. It is an average value based on typical fabric filter units. The value is used to determine the particulate removal efficiency.

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[6] Ibid.

Number of Baghouse Units: This is the number of baghouse units. The value is based on the gross plant size. The value must be an integer. Each unit contains several compartments. It is used to calculate the capital cost of the baghouse.

Number of Compartments per Unit: This parameter specifies the average number of compartments used per baghouse unit. It is used to calculate the capital cost of the baghouse.

Number of Bags per Compartment: The number of individual bags per compartment is calculated by comparing the required bag surface area to the bag dimensions and the total number of compartments. It is used to calculate the capital cost of the baghouse.

Bag Length: Bag length generally fall into two size categories: 30-36 ft or 20 -22 ft in length. It is based on the fabric filter type and used to calculate the capital cost of the baghouse.

Bag Diameter: Bags are generally between 2/3 and 1 foot in diameter. The value is based on the fabric filter type and used to calculate the capital cost of the baghouse.

Bag Life: Bag life is typically between 3-5 years. The bag life values are dependent on the fabric filter type and are used to calculate the cost of the baghouse.

Air to Cloth Ratio: The Air to Cloth ratio is the most important baghouse parameter. It is the ratio of volumetric flue gas flow rate and total bag cloth area. The calculated value is a function of fabric filter type. It is used to determine the cost and energy use of the baghouse.

Total Pressure Drop across Fabric Filter: Baghouse pressure drop (flange-to-flange) is caused by pressure losses in gas flow as it moves through the bag fabric and dust cake. Typical values range from 6 to 8 in. H_2O and depend on the baghouse type selected. The value affects the power consumption.

Percent Water in Fabric Filter Discharge: This is the water content of the collected fly ash. Fly ash disposed with bottom ash is assumed to be sluiced with water and dry otherwise. The occluded water in wet fly ash is difficult to remove, resulting in a rather high water content when the fly ash is mixed with bottom ash.

Fabric Filter Power Requirement: The default calculation is based on the air-to-cloth ratio and the flue gas flow rate. The energy accounts for the auxiliary energy requirements and electro-mechanical efficiencies of fan motors.

Fabric Filter Retrofit Inputs

Inputs for the capital costs of modifications to process areas to implement the Particulate control technology are entered on the **Retrofit Cost** input screen. All costs are in constant 1996 dollars.

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Fabric Filter – Retrofit Cost input screen.

Capital Cost Process Area

Particulate Collector: This is the cost for the collecting equipment, based on actual vendor prices. Included in the cost are the mechanical equipment and labor, particulate removal system, alternate cleaning system, gas conditioning system, structural supports, electrical, and instrumentation.

Ductwork: This is the cost of all the mechanical, electrical, and supports of the ductwork to and from the collector.

Fly Ash Handling: This is the cost of all the mechanical, conveyors, storage, and electrical portions of the ash handling system. The costs are based on actual vendor prices.

Differential ID Fan: This area includes the additional cost of the ID fan and the motor due to the pressure loss that results from the particulate collectors. Also included are the erection, piping, electrical, and foundation costs.

Fabric Filter Capital Cost Inputs
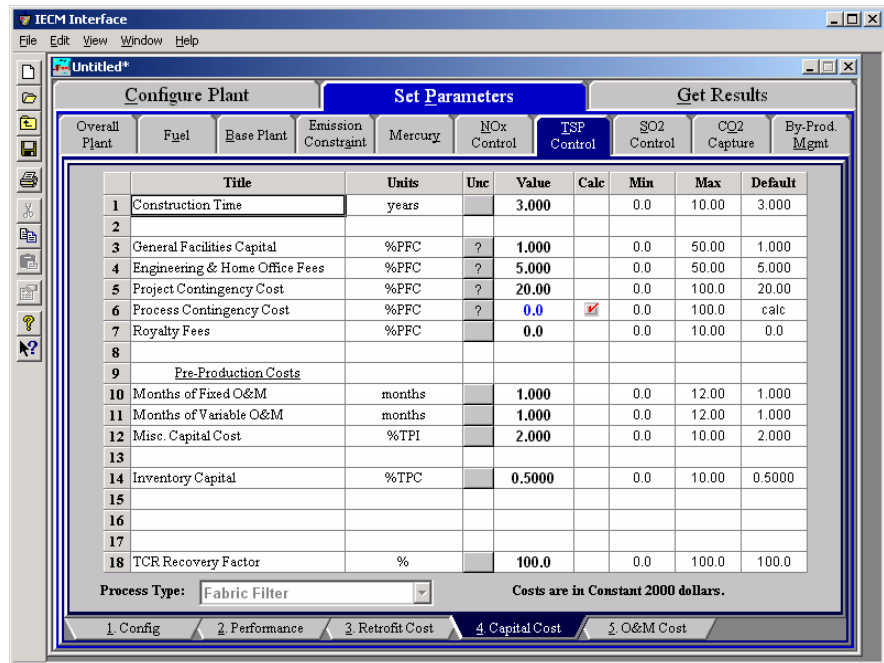
Fabric Filter – Capital Cost input screen.

The necessary capital cost input parameters associated with the fabric filter control technology are shown on this input screen (no distinction is made between the various types of fabric filtersEach parameter is described briefly below.

Indirect Capital Costs: Costs that are indirectly applied to the technology are based on the process facilities cost. Each of the cost factors below is expressed as a percentage of the process facilities cost, and is entered on this screen. Each parameter is described briefly below.

> **Construction Time:** This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

> **General Facilities Capital (GFC):** The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

> **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

> **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

> **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new

regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Pre-Production Costs

These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months)The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

Months of Variable O&M: Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

Misc. Capital Costs: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Fabric Filter O&M Cost Inputs
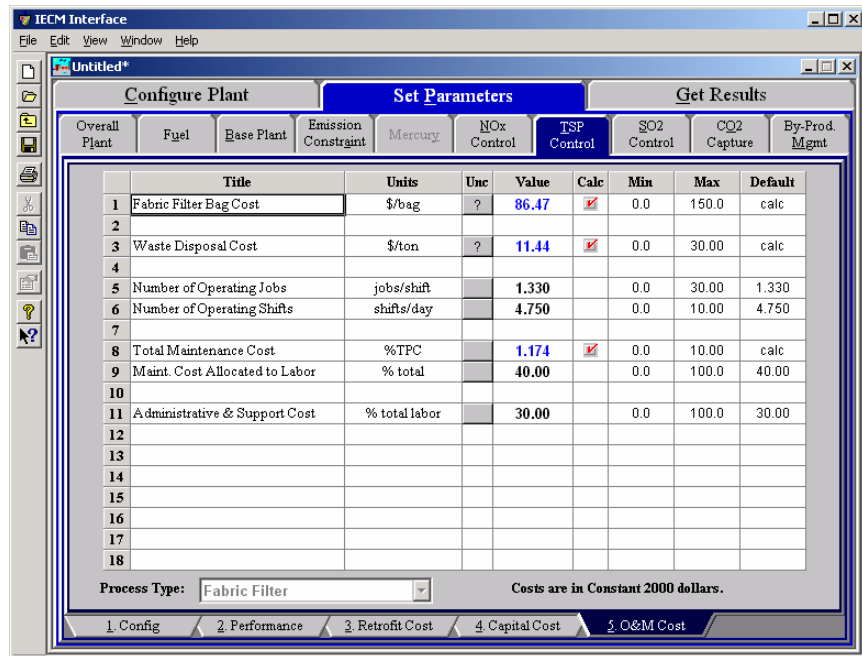
Fabric Filter – O&M Cost input screen.

Fabric Filter Bag Cost: This is the cost of a fabric filter bag as used for the fabric filter technology.

Waste Disposal Cost: This is the disposal cost for the particulate control system.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Fabric Filter Diagram

The **Diagram** result screen displays an icon for the **Fabric Filter** particulate control technology selected and values for major flows in and out of it.
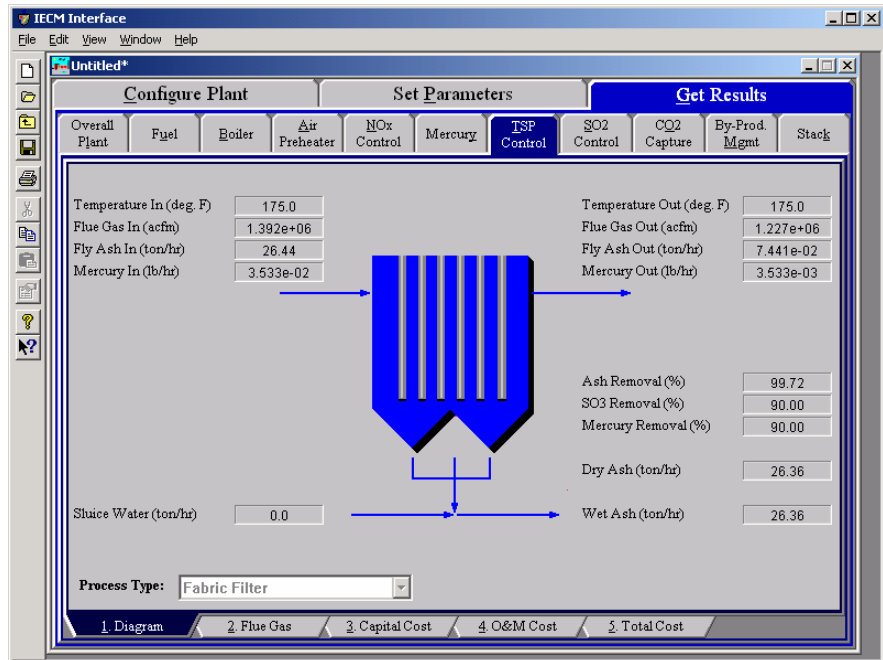
Fabric Filter – Diagram

Each result is described briefly below

Flue Gas Entering Filter

Temperature In: Temperature of the flue gas entering the particulate control technology. This is determined by the flue gas outlet temperature of the module upstream of the air preheater (e.g., the air preheater).

Flue Gas In: Volumetric flow rate of the flue gas entering the particulate control technology, based on the flue gas inlet temperature and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the air preheater. This is determined by the solids exiting the module upstream of the particulate control technology (e.g., the air preheater).

Mercury In: Total mass of mercury entering the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting Filter

Temperature Out: Temperature of the flue gas exiting the particulate control technology. The model currently does not alter this temperature through the particulate control technology.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the particulate control technology, based on the flue gas exit temperature and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the particulate control technology. This is a function of the ash content of the inlet flue gas and the ash removal efficiency performance input parameter.

Mercury Out: Total mass of mercury exiting the particulate control technology. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Fabric Filter Performance

Ash Removal: Ash removal efficiency of the fabric filter technology. This is a function of the ash emission constraint and the inlet ash mass flow rate.

SO_3 Removal: Percent of SO_3 in the flue gas removed from the particulate control technology. The SO_3 is assumed to combine with H_2O and leave with the ash solids as a sulfate (in the form of H_2SO_4).

Mercury Removal: Percent of the total mercury removed from the particulate control technology. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

Collected Fly Ash

Dry Ash: Total mass flow rate of the solids removed from the fabric filter. This is a function of the solids content in the flue gas and the particulate removal efficiency of the fabric filter. The value is given on a dry basis.

Sluice Water: Water added to the dry fly ash. This water is added for transportation purposes.

Wet Ash: Total mass flow rate of the solids removed for waste management. This includes dry fly ash and sluice water. The value is given on a wet basis.

Fabric Filter Flue Gas Results

The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the Particulate Control Technology. For each component, quantities are given in both moles and mass per hour.

Fabric Filter – Flue Gas result screen.

Each result is described briefly below

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Fabric Filter Capital Cost Results

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the particulate control technology.

Fabric Filter – Capital Cost result screen.

Each result is described briefly below

Direct Capital Costs

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the cold-side ESP are the specific and total collection areas of the T-R plate sets, and the flue gas flow rate through the ESP. The primary model factors that effect the capital costs of the fabric filter are the fabric filter type, the air to cloth ratio, the number of bags and compartments, and the flue gas flow rate through the fabric filter.

Collector: This area covers the material and labor, flange to flange, for the equipment and labor cost for installation of the entire collection system.

Ductwork: This area includes the material and labor for the ductwork needed to distribute flue gas to the inlet flange, and from the outlet flange to a common duct leading to the suction side of the ID fan.

Fly Ash Handling: The complete fly ash handling cost includes the conveyor system and ash storage silos.

Differential: The complete cost of the ID fan and motor due to the pressure loss that results from particulate collectors.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the fabric filter that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the fabric filter.

Fabric Filter O&M Cost Results

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the particulate control technology.

Fabric Filter – O&M Cost result screen.

Each result is described briefly below:

Variable Cost Component

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

> **Solid Waste Disposal:** Total cost to dispose the collected fly ash. This does not consider by-product ash sold in commerce.

> **Electricity:** Cost of power consumption of the particulate control technology. This is a function of the flue gas flow rate, ash removal efficiency and the type of coal (ash properties).

> **Total Variable Costs:** This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Component

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

> **Operating Labor:** Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

> **Maintenance Labor:** The maintenance labor is determined as a fraction of the total maintenance cost.

> **Maintenance Material:** The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

> **Admin. & Support Labor:** The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.
>
> **Total Fixed Costs:** This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.
>
> **Total O&M Costs:** This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Fabric Filter Total Cost Results

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the Particulate Control technology. The result categories are the same for both the Cold-Side ESP and the Fabric Filter

Fabric Filter – Total Cost result screen.

Each result is described briefly below.

Cost Component

> **Annual Fixed Cost:** The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.
>
> **Annual Variable Cost:** The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.
>
> **Total Annual O&M Cost**: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Wet FGD

The **SO2 Control** Technology Navigation contains screens that address post-combustion air pollution technologies for Sulfur Dioxide. The model includes options for a Wet FGD. The screens are available if this SO_2 control technology has been selected in **Configure Plant**.

Wet FGD Configuration

Inputs for configuration of the Wet FGD SO_2 control technology are entered on the **Config** input screen.
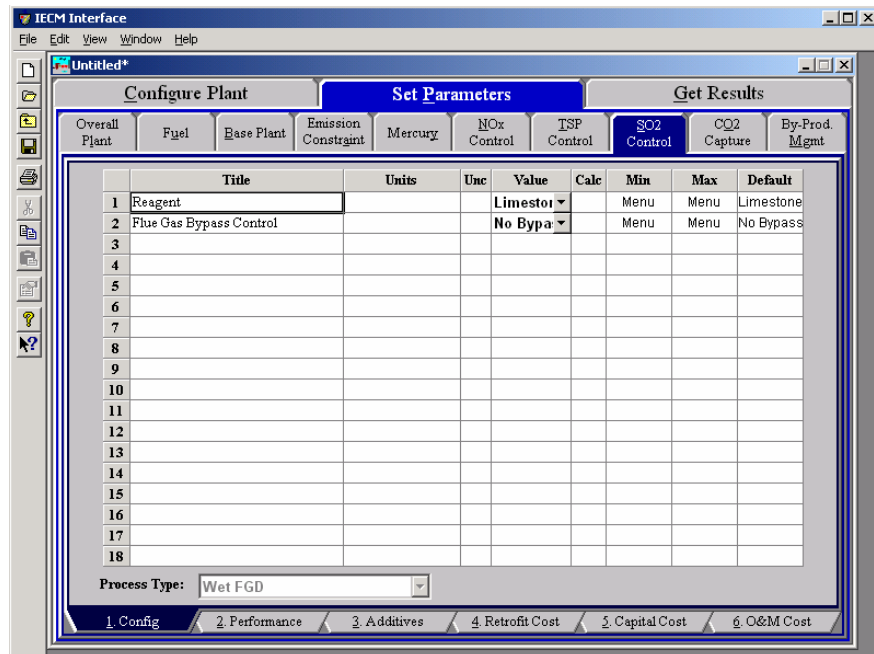
Wet FGD – Config. input screen.

Each parameter is described briefly below.

Reagent

For Wet FGD systems, the choice of reagent affects nearly all of the performance and economic parameters of the FGD. Three choices are available:

Limestone: Limestone with Forced Oxidation—A limestone slurry is used in an open spray tower with in-situ oxidation to remove SO_2 and form a gypsum sludge. The main advantages as compared to conventional systems are easier dewatering, more economical disposal of scrubber products, and decreased scaling on tower walls.

Limestone with Additivess: Limestone with Dibasic Acid Additive—Dibasic acid (DBA) is added to the Limestone to act as a buffer/catalyst in the open spray tower. The main advantages are increased SO_2 removal and decreased liquid to gas ratio.

Lime: Magnesium Enhanced Lime System—A magnesium sulfite and lime slurry (maglime) is used to remove SO_2 and form a precipitate high in calcium sulfite. The high alkalinity of the maglime slurry allows very high SO_2 removal. However, the reagent cost is also higher and solid waste is not easily disposed.

Flue Gas Bypass Control

Popup selection menu that controls whether or not a portion of the inlet flue gas may bypass the scrubber and recombine with the treated flue gas. Bypass allows the scrubber to operate at full efficiency while allowing some of the flue gas to go untreated.

Wet FGD Performance Inputs

Inputs for performance of the Wet FGD SO_2 control technology are entered on the **Performance** input screen. Each parameter is described briefly below.

Wet FGD – Performance input screen.

Actual SO$_2$ Removal Efficiency: This is the annual average SO_2 removal efficiency achieved in the absorber. The calculated value assumes compliance with the SO_2 emission limit specified earlier, if

possible. The efficiency is used to determine the liquid to gas ratio and emissions. This input is highlighted in blue.

Maximum SO₂ Removal Efficiency: This parameters specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual SO_2 removal efficiency for compliance.

Actual SO₃ Removal Efficiency: The default value is taken from the removal efficiency reported by Southern Company.[7] This efficiency then determines the mass of SO_3 removed from the flue gas in the scrubber.

Particulate Removal Efficiency: This is the percent removal of particulate matter entering the FGD system from the upstream particulate collector. Particulate collectors are designed to comply with the specified particulate emission limit. This is additional particulate removal.

Absorber Capacity: This is the percent of the flue gas treated by each operating absorber. This value is used to determine the number of operating absorbers and the capital costs.

Number of Operating Absorbers: This is the number of operating scrubber towers. The number is determined by the absorber capacity and is used to calculate the capital costs. The value must be an integer.

Number of Spare Absorbers: This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.

Liquid to Gas Ratio: The design of spray towers for high efficiency is achieved by using high liquid-to-gas (L/G) ratios. The calculated value is a function of the reagent type, the removal efficiency, and stoichiometry. It determines the energy requirement and capital cost.

Reagent Stoichiometry: This is the moles of calcium per mole of sulfur removed from the absorber. The stoichiometry is calculated as a function of the reagent type. It is used to determine the liquid to gas ratio, reagent usage, reagent waste, and capital cost.

Reagent Purity: This is the percent of the reagent that is lime (CaO) or limestone ($CaCO_3$). The calculated value is a function of the reagent type. This parameter determines the waste solids produced and the reagent needed to remove the necessary SO_2.

Reagent Moisture Content: This is the moisture content of the reagent. The remaining reagent impurities are assumed to be inert substances such as silicon dioxide (sand). This parameter is used to determine the waste solids produced.

Total Pressure Drop across FGD: This is the total pressure drop across the FGD vessel prior to the reheater. This is used in the calculations of the energy requirements (or energy penalty) and thermodynamic properties of the flue gas.

Temperature Rise Across ID Fan: An induced draft (ID) fan is assumed to be located upstream of the FGD system. The fan raises the temperature of the flue gas due to dissipation of electro-mechanical energy.

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[7] Ibid.

Gas Temperature Exiting Scrubber: A thermodynamic equation is used to calculate this equilibrium flue gas temperature exiting the scrubber. The gas is assumed to be saturated with water at the exiting temperature and pressure. The value determines the water evaporated in the scrubber.

Gas Temperature Exiting Reheater: This is the desired temperature of flue gas after the reheater. It is assumed to be equal to the stack gas exit temperature. If scrubber bypass is employed, reheat requirements are reduced or eliminated. It determines the reheat energy required.

Entrained Water Past Demister: This is a liquid water entrained in the flue gas leaving the demister expressed as a percentage of the total water evaporated in the absorber.

Oxidation of CaSO$_3$ to CaSO$_4$: This parameter determines the mixture of chemical species (calcium sulfite and calcium sulfate) in the solid waste stream. The default values depend on the selection of forced or natural oxidation.

Wet FGD Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output energy required for pumps and booster fans.

Wet FGD Additives Inputs

Wet FGD – Additives input screen.

The parameter is described briefly below.

Chloride Removal Efficiency: Chlorides in the flue gas inlet stream are removed by the lime/limestone slurry. This parameter determines the amount of chlorides removed.

Wet FGD Retrofit Cost Inputs

Inputs for capital costs of modifications to process areas to implement the SO_2 control technology are entered on the **Retrofit Cost** input screen for the Wet FGD system. All costs are in constant 1996 dollars.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Each parameter is described briefly below.

Wet FGD – Retrofit Cost input screen.

Capital Cost Process Area

Reagent Feed System: This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.

SO$_2$ Removal System: This area deals with the cost of equipment for SO_2 scrubbing, such as absorption tower, recirculation pumps, and other equipment.

Flue Gas System: This area treats the cost of the duct work and fans required for flue gas distribution to SO$_2$ system, plus gas reheat equipment.

Solids Handling System: This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.

General Support Area: The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.

Miscellaneous Equipment: Any miscellaneous equipment is treated in this process area.

Wet FGD Capital Cost Inputs

Wet FGD – Capital Cost input screen.

Each parameter is described briefly below

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

Process Contingency Cost: This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Pre-Production Costs:

These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

Months of Variable O&M: Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

Misc. Capital Cost: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a wet FGD that has been paid off.

Wet FGD O&M Cost Inputs

Wet FGD – O&M Cost input screen

Each parameter is described briefly below

Bulk Reagent Storage Time: This is the number of days of bulk storage of reagent. This factor is used to determine the inventory capital cost.

Limestone Cost: This is the cost of Limestone for the Wet FGD system.

Lime Cost: This is the cost of Lime for the Wet FGD or Lime Spray Dryer system.

Dibasic Acid Cost: This is the cost of Dibasic acid for the Wet FGD system.

Stacking Cost: This is the stacking cost as used for the Wet FGD system.

Waste Disposal Cost: This is the sludge disposal cost for the FGD system.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

> **Administrative & Support Cost:** This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Wet FGD Diagram

The **Diagram** result screen displays an icon for theWet FGD SO$_2$ control technology selected and values for major flows in and out of it.
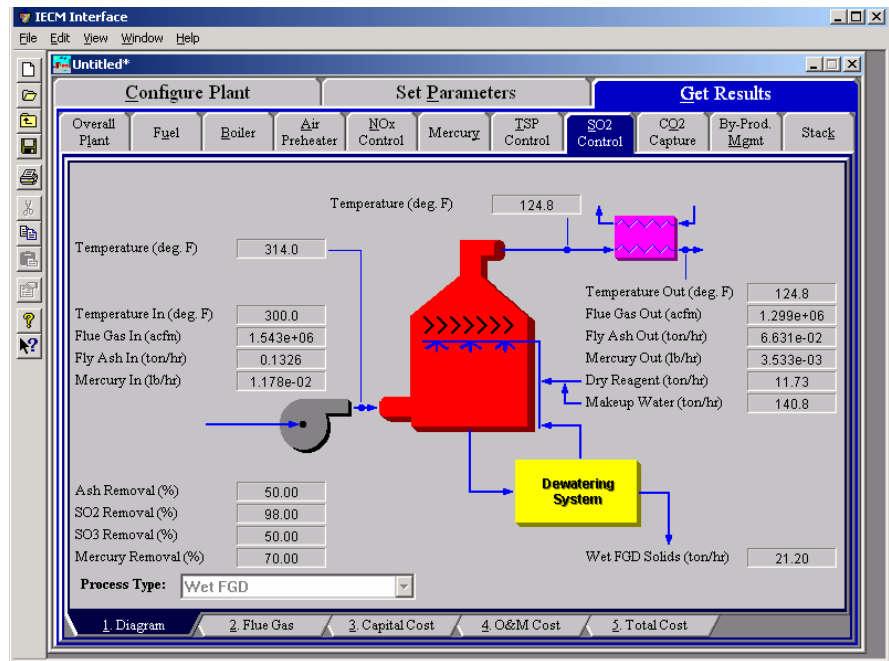
Wet FGD – Diagram.

Each result is described briefly below.

Reagent

> **Dry Reagent:** The total mass flow rate of lime, limestone or limestone with dibasic acid injected into the scrubber. This is a function of the SO$_2$ removal efficiency, the reagent purity and the reagent stoichiometric (all performance input parameters).

> **Makeup Water:** Water needed to replace the evaporated water in the reagent sluice circulation stream.

Flue Gas Entering FGD

> **Temperature In:** Temperature of the flue gas entering the scrubber. This is determined by the flue gas outlet temperature of the module upstream of the scrubber (e.g., a particulate removal technology).

> **Flue Gas In:** Volumetric flow rate of flue gas entering the scrubber, based on the flue gas temperature entering the scrubber and atmospheric pressure.

> **Fly Ash In:** Total solids mass flow rate in the flue gas entering the scrubber. This is determined by the solids exiting from the module upstream of the scrubber (e.g., a particulate removal technology).

Mercury In: Total mass of mercury entering the scrubber. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Temperature: Temperature of the flue gas entering the scrubber after the forced draft fan. This is determined by the flue gas inlet temperature of the FGD and the temperature rise across ID fan input parameter.

Flue Gas Exiting FGD

Temperature: Temperature of the flue gas immediately on exiting the scrubber, prior to any flue gas bypass remixing and prior to reheating.

Temperature Out: Temperature of the flue gas exiting the scrubber. This is a function of flue gas bypass, saturation temperature, reheater and .the flue gas component concentrations.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the scrubber after the reheater, based on the flue gas temperature exiting the scrubber and atmospheric pressure.

Fly Ash Out: Total solids mass flow rate in the flue gas exiting the scrubber after the reheater. This is a function of the ash removal and flue gas bypass input parameters.

Mercury Out: Total mass of mercury exiting the scrubber after the reheater. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

FGD Performance

Ash Removal: Actual particulate removal efficiency in the scrubber. This is set by the scrubber ash removal input parameter.

SO_2 Removal: Actual removal efficiency of SO_2 in the scrubber. This is a function of the maximum removal efficiency (scrubber performance input parameter) and the emission constraint for SO_2 (emission constraints input parameter). It is possible that the scrubber may over or under-comply with the emission constraint.

SO_3 Removal: Percent of SO_3 in the flue gas removed from the scrubber. The SO_3 is assumed to combine with H_2O and leave with the ash solids or sluice water as a sulfate (in the form of H_2SO_4).

Mercury Removal: Percent of the total mercury removed from the scrubber. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

Collected Solids

Wet FGD Solids: Total solids mass flow rate of solids removed from the scrubber. This is a function of the solids content in the flue gas and the particulate removal efficiency of the scrubber. The solids are shown on a wet basis.

Wet FGD Flue Gas

The **Flue Gas** result screen displays a table of quantities of flue gas components entering and exiting the Wet FGD SO_2 Control Technology. For each component, quantities are given in both moles and mass per hour.

Wet FGD – Flue Gas result screen.

Each result is described briefly below

Major Flue Gas Component

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH3): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Wet FGD Capital Cost Results

The **Capital Cost** result screen displays tables for the direct and indirect capital costs related to the SO₂ control technology.

Wet FGD – Capital Cost result screen.

Each result is described briefly below

Direct Capital Costs

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the scrubbers are the flue gas flow rate through the scrubber, the composition of the flue gas, the reagent stoichiometry, and the reagent flow rate.

Reagent Feed System: This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.

SO$_2$ Removal System: This area deals with the cost of equipment for SO$_2$ scrubbing, such as absorption tower, recirculation pumps, and other equipment.

Flue Gas System: This area treats the cost of the duct work and fans required for flue gas distribution to SO$_2$ system, plus gas reheat equipment.

Solids Handling System: This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.

General Support Area: The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.

Miscellaneous Equipment: Any miscellaneous equipment is treated in this process area.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales

taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Total Capital Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the wet FGD that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor" for the wet FGD.

Wet FGD O&M Cost Results

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the SO_2 control technology.

Wet FGD – O&M Cost result screen.

Each result is described briefly below

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Reagent: The total mass flow rate of lime or limestone injected into the scrubber on a wet basis. This is a function of the SO_2 concentration in the flue gas and the reagent stoichiometric performance input value.

Dibasic Acid: If limestone with additives, **LS w/ Add.** has been selected in the reagent pull down menu on the **Wet FGD – Config.** input screen, then this component is displayed. This is the total mass flow rate of dibasic acid added to reagent. It is determined by SO_2 concentration in the flue gas and the dibasic acid stoichiometric performance input parameter.

Steam: Annual cost of steam used for direct or reheat use in the scrubber. This is a function of the steam heat rate, reheat energy requirement and gross plant capacity.

Solid Waste Disposal: Total cost to dispose the collected flue gas waste solids. This does not consider by-product gypsum sold in commerce.

Electricity: Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the scrubber energy penalty performance input parameter.

Water: Cost of water for reagent sluice in the scrubber. This is a function of the liquid to gas ratio performance input parameter for the wet FGD. The cost is a function of the flue gas flow rate and the slurry recycle ratio performance input parameter for the spray dryer.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Wet FGD Total Cost Results

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the SO_2 control technology. The result categories are the same for both the Wet FGD and the Lime Spray Dryer.

Wet FGD – Total Cost result screen.

Cost Component

Each result is described briefly below.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Spray Dryer

The **SO2 Control** Technology Navigation Tab contains screens that address post-combustion air pollution technologies for Sulfur Dioxide. The model includes options for a Lime Spray Dryer. A spray dryer is sometimes used instead of a wet scrubber because it provides simpler waste disposal and can be installed with lower capital costs. These screens are available if the **Lime Spray Dryer** SO_2 control technology has been selected in **Configure Plant**.

Spray Dryer Configuration

Inputs for configuration of the **Lime Spray Dryer** SO_2 control technology are entered on the **Config** input screen

Spray Dryer – Config. input screen.

Each parameter is described briefly below.

> **Reagent:** For the Lime Spray Dryer the only option is **Lime**.

Lime: Magnesium Enhanced Lime System—A magnesium sulfite and lime slurry (maglime) is used to remove SO_2 and form a precipitate high in calcium sulfite. The high alkalinity of the maglime slurry allows very high SO_2 removal. However, the reagent cost is also higher and solid waste is not easily disposed.

Flue Gas Bypass Control: Popup selection menu that controls whether or not a portion of the inlet flue gas may bypass the scrubber and recombine with the treated flue gas. Bypass allows the scrubber to operate at full efficiency while allowing some of the flue gas to go untreated.

Flue Gas Bypass Preference: (Spray dryer only) Popup selection menu that controls whether the bypass is determined by the exit temperature or based on the maximum efficiency. If exit temperature is selected, the flue gas bypass amount is based on the amount of bypass required to raise the exit temperature from the scrubber to the desired stack temperature. If maximum efficiency is selected, the flue gas bypass amount is based on the overall required SO_x removal efficiency.

Spray Dryer Performance Inputs

Inputs for performance of the **Lime Spray Dryer** SO_2 control technology are entered on the **Performance** input screen.

Spray Dryer – Performance input screen.

In a Lime Spray Dryer, an atomized spray of a mixture of lime slurry and recycled solids is brought into contact with the hot flue gas. The water in the slurry evaporates leaving dry reaction products and flyash, which drops out of the scrubber. A particulate control device such as a baghouse is also used to remove the rest of the dry products from the flue gas before releasing it. The SO_2 removal efficiency is the total of SO_2 removed in the scrubber and the baghouse.

Many lime spray dryer input parameters are similar to those defined above for wet lime/limestone systems. Each parameter is described briefly below.

Actual SO$_2$ Removal Efficiency: This is the annual average SO$_2$ removal efficiency achieved in the absorber. The calculated default value assumes compliance with the SO$_2$ emission limit specified earlier, if possible. The default value reflects other model parameter values, including the sulfur retained in bottom ash. This input is highlighted in blue.

Maximum SO$_2$ Removal Efficiency: This parameters specifies the maximum efficiency possible for the absorber on an annual average basis. The value is used as a limit in calculating the actual SO$_2$ removal efficiency for compliance.

Actual SO$_3$ Removal Efficiency: The default value is taken from the removal efficiency reported by Southern Company. This efficiency then determines the mass of SO$_3$ removed from the flue gas in the scrubber.

Particulate Removal Efficiency: Ash and particulate matter are assumed to be removed by a separate particulate removal device, such as a fabric filter. However, this parameters is provided for conditions where particulates are removed directly from the scrubber.

Absorber Capacity: This is the percent of the flue gas treated by each operating absorber. This value is used to determine the number of operating absorbers and the capital costs.

Number of Operating Absorbers: This is the number of operating scrubber towers. The number is determined by the absorber capacity and is used to calculate the capital costs. The value must be an integer.

Number of Spare Absorbers: This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.

Reagent Stoichiometry: This is the moles of calcium per mole of sulfur into the absorber. The stoichiometry is calculated as a function of the required SO$_2$ removal efficiency, inlet flue gas temperature, inlet sulfur concentration, and approach to saturation temperature.

CaO Content of Lime: This is the percent of reagent that is pure lime (CaO). This parameter determines the waste solids produced and the reagent mass requirements, given the stoichiometry needed for SO$_2$ removal.

H$_2$O Content of Lime: This is the moisture content of the lime (CaO). The remaining reagent impurities are assumed to be inert substances such as silicon dioxide (sand). This parameter is used to determine the waste solids produced.

Total Pressure Drop Across FGD: This is the total pressure drop across the spray dryer vessel prior to the reheater. This is used in the calculations of the energy requirements (or energy penalty) and thermodynamic properties of the flue gas.

Approach to Saturation Temperature: This defines the gas temperature exiting the absorber. The approach is the increment over the water saturation temperature at the exit pressure. As the approach to saturation temperature increases, the evaporation time decreases thereby decreasing removal efficiency.

Temperature Rise Across ID Fan: An induced draft (ID) fan is assumed to be located upstream of the FGD system. The fan raises the temperature of the flue gas due to dissipation of electro-mechanical energy.

Gas Temperature Exiting Scrubber: A thermodynamic equation is used to calculate this equilibrium flue gas temperature exiting the scrubber. The gas is assumed to be saturated with water at the exiting temperature and pressure. The value determines the water evaporated in the scrubber.

Oxidation of $CaSO_3$ to $CaSO_4$: This parameter determines the mixture of the two chemical species in the solid waste stream.

Slurry Recycle Ratio: An atomized spray of a mixture of lime slurry and recycled solids is brought into contact with the hot flue gas. This parameter specifies the amount of solid waste recycled and lime slurry used. It is calculated from the sulfur content of the coal.

Spray Dryer Power Requirement: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output energy required for pumps and booster fans.

Spray Dryer Retrofit Cost

Inputs for capital costs of modifications to process areas to implement the SO_2 control technology are entered on the **Retrofit Cost** input screen. All costs are in constant 2000 dollars.

The retrofit cost factor of each process is a multiplicative cost adjustment which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.

Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

Spray Dryer – Retrofit Cost input screen.

Each parameter is described briefly below.

Reagent Feed System: This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.

SO$_2$ Removal System: This area deals with the cost of equipment for SO$_2$ scrubbing, such as absorption tower, recirculation pumps, and other equipment.

Flue Gas System: This area treats the cost of the duct work and fans required for flue gas distribution to SO$_2$ system, plus gas reheat equipment.

Solids Handling System: This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.

General Support Area: The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.

Miscellaneous Equipment: Any miscellaneous equipment is treated in this process area.

Spray Dryer Capital Cost Inputs

Spray Dryer – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

Process Contingency Cost: This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Pre-Production Costs: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-

up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

Months of Variable O&M: Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

Misc. Capital Cost: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Spray O&M Cost Inputs

Spray Dryer – O&M Cost input screen.

Inputs for operation and maintenance are entered on the **O&M Cost** input. Each parameter is described briefly below

Bulk Reagent Storage Time: This is the number of days of bulk storage of reagent. This factor is used to determine the inventory capital cost.

Lime Cost: This is the cost of Lime for the Wet FGD or Lime Spray Dryer system.

Waste Disposal Cost: This is the sludge disposal cost for the FGD system.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Spray Dryer Diagram
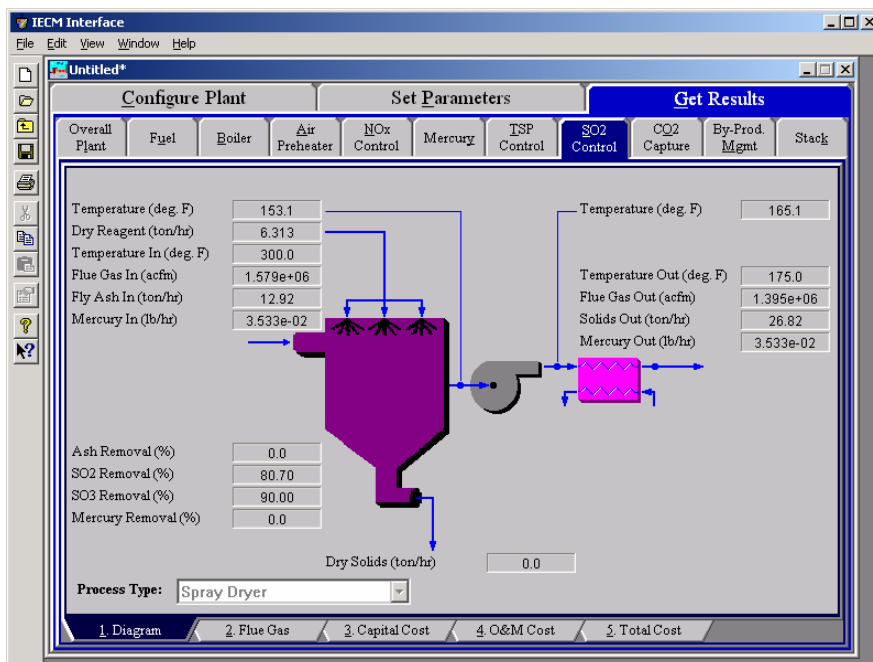
Spray Dryer – Diagram

The **Diagram** result screen displays an icon for the Lime Spray Dryer SO_2 control technology selected and values for major flows in and out of it. Each result is described briefly below:

Reagent

Dry Reagent: The total mass flow rate of lime, limestone or limestone with dibasic acid injected into the scrubber. This is a function of the SO_2 removal efficiency, the reagent purity and the reagent stoichiometric (all performance input parameters). The reagent is assumed to be dry.

Flue Gas Entering Dryer

Temperature In: Temperature of the flue gas entering the scrubber. This is determined by the flue gas outlet temperature of the module upstream of the scrubber (e.g., a particulate removal technology).

Flue Gas In: Volumetric flow rate of flue gas entering the scrubber, based on the flue gas temperature entering the scrubber and atmospheric pressure.

Fly Ash In: Total solids mass flow rate in the flue gas entering the scrubber. This is determined by the solids exiting from the module upstream of the scrubber (e.g., a particulate removal technology).

Mercury In: Total mass of mercury entering the scrubber. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Flue Gas Exiting Dryer

Temperature: Temperature of the flue gas immediately after exiting the scrubber. This is a function of saturation temperature, and .the flue gas component concentrations. This temperature is used to determine the flue gas bypass required.

Temperature: Temperature of the flue gas immediately after exiting the induced draft fan. This is a function of flue gas temperature exiting the scrubber, the flue gas bypass and the temperature rise across ID fan input parameter.

Temperature Out: Temperature of the flue gas immediately after exiting the reheater. This is determined by the gas temperature exiting reheater input parameter.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the reheater, based on the flue gas temperature exiting the scrubber and atmospheric pressure.

Solids Out: Total solids mass flow rate in the flue gas exiting the reheater. This is a function of the ash removal parameter on the scrubber performance input screen.

Mercury Out: Total mass of mercury exiting the scrubber after the reheater. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Spray Dryer Performance

Ash Removal: Actual particulate removal efficiency in the scrubber. This is set by the scrubber performance input parameter.

SO_2 Removal: Actual removal efficiency of SO_2 in the scrubber. This is a function of the maximum removal efficiency (scrubber performance

input parameter) and the emission constraint for SO_2 (emission constraints input parameter). It is possible that the scrubber may over or under-comply with the emission constraint.

SO$_3$ Removal: Percent of SO_3 in the flue gas removed from the scrubber. The SO_3 is assumed to combine with H_2O and leave with the ash solids or sluice water as a sulfate (in the form of H_2SO_4).

Mercury Removal: Percent of the total mercury removed from the scrubber. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

Collected Solids

Dry Solids: Total solids mass flow rate of solids removed from the scrubber. This is a function of the solids content in the flue gas and the particulate removal efficiency of the scrubber. The solids are assumed to be dry.

Spray Dryer Flue Gas Results

Spray Dryer – Flue Gas result screen.

Major Flue Gas Components

Each result is described briefly below:

Nitrogen (N$_2$): Total mass of nitrogen.

Oxygen (O$_2$): Total mass of oxygen.

Water Vapor (H$_2$O): Total mass of water vapor.

Carbon Dioxide (CO$_2$): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO$_2$): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO$_3$): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO$_2$): Total mass of nitrogen dioxide.

Ammonia (NH$_3$): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Spray Dryer Capital Cost Results

Spray Dryer – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the direct and indirect capital costs. Each result is described briefly below:

Each process area direct capital cost is a reduced-form model based on regression analysis of data collected from several reports and analyses of particulate control technology units. They are described in general below. The primary factors in the model that effect the capital costs of the scrubbers are the flue gas flow rate through the scrubber, the composition of the flue gas, the reagent stoichiometry, and the reagent flow rate.

Reagent Feed System: This area includes all equipment for storage, handling and preparation of raw materials, reagents, and additives used.

SO$_2$ Removal System: This area deals with the cost of equipment for SO$_2$ scrubbing, such as absorption tower, recirculation pumps, and other equipment.

Flue Gas System: This area treats the cost of the duct work and fans required for flue gas distribution to SO_2 system, plus gas reheat equipment.

Solids Handling System: This area includes the cost of the equipment for fixation, treatment, and transportation of all sludge/dry solids materials produced by scrubbing.

General Support Area: The cost associated with the equipment required to support spray dryer system operation such as makeup water and instrument air are treated here.

Miscellaneous Equipment: Any miscellaneous equipment is treated in this process area.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

> **Effective TCR:** The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

Spray Dryer O&M Results

Spray Dryer – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the SO_2 control technology. Each result is described briefly below:

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

> **Reagent:** Annual cost of lime or limestone injected into the scrubber on a wet basis. This is a function of the SO_2 concentration in the flue gas and the reagent stoichiometric performance input value.

> **Steam:** Annual cost of steam used for direct or reheat use in the scrubber. This is a function of the steam heat rate, reheat energy requirement and gross plant capacity.

> **Solid Waste Disposal:** Total cost to dispose the collected flue gas waste solids. This does not consider by-product gypsum sold in commerce.

> **Power:** Cost of power consumption of the scrubber. This is a function of the gross plant capacity and the scrubber energy penalty performance input parameter.

> **Water:** Cost of water for reagent sluice in the scrubber. This is a function of the liquid to gas ratio performance input parameter for the wet FGD.

The cost is a function of the flue gas flow rate and the slurry recycle ratio performance input parameter for the spray dryer.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Spray Dryer Total Cost Results

	Cost Component	M$/yr	$/MWh	$/ton SO2 removed	Percent Total
1	Annual Fixed Cost	3.271	1.470	89.75	25.02
2	Annual Variable Cost	4.244	1.907	116.4	32.46
3	Total Annual O&M Cost	7.516	3.377	206.2	57.48
4	Annualized Capital Cost	5.560	2.498	152.5	42.52
5	Total Levelized Annual Cost	13.08	5.876	358.7	100.0
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					

Process Type: Spray Dryer   Costs are in Constant 2000 dollars.

Spray Dryer – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs. Each result is described briefly below.

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Power Block

Power Block Gas Turbine Inputs

Power Block – Gas Turbine input screen.

Gas Turbine/Generator

Gas Turbine Model: This is a selection of the type of turbine model used (manufacturer types currently include "F" Frame and "H Frame). The type determines the inlet temperature, pressure ratio, and size parameters.

No. of Gas Turbines: This is the number of gas turbines. Since each turbine is able to produce a fixed output, the number of turbines will determine the plant size.

No. of Spare Gas Turbines: This is the number of spare gas turbines. The spare is primarily used for cost purposes.

Turbine Inlet Temperature: The turbine inlet temperature is carefully controlled to prevent damage or fatigue of the first stage stator and

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rotor blades. This temperature is one of the two most important parameters that impacts system efficiency.

Turbine Back Pressure: The turbine exit pressure must be higher than atmospheric pressure to provide a positive pressure on the flue gas exiting the turbine.

Adiabatic Turbine Efficiency: The adiabatic turbine efficiency adjusts for inefficiencies in real turbines. The ratio is an estimate of real to ideal performance.

Shaft/generator Efficiency: The combined shaft/generator efficiency adjusts for inefficiencies in generator and shaft between the compressor and the generator. The ratio is an estimate of real to ideal performance.

Air Compressor

Pressure Ratio (outlet/inlet): This is the ratio of the compressor exit pressure to the inlet ambient air pressure. Compression takes place approximately adiabatically.

Adiabatic Compressor Efficiency: The adiabatic compressor efficiency adjusts for inefficiencies in real compressors. The ratio is an estimate of real to ideal performance.

Combustor

Combustor Pressure Drop: Although the combustor operates at essentially constant pressure, a small pressure drop is typically observed in the combustor exit from the compressor exit.

Excess Air For Combustor: This is the excess theoretical air used for combustion. It is added to the stoichiometric air requirement calculated by the model. The value is calculated and based on the boiler type.

Combustor Inlet Pressure: The combustor inlet pressure is currently fixed at a single value.

Gas Turbine Size (Nominal): This is the electricity produced by one gas turbine. It eventually will include multiple turbine types. Multiple turbines must be specified for larger electricity generation.

Power Block Steam Cycle Inputs
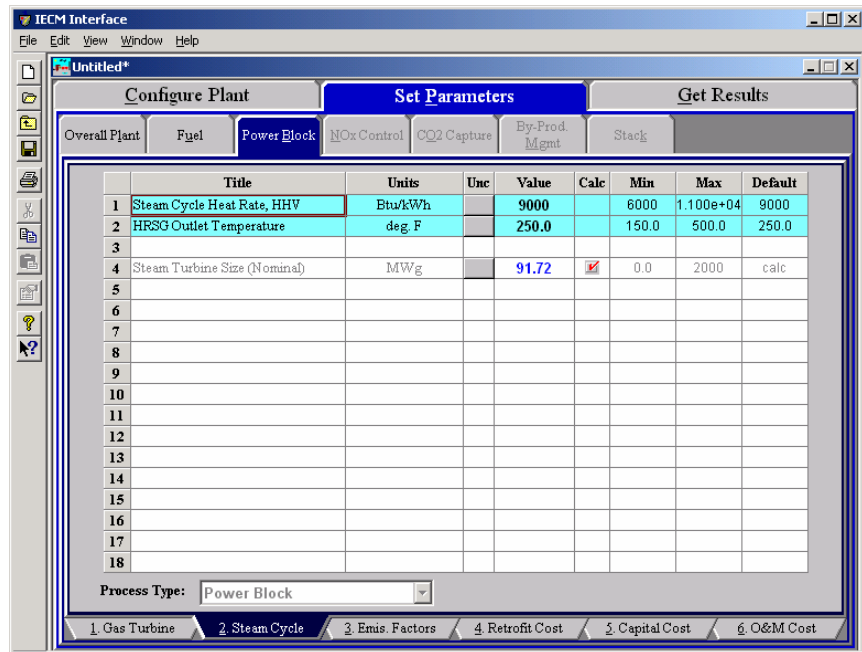
Power Block – Steam Cycle input screen

Steam Cycle Input Parameters

> **Steam Cycle Heat Rate, HHV:** This is the steam cycle heat rate for the heat recovery steam generator.

> **HRSG Outlet Temperature:** This is the desired output temperature from the heat recovery steam generator (HRSG).

> **Steam Turbine Size (Nominal):** This is the net electricity produced by the steam turbine associated with the HRSG (steam cycle).

Power Block Emission Factors
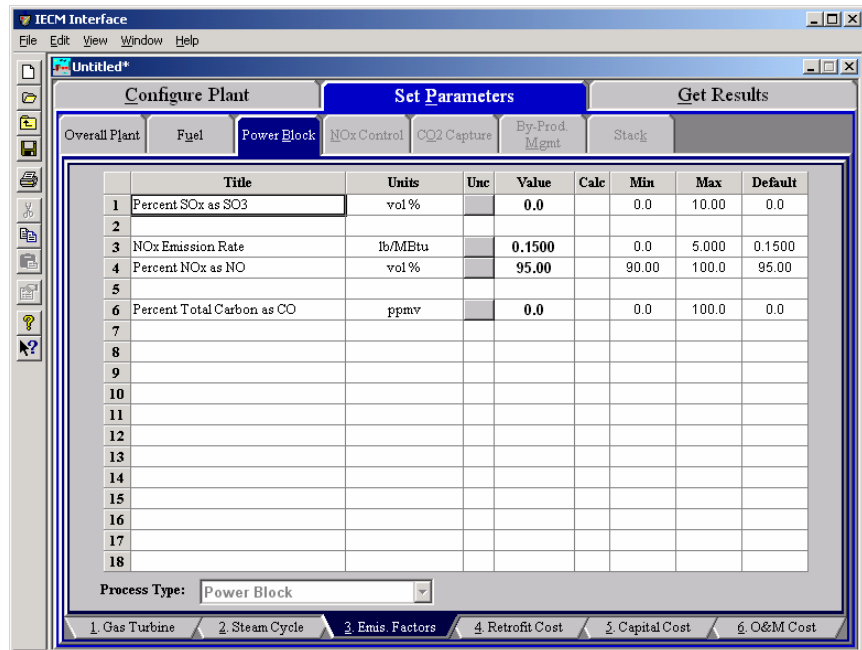
Power Block – Emission Factors input screen.

Emission Factors Input Parameters

Percent SO$_x$ as SO$_3$: This is the volume percent of SO$_3$ in the SO$_x$.

NO$_x$ Emission Rate: This is the rate at which NOx is emitted from the plant based on the production of electricity.

Percent NO$_x$ as NO: This is the volume percent of NO$_x$ in the NO

Percent Total Carbon as CO: This is the percent of the total carbon that is contained in the CO.

Power Block Retrofit Cost
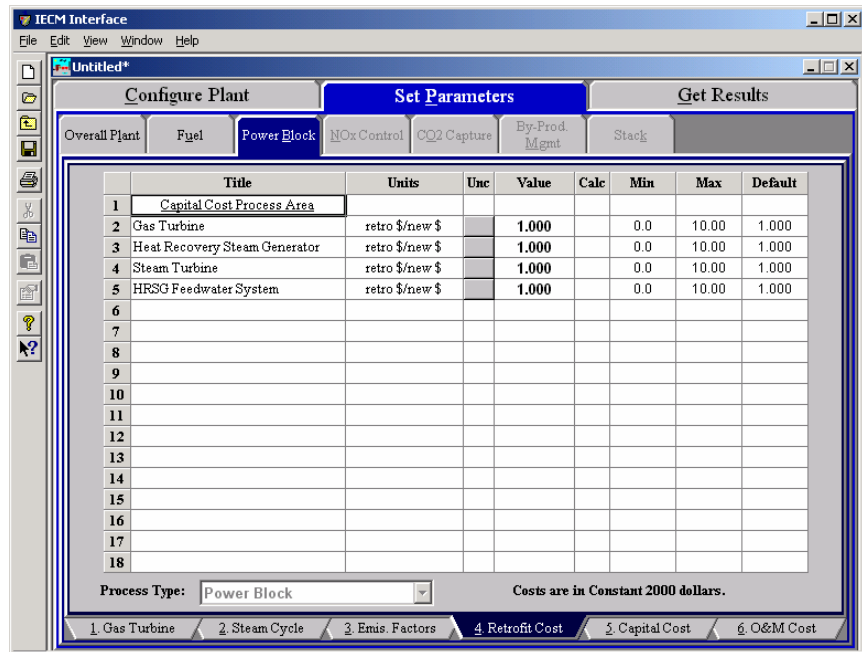
Power Block – Retrofit Cost input screen.

Power Block Retrofit Cost Input Parameters

> **Gas Turbine:** The Gas Turbine retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.

> **Heat Recovery Steam Generator:** The Heat Recovery Steam Generator retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.

> **Steam Turbine:** The Steam Turbine retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.

> **HRSG Feedwater System:** The Boiler Feedwater retrofit factor is a ratio of the costs of retrofiting an existing facility versus a new facility, using the same equipment.

Power Block Capital Cost Inputs

Power Block – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

General Facilities Capital (GFC): The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

Engineering & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

Project Contingency Cost: This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

Process Contingency Cost: This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Pre-Production Costs: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-

up. These are typically applied to the O&M costs over a specified period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

Months of Variable O&M: Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

Misc. Capital Cost: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Power Block O&M Cost Inputs

Power Block – O&M Cost input screen.

Inputs for operating and maintenance costs are entered on the **O&M Cost** input screen.

Water Cost: Water is mainly required for cooling and also as process makeup. Tost of water may vary depending upon the location of the power plant.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Power Block HRSG/Steam Diagram
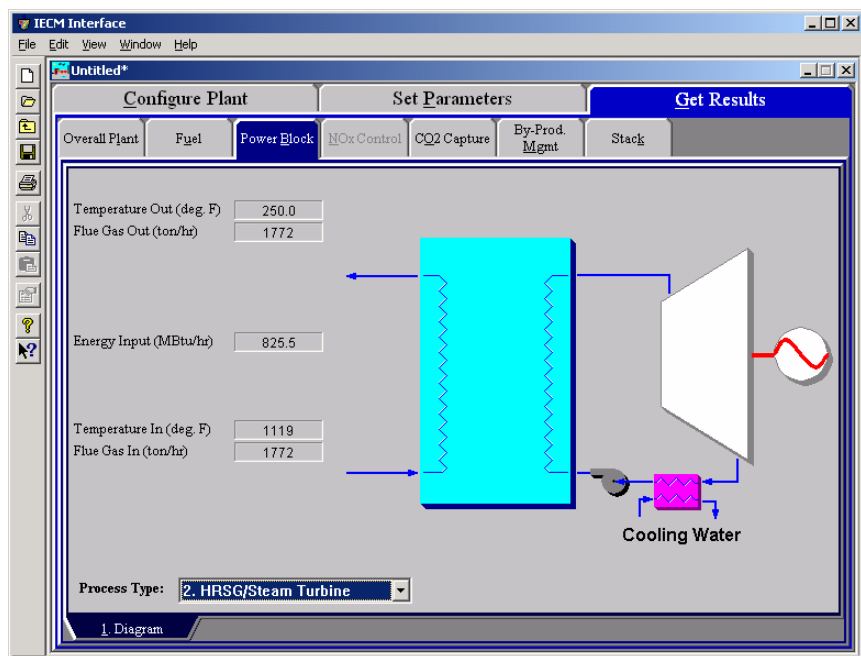
Power Block – HRSG/ Steam Diagram results screen.

Flue Gas Exiting Heat Recovery Steam Generator

Temperature Out: Temperature of the flue gas exiting the amine scrubber system.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the amine scrubber.

Flue Gas Entering Heat Recovery Steam Generator

Energy Input: The energy required to power the heat recovery steam generator.

Temperature In: Temperature of the flue gas entering the amine system area, prior to any processing. This is determined by the flue gas outlet temperature of the process area upstream.

Flue Gas In: Volumetric flow rate of flue gas entering the amine system.

Power Block Gas Turbine Diagram
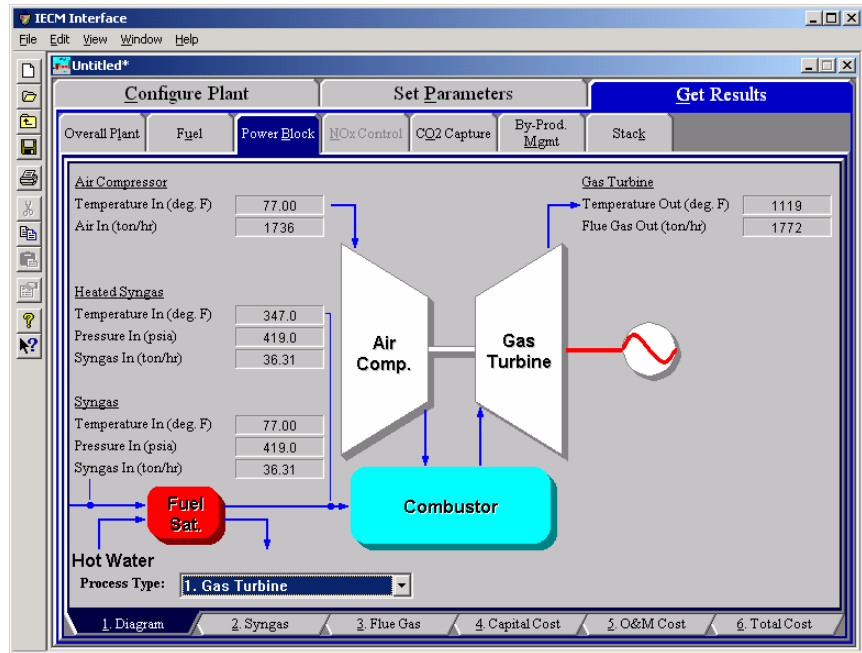
Power Block – Gas Turbine Diagram result screen.

Air Entering Compressor

Temperature In: Temperature of the flue gas entering the amine system area, prior to any processing. This is determined by the flue gas outlet temperature of the process area upstream.

Air In: Volumetric flow rate of the air at the burners, based on the air temperature at the burners and atmospheric pressure.

Heated Syngas Entering Combustor

Temperature In: Temperature of the flue gas entering the amine system area, prior to any processing. This is determined by the flue gas outlet temperature of the process area upstream.

Pressure In: This is the pressure of the heated syngas as it enters the combustor.

Syngas In: This is the mass flow rate of the heated syngas to the combustor.

Syngas Entering Combustor

Temperature In: Temperature of the flue gas entering the amine system area, prior to any processing. This is determined by the flue gas outlet temperature of the process area upstream.

Pressure In: This is the pressure of the synas as it enters the combustor.

Syngas In: This is the mass flow rate of the syngas to the combustor.

Flue Gas Exiting Gas Turbine

Temperature Out: Temperature of the flue gas exiting the amine scrubber system.

Flue Gas Out: Volumetric flow rate of the flue gas exiting the amine scrubber.

Power Block Syngas Results

Power Block – Syngas result screen.

Major Syngas Components

Carbon Monoxide (CO): Flow rate of carbon monoxide in the syngas.

Hydrogen (H$_2$): Flow rate of hydrogen in the syngas.

Methane (CH$_4$): Flow rate of methane in the syngas.

Hydrogen Sulfide (H$_2$S): Flow rate of hydrogen sulfide in the syngas.

Carbonyl Sulfide (COS): Flow rate of carbon sulfide in the syngas.

Ammonia (NH$_3$): Flow rate of ammonia in the syngas.

Hydrochloric Acid (HCl): Flow rate of hydrochloric acid in the syngas.

Carbon Dioxide (CO$_2$): Flow rate of carbon dioxide in the syngas.

Water Vapor (H$_2$O): Flow rate of water vapor in the syngas.

Nitrogen (N$_2$): Flow rate of nitrogen in the syngas.

Argon (Ar): Flow rate of argon in the syngas.

Oxygen (O$_2$): Flow rate of oxygen in the syngas.

Total: Total flow rate of the syngas.

Power Block Flue Gas Results

Power Block – Flue Gas results screen.

Major Flue Gas Components

Each result is described briefly below:

Nitrogen (N$_2$): Total mass of nitrogen.

Oxygen (O$_2$): Total mass of oxygen.

Water Vapor (H$_2$O): Total mass of water vapor.

Carbon Dioxide (CO$_2$): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO$_2$): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO$_3$): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO$_2$): Total mass of nitrogen dioxide.

Ammonia (NH$_3$): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Power Block Capital Cost Results

Power Block – Capital Cost results screen.

This result screen displays tables containing the **Power Block Capital Costs**. Each result is described briefly below:

Power Block Process Area Costs

> **Gas Turbine:**The model bases the capital cost of the gas turbine on the turbine model used either manufacturer type "F" Frame or "H" Frame.

> **Heat Recovery Steam Generator:**The heat recovery steam generator is a set of heat exchangers in which heat is removed from the gas turbine exhaust gas to generate steam for the steam turbine.

> **Steam Turbine:** The cost of a stema turbine is expected to depend on the mass flow rate of steam through the system, the pressures in each stage, and the generator output

> **HRSG Feedwater System:** The boiler feedwater system consists of equipment for handling raw water and polished water in the steam cycle, including a water mineralization unit for raw water, a dimineralized water storage tank, a condensate water, a condensate polishing unit, and a blowdown flash drum.

> **Process Facilities Capital:** The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

Power Block Plant Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

Power Block O&M Cost Results

Power Block – O&M Cost results screen.

Variable Cost Component

Natural Gas: Annual cost of natural gas supplied to the gas turbine.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Component

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Power Block Total Cost Results

Power Block – Total Cost results screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations, maintenance, and capital costs. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Amine System

Amine System Configuration

The screens under the **Co2 Capture** Technology Navigation Tab display and design flows and data related to the **Amine System**.
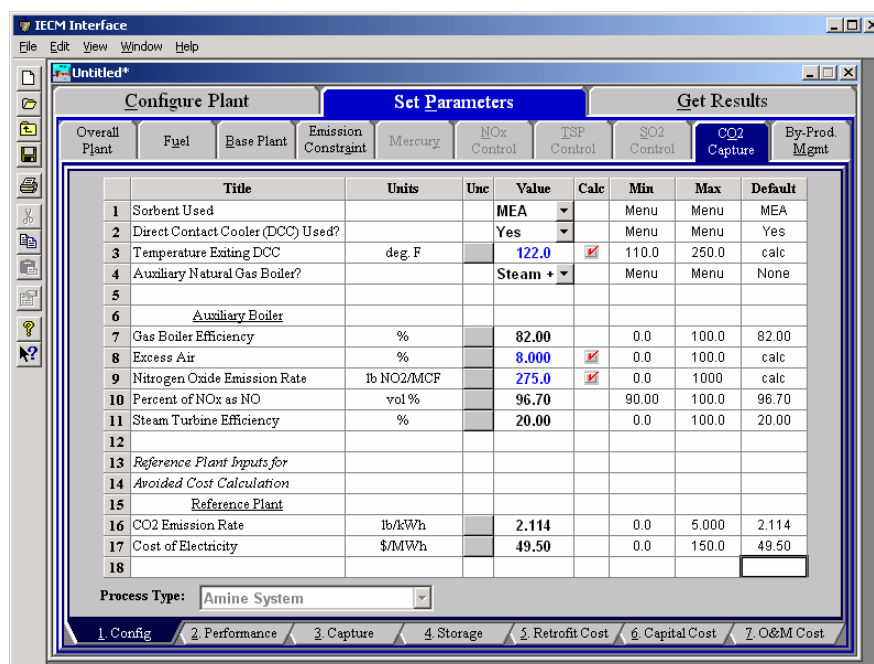
Amine System – Config. input screen.

Each configuration parameter is described briefly below.

Sorbent Used: MEA is the sorbent used in the system and the nominal values of various parameters are based on a process simulation model that uses MEA.

Direct Contact Cooler (DCC) Used: The default setting in the IECM chooses to include a DCC to cool the flue gas before it enters the amine system. The temperature of the flue gas affects the absorption reaction (absorption of CO_2 in MEA sorbent is an exothermic process favored by lower temperatures). Also, the volumetric flow rate of the flue gas stream, which is a key determinant of the sizes of various equipments

(direct contact cooler, flue gas blower, absorber), is directly related to the flue gas temperature. Hence lower flue gas temperature is desired. The typically acceptable range of flue gas temperature is about 50-60 °C. If the flue gas is coming from wet sulfur scrubber, additional DCC may not be required. But in case of flue gas from NG-fired boiler, which often does not pass through a sulfur scrubber, DCC is a must.

Temperature Exiting DCC: The desirable temperature of the flue gas entering the CO_2 capture system is about 45-50 deg C. If a direct contact cooler is installed upstream of CO_2 capture system, then this temperature level may be achieved. Else, this is same as that obtained from the base plant. *This variable is only displayed if a DCC is used.*

Auxiliary Natural Gas Boiler?: A potential option to provide energy for the amine system is by adding an auxiliary Natural Gas (NG)-fired boiler. Often it would be combined with a steam turbine which could generate some additional power (mainly used to supply electrical energy demand of CO_2 capture unit), and the LP steam would be then used for sorbent regeneration. Thus, the original steam cycle of the power plant remains unperturbed and the net power generation capacity of the power plant is not adversely affected. It comes at an additional cost of capital requirement for the boiler (and turbine) and the cost of supplemental NG fuel. Also, the combustion of NG leads to additional CO_2 emissions (and NO_x emissions). The Auxiliary Natural Gas options are:

- **None**
- **Steam Only**
- **Steam + Power**

Auxiliary Boiler

When an auxiliary natural gas boiler is selected the options for its use are either for **Steam Only** or for **Steam + Power**.

Steam Only: When the auxiliary natural gas boiler option has been selected and it is to be used for steam only then the following parameters are used in model calculations and are modifiable by the user.

- **Gas Boiler Efficiency:** This is the percentage of fuel input energy transferred to steam in the boiler. The model default is to calculate the boiler efficiency using standard algorithms described in the literature. The efficiency is a function of energy losses due to inefficient heat transfer across the preheater, latent heat of evaporation, incomplete combustion, radiation losses, and unaccounted losses.

- **Excess Air:** This is the excess theoretical air used for combustion. It is added to the stoichiometric air requirement calculated by the model. The value is calculated and based on the fuel type and boiler type.

- **Nitrogen Oxide Emission Rate:** This parameter establishes the level of NO_x emissions from the boiler. The default values reflect the AP-42 EPA emission factors. It is a function of boiler firing method and the coal rank. The model calculates this value and expresses it in pounds of equivalent NO_2 per ton of coal.

- **Percent of NOx as NO:** This parameter establishes the level of nitric oxide (NO) in the flue gas stream. The remainder of the total NO_x emissions is assumed to be nitrogen dioxide (NO_2). The default parameters reflect the AP-42 EPA emission factors and are dependent on the fuel type.

Steam + Power: When an auxiliary natural gas boiler is selected and is to be used for additional steam and power, then in addition to the above parameters the following parameter is displayed:

- **Steam Turbine Efficiency:** The steam turbine efficiency is the

Reference Plant

The following reference plant inputs are used in the **Avoided Cost Calculation.** Analysts commonly express the cost of an environmental control system in terms of either the cost per tonne of pollutant removed or the cost per tonne "avoided." For an energy-intensive system like amine scrubbers there is a big difference between the cost per tonne CO_2 removed and the cost per tonne CO_2 avoided based on *net* plant capacity. Since the purpose of adding a capture unit is to reduce the CO_2 emissions per net kWh delivered, the cost of CO_2 avoidance (relative to a reference plant with no CO_2 control) is the economic indicator most widely used. It can be calculated as

CO₂ Emission Rate: This is the emission rate for the reference power plant (without CO_2 capture)

Cost of Electricity: This is the cost of electricity for the reference power plant (without CO_2 capture)

Amine System Performance Inputs

Amine System – Performance input screen.

CO2 Removal

CO$_2$ Removal Efficiency: Most studies report the CO$_2$ capture efficiency of the amine-based systems to be 90%, with few others reporting as high as 96% capture efficiency. Here, it has been assumed to be 90% as nominal value, but the user can specify the desired level of CO$_2$ capture efficiency.

Other Removals

The amine-based absorption system for CO$_2$ removal is a wet scrubbing operation. This process also removes some other acid gases and particulate matter in addition to CO$_2$ from the flue gas. These are listed below along with the annual average removal efficiencies:

- SO$_2$ Removal Efficiency: 99.5%

- SO$_3$ Removal Efficiency: 99.5%

- NO$_2$ Removal Efficiency: 25%

- HCl Removal Efficiency: 95%

- Particulate Removal Efficiency: 50%

Trace Removals

Removal of trace metals like mercury and other air toxics is not well-characterized for these systems but is anticipated to be similar to other wet scrubber systems. The model default is none, but the user may change these efficiencies.

- Mercury Removal Efficiency (oxidized):0%

- Mercury Removal Efficiency (elemental): 0%

Amine System Performance Parameters

Maximum Train CO$_2$ Capacity: The default maximum train size has been assumed to be 5000 tonnes per day of CO$_2$. Based on the actual CO2 capture rate the minimum number of trains required to be installed is determined. Different equipment has different maximum capacity limits.

Number of Operating Absorbers: This is the total number of operating absorber vessels. It is used primarily to calculate capital costs. The value must be an integer

Number of Spare Absorbers: This is the total number of spare absorber vessels. It is used primarily to calculate capital costs. The value must be an integer.

Max. CO$_2$ Compressor Capacity: This the maximum amount of CO$_2$ product that can be compressed per hour at the specified pressure.

No. of Operating CO$_2$ Compressors: This is the total number of operating CO$_2$ compressors. It is used primarily to calculate capital costs. The value must be an integer

No. of Spare CO$_2$ Compressors: This is the total number of spare CO$_2$ compressors. It is used primarily to calculate capital costs. The value must be an integer

Amine Scrubber Power Requirment: This is the equivalent electrical output of thermal (steam) energy used for reheat, plus the actual electrical output energy required for pumps and booster fans.

Amine System Capture Inputs
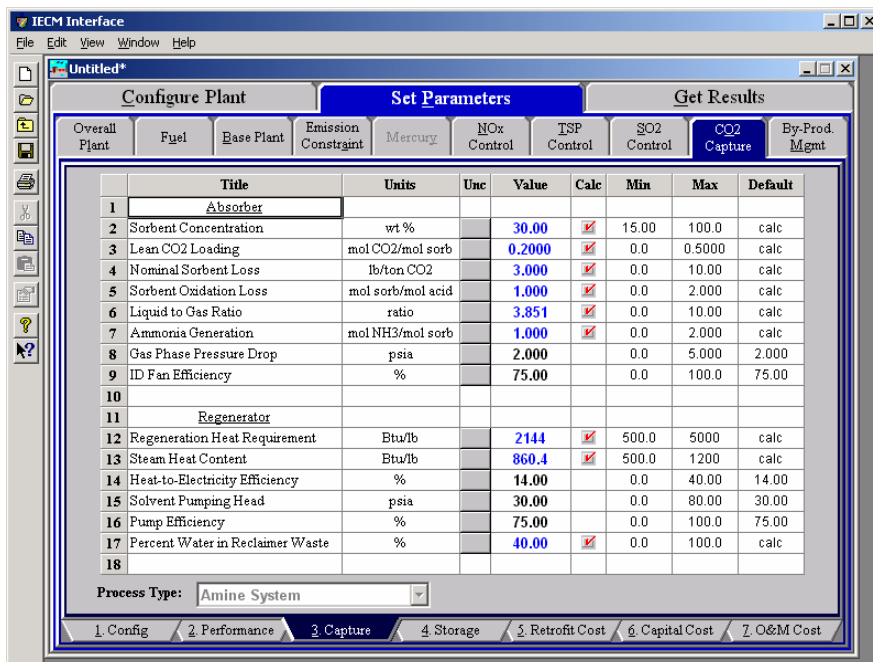
Amine System – Capture input screen.

Absorber

The absorber is the vessel where the flue gas makes contact with the MEA-based sorbent, and some of the CO_2 from the flue gas is dissolved in the sorbent. The column may be plate-type or a packed one. Most of the CO_2 absorbers are packed columns using some kind of polymer-based packing to provide large interfacial area.

Sorbent Concentration: The solvent used for CO_2 absorption is a mixture of monoethanolamine (MEA) with water. MEA is a highly corrosive liquid, especially in the presence of oxygen and carbon dioxide, and hence needs to be diluted. Today the commercially available MEA-based technology supplied by Fluor Daniel uses 30% w/w MEA solvent with the help of some corrosion inhibitors. Other suppliers, who do not use this inhibitor, prefer to use lower MEA concentrations in the range of 15%-20% w/w. Here we use 30% as the nominal value for the solvent concentration and the user may choose any value between 15-40%.

Lean CO2 Loading: Ideally, the solvent will be completely regenerated on application of heat in the regenerator section. Actually, even on applying heat, not all the MEA molecules are freed from CO_2. So, the regenerated (or lean) solvent contains some "left-over" CO_2. The level of lean solvent CO_2 loading mainly depends upon the initial CO_2 loading in the solvent and the amount of regeneration heat supplied, or alternatively, the regeneration heat requirement depends on the allowable level of lean sorbent loading. Here we use a nominal value of 0.2 based on the values reported in the literature, and the user may specify any desired value in the range (0.05-0.3).

Nominal Sorbent Loss: MEA is a reactive solvent. In spite of dilution with water and use of inhibitors, a small quantity of MEA is lost

through various unwanted reactions, mainly the polymerization reaction (to form long-chained compounds) and the oxidation reaction forming organic acids and liberating ammonia. In general, this nominal loss of MEA is estimated as about 1.5 kgMEA/ mton CO_2. It is also assumed that 50 % of this MEA loss is due to polymerization and the remaining 50% of the MEA loss is due to oxidation to acids.

Sorbent Oxidation Loss: The sorbent oxidation loss variable is a ratio of the number moles of sorbent that are lost for every mole of acid formed due to oxidation of the sorbent.

Liquid to Gas Ratio: The liquid to gas ration is the ratio of total molar flow rate of the liquid (MEA sorbent plus water) to the total molar flow rate of flue gas being treated in the absorber. This is one of the parameters derived by the process simulation model.

Ammonia Generation: The oxidation of MEA to organic acids (oxalic, formic, etc.) also leads to formation of NH_3. Each mole of MEA lost in oxidation, liberates a mole of ammonia (NH_3).

Gas Phase Pressure Drop: This is the pressure drop that the flue gas has to overcome as it passes through a very tall absorber column, countercurrent to the sorbent flow.

ID Fan Efficiency: The cooled flue gas is pressurized using a flue gas blower before it enters the absorber. This is the efficiency of the fan/blower to convert electrical energy input into mechanical work output. Typically, the value of blower efficiency is about 75%.

Regenerator

The regenerator is the column where the weak intermediate compound (carbamate) formed between the MEA-based sorbent and dissolved CO_2 is broken down with the application of heat and CO_2 gets separated from the sorbent to leave reusable sorbent behind. In case of unhindered amines like MEA, the carbamate formed is stable and it takes large amount of energy to dissociate. It also consists of a flash separator where CO_2 is separated from most of the moisture and evaporated sorbent, to give a fairly rich CO_2 stream.

Regeneration Heat Requirement: This is the total amount of heat energy required in the reboiler for sorbent regeneration.

Steam Heat Content: The regeneration heat is provided in the form of LP steam extracted from the steam turbine (in case of coal-fired power plants and combined-cycle gas plants), through the reboiler (a heat exchanger). In case of simple cycle natural gas fired power plants, a heat recovery unit maybe required. This is the enthalpy or heat content of the steam used for solvent regeneration.

Heat–to–Electricity Efficiency: The energy penalty (extraction of LP steam) results in some loss of power generation capacity of the plant. The Heat–toElectricity Efficiency gives the equivalent loss of power generation capacity due to the heat requirement for solvent regeneration. From the data this efficiency has been found to lie in the range (9, 22) for a new plant and (22, 30) for retrofit cases. So, the nominal value (for this new plant application) has been taken as 14%.

Solvent Pumping Head: The solvent has to flow through the absorber column (generally through packed media) countercurrent to the flue gas flowing upwards. So, some pressure loss is encountered in the absorber

column and sufficient solvent head has to be provided to overcome these pressure losses. Solvent circulation pumps are used to provide the pressure head. A typical value is about 200 kPa (~ 30 psi).

Pump Efficiency: This is the efficiency of the solvent circulation pumps to convert electrical energy input into mechanical energy output. Typically, the value is assumed to be 75%.

Percent Water in Reclaimer Waste: Typically, the reclaimer waste contains about 40% water.

Amine System Storage Inputs

		Title	Units	Unc	Value	Calc	Min	Max	Default
	1	CO2 Product Stream							
	2	Product Pressure	psia		2000		0.0	4000	2000
	3	Captured CO2 Purity	vol %		99.50		0.0	100.0	99.50
	4	H2O Content	vol %		0.5000	☑	0.0	15.00	calc
	5	Other Content	vol %		0.0	☑	0.0	1.000	calc
	6	CO2 Compressor Efficiency	%		80.00		0.0	100.0	80.00
	7	CO2 Unit Compression Energy	kWh/ton CO2		107.0	☑	0.0	180.0	calc
	8	Transport & Storage							
	9	CO2 Pipeline Distance	miles		100.0		0.0	1000	100.0
	10	Storage Method:			Geologic▼		Menu	Menu	Geologic
	11	*Enhanced Oil Recovery (EOR)*							
	12	*Enhanced Coal Bed Methane (E...*							
	13	*Geological Reservoir (Geologic)*							
	14	*Ocean (Ocean)*							
	15								
	16								
	17								
	18								

Process Type: Amine System

Amine System – Storage input screen

CO$_2$ Product Stream

The concentrated CO$_2$ product stream obtained from sorbent regeneration is compressed and dried using a multi-stage compressor with inter-stage cooling.

Product Pressure: The CO$_2$ product may have to be carried over long distances. Hence it is necessary to compress (and liquefy) it to very high pressures, so that it maybe delivered to the required destination in liquid form and (as far as possible) without recompression facilities en route. The critical pressure for CO$_2$ is about 1070 psig. The typically reported value of final pressure to which the product CO$_2$ stream has to be pressurized using compressors, before it is transported is about 2000 psig.

Captured CO$_2$ Purity: The final CO$_2$ product has to meet certain specifications depending upon the mode of transport and final destination. Impurities such as nitrogen are undesirable as they may pose problems during compression and liquefaction of CO$_2$. In order to avoid corrosion in the pipelines during transport, the moisture levels

have to be controlled. The acceptable level of purity of CO_2 product for most of the applications is about 99.8%

H₂O Content: This the volume percent of water contained in the final CO_2 product.

Other Content: This the volume percent of any substances that are not water or CO_2 contained in the final CO_2 product.

CO₂ Compressor Efficiency: This is the effective efficiency of the compressors used to compress CO_2 to the desirable pressure. Typically, the value of compressor efficiency (η_{comp}) is about 80%

CO₂ Unit Compression Energy: This is the electrical energy required to compress a unit mass of CO_2 product stream to the designated pressure. Compression of CO_2 to high pressures takes lot of energy, and is a principle contributor to the overall energy penalty of a CO_2 capture unit in a power plant.

Transport & Storage

CO₂ Pipeline Distance: The default mode of CO_2 transportation is via pipelines. The user can specify the distance over which the CO_2 needs to be carried.

Storage Method: The default option for CO_2 disposal is underground geological storage.

- **EOR** – Enhanced Oil Recovery

- **ECBM** – Enhanced Coalbed Methane Recovery

- **Geologic** – Geological Reservoir

- **Ocean**

Amine System Retrofit Cost Inputs

Integrated Environmental Control Model User Manual

Capital Cost Process Area

The retrofit cost factor of each process is a multiplicative cost adjustment, which considers the cost of retrofitted capital equipment relative to similar equipment installed in a new plant. These factors affect the capital costs directly and the operating and maintenance costs indirectly.
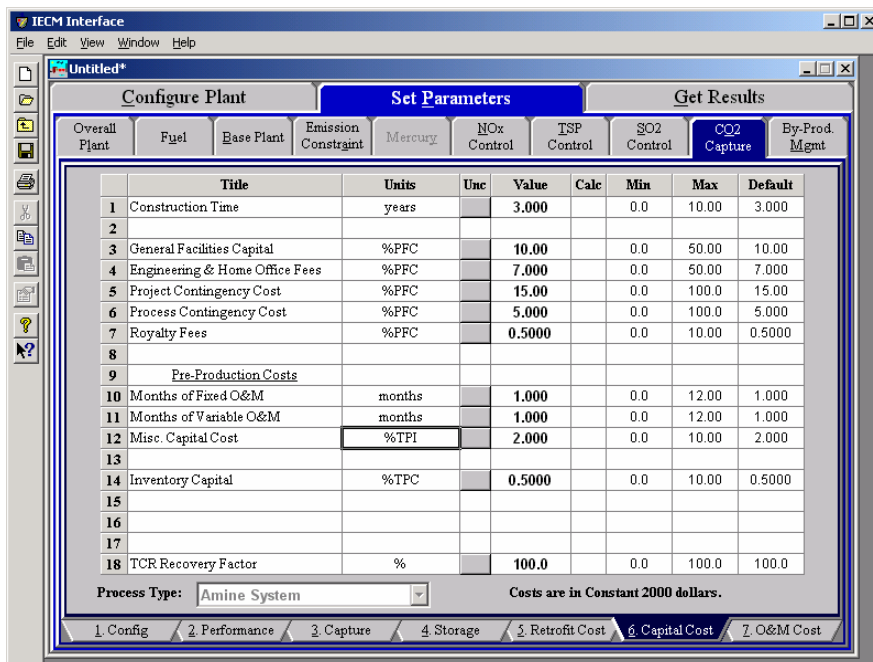
Direct capital costs for each process area are calculated in the IECM. These calculations are reduced form equations derived from more sophisticated models and reports. The sum of the direct capital costs associated with each process area is defined as the process facilities capital (PFC). The retrofit cost factor provided for each of the process areas can be used as a tool for adjusting the anticipated costs and uncertainties across the process area separate from the other areas.

Uncertainty can be applied to the retrofit cost factor for each process area in each technology. Thus, uncertainty can be applied as a general factor across an entire process area, rather than as a specific uncertainty for the particular cost on the capital or O&M input screens. Any uncertainty applied to a process area through the retrofit cost factor compounds any uncertainties specified later in the capital and O&M cost input parameter screens.

The following are the **Capital Cost Process Areas** for the Amine System:

- Direct Contact Cooler
- Flue Gas Blower
- CO2 Absorber Vessel
- Heat Exchangers
- Circulation Pumps
- Sorbent Regenerator
- Reboiler
- Steam Extractor
- Sorbent Reclaimer
- Sorbent Processing
- CO2 Drying and Compression Unit
- Auxiliary Natural Gas Boiler
- Auxiliary Steam Turbine

Amine System Capital Cost Inputs

Amine System – Capital Cost input screen.

Inputs for capital costs are entered on the **Capital Cost** input screen.

Construction Time: This is the idealized construction period in years. It is used to determine the allowance for funds used during construction (AFUDC).

> **General Facilities Capital (GFC)**: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly. The cost typically ranges from 5-20%.

> **Engineering & Home Office Fees:** The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company. These fees typically range from 7-15%.

> **Project Contingency Cost:** This is factor covering the cost of additional equipment or other costs resulting from a more detailed design. Higher contingency factors will be applied to simplified or preliminary designs and lower factors to detailed or finalized designs.

> **Process Contingency Cost:** This quantifies the design uncertainty and cost of a commercial-scale system. This is generally applied on an area-by-area basis. Higher contingency factors are applied to new regeneration systems tested at a pilot plant and lower factors to full-size or commercial systems.

> **Royalty Fees:** Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

> **Pre-Production Costs:** These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up. These are typically applied to the O&M costs over a specified

period of time (months). The two time periods for fixed and variable O&M costs are described below with the addition of a miscellaneous capital cost factor.

Months of Fixed O&M: Time period of fixed operating costs used for preproduction to cover training, testing, major changes in equipment, and inefficiencies in start-up. This includes operating, maintenance, administrative and support labor. It also considers maintenance materials.

Months of Variable O&M: Time period of variable operating costs used for preproduction to cover chemicals, water, consumables, and solid disposal charges in start-up, assuming 100% load. This excludes any fuels.

Misc. Capital Cost: This is a percent of total plant investment (sum of TPC and AFUDC) to cover expected changes to equipment to bring the system up to full capacity.

Inventory Capital: Percent of the total direct capital for raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts. This is typically 0.5%.

TCR Recovery Factor: The actual total capital required (TCR) as a percent of the TCR in a new power plant. This value is 100% for a new installation and may be set as low as 0% for a fabric filter that has been paid off.

Amine System O&M Cost Inputs

Amine System – O&M Cost input screen.

Inputs for operation and maintenance are entered on the **O&M Cost** input. Each parameter is described briefly below

MEA Cost: This is the unit cost of the makeup MEA.

Inhibitor Cost: Addition of inhibitor makes it possible to use higher concentrations of MEA solvent in the system with minimal corrosion problems. Inhibitors are special compounds that come at a cost premium. The cost of inhibitor is estimated as a percent of the cost of MEA. The model default is 20%.

Activated Carbon Cost: This is the cost of the activated carbon in $ per ton.

Caustic (NaOH) Cost: This is the cost of the caustic in $ per ton.

Water Cost: Water is mainly required for cooling and also as process makeup. Tost of water may vary depending upon the location of the power plant.

Reclaimer Waste Disposal Cost: The unit cost of waste disposal for the reclaimer waste.

Number of Operating Jobs: This is the total number of operating jobs that are required to operate the plant per eight-hour shift.

Number of Operating Shifts: This is the total number of equivalent operating shifts in the plant per day. The number takes into consideration paid time off and weekend work (3 shifts/day * 7 days/5 day week * 52 weeks/(52 weeks - 6 weeks PTO) = 4.75 equiv. Shifts/day)

Total Maintenance Cost: This is the annual maintenance cost as a percentage of the total plant cost. Maintenance cost estimates can be developed separately for each process area.

Maint. Cost Allocated to Labor: Maintenance cost allocated to labor as a percentage of the total maintenance cost.

Administrative & Support Cost: This is the percent of the total operating and maintenance labor associated with administrative and support labor.

Transport and Storage Costs

CO2 Transportation Cost: Transportation of CO_2 product is assumed to take place via pipelines. This is the unit cost of CO_2 transport in $/ton –mile.

CO2 Disposal Cost: This is the unit cost of CO_2 disposal. Depending upon the method of CO_2 disposal or storage, either there may be some revenue generated (Enhanced Oil Recovery, Coal Bed Methane) which may be treated as a "negative cost", or additional cost (all other disposal methods).

Amine System Diagram
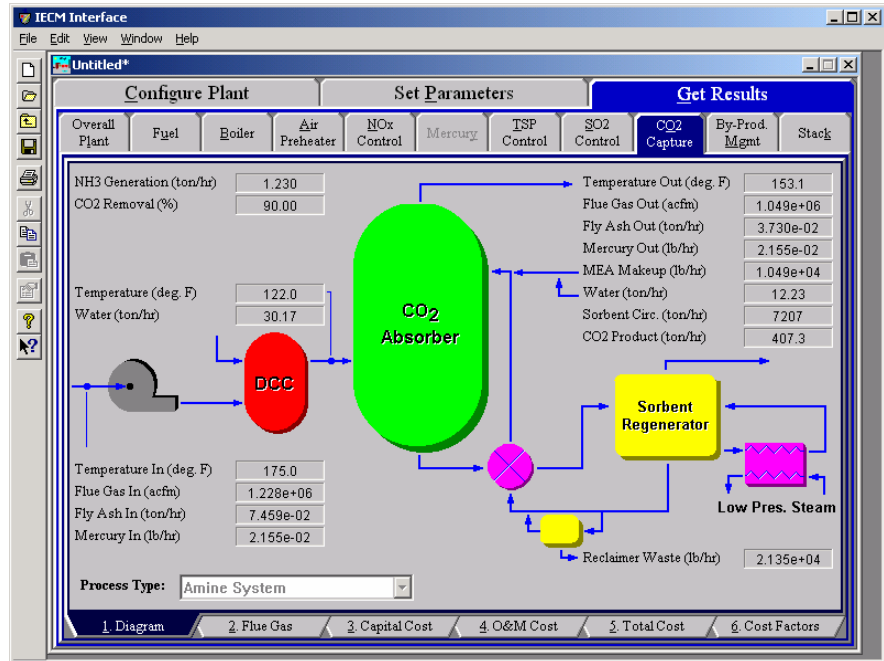
Amine System – Diagram.

Reagent

MEA Makeup: The mass flow rate of fresh MEA needed to replace the amount used in the process.

Water: This is the flow rate of water that is used to mix with the MEA Makeup.

Flue Gas Entering Amine System

Temperature In: Temperature of the flue gas entering the amine system area, prior to any processing. This is determined by the flue gas outlet temperature of the process area upstream.

Flue Gas In: Volumetric flow rate of flue gas entering the amine system.

Fly Ash In: Total solids mass flow rate in the flue gas entering the Amine System. This is determined by the solids exiting from the module upstream.

Mercury In: Total mass of mercury entering the Amine System. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Temperature: Temperature of the flue gas entering the amine scrubber system.

Water: This is the flow rate of water into the Direct Contact Cooler.

Flue Gas Exiting Amine System

Temperature Out: Temperature of the flue gas exiting the amine scrubber system.

> **Flue Gas Out:** Volumetric flow rate of the flue gas exiting the amine scrubber.
>
> **Fly Ash Out:** Total solids mass flow rate in the flue gas exiting the amine scrubber.
>
> **Mercury Out:** Total mass of mercury exiting the amine scrubber. The value is a sum of all the forms of mercury (elemental, oxidized, and particulate).

Amine System Performance

> **CO_2 Product:** Actual amount of CO_2 produced as a result of the amine scrubbing.
>
> **CO_2 Removal:** Actual removal efficiency of CO_2 in the amine scrubber.
>
> **NH_3 Generation:** The flow rate of ammonia by product produced in the amine scrubbing process.
>
> **Sorbent Circ.:** The flow rate of the sorbent through the amine scrubber system.
>
> **Mercury Removal:** Percent of the total mercury removed from the scrubber. The value reflects a weighted average based on the particular species of mercury present (elemental, oxidized, and particulate).

Collected Solids

> **Reclaimer Waste:** Total solids mass flow rate of solids removed from the amine scrubber.

Amine System Flue Gas Results

Amine System – Flue Gas result screen

Major Flue Gas Components

Each result is described briefly below:

Nitrogen (N₂): Total mass of nitrogen.

Oxygen (O₂): Total mass of oxygen.

Water Vapor (H₂O): Total mass of water vapor.

Carbon Dioxide (CO₂): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO₂): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO₃): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO₂): Total mass of nitrogen dioxide.

Ammonia (NH₃): Total mass of ammonia.

Argon (Ar): Total mass of argon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Amine System Capital Cost Results

Amine System – Capital Cost result screen.

The **Capital Cost** result screen displays tables for the capital costs. Each result is described briefly below:

MEA Scrubber Process Area Costs

Direct Contact Cooler: This area includes the equipment required to cool the flue gas in order to improve absorption of CO₂ into the amine

sorbent. In case of coal-fired power plant applications that have a wet FGD (flue gas desulfurization) unit upstream of the amine system, the wet scrubber helps in substantial cooling of the flue gases, and additional cooler may not be required.

Flue Gas Blower: The flue gas has to overcome a substantial pressure drop as it passes through a very tall absorber column, countercurrent to the sorbent flow. Hence the cooled flue gas has to be pressurized using a blower before it enters the absorber.

CO_2 Absorber Vessel: This is the vessel where the flue gas is made to contact with the MEA-based sorbent, and some of the CO_2 from the flue gas gets dissolved in the sorbent. The column may be plate-type or a packed one. Most of the CO_2 absorbers are packed columns using some kind of polymer-based packing to provide large interfacial area.

Heat Exchangers: The CO_2-loaded sorbent needs to be heated in order to strip off CO_2 and regenerate the sorbent. On the other hand, the regenerated (lean) sorbent coming out of the regenerator has to be cooled down before it could be circulated back to the absorber column. Hence these two sorbent streams are passed through a cross heat exchanger, where the rich (CO_2-loaded) sorbent gets heated and the lean (regenerated) sorbent gets cooled.

Circulation Pumps: The cost associated with the equipment required to support FGD system operation such as makeup water and instrument air are treated here.

Sorbent Regenerator: This is the column where the weak intermediate compound (carbamate) formed between the MEA-based sorbent and dissolved CO_2 is broken down with the application of heat and CO_2 gets separated from the sorbent to leave reusable sorbent behind. In case of unhindered amines like MEA, the carbamate formed is stable and it takes large amount of energy to dissociate. It also consists of a flash separator where CO_2 is separated from most of the moisture and evaporated sorbent, to give a fairly rich CO_2 stream.

Reboiler: The regenerator is connected with a reboiler which is basically a heat exchanger where low-pressure steam extracted from the power plant is used to heat the loaded sorbent

Steam Extractor: In case of coal-fired power plants that generate electricity in a steam turbine, a part of the LP/IP steam has to be diverted to the reboiler for sorbent regeneration. Steam extractors are installed to take out steam from the steam turbines.

Sorbent Reclaimer: Presence of acid gas impurities (SO_2, SO_3, NO_2 and HCl) in the flue gas leads to formation of heat stable salts in the sorbent stream, which can not be dissociated even on application of heat. In order to avoid accumulation of these salts in the sorbent stream and to recover some of this lost MEA sorbent, a part of the sorbent stream is periodically distilled in this vessel. Addition of caustic helps in freeing of some of the MEA. The recovered MEA is taken back to the sorbent stream while the bottom sludge (reclaimer waste) is sent for proper disposal.

Sorbent Processing: The regenerated sorbent has to be further cooled down even after passing through the rich/lean cross heat exchanger using a cooler, so that the sorbent temperature is brought back to acceptable level (about 40 deg C). Also, in order make up for the

sorbent losses, a small quantity of fresh MEA sorbent has to be added to the sorbent stream. So, the sorbent processing area primarily consists of sorbent cooler, MEA storage tank, and a mixer. It also consists of an activated carbon bed filter that adsorbs impurities (degradation products of MEA) from the sorbent stream.

Drying and Compression Unit: The CO_2 product may have to be carried to very long distances via pipelines. Hence it is desirable that it does not contain any moisture in order to avoid corrosion in the pipelines. Also, it has to be compressed to very high pressures so that it gets liquefied and can overcome the pressure losses during the pipeline transport. The multi-stage compression unit with inter-stage cooling and drying yields a final CO_2 product at the specified pressure (about 2000 psig) that contains moisture and other impurities (e.g. N_2) at acceptable levels.

Auxiliary Natural Gas Boiler: The cost of the Natural Gas boiler is estimated on the basis of the steam flow rate generated from the boiler.

Auxiliary Steam Turbine: The regeneration heat is provided in the form of LP steam extracted from the steam turbine (in case of coal-fired power plants and combined-cycle gas plants), through the reboiler (a heat exchanger). In case of simple cycle natural gas fired power plants, a heat recovery unit maybe required.

Process Facilities Capital: The process facilities capital is the total constructed cost of all on-site processing and generating units listed above, including all direct and indirect construction costs. All sales taxes and freight costs are included where applicable implicitly. This result is highlighted in yellow.

MEA Scrubber Plant Costs

Process Facilities Capital: (see definition above)

General Facilities Capital: The general facilities include construction costs of roads, office buildings, shops, laboratories, etc. Sales taxes and freight costs are included implicitly.

Eng. & Home Office Fees: The engineering & home office fees are a percent of total direct capital cost. This is an overhead fee paid to the architect/engineering company.

Project Contingency Cost: Capital cost contingency factor covering the cost of additional equipment or other costs that would result from a more detailed design of a definitive project at the actual site.

Process Contingency Cost: Capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment.

Interest Charges (AFUDC): Allowance for funds used during construction, also referred to as interest during construction, is the time value of the money used during construction and is based on an interest rate equal to the before-tax weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period for all funds spent during the year or previous years.

Royalty Fees: Royalty charges may apply to some portions of generating units incorporating new proprietary technologies.

Preproduction (Startup) Cost: These costs consider the operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel or other materials during start-up.

Inventory (Working) Capital: The raw material supply based on 100% capacity during a 60 day period. These materials are considered storage. The inventory capital includes fuels, consumables, by-products, and spare parts.

Total Capital Requirement (TCR): Money that is placed (capitalized) on the books of the utility on the service date. TCR includes all the items above. This result is highlighted in yellow.

Effective TCR: The TCR of the spray dryer that is used in determining the total power plant cost. The effective TCR is determined by the "TCR Recovery Factor".

Amine System O&M Cost Results

Amine System – O&M Cost result screen.

The **O&M Cost** result screen displays tables for the variable and fixed operation and maintenance costs involved with the **CO₂ Capture** technology. Each result is described briefly below:

Variable Cost Components

Variable operating costs and consumables are directly proportional to the amount of kilowatts produced and are referred to as incremental costs. All the costs are subject to inflation.

Sorbent: MEA is the default sorbent used in the system and this is the annual cost of the MEA. This is a function of the concentration of CO2 in the flue gas and the flue gas flow rate.

Natural Gas: If the user has added an auxiliary natural gas boiler, the cost of the natural gas used to fuel the boiler is added here.

Corrosion Inhibitor: The inhibitor helps in two ways – reduced sorbent degradation and reduced equipment corrosion. This is the annual cost of the corrosion inhibitor.

Activated Carbon: This is the activated carbon cost for flue gas conditioning.

Caustic (NaOH): This is the annual cost of caustic. The presence of acid gas impurities (SO_2, SO_3, NO_2 and HCl) in the flue gas leads to formation of heat stable salts in the sorbent stream, which can not be dissociated even on application of heat. In order to avoid accumulation of these salts in the sorbent stream and to recover some of this lost MEA sorbent, a part of the sorbent stream is periodically distilled in this vessel. Addition of caustic helps in freeing of some of the MEA. The recovered MEA is taken back to the sorbent stream while the bottom sludge (reclaimer waste) is sent for proper disposal.

Reclaimer Waste Disposal: This is the reclaimer waste disposal cost per year.

Electricity: The cost of electricity consumed by the Amine System.

Auxiliary Power Credit: An auxiliary natural gas boiler can be added by the user to provide steam and power for the Amine System. If it is added by the user then the additional power it provides is subtracted from the overall operating and maintenance cost, here.

Steam (elec. equiv.): Equivalent electrical penalty of the regeneration steam requirement

Water: This is the annual cost for water to the amine scrubber system, it is mainly required for cooling and also as process makeup.

CO_2 Transport: The CO_2 captured at the power plant site has to be carried to the appropriate storage/ disposal site. Transport of CO_2 to a storage site is assumed to be via pipeline This is the annual cost of maintaining those pipelines.

CO_2 Storage/Disposal: Once the CO_2 is captured, it needs to be securely stored (sequestered). This cost is based upon the storage option chosen on the Amine System – Storage input screen.

Total Variable Costs: This is the sum of all the variable O&M costs listed above. This result is highlighted in yellow.

Fixed Cost Components

Fixed operating costs are essentially independent of actual capacity factor, number of hours of operation, or amount of kilowatts produced. All the costs are subject to inflation.

Operating Labor: Operating labor cost is based on the operating labor rate, the number of personnel required to operate the plant per eight-hour shift, and the average number of shifts per day over 40 hours per week and 52 weeks.

Maintenance Labor: The maintenance labor is determined as a fraction of the total maintenance cost.

Maintenance Material: The cost of maintenance material is the remainder of the total maintenance cost, considering the fraction associated with maintenance labor.

Admin. & Support Labor: The administrative and support labor is the only overhead charge. It is taken as a fraction of the total operating and maintenance labor costs.

Total Fixed Costs: This is the sum of all the fixed O&M costs listed above. This result is highlighted in yellow.

Total O&M Costs: This is the sum of the total variable and total fixed O&M costs. It is used to determine the base plant total revenue requirement. This result is highlighted in yellow.

Amine System Total Cost Results

Amine System – Total Cost result screen.

The **Total Cost** result screen displays a table which totals the annual fixed, variable, operations and maintenance, and capital costs associated with the **Amine System CO$_2$ Control** technology. Each result is described briefly below.

Cost Component

Annual Fixed Cost: The operating and maintenance fixed costs are given as an annual total. This number includes all maintenance materials and all labor costs.

Annual Variable Cost: The operating and maintenance variables costs are given as an annual total. This includes all reagent, chemical, steam, and power costs.

Total Annual O&M Cost: This is the sum of the annual fixed and variable operating and maintenance costs above. This result is highlighted in yellow.

Annualized Capital Cost: This is the total capital cost expressed on an annualized basis, taking into consideration the levelized carrying charge factor, or fixed charge factor, over the entire book life.

Total Levelized Annual Cost: The total annual cost is the sum of the total annual O&M cost and annualized capital cost items above. This result is highlighted in yellow.

Amine System Cost Factors Results

Amine System – Cost Factors result screen.

Important Performance and Cost Factors

This screen displays information that is key to the model calculations. The data is available else where in the model.

Net Plant Size (MW): This is the net plant capacity, which is the gross plant capacity minus the losses due to plant equipment and pollution equipment (energy penalties).

Annual Operating Hours (hours): This is the number of hours per year that the plant is in operation. If a plant runs 24 hours per day, seven days per week, with no outages, the calculation is 24 hours * 365 days. or 8,760 hours/year.

Annual CO_2 Removed (ton/yr): This is thel amount of CO_2 removed from the flue gas by the CO_2 capture system per year.

Annual SO_2 Removed (ton/yr): This is the amount of SO_2 removed from the flue gas by the CO_2 capture system per year.

Annual SO_3 Removed (ton/yr): This is the amount of SO_3 removed from the flue gas by the CO_2 capture system per year.

Annual NO_2 Removed (ton/yr): This is the amount of NO_2 removed from the flue gas by the CO_2 capture system per year.

Annual HCl Removed (ton/yr): This is the amount of HCl removed from the flue gas by the CO_2 capture system per year.

Flue Gas Fan Energy (MW): The flue gas has to be compressed in a flue gas blower so that it can overcome the pressure drop in the absorber tower. This is the electrical energy required by the blower.

Sorbent Pump Energy (MW): The solvent has to flow through the absorber column (generally through packed media) countercurrent to the flue gas flowing upwards. This is the energy required by the solvent circulation pumps to supply pressure to overcome the pressure losses encountered by the solvent in the absorber column.

CO_2 Compression Energy (MW): This is the electrical energy required to compress the CO_2 product stream to the designated pressure. Compression of CO_2 to high pressures takes lot of energy, and is a principle contributor to the overall energy penalty of a CO_2 capture unit in a power plant.

Aux. Electricity Produced (MW): If an auxiliary natural gas boiler is used to provide steam and power for the Amine System, this is the additional electricity that it produces.

Sorbent Regeneration Equiv. Energy (MW): This is the electrical equivalent of the energy required in the form of either steam or heat to regenerate the sorbent.

Fixed Charge Factor (fraction): The fixed charge factor is one of the most important parameters in the IECM. It determines the revenue required to finance the power plant based on the capital expenditures. Put another way, it is a levelized factor which accounts for the revenue per dollar of total plant cost that must be collected from customers in order to pay the carrying charges on that capital investment.

Variable Cost Levelization Factor (fraction):

Cost of CO_2 Avoided

Many analysts like to express the cost of an environmental control system in terms of the cost per ton of pollutant removed or avoided. For energy-intensive CO_2 controls there is a big difference between the cost per ton CO_2 removed and the cost per ton "avoided" based on *net* plant capacity. Since the purpose of adding a CO_2 unit is to reduce the CO_2 emissions per net kWh delivered, the cost of CO_2 avoidance is the economic indicator that is widely used in this field.

Capture Plant

CO_2 Emissions (lb/kWh): This is the amount of CO2 vented to the air for every kilowatt hour of electricity produced in the power plant that is using **CO_2 Capture Technology**.

Cost of Electricity ($/MWh): The IECM framework calculates the cost of electricity (COE) for the overall **Capture Plant** by dividing the total annualized plant cost ($/yr) by the net electricity generated (kWh/yr)

Reference Plant

CO_2 Emissions (lb/kWh): This is the amount of CO2 vented to the air for every kilowatt hour of electricity produced in the power plant with **NO CO2 Capture**.

Cost of Electricity ($/MWh): The IECM framework calculates the cost of electricity (COE) for the overall **Reference Plant** by dividing the total annualized plant cost ($/yr) by the net electricity generated (kWh/yr)

Cost of CO_2 Avoided ($/ton): This is the economic indicator widely used in the field, calculated as the difference between the cost of electricity in the capture plant and the reference plant divided by the difference between the CO2 emissions in the reference plant and the capture plant.

Cost of CO_2 Avoided = (Cost of Electricity $_{cap.}$ – Cost of Electricity $_{ref.)}$

/ (CO_2 emissions $_{ref.}$ – CO_2 emissions $_{cap.)}$

By Product Management

The **ByProduct Mgmt** Technology Navigation Tab screens display and design the management of by products and waste disposal.

By Product Management Performance Inputs
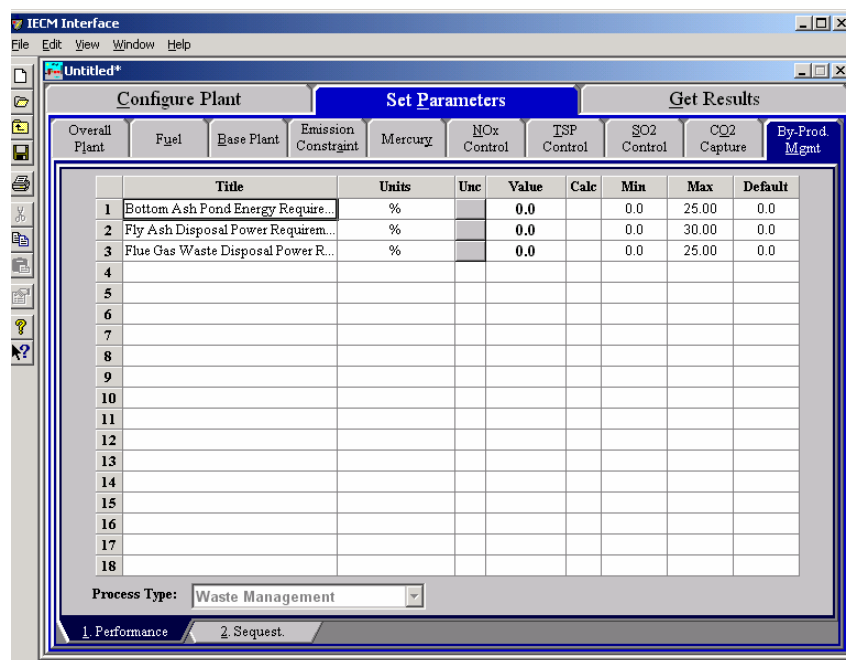
By Product Management – Performance input screen.

General inputs regarding solid waste management are entered on the **Performance** input screen. This screen is displayed for all plant configurations. One or more of the following By Product Management options will be shown on the input screen depending upon the options selected in the **Configure Plant** program area. Each of the possible parameters are described briefly below.

> **Bottom Ash PondEnergy Requirements:** The energy requirement is zero by default. Any requirements are considered by the abatement technologies that dispose solids into the bottom ash pond.

Fly Ash Disposal Power Requirements: The energy requirement is zero by default. Any requirements are considered by the abatement technologies that dispose of fly ash.

Flue Gas Waste Disposal Power Requirements: The energy requirement is zero by default. Any requirements are considered by the abatement technologies that dispose of flue gas waste.

By Product Management Sequestration Input
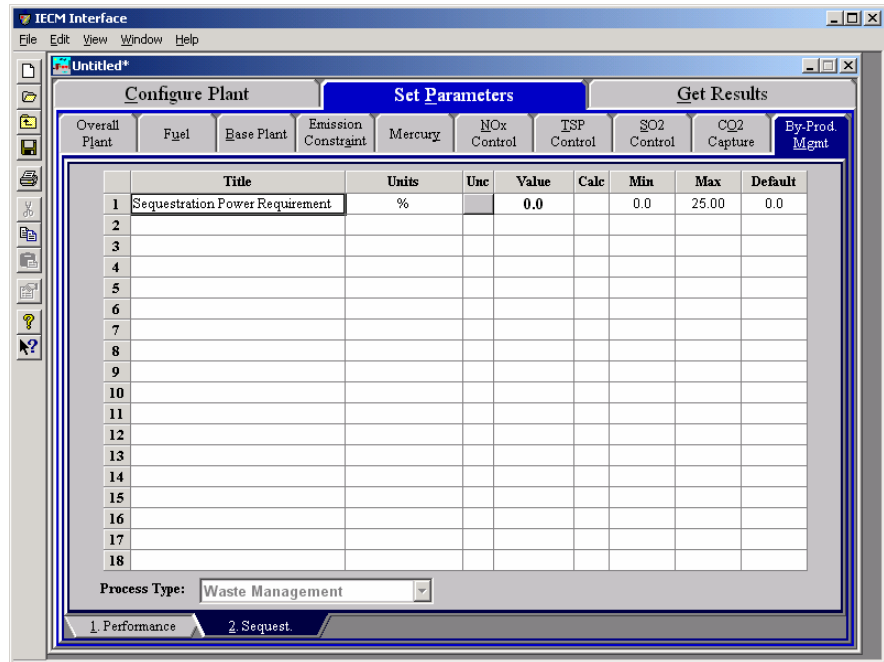
By Product Management – Sequestration input screen.

If the user has selected **CO₂ Capture** in the **Configure Plant** program area this input screen will also be available. Its parameter is described briefly below.

Sequestration Power Requirement: The energy requirement is zero by default.

By Products Management Bottom Ash Pond Diagram

The **By Product Management** Technology Navigation Tab screens displays the flow rates of solid and liquid substances collected which require management (disposal or recovery). There are three **By Product Management** areas, **Bottom Ash Pond**, **Flue Gas Treatment** and **Fly Ash Disposal**. If **CO₂** Capture has been configured for the plant by the user then a **Geological Reservoir** is also available. These are accessed by the **Process Type** drop-down menu. Each

management technology has only one Result Navigation Tab: **Diagram.**
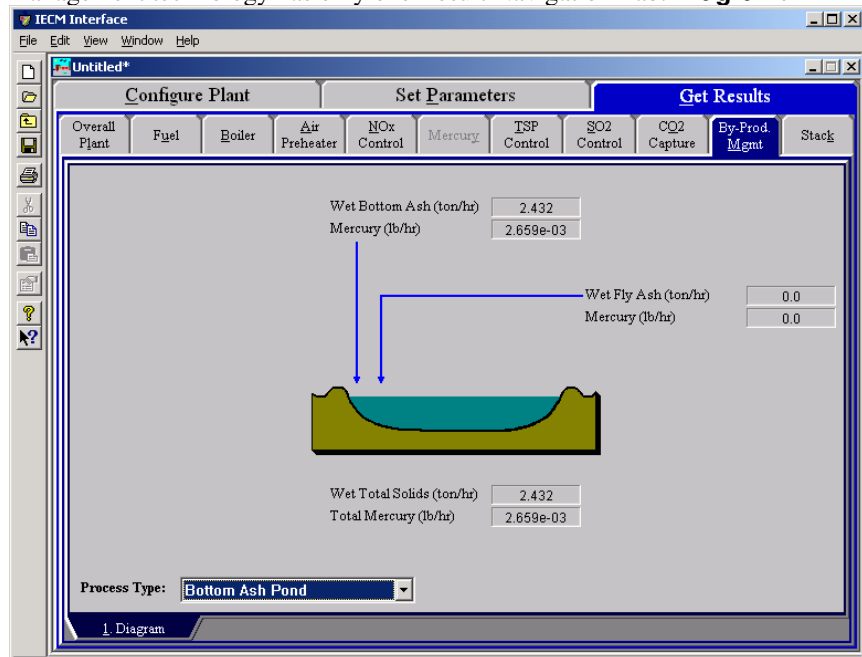
By Products Management Bottom Ash Pond—Diagram result screen

The **Bottom Ash Pond Diagram** result screen displays an icon for the **Pond** and values for major flows into it. Each result is described briefly below:

Bottom Ash Pond Inputs

Solids mixed with sluice water that are collected in the bottom of the boiler and by the particulate removal technologies are transported to the Pond for treatment. The IECM currently provides no additional treatment or consideration of these substances, and therefore simply reports the quantities entering the technology.

Wet Bottom Ash: Mass flow rate of bottom ash solids on a wet basis.

Mercury(contained in Bottom Ash): Mass flow rate of mercury present in the bottom ash solids on a wet basis.

Wet Fly Ash: Mass flow rate of total fly ash solids on a wet basis. This value is zero when the fly ash is disposed in a landfill.

Mercury(contained in Fly Ash): Mass flow rate of mercury present in the fly ash solids on a wet basis.

Bottom Ash Pond – Totals

Wet Total Solids: The sum of the fly ash and bottom ash solids on a wet basis.

Total Mercury: Mass flow rate of mercury present in the combined bottom ash and fly ash solids on a wet basis.

By Products Management Flue Gas Treatment Diagram

The **By Product Management** Technology Navigation Tab screens displays the flow rates of solid and liquid substances collected which require management (disposal or recovery). There are three **By Product Management** areas, **Bottom**

Ash Pond, **Flue Gas Treatment** and **Fly Ash Disposal**. If **CO₂** Capture has been configured for the plant by the user then a **Geological Reservoir** is also available. These are accessed by the **Process Type** drop-down menu. Each management technology has only one Result Navigation Tab: **Diagram.**
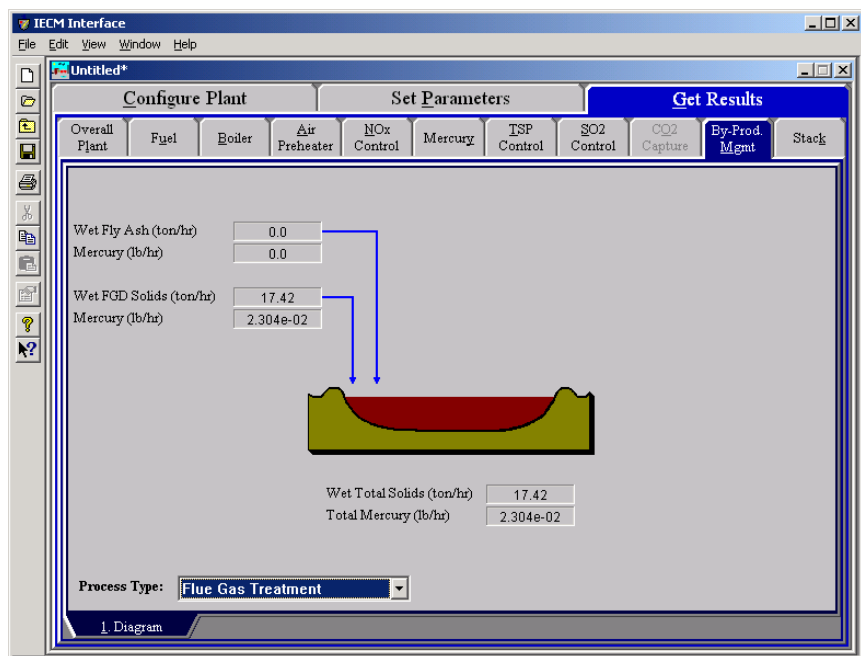
By Products Management Bottom Ash Pond—Diagram result screen

The **Flue Gas Treatment Diagram** result screen displays an icon for the **Landfill** and values for major flows into it. Each result is described briefly below:

Flue Gas Treatment Inputs

Solids mixed with sluice water that are collected in the bottom of the boiler and by the particulate removal technologies are transported to the Pond for treatment. The IECM currently provides no additional treatment or consideration of these substances, and therefore simply reports the quantities entering the technology.

> **Wet FGD Solids:** Mass flow rate of wet FGD solids.

> **Mercury(contained in Wet FGD Solids):** Mass flow rate of mercury present in the Wet FGD solids.

> **Wet Fly Ash:** Mass flow rate of total fly ash solids on a wet basis. This value is zero when the fly ash is disposed in a landfill.

> **Mercury(contained in Fly Ash):** Mass flow rate of mercury present in the fly ash solids on a wet basis.

Flue Gas Treatment – Totals

> **Wet Total Solids:** The sum of the wet FGD solids and the fly ash on a wet basis.

> **Total Mercury:** Mass flow rate of mercury present in the combined wet FGD solids and fly ash solids on a wet basis.

By Products Management Fly Ash Disposal Diagram
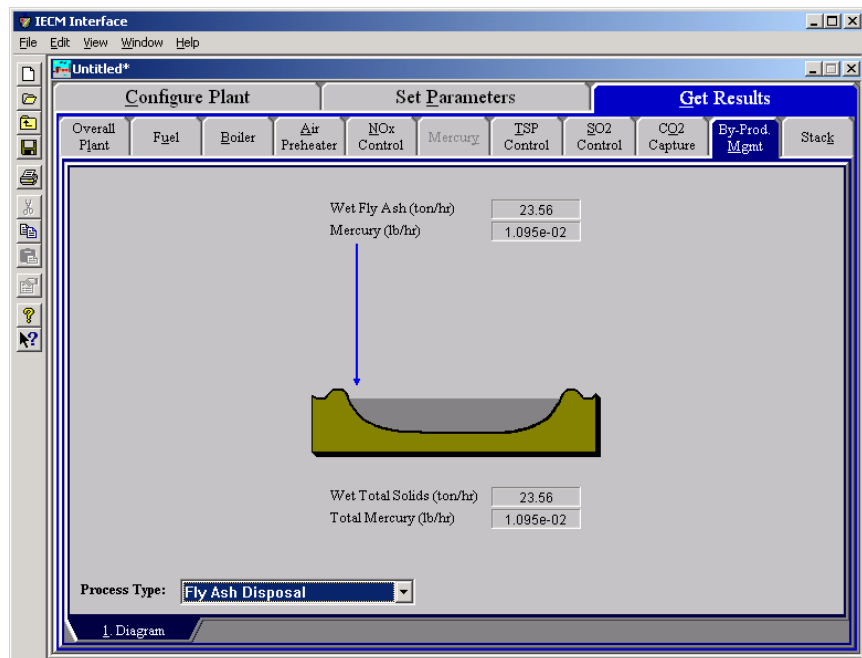
By Products Management Fly Ash Disposal—Diagram result screen

The **By Products Management Fly Ash Disposal Diagram** result screen displays an icon for the **Landfill** and values for major flows into it. This screen is only an option if **CO₂ Capture** has been configured for the plant by the user. Each result is described briefly below:

Fly Ash Disposal Inputs

Solids mixed with sluice water are collected in the particulate removal technologies and may be transported to the Landfill for treatment. The IECM currently provides no additional treatment or consideration of these substances, and therefore simply reports the quantities entering the technology.

> **Wet Fly Ash:** Mass flow rate of total fly ash solids on a wet basis.

> **Mercury:** Mass flow rate of mercury present in the fly ash solids on a wet basis.

Fly Ash Disposal Totals

> **Wet Total Solids:** The sum of the fly ash and FGD solids on a wet basis.

> **Total Mercury:** Mass flow rate of mercury present in the combined fly ash and FGD solids on a wet basis.

By Products Management Geological Resevoir Diagram

By Product Management – Geological Reservoir diagram.

The **By Products Management Geological Resevoir Diagram** result screen displays an icon for the **Geological Reservoir** and values for the concentrated CO_2 that flows into it. The result is described briefly below:

> **Concentrated CO$_2$:** Mass flow rate of CO_2.

Stack

Stack Constraints Inputs
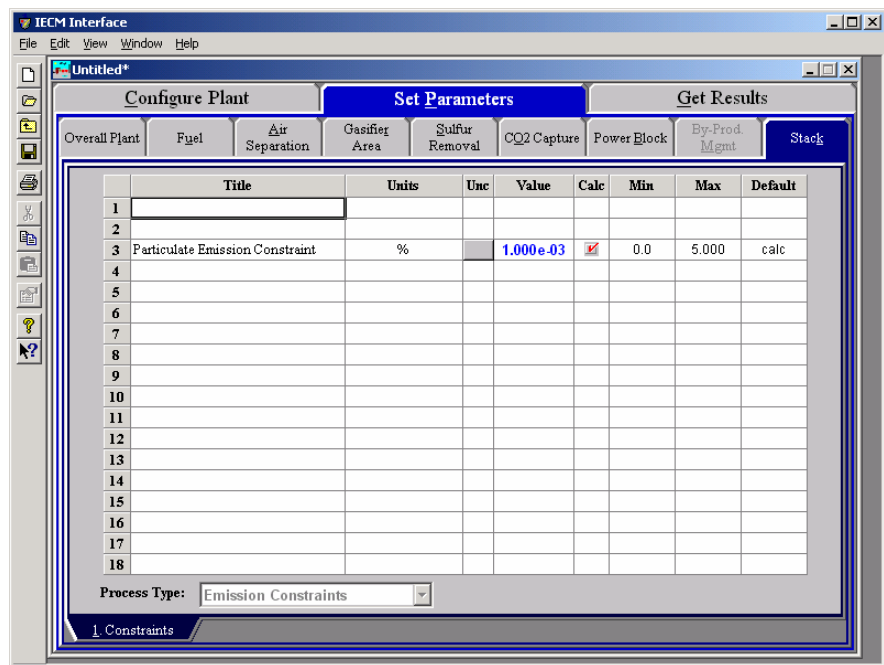
Stack – Contraints input screen.

The **Stack Constraints** input screen allows the user to enter the **Particulate Emission Constriant** as a percent. This screen is only available if the **IGCC** has been selected as the plant type.

Stack Diagram
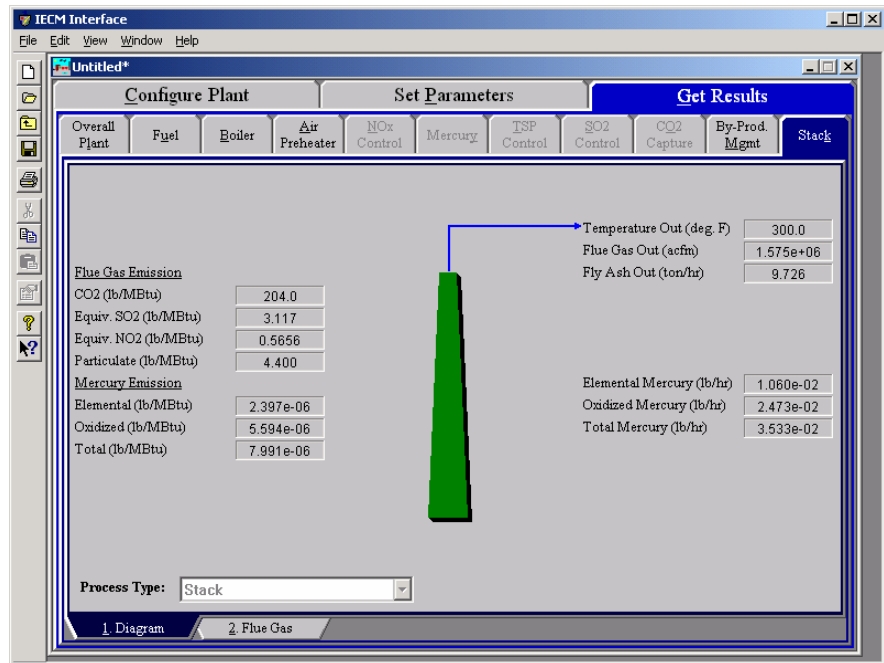
Stack – Diagram.

The **Diagram** result screen displays an icon for the stack and values for major flows out of it. Each result is described briefly below.

> **Temperature Out:** Temperature of the flue gas exiting the stack.
>
> **Flue Gas Out:** Volumetric flow rate of flue gas exiting the stack, based on the flue gas temperature exiting the stack and atmospheric pressure.
>
> **Fly Ash Out:** Mass flow rate of solids in the flue gas exiting the stack.

Flue Gas Emission

> **CO_2:** This is the number of pounds of **CO_2** vented to the air for every MBtu.
>
> **Equivalent SO_2:** This is the number of pounds of **Equivalent SO_2** vented to the air for every MBtu.
>
> **Equivalent NO_2 :** This is the number of pounds of **Equivalent NO_2** vented to the air for every MBtu.
>
> **Particulate:** This is the number of pounds of **Particulate** vented to the air for every MBtu.

Mercury Emission

> **Elemental:** This is the number of pounds of **Elemental Mercury** vented to the air for every MBtu.
>
> **Oxidized:** This is the number of pounds of **Oxidized Mercury** vented to the air for every MBtu.
>
> **Total:** This is the number of pounds of **Total Mercury** vented to the air for every MBtu.

Mercury Exiting Stack
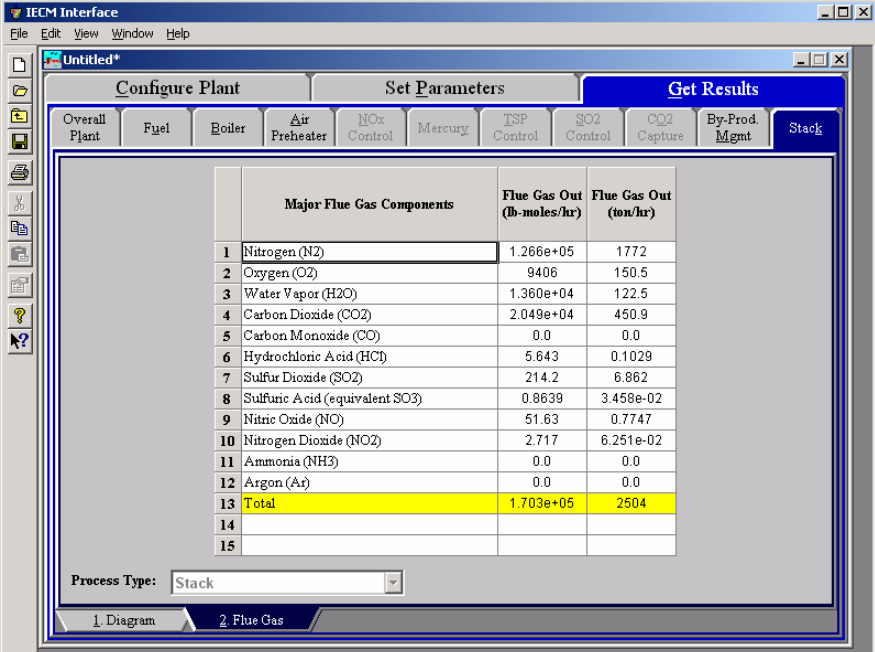
Elemental Mercury: Mass flow rate of elemental mercury (Hg^0) in the flue gas exiting the stack.

Oxidized Mercury: Mass flow rate of oxidized mercury (Hg^{+2}) in the flue gas exiting the stack.

Total Mercury: Mass flow rate of total mercury in the flue gas exiting the stack (elemental, oxidized, and particulate).

Stack Flue Gas Results

The **FlueGas** result screen displays a table of quantities of flue gas components exiting the stack. For each component, quantities are given in both moles and mass per hour.

Stack Flue Gas result screen.

Major Flue Gas Components

Each result is described briefly below

Nitrogen (N_2): Total mass of nitrogen.

Oxygen (O_2): Total mass of oxygen.

Water Vapor (H_2O): Total mass of water vapor.

Carbon Dioxide (CO_2): Total mass of carbon dioxide.

Carbon Monoxide (CO): Total mass of carbon monoxide.

Hydrochloric Acid (HCl): Total mass of hydrochloric acid.

Sulfur Dioxide (SO_2): Total mass of sulfur dioxide.

Sulfuric Acid (equivalent SO_3): Total mass of sulfuric acid.

Nitric Oxide (NO): Total mass of nitric oxide.

Nitrogen Dioxide (NO_2): Total mass of nitrogen dioxide.

Ammonia (NH$_3$): Total mass of ammonia.

Argon(Ar): Total mass ofargon.

Total: Total of the individual components listed above. This item is highlighted in yellow.

Units

Units Inputs

Inputs may be entered using different units. Changing the units in which inputs are entered using the **Input Tools** floating palette is described in *Getting Started*. This section will describe the various unit settings in detail
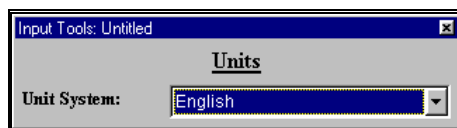
The Input Tools Floating Palette

Unit System

The **Unit System** option determines the unit system in which input values are entered. The choices are **English** and **Metric**. The default setting is **English**.

Units Results

Results may be displayed in different units. Changing the units in which results are displayed using the **Result Tools** floating palette is described in *Getting Started*. This section will describe the various unit settings in detail.
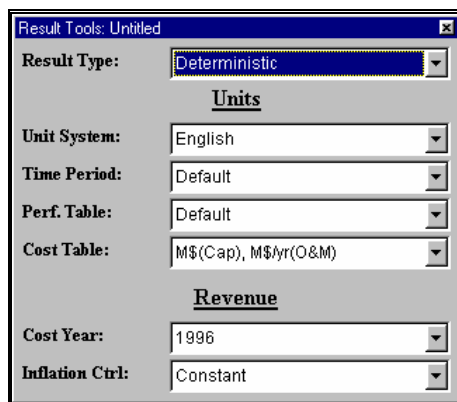
The Result Tools floating palette

Result Type

The **Result Type** option determines the type of values displayed in the result tables. The choices available are **Deterministic**, **Mean**, **Median (50th percentile)**, **2.5 percentile**, **97.5 percentile**, and **Standard Deviation**. The default setting is **Deterministic**.

Unit System

The **Unit System** option determines the unit system in which result values are displayed. The choices available are **English** and **Metric**. The default setting is **English**.

Time Period

The **Time Period** option determines the time period for which result values are displayed. The choices available are **Default**, **Max Hourly** and **Annual Avg.** The default setting is **Default**.

Performance Table

The **Perf. Table** option determines the units in which values are displayed on performance result screens**.** The choices available are **Default**, **% Total**, **mass/kWh**, and **mass/Btu in.** The default setting is **Default**.

NOTE: The **% Total** unit change can be used to determine the volume percent and weight percent of the components of the flue gas. This is possible when viewing the "Gas Summary" result table for any control technology.

Cost Table

The **Cost Table** option determines the units in which values are displayed on cost result screens**.** The choices available are **M\$(Cap), M\$/yr(O&M)** and **\$/kW(Cap), mills/kWh(O&M).** The default setting is **M\$(Cap), M\$/yr(O&M)**.

Cost Year

The **Cost Year** option determines the year for which values are displayed on cost result screens**.** You may choose any year between 1977 and 1998**.** The default setting is **1996**.

Inflation Control

The **Inflation Ctrl** option determines the method by which inflation is calculated for cost result screens**.** The choices available are **Constant** and **Current.** The default setting is **Constant**.

Working with Graphs

Graphs and Values

The table and diagram results are all deterministic values; that is, uncertainties are not taken into consideration. Graphs are probabilistic. This is different from previous versions of the IECM that used Analytica as a calculation engine. Analytica uses the expected value in table and diagram results, which takes into consideration the uncertainties defined.

The new IECM plots **all** samples on the CDF graph. The Analytica results in the Macintosh IECM version only displayed every fourth value (a value that could be adjusted within the model). By eliminating all but every fourth value, the Mac version of the IECM "smoothed" the graph.

Copying Graphs

If a graph window is active, you may use the Windows copy function to copy the graph to the clipboard. Do any one of the following:

- Pull down the **Edit** menu and select **Copy**.

- Click the **Copy** button on the toolbar on the left side of the IECM window.

- Press **Ctrl-C**.

NOTE: When pasting the graph into other applications, it is not certain in which format Windows will paste the graph. Windows may paste a Bitmap image, a Windows Metafile, or a list of values taken from the graph. To be sure how the graph will be reproduced, use the **Save As** function to save the graph, then import it into the application.

Saving Graphs

To save a graph:

1. Make sure that the graph window is the active window.

2. 2. Pull down the **File** menu and select **Save As**. The Save As dialog box will display
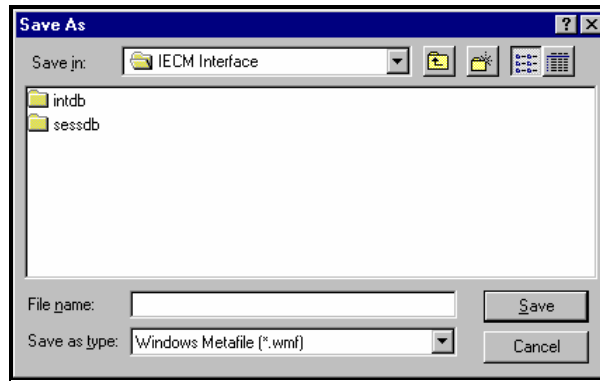
The Save As dialog box

3. Choose the folder to which you want to save from the pull-down **Save in:** box.

4. Type the filename in the **File name:** box.

5. Choose the file format you would like to use from the pull-down **Save as type:** box. Current options are:

   • Windows Metafile (a drawing with separate objects)

   • Windows Bitmap

   • Text (the x and y coordinates)

6. Click the **Save** button.

Running a Probabilistic Analysis

Uncertainty Analysis

As noted in the introduction, a unique feature of the IECM is its ability to analyze uncertainties probabilistically. You may assign probability distributions to any input parameter, including calculated parameters. The combined effect of all uncertain parameters is then calculated. This chapter describes again how to specify input probability distributions, and how to set several additional parameters needed to conduct a probabilistic analysis.

Even after probabilistic values have been set you do *not* have to use them. Probabilistic analysis can be turned on or off individually for technologies or input types or all at once. Turning the probabilistic calculations on and off for particular portions of the plant allows you to evaluate the major sources of uncertainty.

Uncertainty Distributions

The entry of uncertainty distributions is covered briefly in *Getting Started* This section gives a more detailed description of the process.

Uncertainty Parameters

Each uncertainty distribution requires one or more parameters. The table below lists the parameters and numerical value limits required for each distribution type.

Function	Operator	min or mean	mode	max or sdev
Normal, Half-normal(s)	*	x >= 0	N/A	x > 0
	+	x	N/A	x > 0
LogNormal	*	x > 0	N/A	x >= 1
	+	x > 0	N/A	x >= 1
Uniform	*	x >= 0	N/A	x >= 0
	+	x	N/A	x
Triangular	*	x >= 0	x >= 0	x >= 0
	+	x	x	x
Fractiles	*	x >= 0	N/A	N/A

	+	N/A	N/A	N/A
Wedge	*	x >= 0	N/A	x >= 0
	+	x	N/A	x

Distribution Types

Several types of probability distributions are provided with the IECM. Brief descriptions of each uncertainty distribution are included in the model when the uncertainty editor is selected; the information required, and additional notes, appear below. Distributions that are easiest to use are designated with a dagger (†). Consult a standard statistics reference for additional information.

None

None represents no uncertainty.

Normal Distributions

†**Normal** (**mean, stddev**) returns a continuous, normal Gaussian probability distribution with the specified **mean** and the standard deviation, **stddev**.

†**Neghalf_Normal** (**mean, stddev**) returns the lower half of a normal Gaussian probability distribution with the specified **mean** and the standard deviation, **stddev**.

†**Half_Normal** (**mean, stddev**) returns the upper half of a normal Gaussian probability distribution with the specified **mean** and the standard deviation, **stddev**.

This bell-shaped distribution is often assumed in statistical analysis as the basis for unbiased measurement errors. The normal distribution has infinite tails; however, over 99 percent of all values of the normal distribution lie within plus or minus three standard deviations of the mean. Thus, when used to represent uncertainty in physical quantities which much be greater than zero, the standard deviation should not be more than about 20 or 30 percent of the mean.

Lognormal Distribution

Lognormal (**median, gsdev**) returns a continuous lognormal probability distribution with the specified **median** and the geometric standard deviation, **gsdev**. The geometric standard deviation must be 1 or greater.

This distribution is usually used to represent uncertainty in physical quantities which must be positive values that are positively skewed, such as the ambient concentration of a pollutant. This distribution may be appropriate when uncertainties are expressed on a multiplicative order-of-magnitude basis (e.g., factor of 2) or when there is a probability of obtaining extreme large values.

Uniform Distribution

†**Uniform** (**min, max**) returns a continuous probability distribution in which every value between **min** and **max** has an equal chance of occurring.

Use this when you are able to specify a finite range of possible values, but are unable to decide which values in the range are more likely to occur than others. The use of the uniform distribution is also a signal that the details about uncertainty in the variable are not known. It is useful for screening studies.

Triangular Distribution

†**Triangular** (**min, mode, max**) returns a continuous, triangular probability distribution bounded by **min** and **max** and with the specified **mode**.

Use this when you are able to specify both a finite range of possible values and a "most likely" (mode) value. The triangle distribution may be symmetric or skewed. Like the uniform distribution, this distribution indicates that additional details about uncertainty are not yet known. The triangle distribution is excellent for screening studies.

Fractiles

Fractiles. If n is the number of elements in the list L, **Fractiles** (**L**) returns a continuous probability distribution where the first element is the 0% fractile, the second is the 1/(n-1) fractile, the third is the 2/(n-1) fractile, and so on. (The values must be enclosed in square-brackets to register as a "list.")

This distribution looks like a histogram for large sample sizes and can be used to represent any arbitrary data or judgment about uncertainties in a parameter, when the parameter is continuous. It explicitly shows detail of the uncertainties. It is used in the IECM Model to represent all trace species data in the default databases. The finite range of possible values is divided into subintervals. Within each subinterval, the values are sampled uniformly according to a specified frequency for each subinterval.

Wedge Distribution

†**Wedge** (**min, max**) returns a continuous wedge-shaped probability distribution increasing linearly from **min** to **max**.

Use this when you are able to specify a finite range of possible values. The wedge distribution increases linearly from zero probability at the minimum value to the maximum probability at the maximum value. Like the uniform distribution, this distribution indicates that additional details about uncertainty are not yet known. This is a special case of the triangular distribution described below.

Configuring Uncertainty in Results

Some uncertainty parameters may be changed while results are displayed. These are modified using the Uncertainty Tools Floating Palette
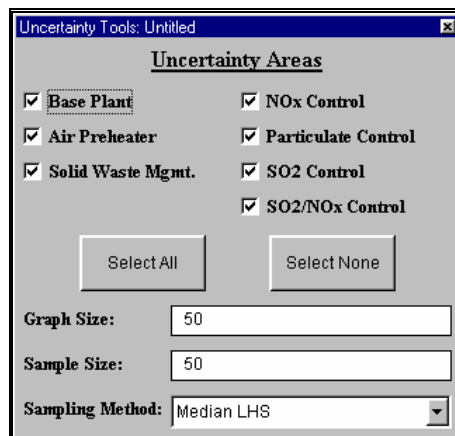
The Uncertainty Tools floating palette

Uncertainty Areas

You may choose technology or technologies for which you would like results with uncertain values by clicking the box to the left of each technology. You may select all or none by clicking the buttons at the bottom of the palette.

Graph Size

The sample size determines the number of possible data points used to draw a graph. This parameter determines how many of the total samples to use for the graph. This value cannot exceed the sample size.

Sample Size

You can also specify the number of samples used with the sampling method. This is the number of iterations performed in a probabilistic analysis. The appropriate sample size depends on the number and types of uncertainty distributions that are specified, and on the accuracy with which the distribution is to be estimated (especially the tails of the distribution). A sample size of 100 is the default. The maximum is 200. The calculation time and memory requirements are proportional to this value.

Sampling Methods

Input and output variables are related to each other by model definitions defined for each variable. These relationships are generally referred to as the "decision tree." The model uses this decision tree to determine which input variables must be calculated to specify the output variable. Only those input variables necessary to specify the output variable value are calculated.

Since each input variable can be expressed as a non-singular distribution, a method of sampling the inputs must be determined. Several methods are available in the model, ranging from a deterministic or single "best guess" value to a completely random sampling of each input distribution. The sampling methods all produce sets of values for the inputs. These sets together form the "sampling space."

Deterministic Evaluation

Output values can be determined by using the most probable value for each input. This method is frequently referred to as the "best guess."

Input variables can be treated deterministically either by specifying only a single value, or by selecting the "Off" option for the "Uncertainty Distribution" pane. This option forces all uncertain parameters to be evaluated deterministically. Selecting the "Off" option forces each uncertainty function used in the decision tree to be evaluated using its expected value. This option overrides any particular uncertainty distribution types.

Monte Carlo

Monte Carlo is the simplest and best-known sampling method. It draws values at random from the uncertainty distribution of each input variable in the decision tree. For a particular sampling run, each input variable is randomly sampled once. The random samples from each input result in one final output value. This process is repeated m times and results in a final solution set. This set can then be evaluated with standard statistical techniques to determine the mean, precision, and confidence.

This method has the advantage of providing an easy method of determining the precision for a specific number of samples using standard statistical techniques. However, it suffers from requiring a large number of samples for a given precision. It also has the drawback of substantial noise in the resulting distribution. For these reasons, Latin Hypercube sampling is preferred as the model default.

Latin Hypercube

Latin Hypercube is a stratified sampling method that divides the sampling space into equally probable intervals, or strata. For each input variable, the method samples each interval in a random order. When the samples from each input variable are combined, one resultant output is determined. This process is repeated m times, forming a final result of m output values. These m output values contain the uncertainty of the output variable, based on all the uncertainties of the entire set of input variables. The value m is referred to as the sample size.

The model contains two variations of Latin Hypercube sampling: Random and Median. **Random Latin Hypercube** (RLH) samples each strata randomly, while the **Median Latin Hypercube** (MLH) samples each strata by its median value. (See: Diwekar, U.M. and J.R. Kalagnanam, (1997) "Efficient Sampling Technique for Optimization under Uncertainty," *AIChE Journal*, Vol. 43, No. 2, pp. 440-7.) Median Latin Hypercube is the default sampling method.

Both forms of Latin Hypercube have the advantage of sampling more uniformly over the input distributions relative to Monte Carlo sampling, resulting in less noise in the final distribution. Another advantage is the reduced number of samples that must be taken to satisfy a given precision. Latin Hypercube has the drawback that the precision is more difficult to calculate using statistical methods. Finally, the output is random but not independent.

Hammersley

A new sampling technique has been added to the IECM which is more efficient than either the Monte Carlo or Latin-Hypercube sampling techniques. It is called the Hammersley sequence sampling technique. (See: Diwekar, U.M. and J.R. Kalagnanam, (1997) "Efficient Sampling Technique for Optimization under Uncertainty," *AIChE Journal*, Vol. 43, No. 2, pp. 440-7.) The sampling method is loosely based on the Monte Carlo method. However, instead of using a random number generator, it uses a quasi-random number generator based on Hammersley points to uniformly sample a unit hypercube. These points are an optimal design for placing n points on a k-dimensional hypercube. The sample points are then inverted over a cumulative probability distribution to define the sample set for any uncertainty variable.

Hammersley has the advantage of high precision and consistent behavior in addition to better computational efficiency. The method reduces the number of samples required relative to the other sampling methods for calculating uncertainty by a factor of 2 to 100. The actual sample reduction varies with the uncertainty function being sampled.

Appendix A - Introduction to Uncertainty Analysis

Uncertainty Analysis

The following section is provided as a means of introducing uncertainty analysis as a tool for model design and operation. However, you should consult standard statistical and other texts (e.g., Morgan and Henrion, Uncertainty, Cambridge Press, 1990) to develop a more complete understanding of the subject.

Introduction

Nearly all analyses of energy and environmental control technologies involve uncertainties. The most common approach to handling uncertainties is either to ignore them or to use simple sensitivity analysis. In sensitivity analysis, the value of one or a few model input parameters are varied, usually from low to high values, and the effect on a model output parameter is observed. Meanwhile, all other model parameters are held at their nominal values. In practical problems with many input variables which may be uncertain, the combinatorial explosion of possible sensitivity scenarios (e.g., one variable "high," another "low," and so on) becomes unmanageable. Furthermore, sensitivity analysis provides no insight into the *likelihood* of obtaining any particular result.

A more robust approach is incorporated in the IECM to represent uncertainties in model parameters using probability distributions. Using probabilistic simulation techniques, uncertainties in any number of model input parameters can be propagated through the model simultaneously to determine their combined effect on model outputs. The result of a probabilistic simulation includes both the possible range of values for model output parameters and information about the likelihood of obtaining various results. You may have seen probabilistic analysis referred to elsewhere as "range estimating" or "risk assessment."

The development of ranges and probability distributions for model input parameters can be based either on statistical data analysis and/or engineering judgments. The approaches to developing probability distributions for model parameters are similar in may ways to the approach you might take to pick a single "best guess" number for deterministic (point-estimate) analysis, or to select a range of values to use in sensitivity analysis.

Philosophy of Uncertainty Analysis

The classical approach to probability theory requires that estimates for probability distributions be based on empirical data. However, in many practical cases, the available data may not be available or relevant to the problem at hand. Thus, statistical manipulation of data may be an insufficient basis for estimating uncertainty. Engineering analysis or judgments about the data may be required.

An alternative approach is the "Bayesian" view. It differs in how probability distributions are interpreted. The probability of an outcome is your "degree of belief" that the outcome will occur, based on all of the relevant information you currently have about the system. Thus, the probability distribution may be based on empirical data and/or other considerations, such as your own technically-informed judgments. The assessment of uncertainties requires thought about all possible outcomes and their likelihood, not just the "most likely" outcome. The advantage to thinking systematically and critically about uncertainties is the likelihood of anticipating otherwise overlooked problems, or identifying potential payoffs that might otherwise be overlooked.

Types of Uncertain Quantities

There are a number of types of uncertainty to consider when developing a probability distribution for a variable. Some of these are summarized briefly here.

Statistical error is associated with imperfections in measurement techniques. Statistical analysis of test data is thus one method for developing a representation of uncertainty in a variable.

Empirical measurements also involve *systematic error*. The mean value of a quantity may not converge to the "true" mean value because of biases in measurement and procedures. Such biases may arise from imprecise calibration, faulty reading of meters, and inaccuracies in the assumptions used to infer the actual quantity of interest from the observed readings of other quantities. Estimating the possible magnitude of systematic error may involve an element of engineering judgment.

Variability can be represented as a probability distribution. Some quantities are variable over time. For example, the composition of a coal (or perhaps a sorbent) may vary over time.

Uncertainty may also arise due to lack of actual experience with a process. This type of uncertainty often cannot be treated statistically, because it requires predictions about something that has yet to be built or tested. This type of uncertainty can be represented using technical estimates about the range and likelihood of possible outcomes. These judgments may be based on a theoretical foundation or experience with analogous systems.

Encoding Uncertainties as Probability Distributions

As indicated in the previous sections, there are two fundamental approaches for encoding uncertainty in terms of probability distributions. These include statistical estimation techniques and engineering judgments. A combination of both methods may be appropriate in many practical situations. For example, a statistical analysis of measured test data for a new emission control technology may be a starting point for thinking about uncertainties in a hypothetical commercial scale system. You must then consider the effect that systematic errors, variability, or uncertainties about

scaling-up the process might have on interpreting test results for commercial-scale design applications.

Statistical Techniques

Statistical estimation techniques involve estimating probability distributions from available data. The fit of data to a particular probability distribution function can be evaluated using various statistical tests. For example, the cumulative probability distribution of a set of data may be plotted on "probability" paper. If the data plot as a straight line, then the distribution is normal. Procedures for fitting probability distribution functions are discussed in many standard texts on probability and are not reviewed here.

Such procedures can be utilized to obtain distribution functions for many of the power plant parameters in the IECM when data are available for operating plants. In other cases, especially where data are limited, expert technical judgments may be necessary to develop appropriate distribution functions for model parameters. The emphasis of the discussion below is on the situations where statistical analysis alone may be insufficient.

Judgments about Uncertainties

In making judgments about a probability distribution for a quantity, there are a number of approaches (heuristics) that people use which psychologists have observed. Some of these can lead to biases in the probability estimate. Three of the most common are briefly summarized.

1. *Availability.* The probability experts assign to a particular possible outcome may be linked to the ease (availability) with which they can recall past instances of the outcome. For example, if tests have yielded high sorbent utilization, it may be easier to imagine obtaining a high sorbent utilization in the future than obtaining lower utilization. Thus, one tends to expect experts to be biased toward outcomes they have recently observed or can easily imagine, as opposed to other possible outcomes that have not been observed in tests.

2. *Representativeness* has also been termed the "law of small numbers." People may tend to assume that the behavior they observe in a small set of data must be representative of the behavior of the system, which may not be completely characterized until substantially more data are collected. Thus, one should be cautious in inferring patterns from data with a small number of samples.

3. *Anchoring and adjustment* involves using a natural starting point as the basis for making adjustments. For example, an expert might choose to start with a "best guess" value, which represents perhaps an average or most likely (modal) value, and then make adjustments to the best guess to achieve "worst" and "best" outcomes as bounds. The "worst" and "best" outcomes may be intended to represent a 90 percent probability range for the variable. However, the adjustment from the central "best guess" value to the extreme values is often insufficient, with the result that the probability distribution is too tight and biased toward the central value. This phenomenon is *overconfidence*, because the expert's judgment reflects less uncertainty in the variable than it should. The "anchor" can be any value, not just a central value. For example, if an expert begins with a "worst" case value, the entire distribution may be biased toward that value.

Judgments also may be biased for other reasons. One common concern is *motivational bias*. This bias may occur for reasons such as:

a. a person may want to influence a decision to go a certain way;

b. the person may perceive that they will be evaluated based on the outcome and might tend to be conservative in their estimates;

c. the person may want to suppress uncertainty that they actually believe is present in order to appear knowledgeable or authoritative; and

d. the expert has taken a strong stand in the past and does not want to appear to contradict himself by producing a distribution that lends credence to alternative views.

Designing an Elicitation Protocol

Studies of uncertainty judgment show that the most frequent problem encountered is overconfidence. Knowledge of how people make judgments about probability distributions can be used to design a procedure for eliciting these judgments. The appropriate procedure depends on the background of the expert and the quantity for which the judgment is being elicited. For example, if you have some prior knowledge about the shape of the distribution for the quantity, then it may be appropriate to ask you to think about extreme values of the distribution and then to draw the distribution yourself. On the other hand, if you have little statistical background, it may be more appropriate to ask you a series of questions. For example, you might be asked the probability of obtaining a value less than or equal to some value x, and then the question is repeated for a few other values of x. Your judgment can then be graphed by an elicitor, who would review the results of the elicitation with you to see if you are comfortable with your answers.

To overcome the typical problem of overconfidence, consider extreme high or low values before asking about central values of the distribution. In general, experts' judgments about uncertainties tend to improve when:

1. the expert is forced to consider how things could turn out differently than expected (e.g., high and low extremes); and

2. the expert is asked to list reasons for obtaining various outcomes.

While the development of expert judgments may be flawed in some respects, it does permit a more robust analysis of uncertainties in a process when limited data are available. Furthermore, in many ways, the assessment of probability distributions is qualitatively no different than selecting single "best guess" values for use in a deterministic estimate. For example, a "best guess" value often represents a judgment about the single most likely value that one expects to obtain. The "best guess" value may be selected after considering several possible values. The types of heuristics and biases discussed above may play a similar role in selecting the value. Thus, even when only a single "best guess" number is used in an analysis, a seasoned engineer usually has at least a "sense" for "how good that number really is." This may be why engineers are usually able to make judgments about uncertainties, because they implicitly make these types of judgments routinely.

A Non-technical Example

To illustrate the process of defining a subjective probability distribution, let's turn to a simple example of eating lunch in a cafeteria. How long does it take from the time

you enter the cafeteria to the time you pay the cashier? Assume that you enter at 12:05 p.m. on a weekday and that you purchase your entire meal at the cafeteria. The answer you give may depend on your recent experiences in the cafeteria. Think about the shortest possible time that it could take (suppose nobody else is getting lunch) or the longest possible time (everyone shows up at the same time). What is the probability that it will take 2 minutes or less? 45 minutes or less? Is the probability that it takes 10 minutes or less greater than 50 percent? etc. After asking yourself a number of questions such as these, it should be possible to draw a distribution for your judgment regarding the time require to obtain and purchase lunch at the cafeteria. Such a distribution might take the form of a fractile distribution giving the probabilities of different waiting times to purchase lunch. For example, your evaluation may conclude that there is only a 1 percent (1 in 100) chance it will take one minute or less, a 60 percent chance of 1 to 10 minutes, a 25 percent likelihood of 10 to 15 minutes, and a 14 percent chance of up to 25 minutes. These probability intervals can be drawn as a histogram and translated into a fractile distribution for a probabilistic analysis.

A Technical Example

A second example focuses on a performance parameter for an advanced pollution control system. This parameter has an important effect on system performance and cost.

The example focuses on an assessment of uncertainty in the performance of an innovative emission control system for coal-fired power plants. In this system, a chemical sorbent circulates between a fluidized bed reactor, where SO_2 in the flue gas is removed by chemical reaction with the sorbent, and a regenerator, in which SO_2 is evolved in a reaction of the sulfated sorbent with methane. There is no commercial experience with this system; the largest test unit has been sized to handle 100 scfm of flue gas. Furthermore, the test units have used batch, rather than continuous, regeneration.

One of the key parameters affecting the performance and cost of this system is the regeneration efficiency, which is defined as the fraction of the spent sorbent which is converted for reuse. In small-scale tests in which the regeneration efficiency has been estimated, the efficiency was found to be roughly 30 to 50 percent. In a more recent test, the regeneration efficiency was not measured due to instrumentation difficulties; however, it may have been lower than the previously obtained values. Regeneration residence times were typically greater than 30 minutes.

A detailed modeling study of the regenerator estimated that a properly sized and designed unit, coupled with heating of the sorbent to a sufficiently high reaction temperature, would result in a regeneration efficiency of just over 99 percent at a 30 minute residence time.

A potential problem that may be occurring in the test units is that regenerated sorbent in the regenerator may be reabsorbing some of the evolved SO_2. However, this was not considered in the modeling study of the regenerator.

Based on this information, it appears that it may be possible to achieve the design target of over 99 percent regeneration efficiency. Clearly, however, it is possible that the actual efficiency may be substantially less than this target value. As a worst case, we might consider the known test results as a lower bound. Thus, there is a small chance the regeneration efficiency may be less than 50 percent. We expect the regeneration efficiency to tend toward the target value of 99.2 percent. Thus, to represent the expectation that the efficiency will be near the target value, but may be substantially less, we can use a negatively skewed distribution. In this case, we

assume a triangle with a range from, say, 50 to 99.2 percent with a mode also at 99.2 percent. The triangle in this case gives us a distribution with a mean of about 83 percent and a median of about 85 percent. This type of triangular distribution, in which a minimum, maximum, and modal value are specified, is often a convenient way of expressing uncertainty distributions when a little information is available.

Appendix B - Technical Support

Reaching Technical Support

Questions, issues or concers regarding the Integrated Environmental Control Model should be directed to:

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