# Air Pollution Control Equipment New Technology Acceptance Process

**Jean Bustard and Michael Durham**
ADA-ES, Inc., 8100 SouthPark Way, Unit B, Littleton, CO 80120
(303) 734-1727; (303) 734-0330 (fax)

**Presented at:**
**AWMA 97th Annual Conference & Exhibition**

Indianapolis, IN

June 22 – 25, 2004

# ABSTRACT

New air pollution control technologies proceed down two separate but dependent paths as they are developed and accepted for use in the coal-fired power generation industry. On the first path, the product or technology is developed, tested at several different levels, and commercialized. On the second, the buyer is educated about the technology and presented with sufficient information to believe that the technology is proven and dependable. These two paths, or processes, overlap during all phases, from identifying the need, to proof-of-concept testing, to demonstrations and commercialization.

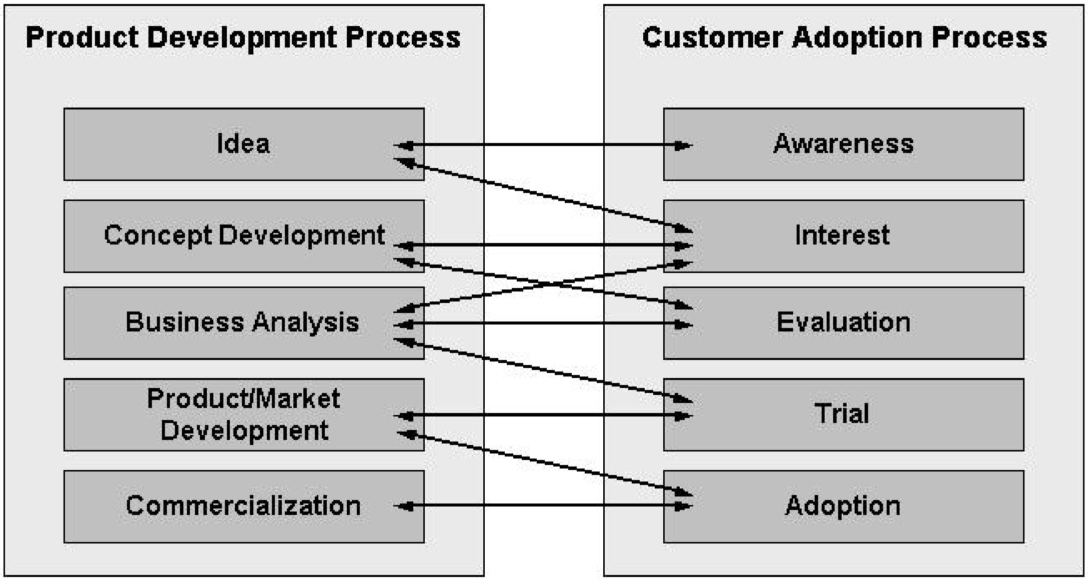
Because of the size of coal-fired power plants and the reliability required of them, this product development process can take five to ten years and cost millions of dollars. It is important that smaller, verifiable pilot- and bench-scale tests are performed to guide the development process and attract interest from users and investors for the scale-up. This paper presents examples of air pollution control equipment development, commercialization, and acceptance histories and timelines.

ADA-ES Publication No. 04002

# INTRODUCTION

The process of developing new technologies and products has many phases, each with a particular set of criteria that must be met for the process to continue. Early in the development process, the inventor must talk with potential customers to begin to introduce the technology and the customer adoption process. Typical phases of these two processes (Kotler[1]), and the interaction between the two, can be seen in Figure 1.

**Figure 1. Interdependence of Product Development and Customer Adoption Processes**



Parallel, dependent development and adoption processes exist in every industry; however, each industry has its own set of standards for performance and acceptance. This paper will discuss the development and adoption processes for new air pollution control technologies in the coal-fired utility market.

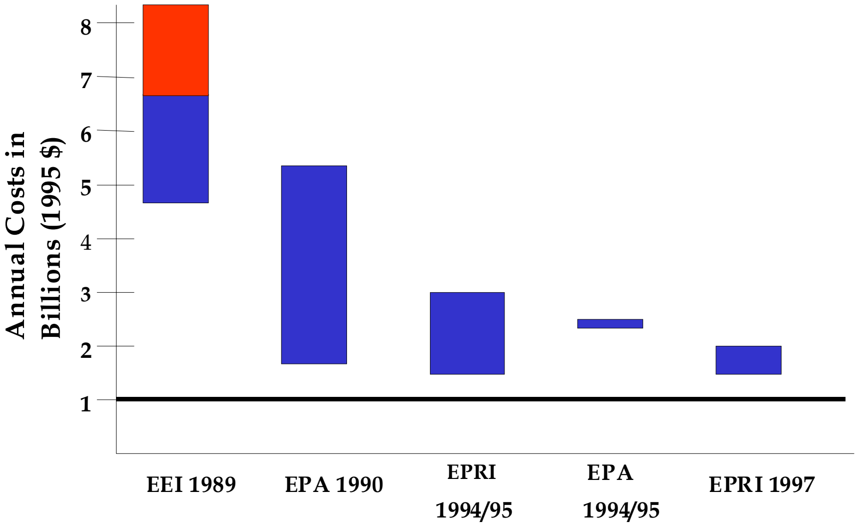
# BACKGROUND

**What is a new technology?** It is really anything that the customer perceives as new. It can be an improvement or a different use of an existing technology (incremental development), or it can be something not in use in any form (discontinuous or breakthrough technology). Examples of incremental technologies in the utility industry are 1) COHPAC®, the use of a fabric filter downstream of the existing electrostatic precipitator (ESP), and 2) hot-side ESPs, moving the ESP from downstream of the air preheater to upstream of the air preheater. There are very few cases of breakthrough technologies being introduced into coal-fired power plants in the past thirty years, but the best example might be selective catalytic reduction (SCR) for $NO_X$ control.

**What are the primary barriers that prevent new technologies from being accepted in the utility industry?** The primary barriers fall into two categories: size and reliability. Air pollution control equipment is typically installed to treat flue gas before it enters the stack. A small plant may have flue gas volumes of about 500,000 acfm. The volume of flue gas treated on a large plant can easily be greater than 2,000,000 acfm. Because of these volumes, the equipment is very large and expensive. Installed costs for a fabric filter are estimated at $50/kW, or more than $12,500,000 for a 250-MW plant. This magnitude of capital costs complicates the decision of the utility to purchase the equipment and limits the ability of companies with new technologies to carry the cost until the equipment is installed, operational, and accepted.

Also, because of the size of equipment and quantity of consumables purchased, the utility industry has a very strong position in influencing prices. Many of the products sold to the utility industry are priced very competitively (commodity pricing) because of the attractiveness of volumes to be purchased. This relates to economies of scale and is in the best interest of consumers. Unfortunately, unless a technology has a proprietary position (patent or trade secret), it is difficult for developers to price their products with enough profit margin to recover their investment costs. Figure 2 presents the projected costs over time for $SO_2$ control under the Federal Acid Rain program. This shows how costs decrease significantly as the technology is implemented.

**Figure 2. History of Cost Projections for the Federal Acid Rain Program (Phase II) (Afonso[2])**



The second barrier is reliability. Utilities and power generators have a very low tolerance for risk. New technologies pose a risk for operational problems that might impact power generation. This risk is extraordinarily high for everyone involved, not the least of whom is the end user. Different and new is not good in this industry–dependable and predictable is. This barrier is equally or even more difficult to overcome than cost associated with size. A new environmental regulation is one driver that can help balance the risks inherent with new technologies.

**What are the drivers for new air pollution control technology development in the utility industry?** In general, there are three drivers:

1. Lower operating costs;
2. Improved performance; and
3. New regulations.

Incremental improvements to existing equipment that increase control efficiency or reduce operating costs provide a differentiator for companies to develop and sell new products, and a reason for customers to switch suppliers. These types of new developments are much easier to introduce into the market; however, the benefit of the new technology still has to overcome the "If it ain't broke, don't fix it" syndrome and the risk of impacting reliability.

A recent study concluded, "There is a strong link between technological innovation and the existence, timing, and stringency of regulatory drivers. Where strong regulatory drivers exist, substantial technological improvements and steady reductions in control costs almost always follow" (Afonso[3]). The key to this link lies in the Business Analysis stage of the development process (see Figure 1). This is where a company evaluates the investment needed to develop and demonstrate the technology, the sales price and market share expected, and whether the required return on investment can be achieved within a reasonable time frame. Without the strong driver of a pending regulation, utilities will not commit to new equipment or new technologies. In the development process, the Business Analysis stage is where most development efforts fall apart.

**What is the best process for new technology implementation?** Even with significant barriers to entry, researchers and equipment suppliers continue to work with utilities to introduce new technologies into the market. The best process is one that progresses in a timely, logical, stepwise fashion. When technology is forced onto the industry too rapidly it is possible to jeopardize the reliability of generation. When technology is implemented on only a few early adopters, the problems are discovered and resolved with limited impact on the industry and consumer. History has shown that there is an effective process for technology development and implementation. The stages of the process are:

1. Laboratory testing: provides a cost-effective means to determine general feasibility and test a variety of parameters.
2. Pilot-scale testing: tests under actual flue gas conditions but at a reduced scale.
3. Full-scale field tests: scale up the size of the equipment and perform tests under optimum operational conditions to define capabilities and limits of the technology.
4. Full-scale field tests at multiple sites: each new site represents new operating conditions and new challenges. Often a technology will work at one site and not at another. For example, test results from the 1999 ICR program for mercury showed

that wet scrubbers could remove 98% of the mercury from one coal and only 5% of the mercury from another coal.

5. Long-term demonstration at several sites: some problems do not show up until the first year or so of operation. An example presented below shows that the initial performance with hot-side ESPs met, and in some cases exceeded, expectations. Warranties were signed off, only to find that six months later the plant could not maintain full load.
6. Widespread implementation: problems will still be found at new sites, but most of the fatal flaws will have already been discovered and resolved.

**Sources of R&D funding?** The U.S. Department of Energy (DOE) provides R&D funding for technology developments that are strategic to maintaining reliable, secure energy sources. In FY 2004, the R&D funding for all fossil energy projects was $722M. The portion set aside for projects specific to coal-fired generation was $179M. This budget was targeted at projects that would result in cleaner, more efficient coal generation.

## FROM CONCEPT TO COMMERCIALIZATION – CASE STUDIES

Since the first Clean Air Act of 1970, the power industry has gone through several rounds of implementing air pollution control technology for particulates, sulfur dioxide, and nitrogen dioxide. In each case, there were very similar experiences as the new technology was applied to this difficult industry:

- Unexpected reaction between chemical reagents added to control the pollutants and flue gas constituents.
- Changes in coal characteristics and plant operating conditions caused wide variation in performance.
- Significant O&M problems that did not show up until after long-term operation.
- Secondary effects on the other components of the power plants were discovered. Examples included higher carbon in the ash from low-$NO_X$ burners, ammonia in the ash from SNCR and SCR, and changes in concrete characteristics when new chemicals were added to the fly ash.

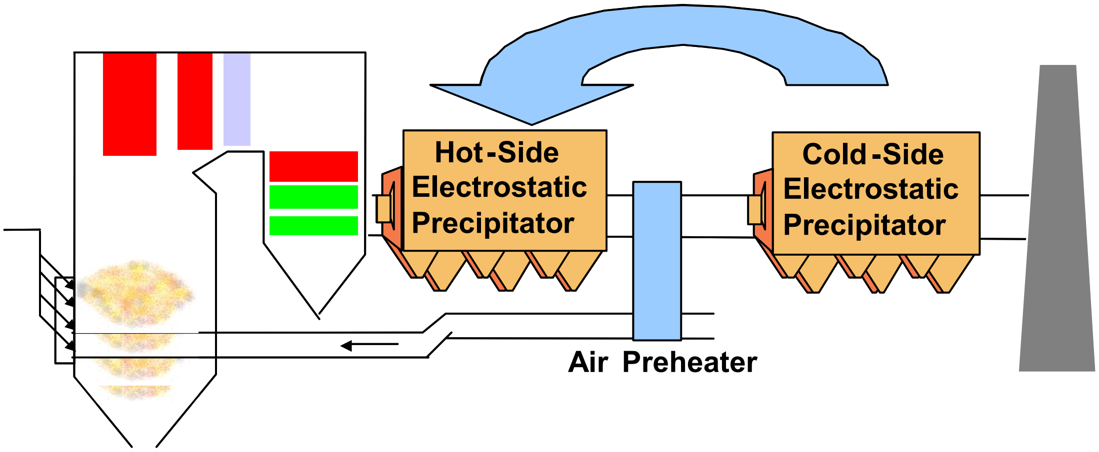
In these cases, the problems that resulted from the new technology had a significant impact on the reliability of power generation. The plants were forced to operate at reduced loads and suffered many unplanned shutdowns for maintenance and repair. Over time, solutions to these operating problems were developed and the technologies now operate more reliably and successfully. The severity of the impact of the initial problems, both in cost to the power consumer and in the reduction of available capacity, depended upon how widespread the technology was applied early in the Adoption phase. For example, the case history of hot-side ESPs, which is presented below, has cost the industry over a billion dollars because after early success, the technology was quickly applied to 150 power plants before a fatal flaw was discovered. Case studies where fatal flaws were discovered before widespread implementation are also presented.

### Case History: Hot-Side ESPs

The 1970 Clean Air Act required reduction in emissions of sulfur dioxide, $SO_2$, from coal-fired power plants. Many utilities opted to reduce $SO_2$ by burning coal with a low sulfur content. These fuels were available in large supplies located in the western states. However, the lower sulfur in the coal resulted in problems with the ESPs due to high-resistivity fly ash.

An attempt was made to avoid resistivity problems by installing the ESP on the "hot-side" (upstream side) of the air preheater rather than on the "cold-side" (downstream side) of the air preheater, which was the conventional design. This would increase the temperature of the flue gas from approximately 300ºF to 800ºF. The increase in operating temperature would result in a significant decrease in resistivity. Figure 3 shows the change in actual location of a cold-side versus a hot-side ESP at a power plant.

**Figure 3. Cold-Side ESPs are Installed Downstream of the Air Preheater**
**Hot-Side ESPs are Installed Upstream of the Air Preheater**



Following early short-term success, hot-side ESPs were rapidly accepted by the industry and were installed on about 150 boiler units to meet legislated emission standards. In 1975, hot-side ESPs represented 70% of utility ESP sales. However, as these new ESPs came online and began operating for an extended period of time, many of them began experiencing time-dependent deterioration of electrical operating conditions that resulted in poorer collection efficiency and increased emissions and opacity problems. After several years and many millions of dollars spent on R&D, the problem was diagnosed as sodium depletion for which there was no cure.

Utilities with hot-side ESPs have been struggling with problems with these systems for over thirty years. Hot-side ESPs have cost the industry well over a billion dollars. Power plants were forced to either derate the unit or shut down to clean the ESP by washing or sand-blasting the plates. However, the ESPs begin to deteriorate after a month or so of operation and the cleaning cycle must be continuously repeated. On the average, these ESPs had to be cleaned every four months and the cleanings required the plant to be offline for as much as a week at a time.

Other more costly remedies included conversion to a cold-side ESP or a fabric filter. Converting a hot-side ESP to a cold-side unit involves extensive modification to the existing ductwork and moving the air preheater. Costs to accomplish these conversions have ranged from $20 to $50 million for each unit.

## Case History: COHPAC®

To meet more stringent emission regulations at Big Brown Station, TXU chose COHPAC® (Compact Hybrid Particulate Collector) as a particulate control technology for both 575-MW units. COHPAC®, a technology patented by EPRI, is a pulsejet baghouse installed downstream of an existing ESP.

After some initial laboratory testing, ADA-ES was hired by EPRI to operate a pilot-scale program beginning in the spring of 1990 to further refine the technology. The pilot-scale tests identified a design flaw in the flow distribution that was resolved and tested further. Using data obtained from several years of successful operation of the pilot plant, a 150-MW unit was designed and installed. The 150-MW unit operated successfully for about a year, so the utility decided to implement the technology on two 600-MW plants. Unit 2 COHPAC® began operation in November 1995 and Unit 1 COHPAC® began operation in April 1996.

Based on results from a 150-MW demonstration baghouse in 1993–1994, achieving a two-year bag life was believed to be possible. A two-year bag life guarantee was also provided by the vendor. However, long-term operation of COHPAC® revealed that bag life was less than the anticipated two-year minimum. It was found that bag fabric strength deteriorated rapidly and the bags developed holes and tears. Bags were failed after less than twelve months of operation.

In addition to bag breakage, another problem presented itself during initial operation. Pressure drop (or drag) across the filter fabrics had become unacceptably high, requiring partial bypass of flue gas to keep baghouse pressure drop within the limits established by the vendor. This inability of COHPAC® to filter full flue gas flow increased opacity and, under some conditions, forced operators to reduce the output of the generators to maintain opacity below the 20% limit. It was apparent that even if bag breakage could be avoided for two years, it was quite likely that the bags would be unusable due to high pressure drop.

TXU and EPRI teamed on a program to identify the cause of the early bag failures and high pressure drop, and to find solutions to these problems. No additional derating of generation occurred after the first year of operation because of non-standard changes to the operating logic. After seven years of operation, bag life is still less than two years on many of the bags. This program is still active today in an effort to develop novel fabric and bags that may provide pressure drop relief (Bustard et al.[4]).

Fortunately for Alabama Power, the limitations of the COHPAC® design were identified before the final design of the COHPAC® baghouses for Plant Gaston. These limitations were incorporated and the Gaston COHPAC® unit operated successfully for four years on the same set of bags.

## Case History: SCR Commercialization in the U.S.

Selective catalytic reduction (SCR) technology was developed and pilot-tested in the United States in the 1970s. It was never used commercially due to high costs and availability of low-$NO_x$ combustion alternatives. First commercial retrofit installations on coal occurred in Europe and Japan starting in 1986. By 1995, there were more than 200 installations. About 120 of these were in Germany, and the majority of these were applied to low-sulfur high-ash brown coals (lignite). The European experience revealed problems with catalyst poisoning on some coals, but these were addressed with design improvements in the decade that the units were installed. However, differences in coal composition, boiler design, balance-of-plant equipment design, and operating and maintenance practices made it difficult to apply the European experience to U.S. boilers.

In the U.S., DOE and EPRI funded several long-term pilot tests to address the differences between European and U.S. coals. DOE ran a two-year Clean Coal project at Southern Company, Plant Crist. They operated nine SCR slipstream reactors in parallel (six 0.2-MW reactors and three 2.5-MW reactors), each with a different catalyst. Operating time varied from about 2,000 to 6,000 hours. EPRI built and operated several 1-MW reactors at several plants. Results were encouraging enough that a few power companies placed contracts for SCR reactors in the 1990s.

Six coal-fired SCR installations were up and running in the U.S. by 1996. Out of these, five were built on new boilers and one was retrofitted to an existing boiler. The target $NO_x$ reductions ranged from 50–70%, though it was found that higher $NO_x$ reductions could be sustained. More SCR operating problems were encountered on these six installations. $SO_3$ formation increased and caused sulfate plume problems, in spite of catalyst formulation changes designed to minimize $SO_2$ conversion to $SO_3$. Ammonia slip and resulting air preheater pluggage occurred on each installation. Fluctuations in reactor inlet temperature and inlet $NO_x$ concentrations were responsible for many of these ammonia slip problems. Adding more catalyst was another (costly) way to avoid ammonia slip.

Currently, more than 50 retrofit SCR reactors are installed or are being constructed to meet Title I SIP-call requirements. These new units all incorporate design modifications developed from lessons learned from several years' operation at the first six sites. The new SCR designs have included air preheater rebuilds to reduce the impact of ammonium sulfate pluggage. The industry has moved from ammonia injection grids to static mixers upstream of the SCR reactor in order to improve $NH_3/NO_x$ ratio going into the reactor so that higher $NO_x$ reductions can be maintained without ammonia slip. Reactors are also equipped with better temperature control to minimize $SO_3$ formation.

The U.S. Power Generation Industry has benefited from careful, step-wise introduction of SCR technology for $NO_x$ control. Designs have been conservative, and reactor problems (though costly) have not adversely impacted boiler capacity or availability. Therefore, the industry has accepted SCR technology, and electricity prices remain competitive so that investments in emission controls may eventually be recovered by investors.

## Case History: TOXECON™ for Mercury Control

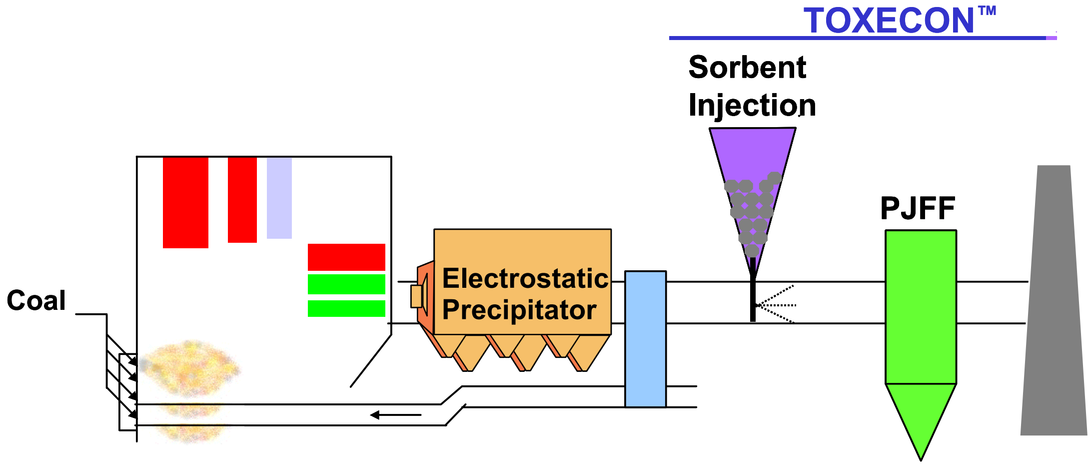
TOXECON™ is another EPRI-patented technology. TOXECON™ is similar to COHPAC® in that it is a pulsejet fabric filter installed downstream of the existing ESP. The primary difference is that TOXECON™ is designed to handle sorbent injection for the control of air toxics. TOXECON™ is currently the most mature retrofit technology for mercury control. Referring to the six-step technology development process, TOXECON™ is currently making progress in steps 4–6.

**Step 1 – Laboratory testing:** These test were funded by EPRI and conducted in the early 1990s.

**Step 2 – Pilot-scale testing:** The first pilot-scale test was conducted in 1991 at Public Service of Colorado's Comanche station (Chang, Bustard[5]). Tests at this scale are continuing today to evaluate TOXECON™ performance on different coals and new sorbents. Between 1991 and today, the measurement technique for mercury also had to be developed. Recent tests have been much more valuable because real-time data have helped decipher puzzling results from earlier tests.

**Step 3 – Full-scale field tests:** The first short-term, full-scale tests were conducted on a COHPAC® baghouse at Alabama Power's Gaston Station in Spring 2002 (Bustard et al.[6]). The configuration is shown in Figure 4. The results from this two-week test showed that activated carbon could achieve 90% mercury control. However, the cleaning frequency of the baghouse increased to an unacceptable level.

**Figure 4. Configuration for Evaluating TOXECON™ at Gaston**



**Step 4 – Full-scale field tests at multiple sites:** Since no TOXECON™ unit actually exists, the only way to test at different sites is to do so at the pilot-scale. This was discussed in Step 2.

**Step 5 – Long-term demonstration at several sites:** Based on the promising results at Plant Gaston, a second test program was funded by DOE and EPRI. The objective of this program was to conduct a yearlong test of carbon injection for mercury control in the TOXECON™ configuration to determine the viability of this technology and the impact on fabric filter performance. This test is to be completed in June 2004.

With regulations looming, a proposal was submitted under the DOE's Clean Coal program to install the first TOXECON™ unit at We Energies' Presque Isle Power Plant in Marquette, Michigan. This program was selected for award and it is anticipated that TOXECON™ will be operational in late 2005. Unlike Gaston, which burns a low-sulfur bituminous coal, Presque Isle burns a Powder River Basin coal.

**Step 6 – Widespread implementation:** TOXECON™ is being considered by many utilities for mercury control. It is hoped that results from the Clean Coal program will be available in time to help define any design issues.

## CONCLUSIONS

All developing air pollution control technologies need to go through a phased approach as the technology matures to become accepted as commercially viable. This approach to implementation of new technology has evolved from thirty years of lessons learned by the power industry from applying new technology. If an attempt is made to accelerate technology development by skipping these steps, there is an increased risk that operating problems could arise that could lead to untimely shutdowns of the plant using the technology.

# REFERENCES

1. Kotler, Philip. *Marketing Management*. New Jersey: Prentice Hall, 2002.
2. Afonso, Rui. (2003). "Utility PM and Precursor Emissions and Multi Pollutant Control Options: Regulatory Landscape, Technologies, and Costs," presented at the NYSERDA Conference: Linking Science and Policy; Albany, NY, October 7–8.
3. Ibid.
4. Bustard C.J., T. Grubb, R. Merritt, S. Sjostrom, R. Chang, A. Casey, K. Turchi, and R. Jeanes (2001). "TXU Big Brown COHPAC Performance Improvement with High Permeability Fabric," presented at the US EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium: The Mega Symposium, Chicago, IL, August 20–23.
5. Chang R. and C.J. Bustard. "Sorbent Injection for Flue Gas Mercury Control," presented at the 87th Annual Meeting and Exposition of the Air & Waste Management Association, Cincinnati (June 1994).
6. Bustard C.J., M.D. Durham, C. Lindsey, T. Starns, K. Baldrey, C. Martin, S. Sjostrom, R. Slye, S. Renninger, and L. Monroe (2001). "Full-Scale Evaluation of Mercury Control with Sorbent Injection and COHPAC® at Alabama Power E. C. Gaston," presented at the A&WMA Specialty Conference on Mercury Emissions: Fate, Effects, and Control, Chicago, IL, August 20–23.