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Project Summary

Verification of Simplified Procedures for Site-Specific SO_2 and NO_x Control Cost Estimates

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Detailed retrofit studies were conducted for 12 coal-fired plants in Ohio, Kentucky, and the Tennessee Valley Authority system. Because detailed studies are expensive and time-consuming, the results from the 12-plant study were used to develop simplified procedures for estimating sulfur dioxide (SO_2) and nitrogen oxides (NO_X) retrofit control costs and performance for 200 SO_2-emitting coal-fired power plants in the 31-state eastern region. The simplified procedures require less time, data and preparation effort. This report documents the results of an evaluation to verify the accuracy of the simplified procedures. The evaluation compared the costs for a number of plants estimated using the simplified procedures to costs estimated using detailed procedures, actual retrofit costs, and more detailed cost estimates provided by utility companies. Based on the evaluation, recommendations for changes to the simplified procedures were developed. Control technologies addressed in this report are conventional lime/limestone flue gas desulfurization, lime spray drying, furnace sorbent injection, duct spray drying, coal switching, physical coal cleaning, and selective catalytic reduction. In general, it was found that the simplified procedures can be used to generate improved cost performance estimates based on generally available information: U. S. Geological Survey photographs and Energy Information Agency Form 767 data.

This Project Summary was developed by EPA's Air and Energy Engineering Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

The objective of the National Acid Precipitation Assessment Program (NAPAP) retrofit cost project is to develop improved (site-specific) cost estimates for retrofitting sulfur dioxide (SO_2) and nitrogen oxide (NO_X) controls on 200 of the largest emitting coal-fired utility power plants. This project was conducted in the four phases depicted in Figure 1. In Phase I, procedures were developed based on plant-specific information obtained from site visits (detailed procedures). Twelve plants in Kentucky, Ohio, and the Tennessee Valley Authority (TVA) system were evaluated under this program phase, and the procedures and results were reviewed by a Technical Advisory Committee and the participating utility companies.

Because detailed studies are expensive and time consuming, the results of the 12-plant study were used to develop simplified procedures for estimating SO_2/NO_X control technology retrofit cost/performance for 200 SO_2-emitting coal-fired power plants in the 31-state eastern region. In simplifying the detailed procedures, the major retrofit factor "drivers" were identified and only the retrofit difficulties associated with these drivers

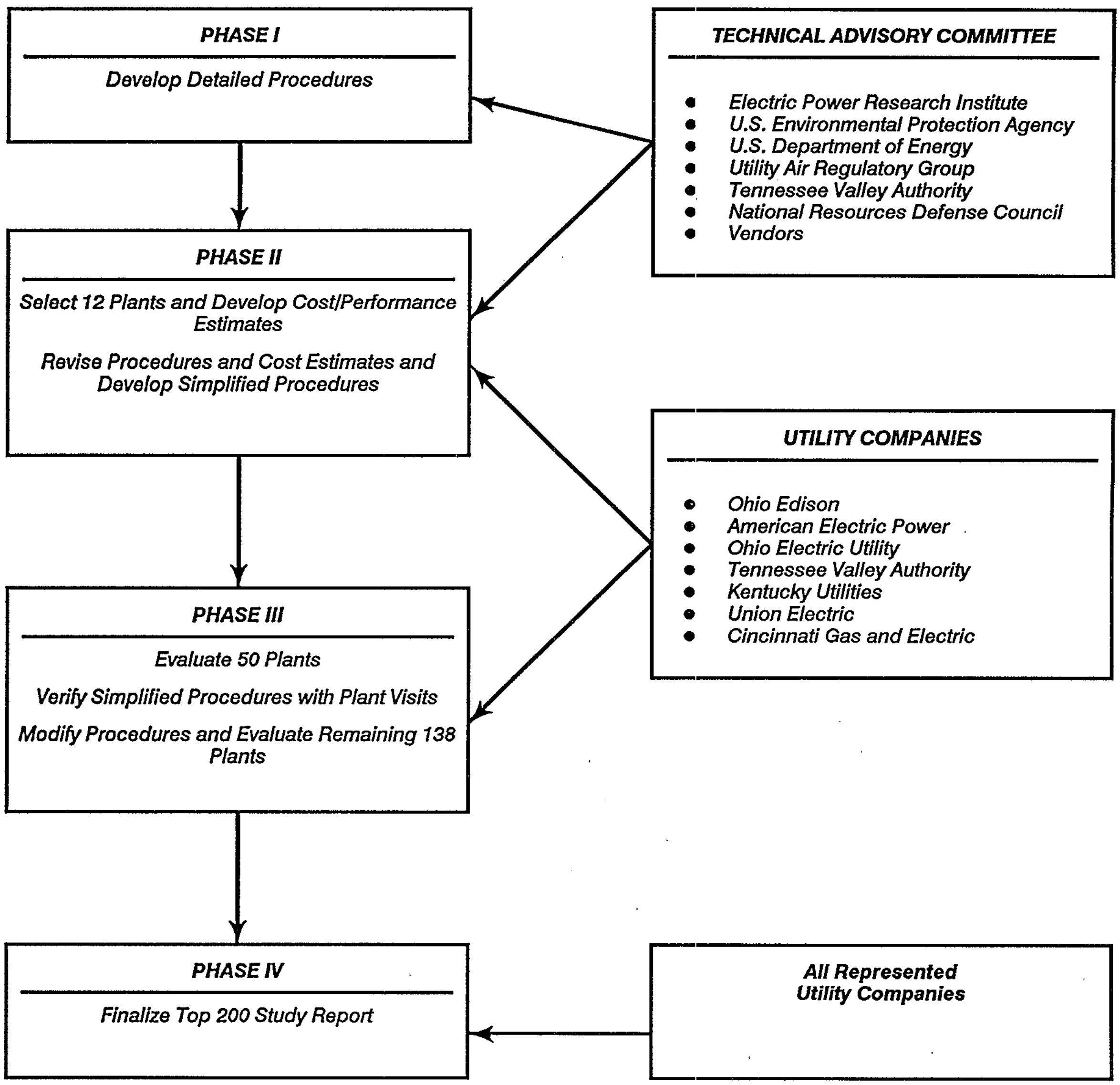

Figure 1. *Top 200 plant study technical approach.*

(e.g., site access and congestion) were estimated. To estimate retrofit factors using the simplified procedures, a plot plan and/or aerial photograph were used instead of information gathered during a site visit. However, assumptions were made to streamline these procedures. For example, average underground obstructions as well as some scope adjustments were always used (e.g., chimney liner, demolition and relocation, draft controls, and new rails) unless one or more of these items were unnecessary or incorrect. After developing cost/performance estimates for 50 plants using the simplified procedures, the procedures were evaluated to verify their accuracy. The results of the simplified procedures were compared to: results obtained by using the detailed procedures, actual retrofit cost, and more detailed estimates provided by participating utility companies.To accomplish this objective, 6 of the 50 plants were selected to evaluate the simplified procedures. Additionally, for 17 boilers, detailed cost estimates or reported actual costs for retrofit FGD systems were available to compare to the detailed and simplified procedure results generated under this program.

The following procedures were used to verify the simplified procedures for the six plants selected for site visits: conduct plant visits and collect site-specific data, develop boiler/control-specific retrofit difficulty factors, develop boiler/plant-specific cost and performance estimates for the SO_2 and NO_X controls selected using the detailed procedures, and compare these results with results developed using simplified procedures. Utility interest in participation in the study was a major consideration in plant selection. Table 1 presents the boiler characteristics for the six plants visited to verify and quantify the accuracy of the simplified procedures.

Simplified Procedures Verification Methodology

Table 2 presents the SO_2/NO_X control technologies that are being evaluated under the NAPAP retrofit control cost study. As this table shows, detailed and simplified procedures were developed for the lime/limestone (L/LS) and lime spray drying (LSD) flue gas desulfurization (FGD) technologies. However, for the other technologies only simplified procedures were developed. The focus of the simplified procedure verification

Table 1. *Boiler Characteristics of the Plants Evaluated*

Plant Name	Boiler Number	Gross Operating Capacity (MW)[a]	Installation Date	Capacity Factor (%)	Firing Type	Coal Sulfur (%)
Rush Island	1	621	1976	42	Tangential	1.1
	2	621	1977	58	Tangential	1.1
Sioux	1	550	1967	43	Cyclone	1.7
	2	550	1967	32	Cyclone	1.7
Meramec	1	137	1953	10	Tangential	1.1
	2	137	1954	12	Tangential	1.1
	3	289	1959	11	Wall	1.1
	4	359	1961	11	Wall	1.1
Labadie	1	620	1970	59	Tangential	2.6
	2	620	1970	52	Tangential	2.6
	3	620	1973	57	Tangential	2.6
	4	620	1973	58	Tangential	2.6
Beckjord	1	100	1952	6	Tangential	1.0
	2	100	1952	8	Tangential	1.0
	3	135	1954	10	Wall	1.0
	4	162	1958	22	Tangential	1.0
	5	255	1962	29	Tangential	2.5
	6	449	1969	57	Tangential	2.5
Miami Fort	5	85	1949	40	Wall	1.0
	6	175	1960	71	Tangential	1.0
	7	524	1975	67	Wall	3.0

[a] *Maximum unit design capability.*

Table 2. *Emission Control Technologies Evaluated*

	Species Controlled		Development Status			Type of Procedures	
	SO_2	NO_X	Commercial	Limited Commercial Experience	Near Commercial Demonstration	Detailed	Simplified
Lime/Limestone (L/LS) flue gas desulfurization (FGD)	X		X			X	X
Additive enhanced L/LS-FGD	X		X			X	X
Lime spray drying (LSD) FGD [a]	X		X		X	X	X
Physical coal cleaning (PCC)	X		X				X
Coal switching and blending (CS/B)	X		X				X
Low-NO_X combustion (LNC)		X		X			X
Furnace sorbent injection (FSI) with humidification	X				X		X
Duct spray drying (DSD)	X				X		X
Natural gas reburning (NGR) [b]	X	X			X		X
Selective catalytic reduction (SCR)		X		X			X

[a] *Commercial on low sulfur coals, demonstrated at pilot scale on high sulfur coals.*
[b] *For wet bottom boilers and other boilers where LNC is not applicable.*

evaluation was twofold. First, the accuracy of the publicly available data and the assumptions used to develop the inputs to the simplified procedures were reviewed. These inputs were then compared to the inputs developed using the more detailed data obtained from the site visits.

Second, for the FGD technologies, retrofit factors and indirect costs were developed using the detailed procedures. These retrofit factors and indirect costs were compared to the simplified procedure results developed before the site visits as well as the simplified procedure results developed with the site visit information. This was done so that differences in the detailed procedures and the simplified procedures could be classified as being due to errors in the quality of the publicly available information or due to the different level of detail between the two procedures.

Additionally, when actual cost data or more detailed cost estimates were available, these costs were compared to the costs estimated using the simplified and detailed procedures. Actual retrofit costs were obtained from the Energy Information Agency (EIA)-767 forms for seven units at six plants. Detailed engineering cost estimates were obtained for 10 units at 6 plants.

Cost estimates developed under this study were generated using the Integrated Air Pollution Control System (IAPCS) cost model. These cost estimates were made to reflect site-specific retrofit impacts by inputting capital cost multipliers, scope adder costs, and capital cost indirect factors that were developed using the simplified and detailed procedures.

Lime/Limestone FGD Procedures

Comparison of Simplified and Detailed Procedure Results

For L/LS and LSD-FGD, retrofit factors and cost estimates were developed using both the simplified and detailed procedures based on the detailed information collected during the site visits. The retrofit factors and cost estimates were then compared to those previously developed using the simplified procedures and based on EIA-767 data and plant plot plans or aerial photographs.

The percent differences between the simplified and detailed procedures based on the data obtained from the site visits are small. The difference for L/LS-FGD varied between -6 and +5% with an average of 2.7%. The difference for LSD-FGD varied between <1 and 5% with an average of 1.9%. These differences are due to simplifying assumptions made when developing the simplified procedures.

The differences between the detailed procedures based on site visit data and the simplified procedures based on publicly available data were also determined. The difference for L/LS-FGD varied from -9 to +16% with an average of 8.8%. The difference for LSD-FGD varied from -24 to +17% with an average of 9.8%.

The difference between the simplified and detailed procedure results is due to procedural differences and errors in assumptions due to having less detailed and incorrect data. The procedural differences result from simplifying the detailed procedures by using average factors for flue gas duct distance, underground obstruction difficulties, and scope adder costs. The incorrect data resulted in changing the need for wet to dry ash handling at the four Missouri plants. Additionally, the absorber locations for one of the Missouri plants, Meramec units 1-4, were changed. Duct work distance and absorber/flue gas handling area access/congestion changes were also made at Labadie and Rush Island when more detailed information was available. A comparison of the simplified procedure results, developed before and refined after the site visits for the two Ohio plants, revealed no significant differences.

Based on these results, it was concluded that the use of EIA-767 form data and U.S. Geological Survey (USGS) photographs can be used to accurately determine the retrofit difficulty for FGD. However, experience is needed to accurately evaluate these sources of information. Additionally, communications with the plant generally can be very helpful in confirming the best location of the FGD process areas and retrofit difficulty issues.

Comparison to Other Cost Estimates

Capital cost estimates using the simplified procedures were developed and compared to estimates developed by architectural and engineering (A&E) firms for six plants. These cost estimates were obtained through the data collection effort for the program. Table 3 summarizes the results of this comparison. As can be seen, the simplified procedure results compare well with the A&E estimates. The difference varied from -12 to +20%, well within the ±30% accuracy of the Electric Power Research Institute (EPRI) FGD cost estimating guidelines.

Table 3. *Comparison of Capital Cost Estimates* [a]

Plant and Unit	*A&E Estimate ($/kW)*	*Simplified Procedure Estimate ($/kW)*	*Absolute* [b] *Difference (%)*
Asbury 1	*274*	*264*	*4*
Sibley 3	*199*	*222*	*12*
Thomas Hill 1	*363*	*355*	*2*
Thomas Hill 2	*282*	*297*	*5*
New Madrid 1	*259*	*221*	*15*
New Madrid 2	*215*	*229*	*7*
Beckjord 5 + 6	*203*	*202*	*<1*
Miami Fort 6	*276*	*283*	*3*
Miami Fort 7	*210*	*169*	*20*

[a] *In 1987 dollars.*
[b] *(A&E estimate - simplified procedure estimate)/A&E estimate x 100.*

Comparison of IAPCS Cost Estimates to Actual Installed Costs

A review of the Flue Gas Desulfurization Information System identified 11 retrofit FGD systems that came on-line after 1980. For seven of these units, actual costs reported in EIA-767 forms and aerial photographs were available and were used to compare the simplified procedure cost estimates to actual reported costs. For these seven units, FGD system cost estimates have been developed using the IAPCS cost model with retrofit factors developed from the simplified or detailed procedures for the following units: Paradise 1 and 2, Widows Creek 7, Mill Creek 1 and 2, and Four Corners 4 and 5. Table 4 summarizes the results of this effort with the actual costs being escalated to the same year dollars as the cost estimates (January 1988).

The cost estimates developed for Four Corners, Paradise, and Mill Creek, unit 1, compare well with the reported actual costs. However, the cost estimates for the Mill Creek, unit 2 and Widows Creek, unit 7, differ significantly. At least two reasons are possible to account for the differences:

1. Mill Creek units 1 and 2 share a common feed and waste handling facility, as do Widows Creek units 7 and 8.
2. The Mill Creek and Widows Creek units were not current state-of-the-technology designs and have undergone significant design changes since start-up.

All of these factors would reduce the actual cost compared to the estimates developed based on current new source performance standard (NSPS) design. However, despite these differences, the reported costs for Mill Creek 2 and Widows Creek 7 appear to be very low. Note that the most recent FGD system actual costs compare favorably to the IAPCS estimates and that the cost of the more recent units ranges from \$180 to \$300/kW. Additional comparisons should be made for the other four units at the Cromby, Eddystone, and Mitchell plants if sufficient data are obtained to conduct the evaluation.

Lime Spray Drying (LSD) FGD With Reuse of Electrostatic Precipitators (ESPs)

As part of the simplified procedure methodology for LSD-FGD, it is assumed that the existing ESP will be used for particulate control if the specific collection area (SCA) is greater than 225 sq ft of plate area per 1000 acfm (28 actual m^3/min) of flue gas. This was the case for all of the Missouri plants and for several of the Ohio units. However, for many of these units, reusing the ESP would result in very difficult and lengthy flue gas duct runs from the outlet of the air heater to the spray dryer absorbers and back again to the ESP inlet. For units that have space immediately adjacent to the air heater and ESP, this option is more practical. Table 5 presents the ESP SCA and comments on applicability of this technology for the six plants visited.

Coal Switching (CS) and Physical Coal Cleaning (PCC)

To estimate the cost of CS, the simplified procedures used one of the two low sulfur base coals contained in the IAPCS cost model. One of the coals is a low sulfur West Virginia bituminous coal and the other is a Montana subbituminous coal. The currently used coal characteristics and cost are input to the model, and the model estimates the cost of CS based on the user specifying the fuel price differential between the current coal and the future price of one of the two low sulfur base coals. Future coal price differentials of \$5 and \$15/ton were input to the model to span the range of possible low sulfur coal prices over high sulfur coals.

IAPCS cost estimates also include the cost of ESP upgrades and changes in waste disposal costs due to differences in coal ash content. The model does not evaluate the impact of CS on the following boiler operating parameters: pulverizer capacity, slagging, fouling, erosion, and flue gas flow rates. Also, costs for additional coal receiving, storage, and handling facilities are not included. These factors are discussed qualitatively for each plant and boiler situation.

Under this effort, the primary objective was to obtain additional information from the six plants visited to better identify and quantify boiler and plant parameters that would be negatively impacted by CS. Table 6 summarizes the results of this effort. As can be seen, the only major issue identified was switching to a subbituminous coal at the Sioux plant. The low sulfur subbituminous IAPCS base coal option was chosen because the plant currently uses a low sulfur subbituminous coal. The procedure methodology assumes that the base coal should be similar to the low sulfur coals currently being used by the plant. However, completely switching a boiler designed to fire a bituminous coal to a subbituminous coal would result in a major unit derating.

Currently, the CS methodology does not quantitatively address capital costs associated with coal receiving, storage, and handling facilities that may be required to blend coals on-site or to bring coal in by a different transportation method. For the Labadie plant, the cost to upgrade its facilities to blend coals was on the order of \$22.5 million (1987 dollars). However, the cost of upgrading facilities would typically be much less than a \$5/ton impact on the coal fuel price differential.

Based on the six plant evaluation of the simplified procedures, a more careful approach should be made in evaluating CS to subbituminous coals on boilers designed for firing bituminous coals. In general,

Table 4. Comparison of Retrofit Factors and Estimated and Reported Costs

Plant and Unit	Retrofit Factor	IAPCS Estimated [b] Cost (\$/kW)	Reported Actual Cost (\$/kW)	Absolute [c] Difference (%)
Paradise 1 or 2	1.35	182	184	1
Four Corners 4 [a]	1.66	316	303	4
Four Corners 5 [a]	1.66	316	303	4
Mill Creek 1	1.26	180	173	4
Mill Creek 2	1.26	180	75	140
Widows Creek 7	1.24	170	140	21

[a] Cost of fabric filters are also included in the FGD cost.
[b] Includes allowance for funds during construction.
[c] (Actual cost - estimated cost)/actual cost x 100.

Table 5. *Summary of LSD-FGD ESP Reuse Applicability*

Plant Name	Unit	ESP SCA[a]	Comments	Applicability
Sioux	1 and 2	268	Marginal SCA; space available on one side; reasonable accessibility to existing flue gas ducting.	Marginal due to SCA
Labadie	1 and 4	319	Good ESP performance; space available on one side; access to existing flue gas ducting is difficult.	Moderate
Labadie	2 and 3	319	Good ESP performance; space not available at sides or behind chimney; access to existing flue gas ducting is very difficult.	Marginal due to SCA
Rush Island	1 and 2	279	Good ESP performance but marginal SCA; reasonable access to existing flue gas ducting; space available on one side and behind chimney.	Mariginal due to SCA
Meramec	1-3	492-522	Good ESP performance and SCA; long duct runs and difficult access to existing flue gas ducting because space is only available on far side of unit 4 for absorbers.	Marginal (good, if absorbers are located where original ESPs are)
Meramec	4	545	Good ESP performance and SCA; moderate duct runs and accessibility to existing flue gas ducting; space available for absorbers at one side of unit.	Good
Beckjord	1-4	205-244	Marginal ESPs; very poor access for ducting.	Poor
	5	247	Same as above.	Poor
	6	646	Good candidate; easy access.	Good
Miami Fort	5	354	Poor access for duct runs.	Marginal
	6	205	Very small ESP SCA.	Poor
	7	275	Marginal ESP SCA; space available on both sides.	Marginal due to SCA

[a] Electrostatic precipitator (ESP) specific collection area (SCA) in terms of square feet of area per 1000 acfm.

Table 6. *Summary Of Coal Switching Issues*

Plant Name	Units	Coal Switching and Blending Issues
Sioux	1-2	Minor boiler derate up to 40% SB[a], major derate >50% SB.
Labadie	1-4	Switch coal may reduce severe slagging problems at high load but will increase ash disposal costs. Switching could also <u>increase</u> slagging problems and cause unit derates.
Rush Island	1-2	Low SO_2 emission reduction potential. No on-site facilities for blending.
Meramec	1-4	Low SO_2 emission reduction potential. No on-site facilites for blending.
Beckjord	1-6	Low sulfur coal on units 1-4. No on-site blending facilities for units 5-6.
Miami Fort	5-7	Compliance coal on unit 8. No on-site blending facilities for units 5-7.

[a] SB = subbituminous.

boilers designed for bituminous coals should continue to burn the same percentage of bituminous coal as currently is being fired.

Due to the lack of coal washability data, it has not been possible to evaluate quantitatively the cost of deep PCC. As such, the costs generated under this study are very qualitative. However, no feedback has been given to date regarding the costs and percent removals projected with the current methodology.

Selective Catalytic Reduction (SCR)

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for SCR were reviewed for accuracy. The most important parameters that will impact the cost of retrofitting SCR are: reactor access and congestion, flue gas duct length to and from the reactor, and demolition costs of existing equipment and general facilities percentage.These parameters are impacted by the location chosen for the SCR reactor.

Table 7 summarizes the changes made to access/congestion difficulty, scope adder costs, and general facilities percentages due to the site visits for the four Missouri plants. The major problem with the simplified procedures identified by this analysis is selecting the correct location based on the information on hand. For the Meramec and Labadie plants, inaccuracies in the available plot plan or the poor resolution of the aerial photograph resulted in incorrectly locating the reactors. For the two Ohio plants, no changes to the reactor locations, duct run lengths, and access/congestion difficulty were needed for Miami Fort. However, for Beckjord units 1-4, the reactor location was changed, resulting in significant increases in duct length.

One option used in the study for several plants has been to call the plant and discuss potential equipment locations. This has been done several times when it was apparent that the quality of the aerial photograph or plot plan was poor. Generally, plant personnel have been cooperative. In the future, it may be desirable to contact every plant after reviewing the available data.

Sorbent Injection Technologies

Based on the information obtained during the plant visit, the assumptions used to develop the retrofit factors and scope adders for the sorbent injection technologies were reviewed for accuracy. The most important parameters that will impact the cost and performance of the sorbent injection technologies are:

- particulate control device size, performance, and difficulty of upgrade (access/congestion associated with adding plate area);
- the need to convert a wet ash handling system to a dry handling system; and
- sufficient flue gas residence time between the air heater and particulate control device to allow for duct spray drying (DSD), droplet drying (2 seconds of straight duct run), or humidification with furnace sorbent injection (FSI).

The impact of superheat and economizer gas lane pluggage for FSI was not evaluated under this program because of the limited commercial demonstration data and boiler information.

Table 8 summarizes the results of the changes made to the simplified procedure inputs after the site visits. In general, the overall qualitative determination of the applicability of the sorbent injection technologies was the same before and after the site visit, the major differences being Beckjord, units 1-5, and Miami Fort, unit 6. These units have small ESP SCAs, and the ducting configuration for units 1-5 was incorrectly interpreted. As a result, because these units have a very short flue gas residence time between the air heater and the ESP inlet and small ESPs, the applicability of any of the sorbent injection technologies is questionable.

With regard to factors that directly impact the cost estimates, the access/congestion difficulty factor changed for 7 of the 21 units and the wet to dry ash conversion assumption changed for 12 of the 21 units. As discussed previously, the error in the ash conversion assumption was due to a misunderstanding. The EIA-767 forms accurately indicate that the Missouri units currently use wet ash handling/disposal systems.

Based on these findings, it appears that the errors in the procedure methodology are related to incorrectly interpreting the data

Table 7. *Summary of Changes Made to SCR Retrofit*

Plant Name	*Units*	*Reason for Changes*
Sioux	*1-2*	*Scope adder cost changes due to longer duct run.*
Labadie	*1-4*	*Change in location of reactor resulted in changes to access/congestion, general facilities, and duct run lengths for all Labadie units.*
Rush Island	*1-2*	*No major changes were made to the SCR retrofit compared to the results obtained prior to the site visit.*
Meramec	*1-4*	*Changes in location of reactors resulted in significant changes in access/congestion and duct run lengths for all Meramec units.*

Table 8. *Summary of Changes or Sorbent Injection Technologies*

		Applicability Before Visit		*Applicability After Visit*	
Plant Name	*Unit*	*FSI* [a]	*DSD*	*FSI*	*DSD*
Sioux	*1-2*	*Good*	*Good*	*Good*	*Good*
Labadie	*1-4*	*Good*	*Good*	*Good*	*Poor to good* [b]
Rush Island	*1-2*	*Good*	*Good*	*Good*	*Moderate*
Meramec	*1-2*	*Good*	*Good*	*Good*	*Good*
	3-4	*Good*	*Good*	*Poor*	*Poor*
Beckjord	*1-5*	*Good*	*Poor*	*Poor*	*Poor*
	6	*Good*	*Good*	*Very good*	*Good*
Miami Fort	*5*	*Good*	*Good*	*Poor*	*Poor*
	6	*Good*	*Poor*	*Poor*	*Poor*
	7	*Good*	*Poor*	*Good*	*Poor*

[a] *Does not consider superheat/economizer gas line pluggage due to insufficient data.*
[b] *Part of flue gas bypassed old ESPs resulting in adequate residence time for 50% of gas flow.*

available. It appears that the publicly available data are sufficient to accurately evaluate the retrofit difficulty of the sorbent injection data for most plants. However, as mentioned earlier, contacting the plant to verify the accuracy of these data and to confirm the accuracy of basic assumptions should reduce the potential for incorrectly interpreting available data. This is particularly true for small, older units because of the resolution of the photograph and the likelihood that unusual ESP flue gas configurations exist due to the retrofit of additional ESP plate area. The Beckjord units 1-5 and Miami Fort unit 6 are good examples of the problem associated with unusual flue gas configurations due to the retrofit of additional ESP plate area. Additionally, a Department of Energy database containing duct and flue gas information upstream of the ESP has been made available to this study.

Economic and Financial Assumptions

At the outset of the NAPAP Task Group I effort, a decision was made to use economic and financial data consistent with accepted industry practices. The accepted standard for the electric utility industry is published in the EPRI's Technical Assessment Guidelines (TAG). The EPRI TAG provides the economic factors and financial data on which the cost estimating procedures used in the electric utility industry are based. Table 9 presents the 1986 TAG values. Retrofitting a plant with SO_2 and/or NO_X control technologies with possibly more stringent control limits could cause additional costs for compliance that are not reflected in this study.

Table 9. *1986 EPRI TAG Values - Capital and Financial Structure*

		Current Dollar[a]	
Type of Security	*Percent of total*	*Cost*	*Return*
Debt (Bonds)	50	11.0	5.5
Preferred	15	11.5	1.7
Common stock	35	15.3	5.3
Discount rate, $/yr			12.5
Inflation rate:		6.0%/yr	
Federal and state income tax rate:		38.0%	
Investment tax credit:		0.0%	
Property taxes and insurance:		2.0%/yr	
Book life		30 yr	

Item	*Unit Cost Data January 1985 value*	*Units*
Operating labor	19.70	*$/person hour*
Water (river)	0.60	*$/1,000 gal* [b]
Lime	65	*$/ton* [b]
Limestone	15	*$/ton*
Land 6,500 $/acre [b]		
Disposal Charges		
Sludge	9.25	*$/ton (dry basis)*
Dry, granular solids	8.0	*$/ton*
Gypsum disposal	4.75	*$/ton*
By-Product Credits		
Sulfuric acid	50	*$/ton*
Sulfur	75	*$/long ton* [b]
Ammonia (anhydrous)	150	*$/ton*
Special Items		
Electric power (in plant)	5.0	*¢/kWh*
Steam (in plant)		
0-70 psia [b]	2.85	*$/1000 lb* [b]
70-250 psia	3.50	*$/1000 lb*
250-2400 psia	5.30	*$/1000 lb*

	Levelization Factors	
O&M		1.75
Carrying charges, %		17.5

[a] *For constant dollars, inflation rate is set to zero.*
[b] *1 acre = 4047 m^2; 1 gal. = 3.79 L; 1 lb = 0.45 kg; 1 long ton = 1.02 metric tons; psia = psig + 14.7 (1 psi = 6.89 kPa; 1 atm = 101.3 kPa); 1 ton= 0.907 metric ton.*

The economic and financial assumptions of the EPRI TAG, as applied in this stage, are:

1. Cost-estimating premises adhere to the cost methodology described in the 1986 EPRI TAG.
2. The indirect capital cost factors were assigned to each technology in accordance with the EPRI TAG. These values were varied in accordance with site-specific conditions and are presented in Table 10.
3. Allowance for funds during construction (AFDC) is estimated by adjusting the total plant cost by an allowance factor (AF) that is a function of the idealized construction period and economic parameters.
4. For annual operating costs, the unit costs for consumables per the EPRI TAG are summarized in Table 9.
5. Total annual maintenance costs are estimated per the 1986 EPRI TAG as a percentage of installed capital cost depending on the nature of the processing conditions and the type of design. The factors assigned to the various technologies are summarized in Table 11.
6. Economic premises for existing electric power generating plants were updated by EPRI and released as a supplement issued May 1, 1983. Revised schedules were published for book life, tax life, and levelization factors. For power plants in operation before January 1, 1979, Internal Revenue Service (IRS) Code Section 169 allows 5-year tax depreciation of new identifiable pollution control facilities completed or acquired after December 31, 1982. This depreciation schedule is applied on a straight-line basis. Book life of retrofitted equipment is equal to the years of remaining life of the power plant rounded off to the nearest 5-year increment. All of these items are identical in the 1986 TAG.
7. The financial and economic premises significantly influence the levelization factors calculated for operating and maintenance (O&M) and carrying charges. Using the 1986 guidelines recommended by EPRI-a 12.5% discount rate (or weighted cost of capital), 6.0% inflation rate (long-term average), 30-year book life (existing facility), and 20-year tax life (straight-line depreciation)-the levelization factors computed for O&M and capital carrying charges are 1.75 and 0.175 for current dollars and 1.0 and 0.105 for constant dollars, respectively.
8. All costs are presented in current and constant dollars (in the current dollars, the effect of escalation due to inflation is accounted for) and reflect June 1988 dollars. Capital costs are escalated using Chemical Engineering indices. Current dollar costs account for inflation; constant dollar costs do not.

Table 10. *Nominal Indirect Cost Schedule*

Indirect Component [a]	PCC	LNC	FSI	NGR	SCR	LSD	DSD	ESP	FF [b]	FGD
General facilities, %	0	10	10	10	10	10	10	10	10	10
Engineering and home office fees, %	0	10	10	10	10	10	10	10	10	10
Project contingency, %	0	30	30	30	30	30	30	30	30	30
Process contingency, %	0	10	20	10	20	4.3	30	0	0	1.4
Sales tax, %	0	0	0	0	0	0	0	0	0	0
Royalty allowance, %	0	0	0	0	0.5	0	0	0	0	0
Preproduction cost [c]	c	c	c	c	c	c	c	c	c	c
Inventory capital [d]	d	d	d	d	d	d	d	d	d	d
Initial catalyst [e]	0	0	0	0	0	0	0	0	0	0
Idealized construction period, yr [f]	0	1	1	1	1	3	1	1	1	3

[a] *Applied to process capital except as noted.*
[b] *FF = fabric filter.*
[c] *1 month of fixed operating cost.*
1 month of variable operating cost.
2 percent of total plant investment.
[d] *60-day supply of consumables.*
[e] *SCR catalyst costs are estimated based on unit size and desired NO_x removal efficiency.*
[f] *Used for estimating allowance for funds during construction (AFDC).*

Table 11. *Maintenance Cost Factors*

	PCC	LNC	FSI	NGR	SCR	LSD	DSD	ESP	FF	FGD
EPRI schedule (percent of total process capital).	0	2	4	2	4	6	6	8	4	8

Conclusions

Based on the six-plant evaluation effort to verify the accuracy of the simplified procedures, the following changes to the procedures were made:

1. After receiving the publicly available information, identifying the equipment layouts, and selecting inputs to the simplified procedures to develop retrofit factors and scope adder costs, the plant was contacted to confirm the accuracy of the data and assumptions.
2. To continue to verify the accuracy of the procedures and cost estimates generated, the plant evaluation and cost estimates were made available to the plant for review and comments. Appropriate comments and comparative cost estimates were incorporated into the report. Additionally, where actual costs of retrofit are available, these costs were compared to estimates generated using the simplified procedures.
3. Evaluation of retrofitting LSD-FGD was eliminated for units that have marginally sized ESPs (SCA = 225-300 sq ft/1000 acfm) and do not have space for plate area addition.
4. Evaluation of PCC was eliminated except for mine mouth plants with moderate to high sulfur coal, because the emission reductions that are achievable are low, and insufficient data are available to accurately estimate deep coal cleaning costs.
5. Because the current CS methodology assumes total switching to a low sulfur coal, units designed to fire bituminous coals were not switched to a subbituminous coal unless the plant indicates that this is a reasonable option and the cost of unit derating is included in the cost of CS.
6. Hot side SCR was evaluated for units that have space near the boiler.
7. Evaluation of retrofitting FSI and DSD technologies were eliminated for units that have marginally sized ESPs (SCA = 225-300 sq ft/1000 acfm) and do not have space available for plate area addition and sufficient space between the air heater and particulate control device to allow for DSD droplet drying or humidification with FSI.

Making these changes to the simplified procedures improves the accuracy of the cost estimates, ensure continued feedback from industry regarding the accuracy of the procedures/estimates, and eliminates the evaluation of technologies that are not likely to be used, that have limited SO_2 reduction potential, or those for which insufficient data are available to accurately develop cost and performance estimates.

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The complete report, entitled "Verification of Simplified Procedures for Site-Specific SO_2 and NO_X Control Cost Estimates," (Order No. PB 90-187 261/AS; Cost: $23.00, subject to change) will be available only from:
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5285 Port Royal Road
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