COMPARISON OF EGU1 AND EGU2 TO CONSENT DECREES AND BACT LIMITS

Submitted On Behalf of
Midwest Ozone Group
and
Utility Air Regulatory Group

Submitted to
Midwest Regional Planning Organization

Prepared by
J. Edward Cichanowicz
Michael Hein
James Marchetti

August 1, 2005

COMPARISON OF EGU1 AND EGU2 TO CONSENT DECREES AND BACT LIMITS

SECTION 1

INTRODUCTION

This document provides comments on behalf of the Midwest Ozone Group (MOG) and the Utility Air Regulatory Group (UARG) regarding the proposal described in the Midwest Planning Organization's (RPO) Interim White Paper (January 14, 2005). Specifically, these comments address reduction levels for NOx and SO2 emissions presented in the Interim White Paper, that go beyond reductions presently contemplated in the proposed Clear Skies Act, and being imposed by the EPA through the Clean Air Interstate Rule (CAIR).

The Interim White Paper provides two scenarios for SO2 and NOx control levels. The first scenario, referred to as ID EGU 1, describes rate-based emission standards of 0.15 and 0.10 lbs/MBtu, respectively, for SO2 and NOx. The second scenario, referred to as ID EGU 2, describes rate-based emission standards of 0.10 and 0.07 lbs/MBtu, respectively, for SO2 and NOx. The Interim White Paper states the ID EGU 1 scenario was derived from the "new source review" consent decrees that have been agreed to with the Department of Justice, and the ID EGU 2 scenario was derived from recent permits proposed or awarded for new coal-fired generation.

This document shows that with regard to the EGU1 emission rates for NOx and SO2, the White Paper rates reflect only the strictest of the emission rates in the consent decrees. Specifically, the consent decrees require only a portion of the units addressed to retrofit SCR and conventional flue gas desulfurization (FGD), for control of both NOx and SO2. Many other units are allowed to use alternatives to SCR and FGD, not be controlled at all, or retire. The EGU 1 rates in the White Paper reflect only the outlet rates of SCR and FGD-equipped units, and not the broader category of controlled (and uncontrolled) units subject to the consent decrees.

With regard to the EGU2 rates for NOx and SO2, this document shows how new plant design conditions for NOx, and to an extent SO2, are not relevant to the design and retrofit of SCR and FGD to existing plants. With regard to NOx, new plant SCR capital cost can be a factor of 2-3 times lower than for retrofit to existing units, completely changing the cost evaluation. With regard to SO2, the relatively large fraction of new units planning to use PRB distorts SO2 outlet rates. The fuel use choices for these new units do not reflect the fuel options for plants in the Midwest RPO region. Specifically, the SO2 exit rate typical of new units will require FGD SO2 removal of 90% for PRB coal. This requirement exceeds the degree of control proposed for revised New Source Performance Standards.

For both EGU1 and EGU2 NOx rates, the Interim White Paper also needs to recognize that most SCR-equipped units have relatively new catalysts, and thus far have had a requirement to operate only during the ozone season. As the catalyst ages, less emission reductions can be expected. Moreover, emission rates achieved during ozone season-only operation may be lower than rates that can be achieved year-round, because of less time available for undertaking maintenance and for implementing performance-improving measures.

Finally, the Interim White Paper does not address whether the EGU1 or EGU2 levels could be achieved by the desired target compliance date of 2009. Prior work conducted to evaluate the proposed version of CAIR shows the target installation date of 2009 is not attainable for either EGU1 or EGU2 levels. Although an analysis of feasible SCR and FGD installation dates was not conducted for purposes of commenting on the Interim White Paper, the present document summarizes the results of the analogous study conducted in 2004 regarding CAIR. It should be noted the recently issued CAIR Phase I NOx compliance date of 2009 and the SO2 compliance date of 2010 do not support or corroborate the Midwest RPO position. First, the CAIR Phase I limits are not as stringent as those that would be required by either EGU1 or EGU2. Second, the final CAIR includes a 200,000 ton pool of supplemental NOx allowances that serve to provide a buffer or margin for units that will comply past the Phase I deadline. For these reasons, the deadlines for compliance with CAIR are not relevant to the deadlines that states in the Midwest RPO region might want to impose for compliance with potential, more stringent standards.

SECTION 2

SUPPORTING DATA AND EXPERIENCE FROM EXISTING PLANTS

Section 2 presents and analyzes data and experience cited in the Interim White Paper addressing NOx and SO2 limits from existing units attributable to consent decrees.

CONSENT DECREE STATUS

The EGU1 SO2 and NOx emission rates of 0.15 and 0.10 lbs/MBtu, respectively, are reportedly linked to rates contained in “new source review” consent decrees agreed to by utilities, as of early 2005. This section presents an analysis of the consent decrees as of April 1, 2005, affecting nine utilities and 125 individual operating units. Of the 125 units, 26 will either terminate operation early or be declared retired, at dates ranging from the present to 2012. An alternative for these units is to either fuel switch to natural gas, repower with natural gas combined cycle, or deploy FGD and/or SCR; however this alternative is viewed as an unlikely option due to the small size and low capacity factor of the units slated for retirement. A total of 73 units will deploy selective catalytic reduction (SCR) or alternative NOx control technology to meet strict NOx targets, or flue gas desulfurization (FGD) or an alternative to meet strict SO2 targets. Some units will deploy both control options. The remaining units will be operated under a system cap to meet future mandates, be they either CAIR or other local requirements.

The proposed NOx and SO2 emission rates are described subsequently.

Nitrogen Oxides (NOx)

Figure 2-1 depicts for 50 units the NOx emission rates agreed to by various utilities. Twelve units at Presque Isle, Valley, and Sammis (on the extreme right side of the chart) have limited NOx control options due to furnace design and plant layout. Accordingly, these units will utilize SNCR or other alternative NOx controls to meet NOx rates varying from 0.25 to 0.42 lbs/MBtu. A total of 38 units are scheduled to deploy SCR to meet NOx rates between 0.06 and 0.13 lbs/MBtu, with most of these targeting NOx outlet rates of 0.10 lbs/MBtu.

The average of all the 50 units with specific NOx emission target rates is 0.16 lbs/MBtu, as measured on a 30 day rolling average. Excluding the units employing SNCR and other alternative NOx controls (i.e., including only units that will retrofit SCR), the average consent decree-induced NOx rate is approximately 0.10 lbs/MBtu, consistent with the EGU 1 rate in the Interim White Paper. Most of these units fire low-to-medium sulfur content coals; the highest sulfur coal is employed at Mt. Storm (1.7%).

Sulfur Dioxide (SO2)

Figure 2-2 depicts the SO2 emission rate and /or the SO2 percent removal efficiency agreed to for units that will control SO2. The SO2 emission rate is depicted by the triangular data points, and is quantified by the scale on the right. The SO2 removal efficiency is quantified by the scale on the left axis. For many units, an operator can choose to meet either the specified SO2 removal by use of flue gas desulfurization (FGD), or a fixed SO2 emissions rate.

The units represented in Figure 2-2 can be considered in several categories.

<u>High Performance Flue Gas Desulfurization (FGD).</u> Consent agreements for 24 units (on the extreme left side of the figure) require the use of some form of FGD at relatively high SO2 removal. Of these 24 units, a total of 20 report the intent to provide 95% SO2 removal. However, 10 of these latter 20 units can choose an alternative, presumably low FGD removal efficiency, as long as a certain rate is met for that unit. This fixed rate ranges from 0.13 to 0.25 lbs/MBtu.

<u>Strict Fixed SO2 Emission Rate</u>. A total of fifteen units have consented to meet fixed strict SO2 emission rates from 0.13 to 0.18 lbs/MBtu, without committing to high SO2 removal percentages. These units will be required to adopt some type of FGD technology; but could employ low sulfur coal and lower SO2 removal efficiency, allowing dry FGD or dry sorbent injection, as an alternative to high performance wet FGD.

<u>Intermediate Fixed SO2 Emissions Rate</u>. A total of 17 units (depicted on the extreme right side of the figure) will meet SO2 emission rates that do not necessarily require the use of control technology. These rates, which range from 0.8 lbs/MBtu to 1.3 lbs/MBtu, can presumably be attained by blending PRB or other low sulfur coals with those coals more typical of use by utilities in the Midwest.

In total, 56 units that have consented to deploy some form of FGD or use coal blending will meet an average of 0.54 lbs/MBtu, for most as measured on a 30 day rolling average basis. Of the 24 units that have agreed exclusively to install FGD, the SO2 emissions average is limited by the option to deploy either 95% SO2 removal, or meet a fixed rate. It should be noted the requirement to meet 0.15 lbs/MBtu imposes an SO2 removal efficiency of 95% or less for units that fire coal with 1.6% sulfur content or less.

Observations

The EGU1 emission rates for NOx and SO2 are more stringent than the average control requirement imposed by recent consent decrees.

Regarding NOx, the average controlled NOx rate of the 50 units that have consented to apply either SCR or an alternative control option is 0.16 lbs/MBtu. Although the average for the SCR-equipped units is the same as the rate for EGU1 – 0.10 lbs/MBtu – the consent agreements do not mandate that all controlled units apply SCR. Rather, a number of alternatives such as SNCR and various forms of fuel reburn are utilized. Consequently, EGU1 for NOx reflects the performance rate of the most strictly controlled, not all controlled, generating units. This emission rate is not appropriate for system compliance.

Regarding SO2, the conclusions are similar. Specifically, the EGU1 rate of 0.15 lbs/MBtu does not reflect the consent agreements, but only the strictest levels associated with units that will retrofit FGD. The average SO2 rate for units anticipated to employ high performance FGD is 0.13 lbs/MBtu, which is less than the EGU1 rate; however at least half of these units are not required to operate FGD at greater than 95%, regardless of the outlet SO2 emission rate.

In this context, EGU 1 is more strict than the average consent decree-driven limits. EGU1 imposes greater than 95% SO2 removal for coals with greater than 1.6% sulfur content, and up to 97% SO2 removal will be required for the 2.5% sulfur coals that typify native Ohio, Illinois, and Indiana coals. Consequently, EGU1 for SO2 reflects the performance rate of the most strictly controlled, and not all of the controlled generating units. This emission rate is not appropriate for system compliance.

FIGURE 2-1. CONSENT DECREE NOx EMISSION RATE REQUIREMENT FOR EXISTING UNITS

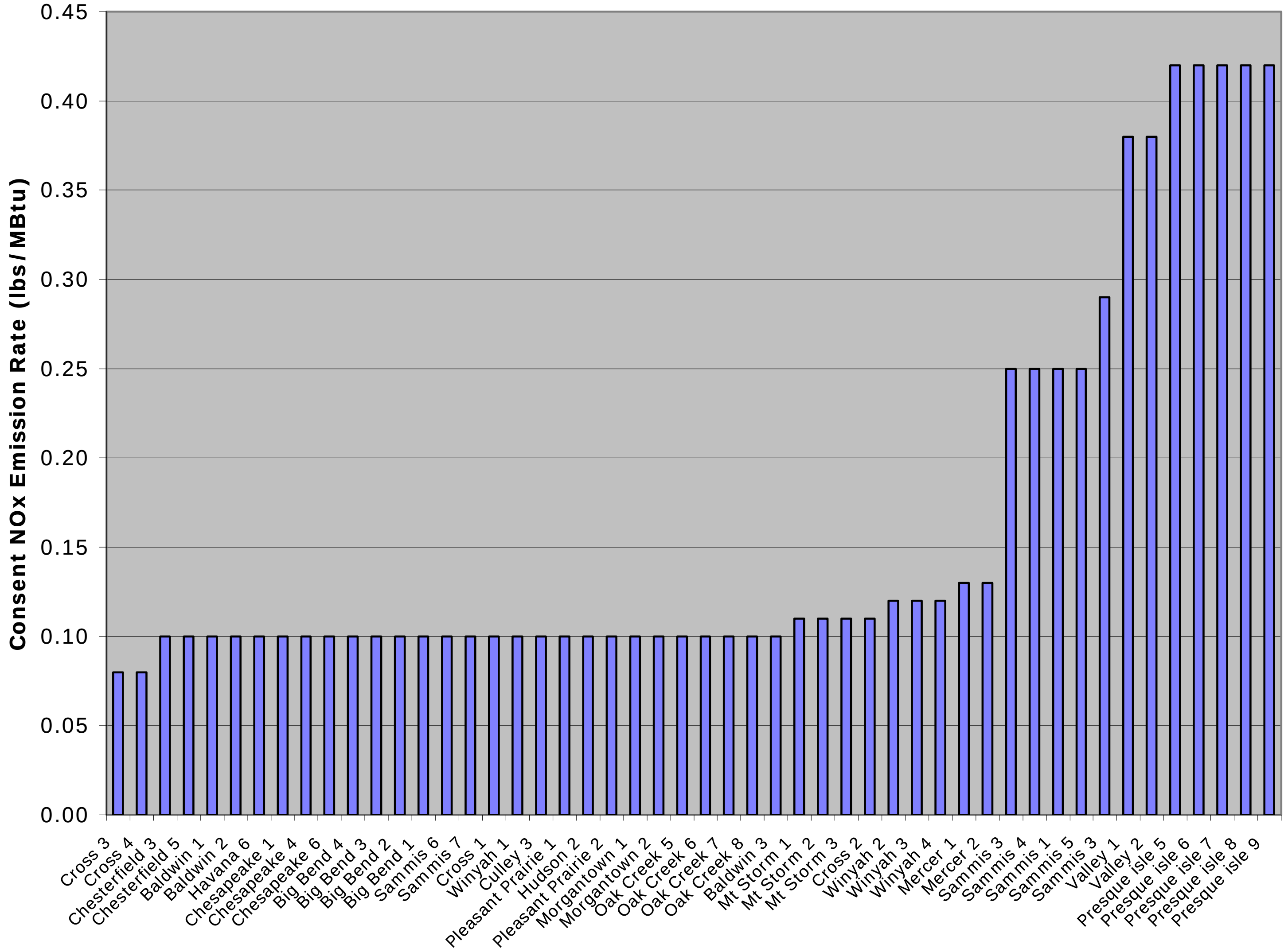
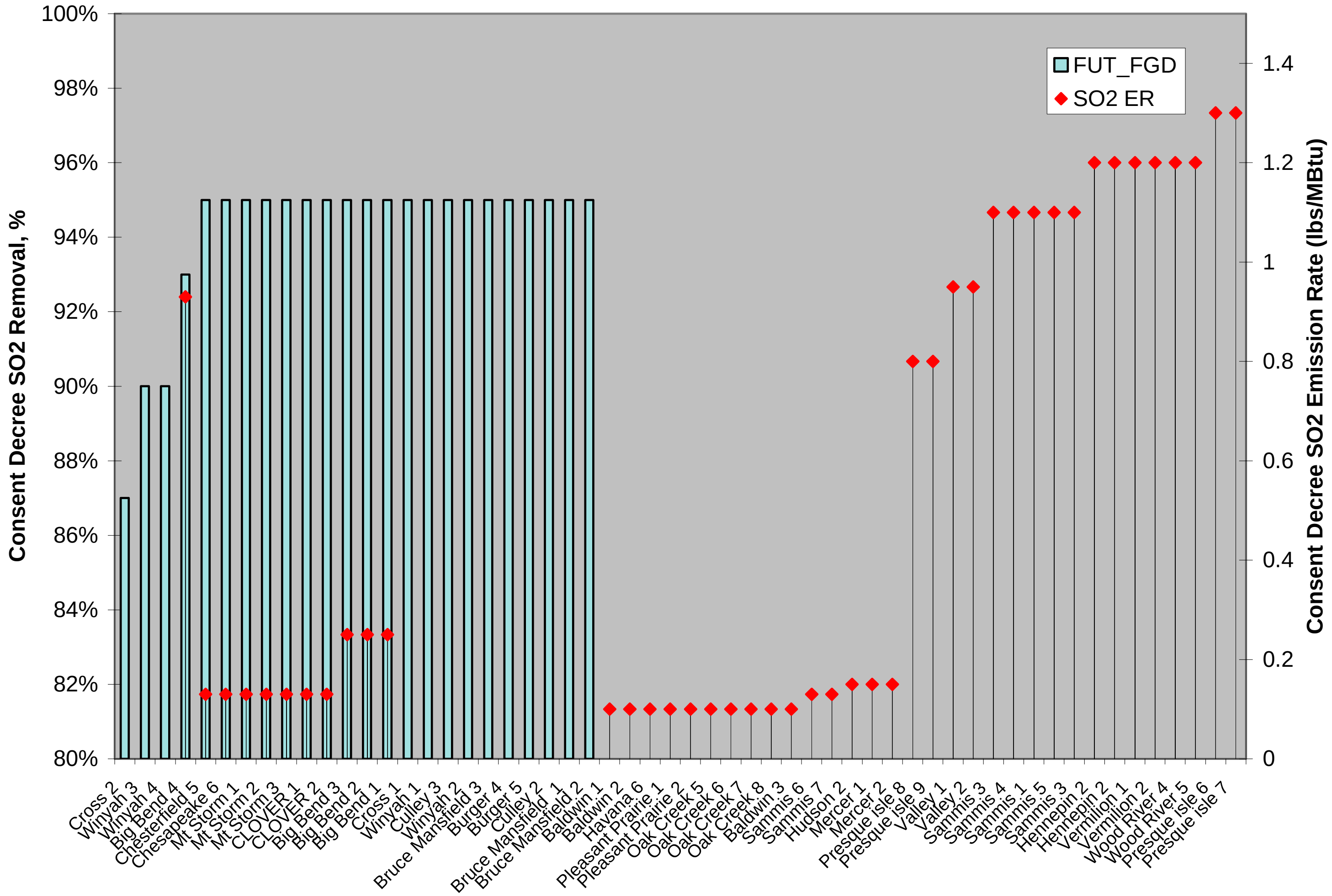


FIGURE 2-2. CONSENT DECREE SO2 REMOVAL AND EMISSION RATE REQUIREMENT FOR EXISTING UNITS



SECTION 3

THE ROLE OF PROPOSED AND PERMITTED NEW UNITS

The second scenario, ID EGU 2, is defined by SO2 and NOx emission rates of 0.10 and 0.07 lbs/MBtu, respectively.

Figures 3-1 and 3-2 present a bar chart depicting the proposed or final NOx and SO2 emission limits from 29 new, greenfield coal-fired power plants that have either recently been proposed, or received permits. This list, not necessarily intended to be completely comprehensive and thus reflect all known proposed plants, is representative enough from which to base the discussion of new plant permit level relevance.

The 29 units are shown ordered by design coal and boiler type. With the exception of the six fluidized bed units on the right side of the chart (Seward 4 through RD Nixon 2), all units represent pulverized coal-fired design. The 13 pulverized coal units on the extreme left (Council Bluffs through Trimble County 2) represent designs either for PRB coal, PRB-blends, or subbituminous coals. A total of 16 units reportedly are designed for eastern bituminous coal – ten utilizing pulverized coal design (Elm Road 1 through Thoroughbred 2), and six utilizing fluidized bed (Seward 4 through RD Nixon 2). Key observations regarding the NOx and SO2 limits permitted are summarized as follows:

Nitrogen Oxides (NOx)

Figure 3-1 shows for PRB, PRB-blends, and western coals, the proposed and permitted new unit NOx emissions ranges from lows of 0.05 lbs/MBtu (Trimble County Unit 2) and 0.06 lbs/MBtu (Weston #4; Spruce #2), up to the NSPS level of 0.15 lbs/MBtu (Springerville # 3 and 4). The Trimble County permit is predicated on the option of firing up to 60% PRB as a blend with eastern bituminous coal. Including the Springerville units, the average NOx rate permitted for the PRB, western coal, and PRB-blend units is 0.09 lbs/MBtu (and is 0.07 lbs/MBtu excluding Springerville). For the 10 pulverized coal-fired units that will utilize bituminous coal, the average new unit permitted will feature a NOx emission rate of approximately 0.08 lbs/MBtu.

Accordingly, the ID EGU 2 NOx rate of 0.07 lbs/MBtu is less than the 0.09 lbs/MBtu rate reflecting both new pulverized coal units that fire exclusively or predominantly PRB coal, and the 0.08 lbs/MBtu that reflects new pulverized coal-fired plants firing eastern bituminous coal. The EGU 2 NOx rate is also less than the 0.10 lbs/MBtu NOx emission rate for the six fluidized bed units.

FIGURE 3-1. NOx EMISSIONS FROM PLANNED AND PERMITTED NEW UNITS

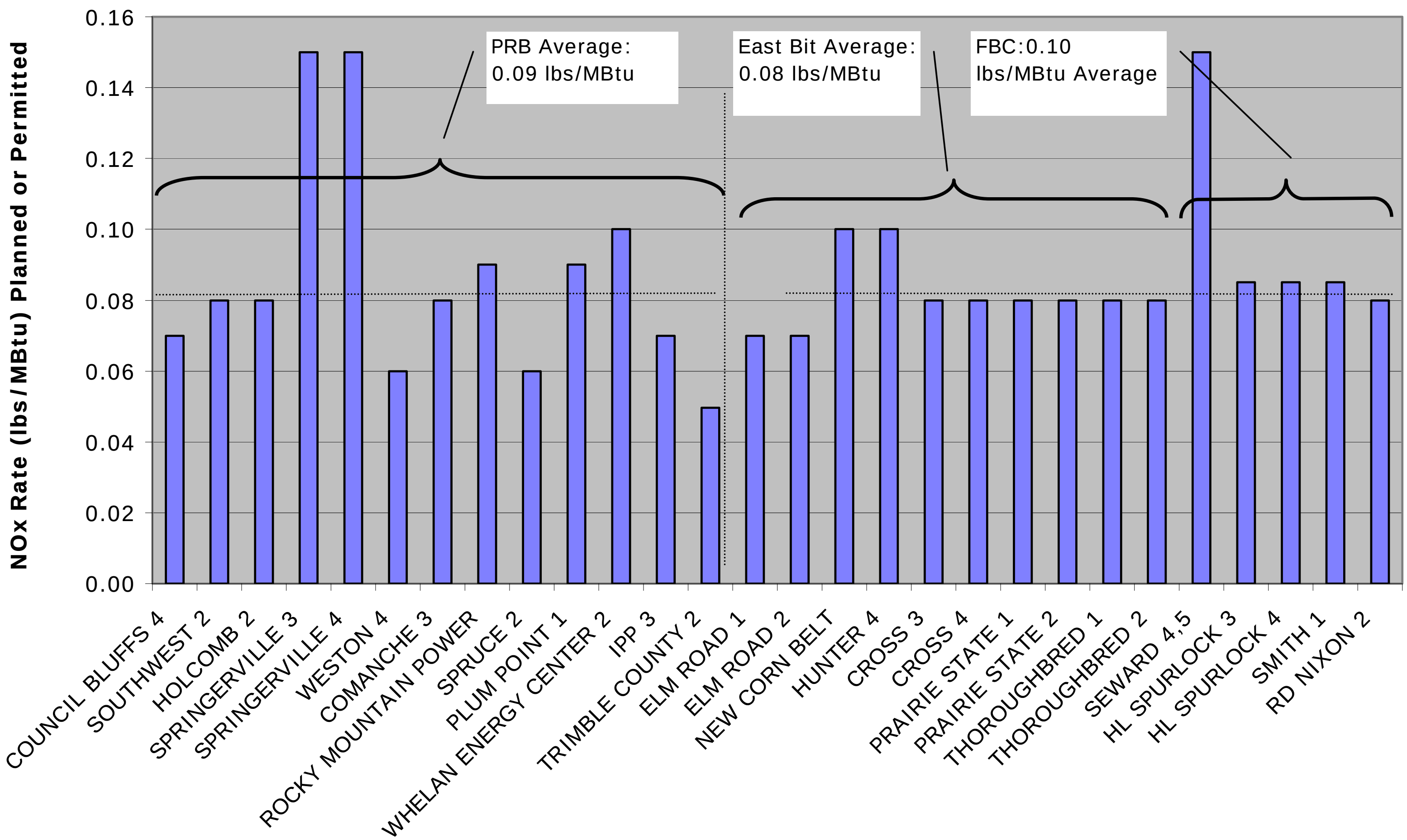
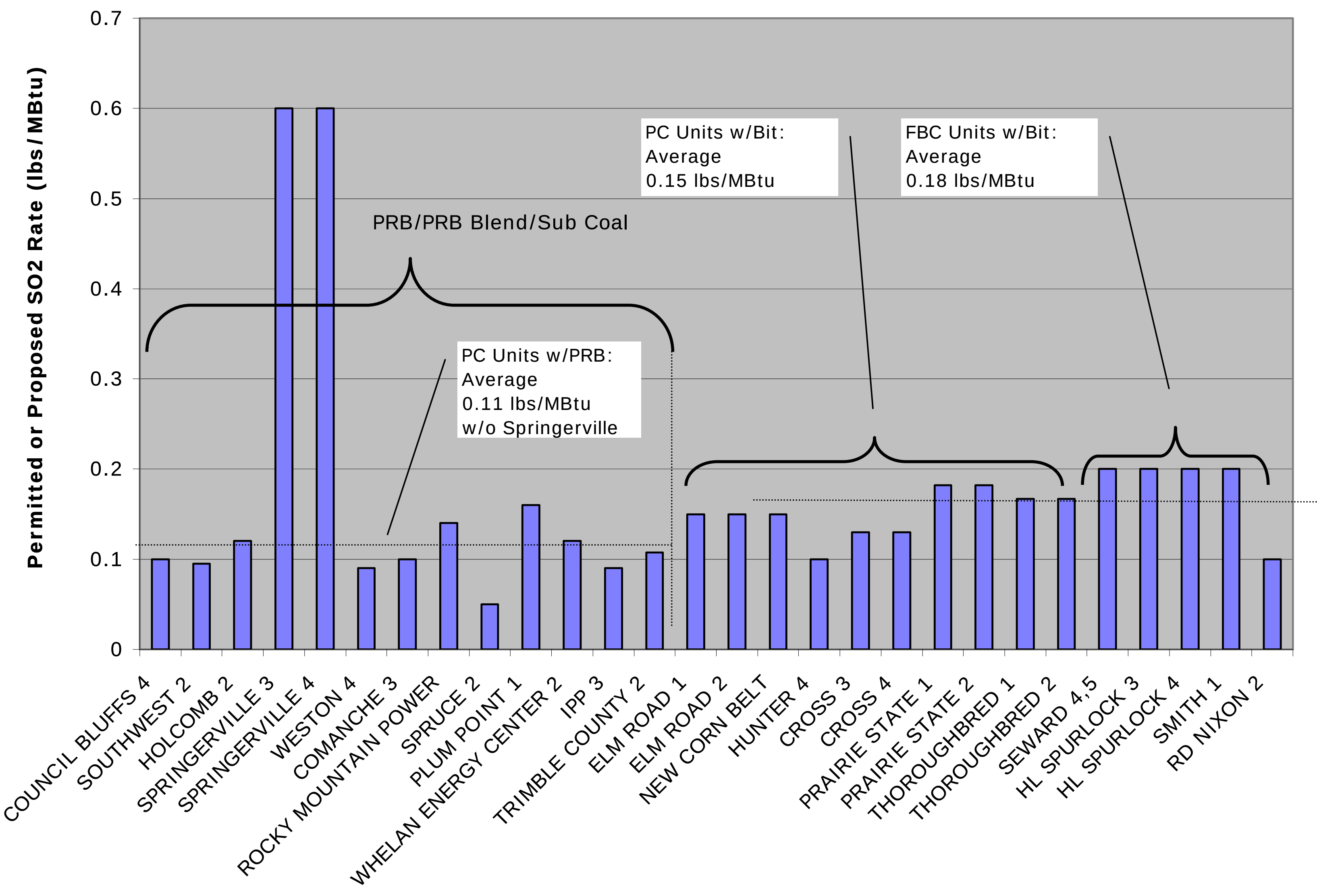


FIGURE 3-2. SO2 EMISSIONS FROM PLANNED AND PERMITTED NEW UNITS



Sulfur Dioxide (SO2)

For PRB, PRB-blends, and western coals, Figure 3-2 shows the permitted SO2 emissions range from a low of 0.05 lbs/MBtu (Spruce Unit 2) and 0.09 lbs/MBtu (Weston 4; IPP 3), up to the NSPS level of 0.60 lbs/MBtu (Springerville # 3 and 4). Including the NSPS-permitted Springerville plant, the average SO2 rate permitted is 0.18 lbs/MBtu (and 0.11 lbs/MBtu excluding Springerville). For the 10 pulverized coal-fired units that utilize bituminous coals, the permitted SO2 rate is between 0.10 lbs/MBtu at Hunter 4 and 0.18 lbs/MBtu, and averages 0.15 lbs/MBtu. The SO2 emission rate for the six fluidized bed units averages 0.18 lbs/MBtu.

Accordingly, the ID EGU 2 inferred SO2 rate of 0.10 lbs/MBtu is lower than the SO2 rate that typifies any of three categories of new generation – pulverized coal with PRB; pulverized coal with bituminous coals, and fluidized bed combustion. The ID EGU 2 value for SO2 is also well below the recently proposed revised NSPS SO2 rate of 0.21 lbs/MBtu.

APPLICABILITY OF NEW UNIT PERMITS

The concept that NOx and SO2 limits for existing units should be derived from planned or permitted new units is inappropriate. The basis for this belief is described as follows.

Nitrogen Oxides (NOx)

The planned or proposed NOx levels for new, greenfield plants are not considered an appropriate basis to establish emission limits for existing plants. Most significantly, the cost to achieve these extremely low levels on existing units can be significantly higher than the cost to meet these levels with a new unit.

The most significant factor affecting SCR cost is the capital requirement. The capital cost to retrofit SCR on an existing unit can be a factor of 2-3 times greater than the capital cost installation on a new unit, primarily due to additional structural requirements, labor for installation, and balance-of-plant modifications, including recently recognized measures for SO3 control. For new greenfield sites, estimates for SCR capital cost alone are rare, as one supplier usually provides both the boiler and SCR equipment. Cost data from several new units constructed in the late 1990s suggests new unit SCR requires $45-55/kW of capital investment.

Assuming a capital cost of $50/kW, a catalyst life of 16,000 hours (e.g. one layer of a three layer reactor is exchanged at two-year intervals), a NOx content entering the SCR reactor of 0.25 lbs/MBtu, and an outlet target of 0.07 lbs/MBtu, the annual cost per ton can be $1600/ton.

For retrofit, the capital cost of SCR can significantly exceed $100/kW. Two surveys of utility incurred costs for SCR reported averages of $120 and $125/kW, depending on the size and design of the unit. Existing units will have higher baseline NOx emissions, perhaps averaging 0.35 lbs/MBtu. The higher initial NOx entering the reactor will require larger catalyst volume, perhaps necessitating an additional catalyst layer (e.g. 3+1 design in lieu of a 2+1 design). Consequently, if the same outlet value of 0.07 lbs/MBtu is selected, and the same 16,000 hour period between catalyst replacement is assumed, the NOx control cost-effectiveness for an existing unit will be

$2,550/ton. The more than 50% increase in cost per ton for NOx removal for an existing unit, as compared to a new unit, reflects the significantly more challenging retrofit.

One advantage for new units relative to existing units is the availability of space to incorporate static mixers into the design, to improve performance. Of the numerous design factors that influence SCR performance, perhaps none is more important than achieving a uniform ratio of NH3/NO entering the process reactor. A key to achieving this mixing is the use of static mixers, which can require significant ductwork length to create the desirable process conditions. With existing units, not all units offer adequate space for static mixers to achieve extremely high NOx reduction, and creating sufficient space even if feasible can incur considerable cost.

Sulfur Dioxide (SO2)

The selection of 0.10 lbs/MBtu in the Interim White Paper as typical of new unit permits reflects a bias toward the use of PRB coal in many proposed new units. PRB coal can vary significantly in sulfur content, and in the required SO2 removal efficiency to achieve a given emission rate. Figure 3-3 summarizes the sulfur content of various PRB coals selected from the EIA Form 767, depicting the coal sulfur content and SO2 removal efficiency necessary to meet a 0.10 lbs/MBtu level. Notably, to meet the proposed EGU 2 rate, approximately 90% SO2 removal is required from one of the lowest sulfur-containing coals in the world.

Figure 3-4 presents the SO2 removal efficiency required for a broader population of U.S. coals to meet the targeted level of 0.10 lbs/MBtu. Significantly, with regard to high sulfur coal produced in Illinois, Indiana, and Ohio, a reduction of 97% and 98% is required for coals with 3% and 4% sulfur content, respectively. This degree of SO2 control would require each unit to replicate the site-specific attributes of the best plants that have consistently provided 98% SO2 removal, including availability of Mg-lime reagent. Replicating the performance-improving conditions of the most successful plant in the broad utility population may not be possible.

OBSERVATIONS

The EGU2 NOx and SO2 rates derived from new unit permits, as proposed in the Interim White Paper, represent extremely aggressive targets. Notably, all targets are more strict than the recently proposed New Source Performance Standards for NOx (0.11 lbs/MBtu) and SO2 (0.21 lbs/MBtu) Most significantly, especially with respect to NOx, the new plant process conditions may allow deploying SCR as an integrated, inherent part of boiler design. This design degree of freedom, which lowers capital and operating cost, is not available to SCR retrofit of existing units.

EGU2 NOx rates will require almost universal deployment of SCR on almost all operating units. With regard to certain smaller, older units, if faced with the expense of an SCR retrofit, utilities will in many cases choose to retire those units early, which may impact the reliability of the electric system. The strict NOx targets would require most SCR-equipped units to demonstrate for 12 months performance levels in the upper quartile of SIP-Call units that currently operate their SCR equipment for only five months. Achieving this level of SCR performance for 12 months is unproven.

For SO2, the target limits would require retrofit of FGD on most units. Again, for smaller units, premature retirement may be a more economical option than incurring the additional capital and operating costs of FGD. It is notable that not only are both EGU 1 and EGU 2 below the recently proposed NSPS, but EGU 2 requires achieving 90% SO2 removal from one of the lowest sulfur coals found in the world.

FIGURE 3-3. SO2 REMOVAL EFFICIENCY FOR PRB COALS FROM EIA TO MEET 0.10 LBS/MBTU

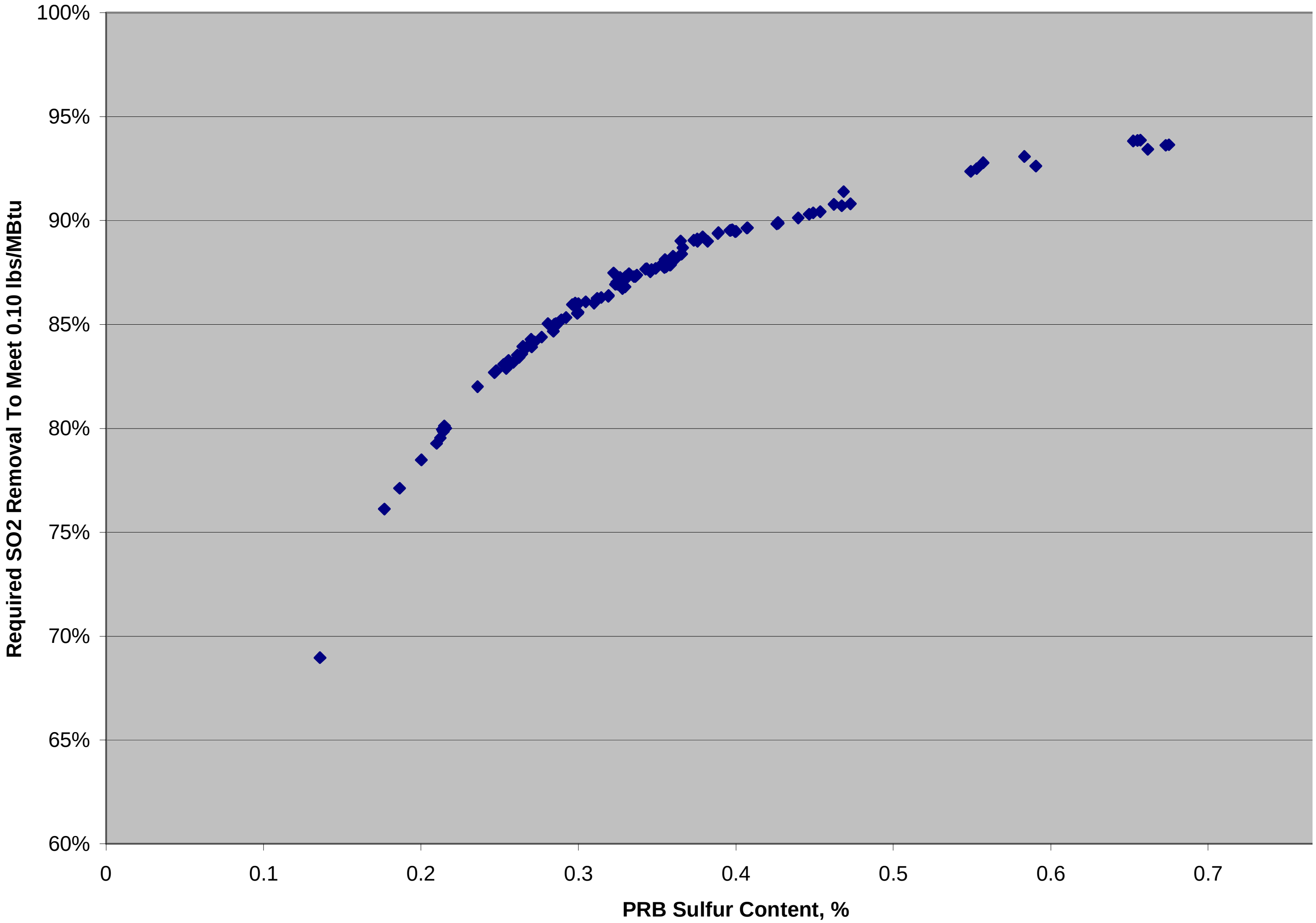
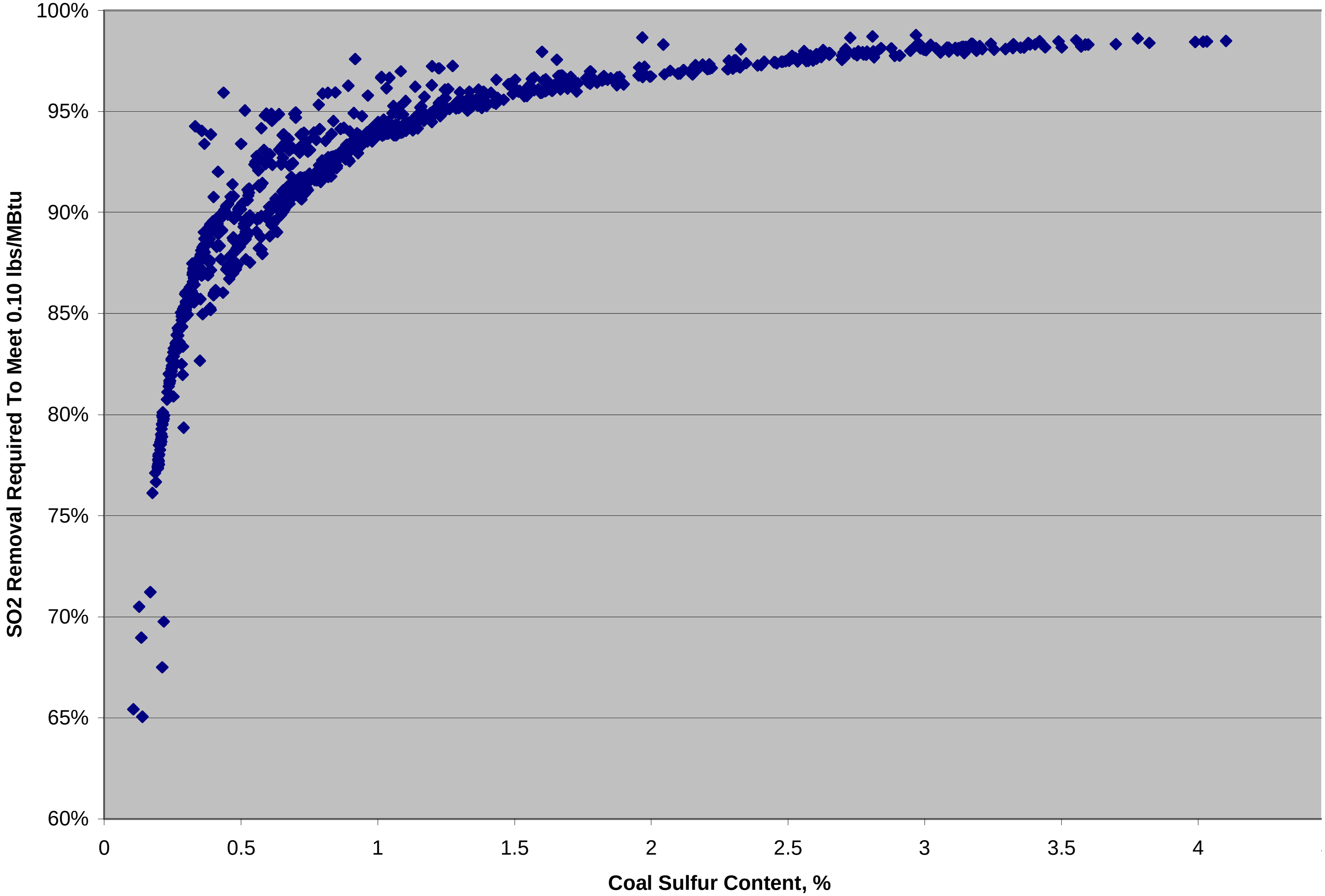


FIGURE 3-4. SO2 REMOVAL EFFICIENCY FOR EIA 767 REPORTED COALS TO MEET 0.10 LBS/MBTU



SECTION 4

SIGNIFICANCE OF NOx SIP-CALL COMPLIANCE

Data describing NOx emission rates of SCR-equipped units operating in the third quarter of 2004 has been publicly available since mid-December of 2004. Figure 4-1 presents a chart of the SCR NOx outlet data from 3Q 2004, showing the average NOx emission rates obtained over the third quarter. This most recent experience, when taken at face value, suggests a significant fraction of SCR-equipped units over a 5 month period can meet the EGU 1 levels of 0.10 lbs/MBtu, and possibly even the EGU 2 rate of 0.07 lbs/MBtu. These results, certainly encouraging and a credit to the operating utilities, should be viewed in the context that catalysts are still relatively new and thus offer high activity, thus promoting higher NOx control, and that these units benefit by operating only seasonally. Both of these topics are addressed as follows:

Catalyst Life Is "New" vs. End-of-Life

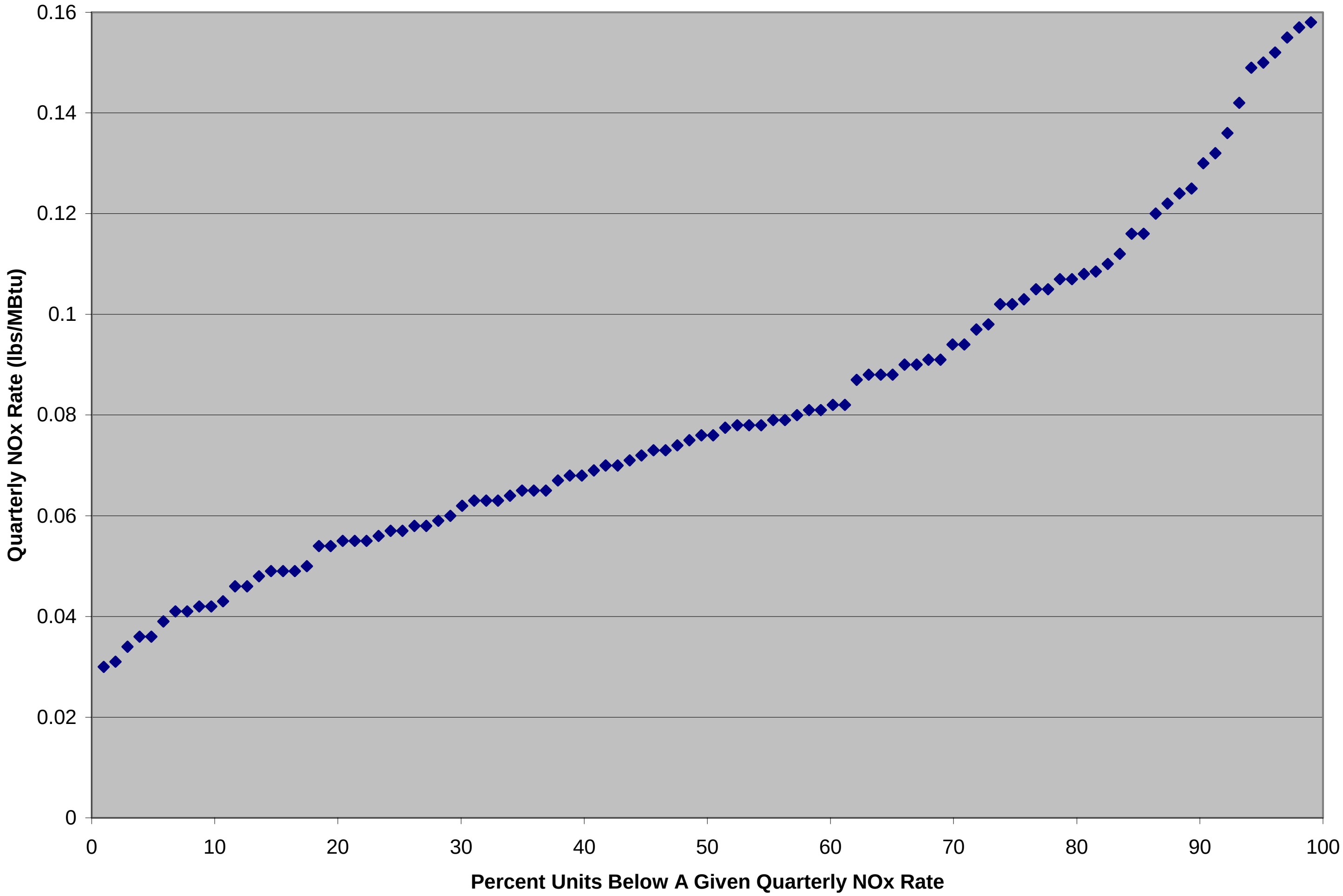
The performance of SCR process equipment depends on the activity of the catalyst, which invariably degrades with operating time. Most units are designed to operate for 16,000- 24,000 hours before addition or replacement of catalyst; most of the units reported in Figure 4-1 have operated for less than 8,000 operating hours. NOx removal is documented to degrade with increased operating time. Although frequently replacing catalyst to maximize catalyst activity and reactor potential is an option, the levelized cost of NOx control will increase.

Seasonal vs. Annual Operation

Most SCR-equipped units in Figure 4-1 operate with SCR for 5 months, and enjoy a 7 month period of operation when maintenance or performance-improving measures can be implemented. Some units – such as Georgia Power's Bowen station – have experienced significant catalyst plugging problems that would have forced extended, costly outages if annual operation was required. Annual operation will not allow for a 7 month recovery and remediation period.

In summary, the new, greenfield unit-inspired NOx rate of 0.07 lbs/MBtu, perhaps achievable for some newly-equipped units on a 5 month basis, may not be achievable for an entire population, or even for a substantial fraction, of existing units, on an annual, long-term basis. Imposing this degree of NOx control will require significant operating cost.

FIGURE 4-1. QUARTERLY SCR OUTLET NOx EMISSIONS MEASURED DURING 3Q 2004



SECTION 5

2009 COMPLIANCE TARGET

The Interim White Paper proposes that the ID EGU 01 and ID EGU 02 scenarios would be implemented by January 1, 2009. This section of the report discusses why this schedule is unrealistic and cannot be attained.

The authors of this report in 2004 evaluated (for UARG) the feasibility of meeting the Clean Air Interstate Rule (CAIR) mandates (UARG, 2004). These mandates required the retrofit of 43 and 46 GW SCR and FGD, respectively, within 28 states by 2010. The conclusion of this analysis – that limited availability of boilermakers restricts equipment installation - is believed valid for the MW RPO proposal. An analysis for the specific MW RPO case is not repeated, but relevant results from the 2004 UARG analysis are highlighted in this section.

Project Duration

Retrofitting power generation equipment with environmental controls requires five discrete steps:

- Preparing a detailed specification for equipment and performance, which (particularly for SCR NOx control) should entail baseline testing;
- Obtaining construction permits for process equipment, which for FGD in some cases requires opening a new or expanding an existing landfill;
- Issuing the procurement specification, soliciting bids, selecting successful bidder and negotiating a binding contract;
- Conducting the engineering of process design; and
- Initiating construction, site preparation, fabrication of material, installation, and startup/shakedown operations.

With regard to construction permits, most states require a permit for a new landfill, even for benign FGD byproduct such as wallboard quality gypsum. Landfill permit applications usually are considered in an administrative forum where actions of certain groups often can delay or even prevent issuance of permits. For example, plant owners in Georgia expect that at least two years will be needed to acquire a landfill permit for FGD byproduct.

The U.S. EPA in their 2002 report evaluating the feasibility of the Clear Skies Initiative (EPA, 2002) assumed project durations of 27 and 21 months for FGD and SCR equipment, respectively. As shown in Table 5-1, utility owners installing this equipment report project durations that exceed EPA's by 10-20%. However, EPA assumptions are adopted for this analysis.

Table 5-1. Summary of Project Schedules

Study	Control Option	Duration (Months)	Comment
EPA	FGD	27	derived by inputs from Suppliers
	SCR	21	
UARG	FGD	32	derived from discussions with Owners
	SCR	24	

Boilermaker Availability

The availability of boilermakers - highly trained skilled labor, necessary for key SCR and FGD construction – is limited, and will determine the rate at which SCR and FGD can be installed. Qualified boilermakers require a 3-4 year apprenticeship, thus rapid growth cannot be quickly accommodated.

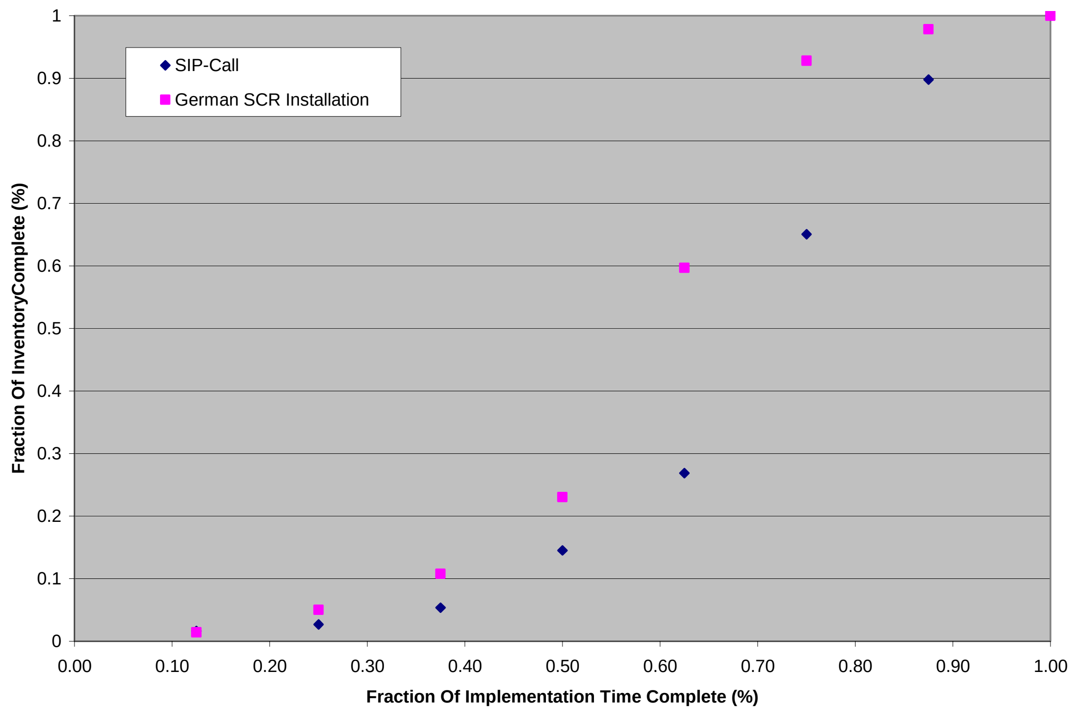
The EPA in the 2002 CSI analysis (EPA, 2002) adopted several key assumptions defining the (a) number of boilermakers available, and (b) fraction available to work in the utility environmental sector. The UARG 2004 analysis adopted these assumptions – 29,000 available boilermakers, and 35% available to work in the utility environmental sector. Regarding the number of man-hours each boilermaker can provide annually, the UARG 2004 analysis adopted the assumption by the Institute of Clean Air Companies (ICAC, 2004) that each worker can expend 1685 working hours per year.

Schedule of Installation

A schedule defining SCR and FGD installation for either CAIR or the MW RPO is anticipated to replicate SCR installation for the SIP-Call, and in Europe in the mid-to-late 1980s. The installation rate of SCR from these periods, which extended 5 years for the SIP-Call (1999-2004) and 6 years for European mandates (1986-1991) respectively, was used to derive a normalized relationship. Figure 5-2 presents the relationship between the fraction of inventory installed and the duration of the installation period. Figure 5-2 was used with the methodology described in the next section to determine the end-points for equipment installation.

The actual boilermaker man-hours required for SCR and FGD installation was determined from approximately 12 installation projects, presented in the previously referenced UARG study.

Figure 5-2. Normalized Historical Installation Profile: NOx SIP-Call (1999-2004) and German NOx Regulations (1986-1991)



Methodology

Two scenarios - driven by an optimistic and a probable start time for SIP approval – are evaluated.

<u>Optimistic</u>. For this case, SIP plans are due January 1, 2006; and all control equipment must be operable by October 1, 2009 to meet a 2010 mandate. Engineering for the first 6% of installations begins in the first quarter of 2006. Based on the schedule of boilermaker construction profiles, the January 1, 2006 start date implies the first boilermakers are on-site for SCR by October 1, 2006, and for FGD by January 1, 2007.

<u>Probable</u>. This "probable" scenario recognizes EPA projections that SIPs will not be complete until July 1, 2006. Accordingly, the first engineering is assumed to start July 1, 2006, six months following the optimistic date. Under this scenario, the first boilermakers are on-site for SCR and FGD by April 1, 2007, and July 1, 2007, respectively.

The following methodology was executed given these start dates:

- Identify Retrofit Capacity Installation Per Quarter. Based on predictions to retrofit FGD and SCR, a random ordering of units for installation was determined, with no bias as to generating system size or location.

- Boilermaker Hours Required For Installation. Once the random ordering of units to be retrofit was established, boilermaker hours required in each quarter were calculated, using the "profile" in Table 5-2. Thus, a unique "demand" for boilermaker hours was produced for each individual unit.

- Boilermaker Hours Available. The boilermaker hours available in each quarter were calculated assuming each of the 10,130 individual laborers would expend 1685 hours annually in the field.

- Calculate Shortfall. Comparing the supply versus demand of boilermaker hours for each quarter identified the shortfall. Where labor did not limit installation, the entire retrofit capacity in that quarter was assumed to be completed. Where calculations showed a "shortfall" of labor, the retrofit capacity that had to be deferred was determined. The delayed retrofit capacity was scheduled for the next quarter, using the original random ranking assigned to all units. Again, no preference was awarded to units depending on system size or location.

This strategy is proposed to realistically predict the schedule for required man-hours for each unit, and thus define the man-hour shortage.

Table 5-2
Fractional Demand for Boilermakers Time, as Percent
(Per Quarter Following Projection Start)

Technology	Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9
FGD	0	0	0	0	10	27	34	23	6
SCR	0	0	0	20	25	40	15	n/a	n/a

Figures 5-3 and 5-4 present estimated completion dates for SCR and FGD retrofit, based on the optimistic start date of January 1, 2006, and the availability of boilermakers for 1685 hours per year. Figure 5-3 depicts the total generating capacity of units completed, by quarter, and Figure 5-4 depicts the total number of projects completed, again by quarter.

This analysis is conservative. Despite the assurances offered by representatives of the boilermaker trade union, it is not clear there will be a pool of 28,000-30,000 boilermakers from which to draw. It is significant the U.S. Bureau of Labor Statistics projects 25,000 boilermakers will be available for the relevant time period, as the new entrants will be adequate to only replace the retiring workforce. Further, other factors such as permitting and supply bottlenecks will require at least another additional year in the CAIR Phase 1 deadline.

Moreover, the present study makes no adjustment for the impact of compromised productivity in the final stages of equipment installation. Experience from the NOx SIP-Call SCR installations suggests that as the labor pool is depleted, the least experienced workers are taken from the labor pool for specific projects; these less experienced workers historically deliver lower productivity. It is clear that lower productivity – witnessed during the SIP-Call and presumed to be unavoidable for CAIR – will extend project schedules.

Significantly, this analysis shows that CAIR mandates for 2010 cannot be met, based on expected assumptions regarding the amount of capacity that will need to be retrofit with SCR and/or FGD. In the final CAIR, EPA has revised downward the amount of capacity that it projects will need to be retrofitted by 2010 (for SO2), and by 2009 (for NOx). Based on these revised expectations, EPA indicates that the Phase I CAIR deadlines will be achievable.

The point for the present analysis is that the MW RPO, and the states in the region, have ignored to date the important question of feasibility of achieving EGU1 and EGU2 reduction levels by the desired 2009 deadline. The analysis done for CAIR suggests that such stringent levels of reductions could not be achieved by 2009. Regardless, the issue of feasibility cannot be ignored when evaluating various options for possible further emission reductions beyond CAIR, as the Interim White Paper has done.

Figure 5-3: FGD, SCR Completion Date, Per Capacity
Optimistic Start Date (January 1, 2006) and 1685 Annual Boilermaker Hours

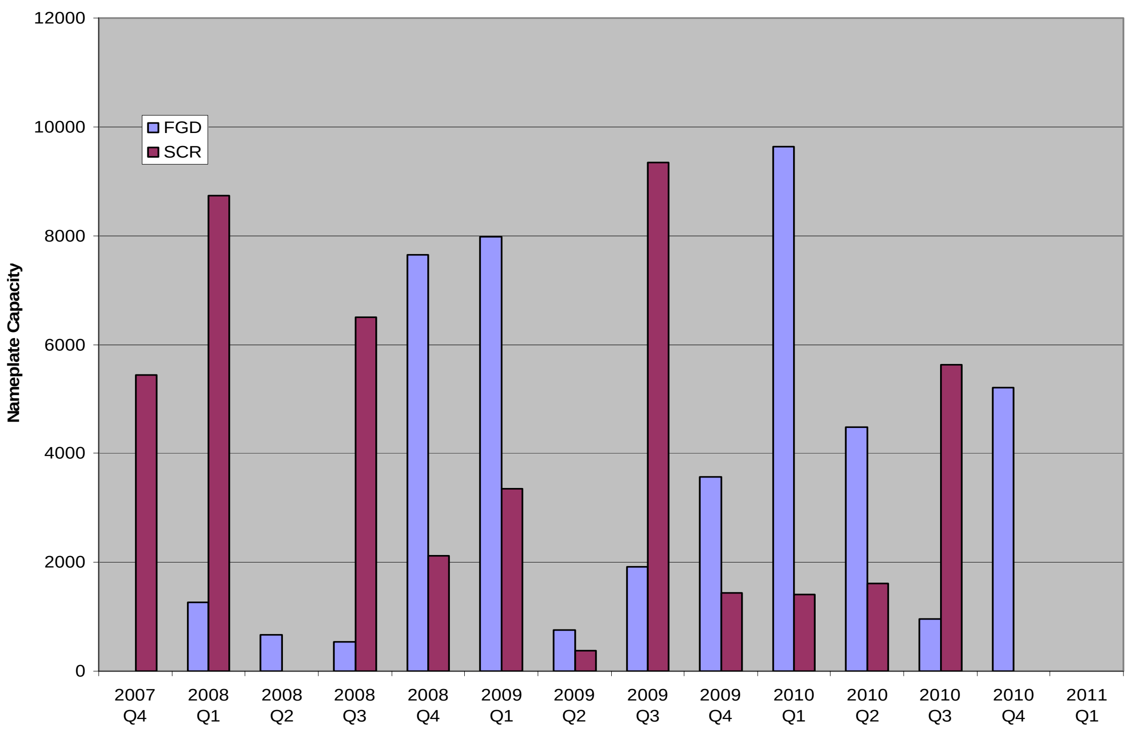
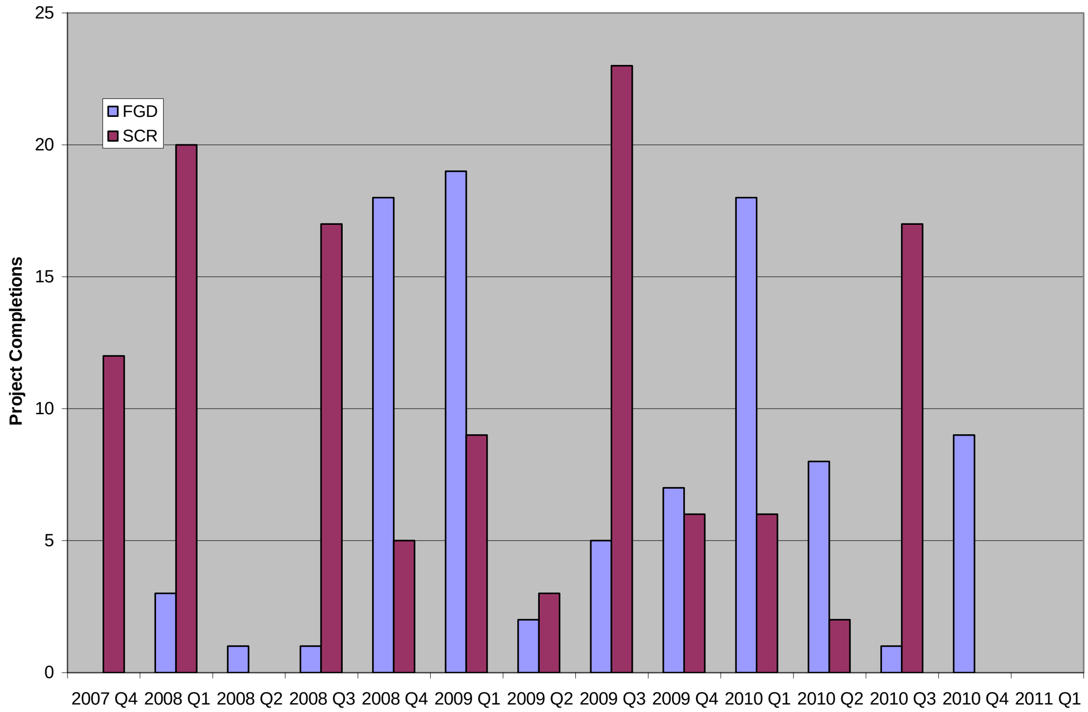


Figure 5-4: FGD, SCR Completion Date, Per Number of Projects
Optimistic Start Date (January 1, 2006) and 1685 Annual Boilermaker Hours



REFERENCES

EPA, 2002 — Environmental Protection Agency, "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-Pollutant Strategies", October, 2002.

ICAC, 2004 — "IAQR Projected 2015 Control Technologies Can Be Installed by 2010", ICAC Paper, 2004.

UARG, 2004 — UARG, Analysis of CAIR Compliance Schedule: A Response to ICAC Estimates, analysis prepared for the Utility Air Regulatory Group, July, 2004.