DRAFT

RAS NOx Study

Reliability Impacts of the EPA NOx SIP Call

Reliability Assessment Subcommittee

of the

North American Electric Reliability Council

February 2000

TABLE OF CONTENTS

INTRODUCTION

About NERC and RAS

On November 9, 1965, a blackout left 30 million people across the Northeastern United States and Ontario, Canada in the dark. In an effort to prevent this type of blackout from ever happening again, electric utilities formed the North American Electric Reliability Council (NERC) in 1968 to promote the reliability of the electricity supply for North America. This mission is accomplished by working with all segments of the electric industry as well as customers. NERC reviews the past for lessons learned, monitors the present for compliance with policies, standards, principles, and guides, and assesses the future reliability of the bulk electric systems.

NERC's members are ten Regional Councils encompassing virtually all of the electric systems in the continental United States, Canada, and the northern portion of Baja California Norte, Mexico. The members of these Regional Councils come from all segments of the electric industry — investor-owned, federal, rural electric cooperatives, state/municipal and provincial utilities, independent power producers, and power marketers.

The NERC Board of Trustees formed the Reliability Assessment Subcommittee (RAS) of the Adequacy Committee (formerly the Engineering Committee) in 1970 to annually review the overall reliability of existing and planned electric generation and transmission systems of the Regional Councils. RAS is responsible for the preparation of the annual Reliability Assessment of the North American bulk power system and seasonal assessments, which assess the reliability issues for the upcoming operating season.

EXECUTIVE SUMMARY

The NERC Reliability Assessment Subcommittee (RAS) directed a study to ascertain the incremental impact on electric system reliability of the U.S. Environmental Protection Agency's (EPA) final rules for nitrogen oxide (NOx) emissions that will require electric generators in a 22-state area to comply with Regional emission limits beginning with the 2003 ozone season (State Implementation Plan, SIP Call). The emission limits will require installation and use of new equipment and processes at a number of generating stations in these states. One of the new equipment/processes is selective catalytic reduction (SCR), which requires some extension of planned generation maintenance outages to accomplish the retrofits. These extended planned outages potentially could degrade reliability.

Conclusions

Range of Impacts	
Not Significant	No differences, or if there are, the differences are not noticeable to operations.
Significant	Difficult to manage operationally, but may be mitigated through longer-term planning (i.e., season ahead to one year ahead).
Cause for Concern	Real differences that may be operationally manageable through emergency procedures and/or short-term planning.

Analysis of the potential impacts to reliability through computer simulations indicated that the incremental adverse impact of the SIP Call on reliability in the NERC Regions[1] that comprise the 22-state SIP Call area, range from *not significant* to *cause for concern*. In particular, small impacts were identified in the MAAC and SERC Regions. However, there were some scenarios in ECAR and MAIN that produced *significant* impacts or *cause for concern*.

In addition to the analysis on the impact of capacity additions, analyses were performed for ECAR and MAIN to determine the sensitivity of the results to variations in other factors: the degree of planned maintenance outage coordination, length of the retrofit window, and the SCR retrofit outages assumed. The analyses indicated that adverse impacts could be at least partially mitigated through the application of increased maintenance outage coordination within the Regions and/or commencement of the retrofit program in 2000 or 2001.

Based on the result of the analyses, it logically follows that any reduction in the amount of SCR equipment needed for compliance, or extension of the retrofit window, would lessen the adverse impacts of the NOx SIP Call. Application of alternative NOx reduction technologies that do not require additional generation outage time for retrofits might reduce the number of units requiring SCR equipment, thereby reducing the impact of retrofits. Similarly, use of State Supplemental Allowance Credits, proposed by the EPA, could effectively extend the retrofit window, again reducing the SIP Call impacts. Some advanced technologies were considered but not explicitly analyzed because of their limited application, not having been applied to units above 600 MW. Use of the allowance credits was not explicitly analyzed because conclusions on its effect can be drawn from the analysis of the length of the retrofit window.

1 The study results for the reference scenarios do not compare well with reliability studies performed by the ECAR and MAIN Regions. The analysis resulted in some loss of load expectation (LOLE) values considerably greater than either Region might otherwise expect. However, because a consistent methodology, assumption, and model were used in assessing the two Regions, this study is appropriate for assessing the relative reliability impacts caused by the SIP Call between and among the Regions impacted by the SIP Call.

Discussion

This study highlights the importance of having sufficient capacity to meet the future projected demand in each Region. The results are highly sensitive to the level of capacity additions in the ECAR and MAIN Regions. If demand continues to grow as projected, the market will need to provide new resources throughout the period (generating capacity and/or interruptible loads) that are consistent with planning reserve requirements or needs. Based on the submitted capacity plans for ECAR, the projected capacity margin is expected to be the lowest in 2002. Superimposing the SIP Call retrofit program, on top of already projected low reserve margins[2], creates a sizable additional reliability risk above the no-retrofit base conditions. The same is true for MAIN in 2003, but to a lesser degree. It is important to note that the system conditions that are projected in the 2001 to 2003 period, during which the SCR retrofit outages would occur, are critical in determining the impact of the retrofits on reliability. However, capacity additions will be essential to maintain Regional reliability with or without the retrofit outages. If a lack of capacity additions results in low margins, then the retrofit outages will only aggravate what will be a difficult situation. Unfortunately, analysis of the projected capacity plans for ECAR and MAIN indicates that both Regions may struggle to attain their reserve requirements in the retrofit period years, even with the inclusion of the announced[3] merchant capacity into the capacity plans.

A number of the simulations also highlight the impact that coordination of planned generation maintenance outages might have in managing the reliability impact attributable to the SIP Call. Analysis of the comparative cases suggests that planned outage coordination, to the extent it can be accomplished, have the potential to offset a portion of the impacts generated by the retrofit outages. Of course, converting the potential benefits of planned maintenance outage coordination into actual results would require a significant cooperative effort within each of the ECAR and MAIN Regions, or appropriate market incentives that induce generation operators to independently minimize simultaneous outages. Outage coordination may need to occur to a much greater extent and over larger areas than has occurred in the past.

The scenarios discussed in this report were chosen after a screening study was performed to identify candidate scenarios that were likely to result in any significant adverse impact on reliability. Scenarios were then selected to estimate the range of potential impacts. As such, some scenarios may not be representative of conditions that are the most likely to occur. Study resource limitations prevented RAS from analyzing a greater number of more extensive scenarios.

.

2 ECAR analyses show those margins to be adequate.

3 Based on the announced merchant capacity as of September 1999. Additional announcements have been made since that time.

BACKGROUND: THE NOx SIP CALL

On September 24, 1998, the U.S. Environmental Protection Agency (EPA) issued a final rule establishing more stringent emission limits for nitrogen oxides (NOx) in 22 Eastern states and the District of Columbia (the SIP Call) (63 Fed. Reg. 57,356). The emission reductions are intended to control the regional transport of ground-level ozone from the Midwest and Southeast to several Northeastern states during the summer "ozone season."

The new emission limits force affected states to revise their state implementation plans (SIPs), which detail their strategies for meeting regulatory requirements under the Clean Air Act. Under the schedule imposed by the rule, states were required to revise their SIPs by September 30, 1999 to set new emission limits for electricity generating units of 25 MW or greater capacity, and large industrial boilers with heat inputs of 250 MMBtu/hour or more. Such emission sources were required to meet the new NOx emission limits, which represents an 85% reduction from 1990 levels, by the ozone season (May to September) of 2003.

In connection with its emission-reduction mandate, EPA issued a final rule setting out a model emission-trading program for affected sources, which states may incorporate into their SIP revisions to facilitate implementation flexibility and reduced compliance costs. Even with the assistance provided by the emission-trading program, many units in the SIP Call Region will have to install selective catalytic reduction (SCR) control equipment in order to meet the new NOx emission limits.

The Regions having to make the greatest emission reductions are ECAR, MAIN, and SERC. In September and October 1998, ECAR, MAIN, and SERC individually sent letters to the EPA expressing concern over the potential impact of EPA's NOx rules on the reliability in their respective Regions. These letters stated that the extended outages of coal units during the 2000–2003 period, in which retrofits required to reduce NOx emissions, could materially impair reliability. In addition, these letters respectfully requested that EPA reconsider the implementation schedule to ensure that the retrofit work could be accomplished without jeopardizing reliability. In response to these concerns, EPA set up a compliance supplement pool of up to 200,000 tons of summer NOx allowances that states can award to generating units in 2003 and 2004. The supplemental pool can be allocated to unite on which controls cannot be installed in time for compliance in 2003 without unduly compromising electric system reliability, or for which allowances cannot be bought from the allowance trading pool.

The NOx SIP Call has been the source of considerable debate. Both sides of the debate have performed reliability studies. These studies have results ranging from no material adverse reliability effect, to a very significant reliability impact. Given the many conflicting statements being made about reliability by EPA and by studies conducted by various other groups, the NERC Board of Trustees requested that the NERC Reliability Assessment Subcommittee (RAS) of the Adequacy Committee (formerly the Engineering Committee) examine the potential reliability impacts of the EPA NOx SIP Call on near-term supply adequacy. RAS formed a NOx Task Force to review those studies.

RAS met with representatives of EPA and the various study groups and had the opportunity to ask questions of the study producers and their sponsors. A review of the previous studies is included in this report, the RAS NOx Task Force found that the wide range of results is attributable primarily to the disparate methodologies and assumptions used in the studies. The Task Force also found that the studies were either flawed or otherwise insufficient for drawing conclusions as to the potential reliability impact of EPA's NOx rules. As a result, in early 1999, the RAS NOx Task Force recommended that NERC RAS should conduct its own independent analysis to form its own conclusions.

At about the same time, the Edison Electric Institute (EEI) had retained a consultant to perform a study on the reliability impacts of the NOx regulations, and EEI approached NERC for assistance.

An agreement was reached between NERC and EEI for the NERC RAS to direct the EEI-funded study. This report details the results of that study.

Challenges to the Rule

A number of industry groups and Midwestern and Southeastern states challenged EPA's rule, filing petitions with the U.S. Court of Appeals for the D.C. Circuit in October 1998. The petitions argued that EPA ignored significant alternative emission-control proposals that were made by the states and industry in their comments on the proposed SIP Call. The petitions also argued that the NOx reduction rule unfairly focused on electric generating units to the exclusion of other important emission sources, and that the reductions would not yield the intended air quality benefits for downwind states. Oral argument on the case was held on November 9, 1999, with a ruling by the court expected in the spring of 2000.

The U.S. Court of Appeals for the D.C. Circuit issued two important rulings in May 1999 that effected the implementation of the SIP Call. First, on May 14, the court remanded to the U.S. EPA its new national ambient air quality standards (NAAQS) for ozone and fine particulate matter, which EPA adopted in July 1997. The court disagreed with certain aspects of the manner in which EPA exercised its broad authority to set air quality standards under the Clean Air Act. The court instructed EPA that it must use an "intelligible principle" explaining and limiting its discretion to set standards in relation to their effect on human health. The NOx control levels established in the SIP Call rely on EPA's successful defense of the new eight-hour ozone standard.

Second, on May 25, the court stayed indefinitely states' obligations to implement the NOx reduction requirements established under the SIP Call. Accordingly, states are subject to neither the September 30 SIP filing deadline, nor the default penalty of having EPA impose Federal Implementation Plans. Further, the next steps for the SIP Call are generally unclear, as the court did not comment on the extent to which its ruling was influenced by (1) the states' petition for partial stay of the filing deadline and/or (2) its earlier ruling on the ozone National Ambient Air Quality Standards (NAAQS). The court's decision on the substantive aspects of the challenge is not expected until the spring of 2000.

Response to the Rulings

In response to the rulings, a number of alternative actions have been taken to address NOx emissions in the SIP Call Region.

1. The EPA petitioned for rehearing of the NAAQS decision by the full eleven-judge court — a broader review than the three-judge panel that had issued the court's ruling. On October 29, 1999 the court denied the requested rehearing. It is expected that the EPA will seek Supreme Court review.
2. In an attempt to reach a partial out-of-court settlement and to obtain greater NOx reductions than would be possible using the one-hour ozone standard, EPA engaged the affected states in negotiations during the summer of 1999 over the level of reductions to be made. EPA hoped through these discussions to broker a compromise with at least some of the states while the court was addressing broader issues. This effort was abandoned in early September 1999 as northeastern and midwestern states failed to reach agreement over the appropriate level of reductions, leaving the resolution to the court.
3. On November 3, 1999 the Justice Department (DOJ) filed enforcement suits and issued notices of violation (NOV) on behalf of the U.S. EPA against 25 generating facilities owned by seven investor-owned utility companies and a major public power system in the Midwest and South. The civil complaints (filed in seven federal courts) and the NOVs allege violations of the Clean Air Act's new source review (NSR) requirements. Specifically, they argue that the facilities

underwent “major modifications,” but failed to comply with the NSR requirements triggered by such modifications, which would have required more stringent emission controls at the facilities. DOJ argues that the modifications extended the life of the existing units, allowing the companies to avoid building newer, cleaner units. The targeted utilities have argued that their actions fully complied with the Act.

4. Following the failure of the EPA-brokered negotiations, New York’s attorney general on September 14 announced his intention to sue 17 upwind coal-burning generating facilities that he claims are impairing New York’s air quality. The attorney general alleged the plants are noncompliant with the Clean Air Act by failing to install required emission controls when they undertook certain maintenance and/or improvement activities at the plants. Following EPA’s November 3 enforcement initiative, New York filed civil actions against six out-of-state utility companies, alleging NSR violations at sixteen (16) facilities. New York’s governor in mid-October also called for NOx emission reductions from coal- and oil-based generating units in New York. Connecticut and New Jersey subsequently filed similar noncompliance suits against several upwind utilities.

5. On December 17, 1999, EPA issued a final rule responding to petitions filed in 1997 by four Northeast states under section 126 of the Clean Air Act, providing an alternative approach to Regional NOx reductions. The section 126 rule is based only on the old one-hour standard, rather than both it and the new eight-hour ozone standard (.08 ppm), upon which the 1998 NOx SIP Call was based. The section 126 rule differs from the SIP Call in at least two other key aspects. First, because the rule responds only to downwind state petitions related to the one-hour standard, the section 126 rule affects only 12 of the 22 states (and requires only 60 percent of the emission reductions) targeted by the SIP Call. These states include Delaware, Indiana, Kentucky, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia, and the District of Columbia. Ten others would only be subject to the implementation schedule upon action by the court. These states include Alabama, Connecticut, Georgia, Illinois, Massachusetts, Mississippi, Rhode Island, South Carolina, Tennessee, and Wisconsin.

   Second, since section 126 empowers EPA to regulate major sources directly, EPA itself set emissions limitations and allocations to large electric and industrial boilers and has put into place an emissions trading program for all affected facilities. Therefore, state implementation plans will not require revisions to effectuate either the required reductions or the interstate-trading program. These and other differences from the SIP Call change, and generally reduce, any potential reliability concerns associated with the NOx reductions. EPA’s final action on four additional states’ petitions is pending, although the majority of upwind sources targeted by those petitions are covered by the December 1999 rule.

States’ Implementation Status

All of these recent developments have raised questions about the extent and timing of Regional NOx controls. At the time of the stay of the SIP Call implementation schedule, a number of states had already developed and/or adopted SIP revisions. Although most states have suspended their implementation activities due to the court’s ruling, some are continuing to develop draft plans and accept comments.

In terms of companies’ response, questions about supply impacts of the NOx reductions have reinforced other market signals supporting new capacity investments. Turbine manufacturers are reporting record orders and developers are reporting that development schedules are limited most by the availability of gas turbine equipment. Companies that are not building new units in the SIP Call Region are evaluating their NOx control options and in some cases proactively ordering control equipment.

ANALYSIS OF PREVIOUS STUDIES

The following is a summary of the analyses of the other NOx SIP Call studies performed through May 1999, that address the reliability impacts of EPA's NOx rules. The NERC RAS NOx Task Force Study is included in Appendix A for reference.

EPA Study

EPA hired ICF Kaiser Consulting Group (ICF) to conduct the analytical work associated with EPA's NOx rules. The model used by ICF is a linear programming model that selects investment options to meet demand and energy requirements. The primary intent of the analysis was to model the dispatch of generating units to determine NOx emissions. Use of the program results to analyze reliability impact was apparently a secondary consideration. Based on this analysis, EPA concluded that its NOx rules would not result in a material adverse effect on reliability.

The shortcomings of EPA's study included:

1. A perhaps optimistic assumption that enough generation will be built to meet the minimum planning reserve margin requirement of the NERC Regions studied.
2. EPA assumed a reduction in the industry's demand and energy projections to account for EPA's representation of Climate Change Action Plan programs. EPA did not provide details of those assumptions as requested by the NERC RAS NOx Task Force.
3. Certain key sensitivity studies were not performed.

Utility Air Regulatory Group (UARG) Study

The Utility Air Regulatory Group (UARG) is a utility trade association coalition that represents a subset of utility interests in addressing emissions reduction programs. Membership in the coalition is mainly composed of several large utility companies in the Midwest and Southeast that rely heavily on coal-fired electricity generation.

UARG retained Applied Economic Research Company (AER) to evaluate the impact of EPA's NOx rule on reliability within ECAR. AER used ECAR data and the Oak Ridge Competitive Electricity Dispatch Model. AER assumed much longer retrofit outage times and a greater number of SCR retrofits than did EPA. UARG assumed that there would not be generation added in an amount necessary to meet the minimum reserve requirement. UARG concluded that the EPA NOx rules would result in significant adverse reliability impacts.

The shortcomings of the UARG study include:

1. The UARG approach did not examine a wide enough range of sensitivities.
2. There was not a formal written report for the UARG study. All information about the study was provided in the form of presentation slides. Additional information requested by the RAS NOx Task Force was not provided by UARG.
3. Since UARG's base case contains only the future generation additions that were presently permitted or under construction, the incremental reliability impact of the EPA NOx rules in this base case are likely to be overstated.
4. UARG did not perform a statistical analysis to determine how much support would be available from systems outside ECAR, but instead assumed no such support would be available. UARG

assumption that there would be no support available from systems outside ECAR overstates the reliability impact if such support is available.

5. UARG did not consider how much more frequently interruptible loads could be interrupted as a result of the EPA NOx rules.

OAC Studies

The Ozone Attainment Coalition (OAC) has performed two studies of the impact on reliability of EPA's NOx rules. The OAC is composed of several eastern U.S. utilities and other groups. The first OAC analysis (*Electric System Reliability: A Red Herring to Delay Clean Air Progress*, September 1998) was a critique of the above-mentioned UARG study. M. J. Bradley & Associates and E^3 Ventures, Inc. performed this critique, from which OAC concluded that the UARG study provided an incomplete basis for evaluating the impact of NOx controls on reliability and that the EPA NOx rules would not result in material adverse reliability impacts. EPA supports the OAC critique.

The second OAC study (*NOx SIP Call Compliance and Electric System Reliability: Compatible Goals for Achieving Needed Air Quality Benefits*, May 1999) was also performed jointly by M. J. Bradley & Associates and E^3 Ventures, Inc. The study methodology was similar to that of the first study.

The shortcomings of the OAC studies are:

1. The first OAC study assumed that each of ECAR's generating units would be maintained only once every three years instead of the once-per-year schedule traditionally used by ECAR members, thus understating the amount of capacity that would be out of service during the maintenance periods of the year.

2. The OAC study assumed that interruptible load would be available as a demand-side resource at any time. OAC did not analyze how much more frequently interruptible loads would have to be interrupted as a result of the EPA NOx rules.

3. OAC failed to do sufficient sensitivity studies such as assuming a level of capacity additions less than that shown in ECAR's plans. A large portion of the capacity in ECAR's expansion plans is uncommitted and is an expression of need rather than committed capacity.

4. OAC's definition of "reserve margin" is not consistent with that of the industry because OAC includes interconnection capability for ECAR in its calculation of "reserve margin." Although ECAR can usually import power in the event of emergencies over its interconnections, only firm sales and purchases over these interconnections are included in the industry's standard definition of "reserve margin." Thus, the true "reserve margin" for ECAR is less than that reflected in the OAC study.

Other Studies

The MAIN Region has made a preliminary analysis of the reliability impact of EPA's NOx rules on the MAIN Region. This preliminary analysis did not indicate a reliability concern unless adjoining systems would be unable to provide assistance as needed by MAIN. The MAIN Engineering Committee was not comfortable with some of the assumptions that were used in the analysis and have requested that follow-up studies be performed. The NERC NOx Task Force did not make a detailed review of MAIN's preliminary analysis.

MAIN's final *MAIN Guide No. 6 Reliability Study, 1999–2008,* dated October 14, 1999 (the annual MAIN assessment of resource adequacy) concluded that planned resources meet the MAIN criteria for reserve margins. That report included some assumptions of the NOx retrofit outages, but did not specifically analyze the incremental impacts of the outages. Therefore, the RAS NOx Task Force did not pursue further analysis of that study. The MAIN study is available on the Regional web site at www.maininc.org.

ECAR has completed its analyses for the ECAR Region, which is under final review by the ECAR Executive Board at this time. That report has not yet been made available to the NERC RAS NOx Task Force.

Common Limitations of EPA, UARG, and OAC Studies

The common limitation of the EPA, UARG, and OAC studies (other than the above-described absence of needed sensitivity studies) is the absence of a traditional probabilistic analysis such as a loss-of-load-expectation (LOLE) analysis. Such an analysis is needed in order to quantify the reliability impact of the EPA NOx rules. An LOLE analysis provides the expected number of days per year that firm load would be interrupted. Calculating the LOLE with and without the EPA NOx rules allows one to see the quantitative incremental impact of those rules.

Key Study Assumptions

The Task Force found that the key assumptions for analysis of the reliability impact of the EPA NOx SIP Call are:

1. Load forecasts,
2. the amount of generation that will be added during the retrofit period,
3. the amount of generating capability that will be retrofitted with SCR technology, and
4. the outage time required to integrate SCR retrofits.

The key assumptions used by EPA, UARG, and OAC vary considerably. For example, the capacity needing SCR retrofits ranges from 73 GW (EPA estimate) to 163 GW (UARG estimate). Outage times for integration of SCR retrofits range from no extension of normal maintenance outage periods to a four weeks (weighted-average) outage extension.

Since there was a wide variation in the key assumptions used by EPA, UARG, and OAC, since such variation could result in either little or considerable reliability impact, and since a lack of sensitivity analyses were performed by these groups, it was important that NERC RAS perform its own study.

STUDY METHODOLOGY

In March 1999, the Edison Electric Institute (EEI) retained PHB Hagler Bailly (PHB), an energy and economic consultant, to perform a study on the reliability impacts of the NOx regulations. Another consultant, Zinder and Cichanowicz, was retained to analyze and develop the level of SCR retrofits needed for the study, and any extensions necessary to maintenance outages to accomplish the SCR retrofits. EEI approached NERC for assistance and an agreement was reached between NERC and EEI for the NERC RAS to direct the EEI-funded study. The consultant performed the studies in two phases: a screening study and a sensitivity study.

The screening study (completed in June 1999) was performed to identify what parameters had the greatest adverse impact on reliability. Results from the screening study indicated small reliability impacts in MAAC and SERC. Based on those results and limited funding, no further analysis was performed for those Regions.

However, the screening study pointed to a number of important factors that may impact reliability:

- Amount of generation requiring SCR retrofit,
- length of the retrofit outages,
- degree of coordination of planned generation maintenance outages,
- availability and deliverability of outside resources, and
- use of interruptible demand.

After presentation of the screening study results to the NERC Adequacy Committee in July 1999, RAS directed the consultant to perform a limited sensitivity study as the second phase of the study. The sensitivities analyzed the following factors:

- Degree of coordination of planned generation maintenance outages,
- amount of capacity additions, and
- use of interruptible demand.

RAS requested additional reference cases without SCR retrofits, using assumptions from the sensitivity studies. Based on the result of the screening study and limited funding, a set of ten representative scenarios were designed and simulated for the ECAR and MAIN Regions. The scenarios do not attempt to show all possible permutations, but focused on analysis of the parameters that could potentially have a significant, adverse impact on reliability.

Conversely, the basic assumptions made by the RAS concerning demand forecasts, existing operable generation capacity, planned outage duration, and generator forced outage rates, etc., were more in keeping with data used by NERC and the Regions in their reliability analyses. These assumptions added a commonality to the scenarios.

Reliability Measurement — Loss of Load Expectation (LOLE)

As a basis to measure the reliability impacts of the NOx regulations, loss-of-load expectation (LOLE) was used throughout the screening and sensitivity studies. This reliability index is defined as the expected number of days per year on which available generating capacity is less than daily peak load. LOLE does not, however, indicate the magnitude of the capacity deficiency or how much firm load that would be interrupted as a result of that deficiency. Traditionally, utilities use an LOLE of one day per ten years (0.1 day/year) as a reliability criterion to plan for resource additions.

Data Sources

The following is a list of the data sources that were used for the RAS screening study:

Planning Data Assumptions	
Demand	NERC 1998 Electricity Supply and Demand (*ES&D*) Database, PHB developed its own weekly load models using this data.
Operable Generation Capacity	NERC 1998 *ES&D* Database, including all future changes to capacity regardless of status code, PHB developed its own weekly models using this data.
Planned Outage Duration	NERC 1999 *Generator Availability Data System (GADS) data for 1993–1997* outages.
Generator Forced Outage Rates	NERC 1999 GADS data (1993–1997 outages) — Units were represented with weighted Equivalent Forced Outage Rates (EFORs) based on GADS.

<table>
<tr><th colspan="4">NOx Mitigation Technology Assumptions</th></tr>
<tr><td rowspan="11">Amount of SCR Capacity</td><td colspan="3">Zinder/Cichanowicz Database and Algorithm and the initial EPA assumptions on the amount of capacity to be retrofitted with SCR were used. The amount of SCR capacity implied in the Zinder/Cichanowicz scenario is about 151,000 MW. The EPA analysis implied SCR capacity retrofits of about 73,000 MW.</td></tr>
<tr><td>REGION</td><td>EPA Rule</td><td>PHB Z/C</td></tr>
<tr><td>ECAR</td><td>36.3</td><td>62.9*</td></tr>
<tr><td>MAAC</td><td>9.4</td><td>14.1</td></tr>
<tr><td>MAIN</td><td>5.3</td><td>20.4</td></tr>
<tr><td>NPCC</td><td>0.7</td><td>0.7</td></tr>
<tr><td>SERC</td><td>19.0</td><td>4.4</td></tr>
<tr><td>SPP</td><td>2.2</td><td>45.3</td></tr>
<tr><td>MAPP</td><td>0.0</td><td>3.8</td></tr>
<tr><td>Total</td><td>72.9</td><td>151.6</td></tr>
<tr><td colspan="3">* An ECAR survey of its 83.3 GW of coal-fired generators indicated 52.3 GW of the 76.5 GW responding to the survey (92%) is planned to be retrofitted using SCR. If extrapolated for all of ECAR's coal-fired capacity, retrofits could impact 56.8 GW. Additional detail of retrofit assumptions of other NOx studies is contained in Table 1 of Attachment 3 to Appendix A of this report.</td></tr>
</table>

NOx Mitigation Technology Assumptions (continued)	
Length of Retrofit Window	Most of the RAS analyses were conducted assuming an SCR equipment retrofit window of 18 months (January 2002 through June 2003). To provide sensitivity for this factor, a limited number of cases were also run with a window of a 30-month duration (January 2001 through June 2003).
SCR Retrofit Outage Extension	For all RAS analyses, a 4.5-week maintenance outage extension was assumed. For the SCR retrofit units, an analysis was done by Zinder/Cichanowicz to develop the length of the SCR outage based on a few generic unit characteristics. These estimates of the required NOx-related planned outage extension were used for both the Zinder/Cichanowicz scenarios and the EPA unit compliance scenarios. The SCR outage generally was assumed to take place concurrent with the longest planned outage during the retrofit period. PHB analysis indicated that the outage extensions ranged from 0 to 10 weeks, with the MW-weighted average outage extension was 4.5 weeks. It should be noted that the ECAR survey showed a 0- to 15-week range of retrofit outage extensions, with 2- to 4-week weighted average extension (depending on other scheduled maintenance being performed). The EPA analysis had modeled a one additional week extension.

Assumptions

Other NOx Mitigation Technologies

It was assumed that only units requiring the installation of SCR could potentially require extensions to their normal planned maintenance outages. All other applications of the various mitigation technologies were assumed to be performed within the scope of planned outages without extension.

The PHB study did not include the use of amine enhanced fuel lean gas reburn, an emerging NOx control technology, in the analysis. Like the Selective Non-Catalytic Reduction (SNCR) technology, it is assumed that no additional retrofit outage time would be required for that technology. If this emerging technology is proven to be efficient and economical and is commercially available in time to be selected by utilities for retrofit purposes, then it could replace some of the SNCR technology assumed in these analyses and the resulting higher efficiencies would, in turn, reduce the amount of SCR that is needed.

Transmission Import Capability

Screening Study

In the screening study, transmission import capability was modeled as 40% of the sum of the non-simultaneous First Contingency Total Transfer Capabilities (FCTTCs) into each Region, as reported based on the average of the NERC 1998 summer and 1998/99 winter assessments.

Sensitivity Study

In the sensitivity study, transmission import capability was modeled as 59% of the sum of the non-simultaneous FCTTCs for both ECAR and MAIN. Both Regions thought that 40% used in the screening study was too low. The 59% value was determined for MAIN to be more representative of the difference between simultaneous and non-simultaneous FCTTC. The 59% value was also agreed to for ECAR, but under certain circumstances, the 59% value may be too high.

Multi Area Methodology

All of the analyses were conducted using a two-area approach to LOLE. Area 1 is defined as the area of interest (i.e., ECAR or MAIN), and Area 2 is defined to be the remainder of the Regions in the Eastern Interconnection.

Generator unavailability in the two areas was modeled using equivalent outage factors for each generator class in each Region, based on the NERC Generating Availability Data System (GADS). Load duration was modeled based on FERC Form 714 hourly load data for 1997, scaled to the 1998 NERC Electricity Supply & Demand (*ES&D*) peak load and energy forecasts for future years. This information was used to develop the capacity and weekly demand data used in the analysis.

Once the NOx compliance technologies were selected and the outage assumptions developed, the two-area analysis was run using PHB Hagler Bailly's proprietary modeling program, GENREL. The program has an outage scheduling optimization module that schedules generation outages to optimize the reliability within each Region. No NOx retrofit outages were allowed to begin after May 1, 2003, but outages that began prior to May 1, 2003 could be continued into the summer season, if such timing was part of the optimal schedule the program developed for each Region. There were no other restrictions placed on the GENREL optimization module for other peak periods.

Loss of Load Expectation (LOLE) was calculated for each of the retrofit years (2001, 2002, and 2003) in the base case (i.e., no NOx-related retrofits) and all scenarios with NOx-related retrofits.

Scenario Descriptions

The study scenarios were developed to evaluate only those situations that were thought to have a potential impact on reliability. Also, RAS examined the relative sensitivity of some of the major factors that could affect the LOLE results. The following is a description of these factors:

Planned Generation Maintenance Outage Coordination

To model the coordination of planned generation maintenance outages, LOLE programs approximate coordination by attempting to optimize reserve margins over a year or season. The PHB GENREL program includes such an optimization routine.

Screening Study

In the screening study, planned generation maintenance outages were optimized using the GENREL program's outage optimization module. This module optimizes outage scheduling to levelize reserve margin throughout the year within each Region. Optimization was done within each of the Regions in Area 2, but not among the Regions in Area 2, and not between Areas 1 and 2.

Sensitivity Study

Sensitivities were run using an approach which optimized outage schedules in the six to eight largest systems within Area 1. The remaining systems within Area 1 were aggregated and optimized as a single system. Each Region in Area 2 was also optimized separately. RAS recognized that this is not necessarily realistic, but is more representative of the level of maintenance outage coordination that might actually be necessary.

Capacity Additions

Screening Study

For the screening study, capacity additions were added based on capacity plans submitted by the Regions to NERC for the 1998 *ES&D*. It should be noted that the ES&D data does not include generating plants that were not under contract (Independent Power Producers or merchant plants), but does include placeholder capacity in the form of surrogate generator units or planned purchases for some Regions. The placeholder capacity for ECAR is substantial. However, the amount of announced additional merchant generation for ECAR and the other Regions in the analysis (that is not captured in *ES&D*) is also substantial.

Sensitivity Study

For the sensitivity study, capacity was added to that used in the screening study to whatever degree necessary for the Region under study (Area 1) to meet its reserve requirement. Uncommitted forecasted additions in excess of these target margins were removed from the scenario. Committed generation additions in excess of the target margins were maintained in the analyses. The following margins were used:

ECAR	10% capacity margin (which equates to 11.1% reserve margin) — based on Total Internal Demand, as a surrogate for ECAR's Dependence on Supplemental Capacity Resources (DSCR) criteria[4]
MAIN	18% reserve margin — based on Net Internal Demand

An additional sensitivity was done to simulate a condition where only two thirds of the regional reserve requirements is achieved. This was done to recognize the uncertainty associated with yet-to-be-committed capacity additions and the potential effect on reliability when coupled with the NOx retrofit outages.

Reliance on Interruptible Demand

Most of the screening and sensitivity cases were run on the presumption that interruptible demand was interrupted at all times i.e., Net Internal Demand (NID). However, to provide a sensitivity for this factor, certain cases were run on the presumption that interruptible demand was not interrupted i.e., Total Internal Demand (TID).

Retrofit Window

Most of the cases were run assuming an SCR equipment tie-in installation window of 18 months (January 2002 through June 2003). However, to provide sensitivity for this factor, a limited number of cases were also run with a window of 30-months duration (January 2001 through June 2003).

4 ECAR projects a 7.4% capacity margin in 2002, and meets its one-to-ten days DSCR criterion as long as generation availability is maintained at or about 80.3% (the 1999 availability level). For further detail, refer to the ECAR Report 99-GRP-57, available on the ECAR website at: www.ECAR.org.

Supplemental Allowance Pool

No analysis was performed on the potential impacts on the retrofit window of the supplemental NOx allowance pool of up to 200,000 tons of summer NOx allowances that states can award to generating units in 2003 and 2004. That would effectively extend the compliance date, and therefore, the retrofit window. This will have the same effect as increasing the retrofit outage window and therefore further reduce the impact on reliability. However, this allowance pool would be allocated by individual states and may be spread over all the sources of NOx, thus diluting the benefit of a NOx early credit and banking program to the utility sector.

DISCUSSION OF STUDY RESULTS

Specific comparisons were conducted to determine the relative contribution of each of several factors in the overall Loss of Load Expectation (LOLE) calculations. The results of those comparative cases are characterized in the discussion of both the screening and sensitivity studies by the following terms:

Not Significant	No differences, or if there are, those differences are not noticeable to operations.
Significant	Real differences that may be operationally manageable through emergency procedures and/or short-term planning.
Cause for Concern	Difficult to manage operationally but may be mitigated through longer-term planning (i.e., season ahead to one year ahead).
Cause for Alarm	Effects on reliability will be serious, and the consequences cannot be managed operationally.

Screening Study Results

To gauge the overall impact of the NOx SIP Call quickly, RAS directed the consultant to perform a screening study using readily available data. Those data sources are explained in the Study Methodology section of this report.

Level of Retrofit Outages — EPA Versus Zinder/Cichanowicz

The EPA analysis of the NOx SIP Call assumed approximately 73,000 MW of generating capacity would have to be retrofitted with SCR technology. Zinder/Cichanowicz (Z/C), the consultant used in the EEI-funded study, estimated that approximately 151,000 MW of capacity would have to be retrofitted with SCR equipment.[5] As expected, increasing the amount of capacity to be retrofitted with SCR equipment increased the Loss of Load Expectation (LOLE) in the probabilistic analysis of the screening study (see Figure 1).

In ECAR, 2002 was found to be the critical year where there was a *significant* impact for the Z/C retrofit scenario. Otherwise, the Z/C and EPA retrofit scenarios both produce impacts, which are *not significant*.

For MAIN, 2003 was found to be the critical year where there was a *significant* impact for the Z/C retrofit scenario. Otherwise, the Z/C and EPA retrofit scenarios both produce impacts, which are *not significant*.

---

5 A survey of retrofit plans in ECAR tracked more closely with the Zinder/Cichanowicz values. Although the ECAR survey indicated a two-week average outage extension, a 4.5 week weighted average extension was applied to both the EPA and Z/C cases for consistency.

The screening study indicated that the impacts were *not significant* for the level of SCR retrofits assumed in the EPA scenario in either ECAR or MAIN. Therefore, the EPA scenario was not examined extensively in the sensitivity analysis.

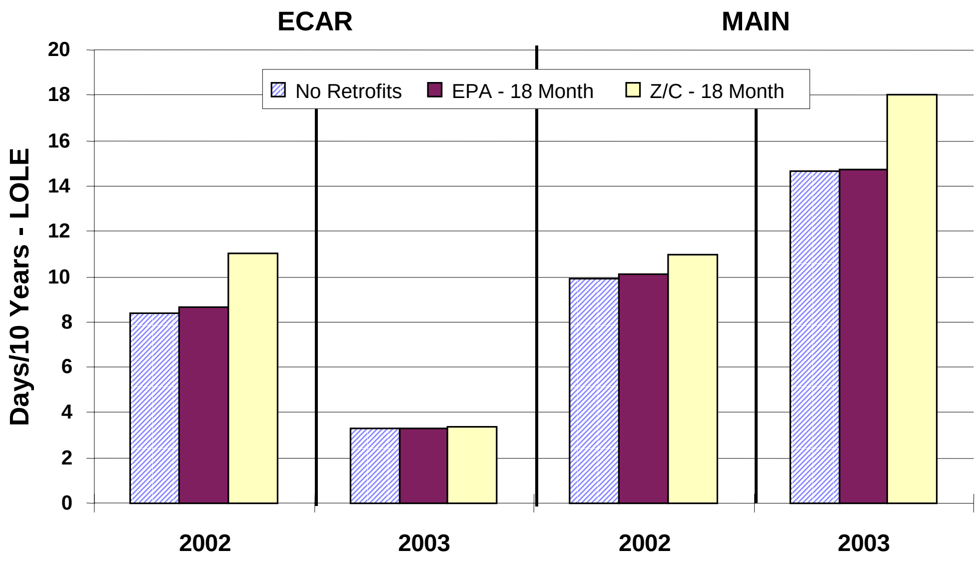


Figure 1

EPA Versus Zinder/Cichanowicz

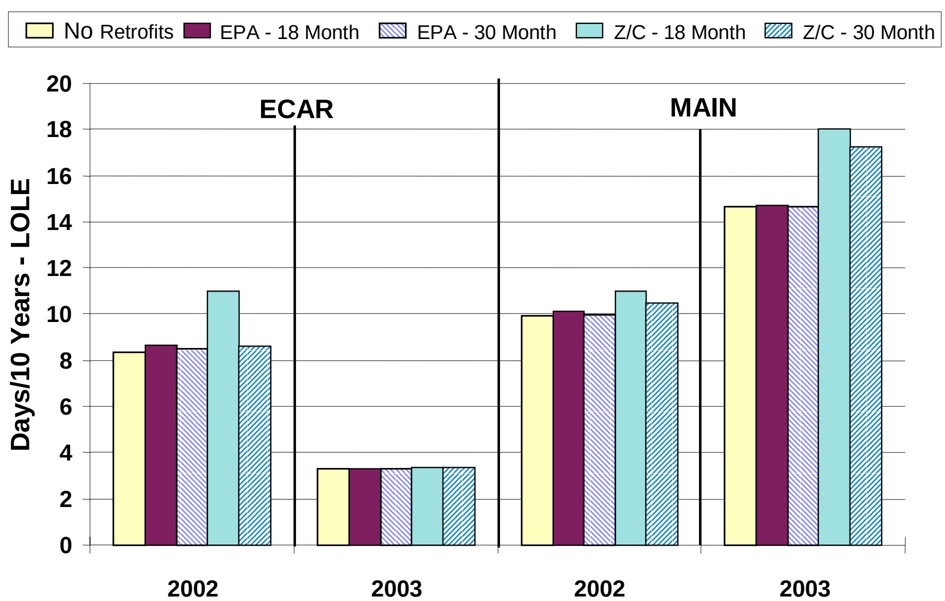


Figure 2

Length of Retrofit Window — Eighteen Versus Thirty Months

Length of Retrofit Window — Eighteen Versus Thirty Months

In the screening study, most of the cases were run assuming an SCR equipment tie-in installation window of 18 months (January 2002 through June 2003). However, to provide sensitivity for this factor, a limited number of cases were also run with a window of a 30-month duration (January 2001 through June 2003). Figure 2 compares the differences. In ECAR, 2002 was found to be the critical year where there was a *significant* impact for the 18-month retrofit window scenario. Otherwise, the 18- and 30-month retrofit window scenarios both produce impacts for both ECAR and MAIN, which are *not significant*.

The screening study indicated that the impacts were *not significant* for the 30-month retrofit window in either ECAR or MAIN. Therefore, no significant additional analysis of the 30-month window scenario was pursued in the sensitivity study.

Sensitivity Study Results

Based on the results of the screening study, RAS determined that there were a number of factors that should be investigated further, in addition to the retrofit outages themselves, including the impacts of planned maintenance outage coordination, the level of capacity additions, and the use of interruptible demand.

Results of the screening study and the sensitivity study cannot be directly compared with each other. A number of key assumptions were refined from the screening study for the sensitivity analysis.

The scenarios selected by RAS do not attempt to show all possible permutations, but focused on analysis of the parameters that could potentially have a significant, adverse impact on reliability. The reliability indicated in the study results can be improved by any or all of the following: reducing the amount of SCR retrofits required, lengthening the retrofit window (perhaps by use of the supplemental allowance pool), or shortening the SCR retrofit outage time. Additional details on the assumptions used in this analysis are contained in the Study Methodologies section of this report.

Impact of the SCR Retrofit Outages

A number of cases were run to gauge the potential impact of the NOx SIP Call. All of the cases were based on an 18-month SCR retrofit window and serving Net Internal Demand. The scenarios, depicted in Figure 3, had the following results:

S-1. Decentralized Coordination with Regional reserve requirements being met
- For ECAR, the results show a doubling of LOLE in 2002 with the SCR retrofits, which is a *cause for concern*. The impact is less pronounced for 2003, but is still *significant*.
- For MAIN, the impact of the SCR retrofits is *not significant* in 2002, but is *significant* in 2003.

S-2. Decentralized coordination with only 2/3 of the Regional reserve requirements being met
- For ECAR, the impact of the retrofits is a *cause for concern* in 2002. Again, the impact is lower for 2003, but is still *significant*.
- For MAIN, the impact of the retrofits is *not significant* for 2002, but is *significant* in 2003.

S-3. Centralized coordination with Regional reserve requirements being met
- For ECAR, the impact of the retrofits is *not significant* in either 2002 or 2003.
- For MAIN, the impact of the retrofits is *not significant* in either 2002 or 2003.

S-4. Centralized coordination with only 2/3 of the Regional reserve requirements being met
- For ECAR, the results show a *significant* impact in 2002 with the SCR retrofits. The impact is *not significant* in 2003.
- For MAIN, the impact of the SCR retrofits is *not significant* in 2002, but is *significant* in 2003.

Additional detail of the LOLE results is contained in Appendix B.

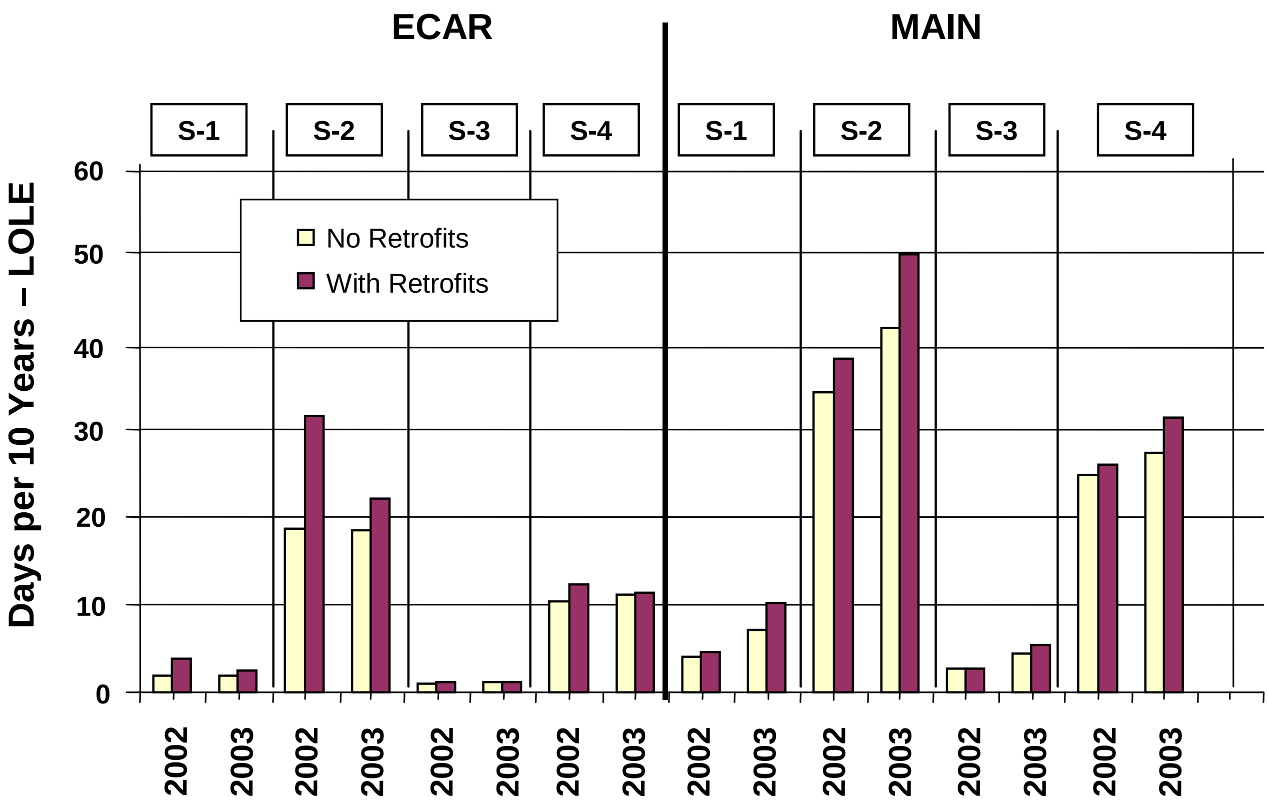


Figure 3

Impact of SCR Retrofit Outages

Impact of Outage Coordination

A comparison was done between scenarios where planned maintenance outages were coordinated on a centralized basis for each Region studied, and where outages were only coordinated on an individual system basis. Figure 4 highlights the importance of planned maintenance outage coordination in improving reliability, even without the impacts of the retrofits. If Regions are able to improve outage coordination, the adverse reliability impacts of the NOx SIP Call can be partially mitigated.

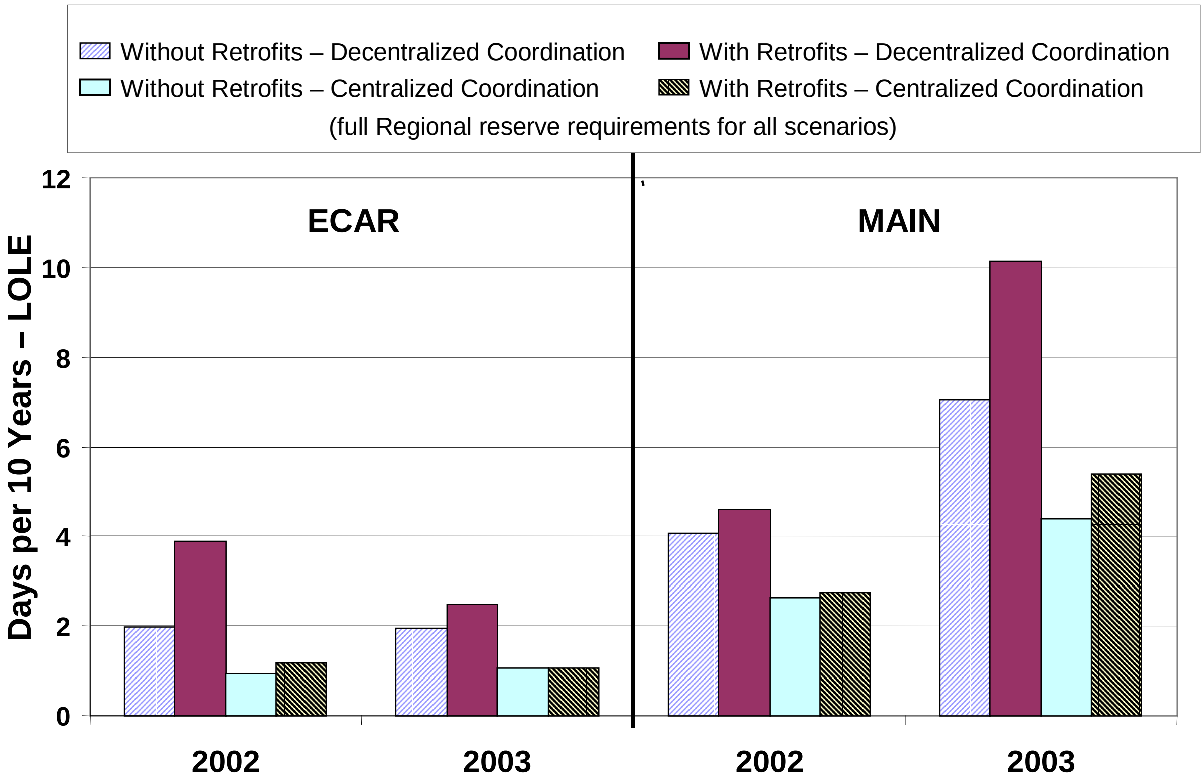


Figure 4

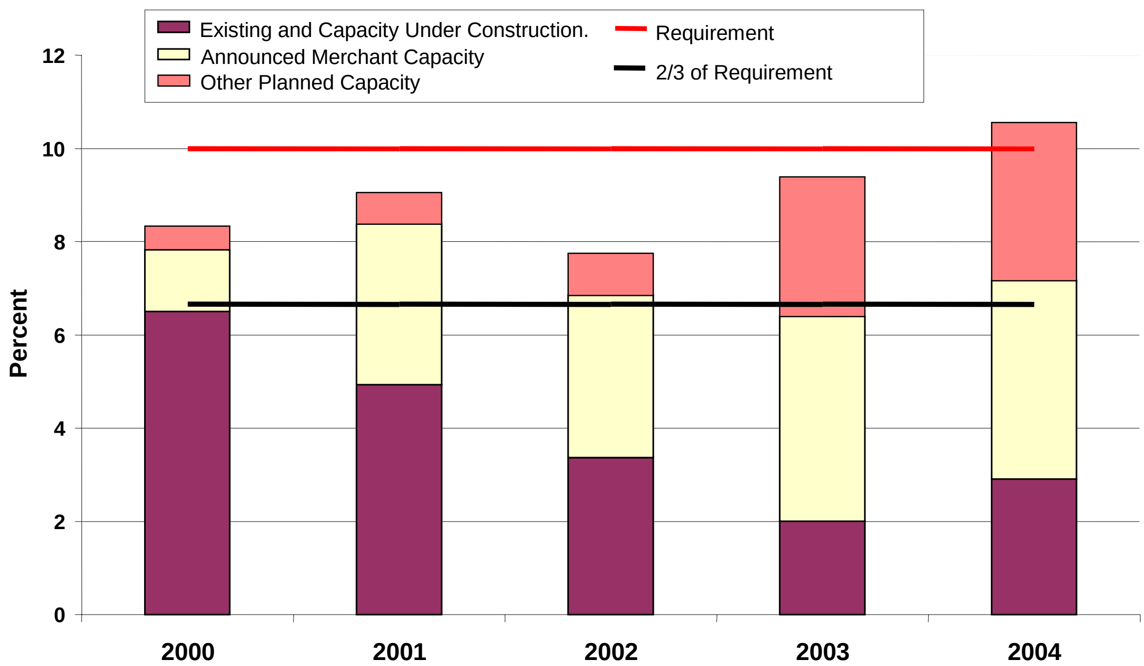
Impact of Outage Coordination

However, it must be recognized that the optimized level of coordination modeled in this analysis is idealistic. There are a number of barriers to attaining the level of coordination modeled, the most prominent of which is competitive pressures. Any steps to improve coordination will help to mitigate any adverse reliability impacts of the SIP Call.

Additional details are contained in Appendix B.

Impact of Capacity Additions

Generation additions have always been somewhat cyclical, with periods of high and low capacity margins, reflecting the characteristics of economic growth. Periods of strong economic growth typically drive electricity demand upward, leading to lower capacity margins. When demand was growing at about 7% per year in the late 1960s and very early 1970s, margins were low as utilities were struggling to build enough capacity to keep up with the growth. Conversely, recessionary economic conditions typically stall any change in capacity margins. When demand growth dropped off after the oil embargo in 1973, margins became high as generation already under construction came on line. The electric industry in North America is currently at a low point on one of those cycles, with capacity margins at relatively low levels. This is coupled with what has been a very strong economy in North America, driving continued demand growth. Therefore, there is an increasing need for new generating capacity.



Note: ECAR Capacity Margin is based on Total Internal Demand. Data from 1999 ES&D and EPSA as of Sept. 1999.

Figure 5

ECAR Capacity Margins

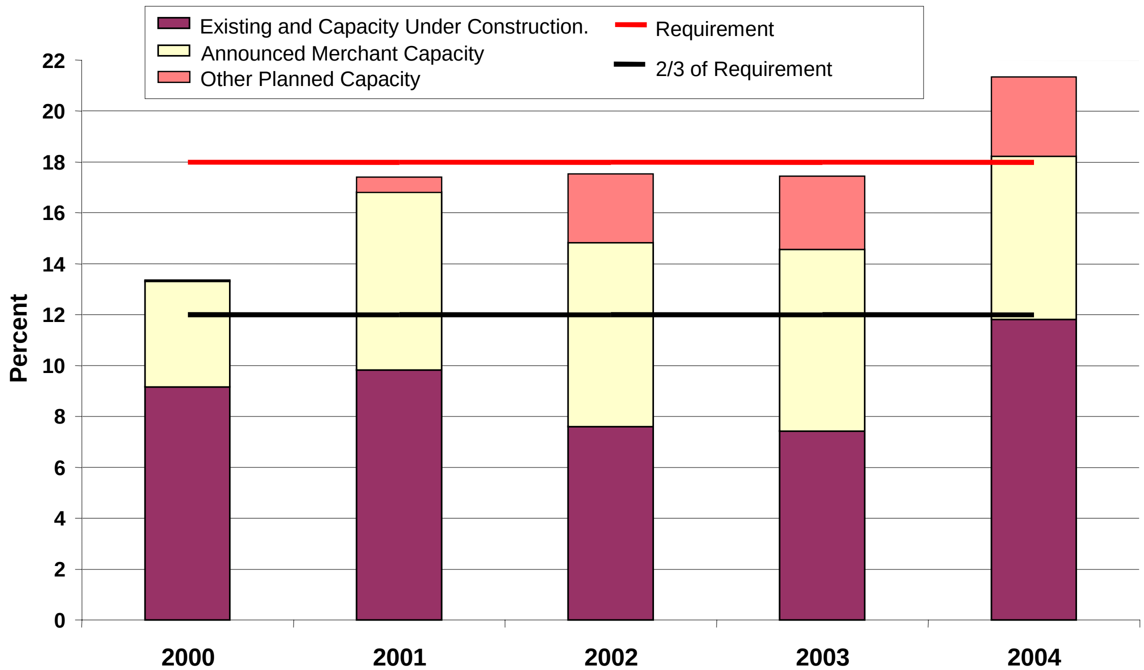
At the same time, the industry is currently undergoing a transition to a competitive market in generation. Consequently, the merchant generators have taken the active lead in the addition of the needed new generation capacity. Announced merchant generation additions[6] are highlighted in Figures 5 and 6 (adjusted to reflect plants that have a likelihood of completion).

---

6 Based on the announced merchant capacity as of September 1999. Additional announcements have been made since that time.

It should be noted that the “Other Planned Capacity” portion of Figures 5 and 6 includes capacity that is placeholder capacity in the form of surrogate generator units or planned purchases. Much of those resource requirements are expected to be developed by the merchant plant industry and, therefore, may constitute duplication of capacity included in the “Announced Merchant Capacity” portion of the graph.

It is readily apparent that ECAR and MAIN are relying on merchant generation additions to meet their respective reserve requirements. Without the needed additional generating capacity, reliability conditions in both Regions would be seriously impacted.



Note: MAIN Capacity Margin is based on Net Internal Demand. Data from 1999 ES&D and EPSA as of Sept. 1999.

Figure 6

MAIN Capacity Margins

To analyze the sensitivity of reliability to capacity additions, RAS examined scenarios where only enough generation was added in ECAR and MAIN to achieve two-thirds of their reliability reserve requirements for 2002 and 2003. These scenarios were also run with and without the SCR retrofit outages for the NOx SIP Call. The results of the comparison in Figure 7 highlight the strong sensitivity of reliability to the level of capacity additions within the Regions. This result is apparent even in the no retrofit cases, indicating that if capacity additions are not built at a rate to achieve the Regional reserve requirements, the SCR retrofit program will only aggravate an already difficult situation.

Additional details are contained in Appendix B.

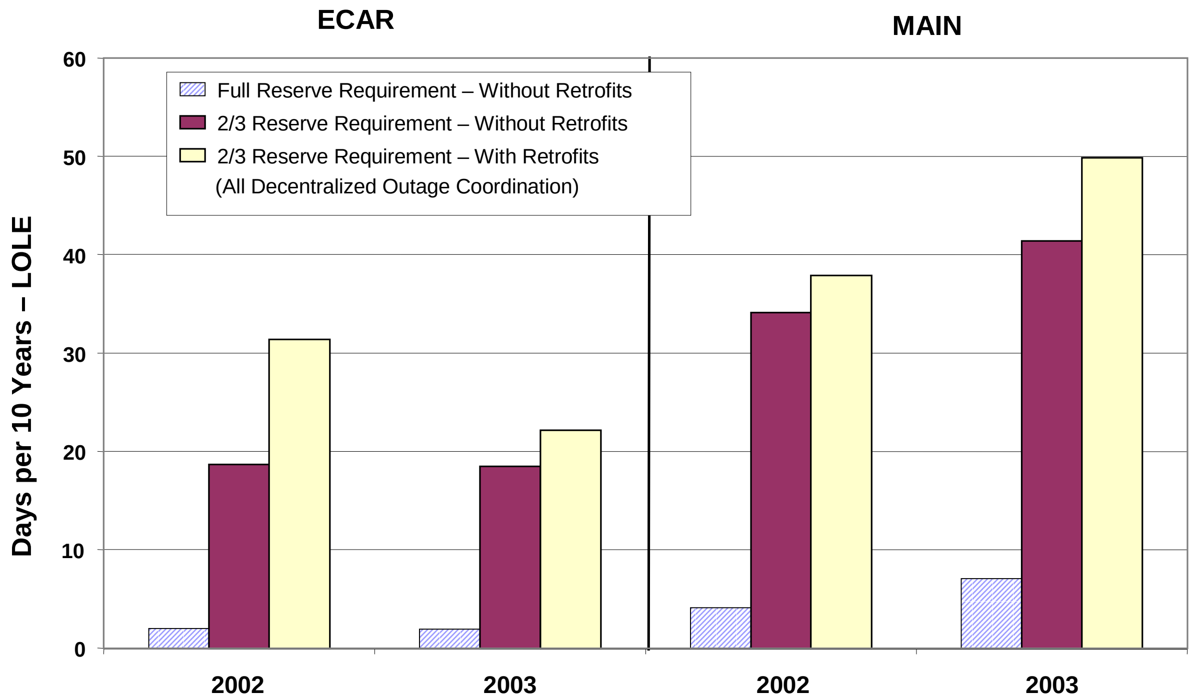


Figure 7

Impact of Capacity Additions

Impact of the Use of Interruptible Demand

Interruptible demand contracts have varying terms of agreement. In some instances, the interruptible contracts only allow interruption on a specific number of occasions throughout the year, or limit the timeframe in which the service interruptions can occur, typically at the time of system peak or during system capacity emergencies. To analyze the reliability impacts of the SIP Call retrofits, some scenarios were based on interruptible demand always being available (calculations were based on Net Internal Demand, NID Scenario), and other scenarios were based on interruptible demand never being available (calculations were based on Total Internal Demand, TID Scenario). Interruptible demand in ECAR and MAIN is substantive, and the extreme assumption of interruptibles being either always available or never available results in very large differences in the annual LOLE results.

Analysis performed by the consultant indicated that virtually all of the LOLE contribution from the unavailability of interruptible demand in the TID Scenario occurred during the summer and winter seasonal peak periods. If the interruptibles are assumed to be available during those peak weeks in the TID Scenario, then the resultant annual LOLE is close to the LOLE calculated in the NID Scenario. This is indicative that the issue of interruptible demand is not an important factor in minimizing the reliability impacts relative to the SCR retrofit program.

APPENDICES

APPENDIX A — CRITIQUE OF STUDIES THAT HAVE ADDRESSED THE RELIABILITY IMPACTS OF EPA'S NOx SIP CALL

NERC RAS NOx Task Force

January 2000

TABLE OF CONTENTS

I. STATEMENT OF ASSIGNMENT

At its October 1998 meeting, the NERC Reliability Assessment Subcommittee (RAS) appointed a task force (RAS NOx Task Force) to perform a high level review of the bulk system reliability aspects of EPA's and others' analyses of EPA's NOx SIP Call. The task force was instructed to capture key aspects of these analyses and recommend a course of action for RAS to address the potential effect on bulk power system reliability of EPA's SIP Call. The task force consists of four RAS members: Jim Bruggeman (lead), John Conti, Esam Khadr, and John Osborn. The task force also received input form Murty Bhavaraju (PSE&G), Mark Brownstein (PSE&G), and Mike Geers (Cinergy).

II. EXECUTIVE SUMMARY

Background and Recommendation

In the fall of 1998, EPA placed into effect final rules for NOx emissions that essentially require electric utilities in a 22-state area to comply with a regional emission level of about 563,000 tons beginning with the 2003 Ozone season. This emission level represents an 85% reduction from 1990 levels. To comply with these rules, generating units in the impacted area would need to be modified, including major retrofits. The Regions having to make the most retrofits are ECAR, MAIN and SERC. This rulemaking has been the source of considerable debate — both sides of the debate have performed reliability studies. These studies have results ranging from there being no material adverse reliability effect to there being a very significant reliability impact. This wide range of results is attributable primarily to the disparate methodologies and assumptions used in these studies. As explained in more detail below, the RAS NOx Task Force found that these studies are either flawed or otherwise insufficient for drawing conclusions as to the potential reliability impact of EPA's NOx rules. As a result, in early 1999, the RAS NOx Task Force recommended to RAS that they should conduct their own independent analysis to draw those conclusions.

In September and October of 1998, ECAR, MAIN, and SERC individually sent letters to the EPA expressing concern over the potential impact of EPA's NOx rules on the reliability in their respective Regions. These letters stated that the extended outages of coal units during the 2000–2003 period for retrofits required to reduce NOx emissions could materially impair reliability. In addition, these letters respectfully requested that EPA reconsider the implementation schedule to ensure that the retrofit work could be accomplished without jeopardizing reliability. In response to these concerns, EPA set up a compliance supplement pool of up to 200,000 tons of summer NOx allowances that states can award to generating units in 2003 and 2004 for which controls cannot be installed in time for compliance in 2003 without unduly compromising electric system reliability or for which allowances cannot be bought from the allowance trading pool.

Task Force Efforts

During the summer of 1998, the NERC Engineering Committee (EC) instructed RAS to investigate the potential reliability impacts of EPA's NOx rules. At the October 1998 RAS meeting, an EPA representative provided an overview of their work leading to its NOx rules. At that meeting, RAS spent considerable time discussing the EC's concern and appointed four of its members as a task force (the

RAS NOx Task Force) to perform a high-level review of the above-mentioned studies. The members of this task force included representatives of DOE, MAAC, ECAR, and SPP.

The RAS NOx Task Force spent considerable time and effort reviewing these studies. The task force met with EPA to go over answers to a set of detailed questions. Subsequently, the entire RAS heard presentations by representatives of the parties that have performed these studies. In addition, the entire RAS has discussed these studies.

Analysis of Existing Studies

The following are analyses of the studies performed to date that address the reliability impacts of EPA's NOx rules.

EPA Study

EPA hired ICF Kaiser Consulting Group (ICF) to conduct the analytical work associated with EPA's NOx rules. The model used by ICF is a linear programming model that selects investment options to meet demand and energy requirements. The primary intent of the analysis was to model the dispatch of generating units to determine NOx emissions. Use of the program results to analyze reliability impact was apparently a secondary consideration. Based on this analysis, EPA concluded that its NOx rules would not result in a material adverse effect on reliability.

The shortcomings of EPA's study included:

1. A perhaps optimistic assumption that enough generation will be built to meet the minimum planning reserve margin requirement of the NERC Regions studied;

2. A reduction in the industry's demand and energy projections to account for EPA's representation of Climate Change Action Plan programs; and

3. Certain key sensitivity studies were not performed.

UARG Study

The Utility Air Regulatory Group (UARG) is a utility trade association that represents a subset of utility interests in addressing emissions reduction programs. Membership in the association is mainly composed of several large utility companies in the Midwest and Southeast that rely heavily on coal-fired electricity generation.

UARG retained Applied Economic Research Company (AER) to evaluate the impact of EPA's NOx rules on reliability within ECAR. AER used ECAR data and the Oak Ridge Competitive Electricity Dispatch Model. AER assumed much longer retrofit outage times and a greater number of SCR retrofits than did EPA. UARG assumed that there would not be generation added in an amount necessary to meet the minimum reserve requirement. UARG concluded that the EPA NOx rules would result in significant adverse reliability impacts.

The shortcomings of the UARG study include:

1. The UARG approach did not examine a wide enough range of sensitivities.

2. Failure to provide information regarding UARG's study assumptions that were requested by the RAS NOx Task Force.

3. Since UARG's base case contains only the future generation additions that were presently permitted or under construction, the incremental reliability impact of the EPA NOx rules in this base case may be overstated.

4. UARG did not perform a statistical analysis to determine how much support would be available from systems outside ECAR, but instead assumed no such support would be available. UARG, assuming that there would be no support available from systems outside ECAR, overstates the reliability impact if such support is available.

5. UARG did not analyze how much more frequently interruptible loads would have to be interrupted as a result of the EPA NOx rules.

OAC Studies

The Ozone Attainment Coalition (OAC) has performed two studies of the impact on reliability of EPA's NOx rules. The OAC is composed of several eastern U.S. utilities and other groups. The first OAC analysis (*Electric System Reliability: A Red Herring to Delay Clean Air Progress*, September 1998) was a critique of the above-mentioned UARG study. M. J. Bradley & Associates and E^3 Ventures, Inc. performed this critique from which OAC concluded that the UARG study provided an incomplete basis for evaluating the impact of NOx controls on reliability and that the EPA NOx rules would not result in material adverse reliability impacts. EPA supports this OAC critique.

The second OAC study (*NOx SIP Call Compliance and Electric System Reliability: Compatible Goals for Achieving Needed Air Quality Benefits*, May 1999) was also performed jointly by M. J. Bradley & Associates and E^3 Ventures, Inc. The study methodology was similar to that of the first study.

The shortcomings of the OAC studies are:

1. The first OAC study assumed that each of ECAR's generating units would be maintained only once every three years instead of the once-per-year schedule traditionally used by ECAR members, thus understating the amount of capacity that is out of service during the maintenance periods of the year.

2. OAC did not analyze how much more frequently interruptible loads would have to be interrupted as a result of the EPA NOx rules.

3. OAC failed to do sufficient sensitivity studies such as assuming a level of capacity additions less than that shown in ECAR's plans. A large portion of the capacity in ECAR's expansion plans is uncommitted and is an expression of need rather than committed capacity.

4. In viewing Figures 8 and 10 in OAC's May 1999 report, the reader should be aware that OAC's definition of "reserve margin" is not consistent with that of the industry because OAC includes 5,000 MW of interconnection capability for ECAR in its calculation of "reserve margin." Although ECAR can usually import power in the event of emergencies over its interconnections, only firm sales and purchases over these interconnections (the net of which is far less than a 5,000 MW purchase) are included in the industry's standard definition of "reserve margin." Therefore, the true "reserve margin" for ECAR is less than that reflected in the OAC study.

Other Studies

The MAIN Region has made a very preliminary analysis of the reliability impact of EPA's NOx rules on the MAIN Region. This preliminary analysis does not indicate a reliability concern. The MAIN Engineering Committee is not comfortable with some of the assumptions that were used in the analysis and has requested that follow-up studies be performed. The task force did not take the time to make a detailed review of MAIN's preliminary analysis since these follow-up studies are to be made. ECAR has undertaken reliability analyses for the ECAR Region. SERC has not done such a study and does not plan to. When made available to the RAS NOx Task Force, the task force plans to review these ECAR and follow-up MAIN studies.

Common Shortcomings of EPA, UARG, and OAC Studies

A common shortcoming of the EPA, UARG, and OAC studies (other than the above-described absence of needed sensitivity studies) is the absence of a traditional probabilistic analysis such as a loss-of-load-expectation (LOLE) analysis. Such an analysis is needed in order to quantify the reliability impact of the EPA NOx rules. For example, an LOLE analysis provides the expected number of days per year that firm load would be interrupted. Calculating the LOLE with and without the EPA NOx rules allows one to see the quantitative incremental impact of those rules.

Key Study Assumptions

The task force found that the key assumptions for analysis of the reliability impact of the EPA NOx SIP Call are:

1. Load forecasts,
2. The amount of generation that will be added during the retrofit period,
3. The amount of generating capability that will be retrofitted with SCR technology, and
4. The outage time required to integrate SCR retrofits.

The key assumptions used by EPA, UARG, and OAC vary considerably. For example, the capacity needing SCR retrofits ranges from 73 GW (EPA estimate) to 163 GW (UARG estimate). Outage times for integration of SCR retrofits range from no extension of normal maintenance outage periods to a weighted-average four weeks extension of normal maintenance outage periods.

Since there is a wide variation in the key assumptions used by EPA, UARG, and OAC, such variation could result in either little or considerable reliability impact, and since a lack of sensitivity analyses were performed by these groups, it is important that RAS perform its own study.

III. FINDINGS

The findings of the RAS NOx Task Force are as follows:

1) The differences in the conclusions made by EPA, UARG, and OAC as to the impact of the EPA NOx rules on reliability arise primarily from the very significant differences in the assumptions that they used in their analyses. These differences are discussed further below and in Attachment 3 to this report. Since all of these analyses lacked a sufficient amount of sensitivity analysis and the models used were, at least in part, "black boxes" for proprietary reasons, the task force concluded that RAS should conduct it own analysis using models it understood and assumptions with which it felt comfortable.

2) The task force found that the key assumptions for analysis of the reliability impact of the EPA NOx SIP Call are:

    a) Load forecasts,

    b) The amount of generation that will be added during the retrofit period,

    c) The amount of generating capability that will be retrofitted with SCR technology, and

    d) The outage time required to integrate SCR retrofits.

    The key assumptions used by EPA, UARG, and OAC vary considerably. For example, as shown in Table 1 of Attachment 3, the capacity needing SCR retrofits ranges from 73 GW (EPA estimate) to 163 GW (UARG estimate). Outage times for integration of SCR retrofits range from no extension of normal maintenance outage periods to a weighted-average four weeks extension of normal maintenance outage periods.

3) The reduction that EPA made to the utilities' forecasts of energy and demand may not be reasonable. Experience has shown that the utilities' forecasts may already be too low. In recent years, actual demands have been higher than forecasted demands and utilities projected load growth rates are lower than historical growth rates. For example, the Eastern Interconnection envisions a 1.8% peak-demand load growth, whereas the historical growth rate has been 2.4%.

    If the reduction that EPA made to utilities' forecasts of demand results in reserve margins much higher than reality, then the reliability impact of its NOx rules would be understated. The RAS NOx Task Force has asked EPA to provide capability, demand, and reserve information that it used in its analysis as well as the utility-provided capability, demand and reserve information that it modified —EPA has not yet responded to this request.

4) The EPA analysis assumes that utilities and/or IPPs will build enough generation to meet the reserve margin criteria for the Regions. If enough generation is not built to achieve these criteria, then reliability will not be as good as projected by EPA. As for the Regions' plans in the EIA-411, with the huge amount of unknown capacity, the Regional plans may well be a statement of need, not intentions, to build. On the other hand, it should be noted that the EIA-411 data does not include all planned merchant plant generation additions.

5) If EPA is correct in its base-case assumption that normal maintenance outages will not have to be extended for retrofit connections, then reliability should not be impacted as a result of the retrofits.

6) If maintenance periods have to be extended, then reliability will be lessened, but without further analysis it is not known whether there is a material impact on reliability. EPA says its sensitivity studies assuming seven-week and nine- week connect times do not indicate a reliability concern.

7) A common shortcoming of the EPA, UARG, and OAC studies (other than the above-described absence of needed sensitivity studies) is the absence of a traditional probabilistic analysis such as a loss-of-load-expectation (LOLE) analysis. Such an analysis is needed in order to quantify the reliability impact of the EPA NOx rules. For example, an LOLE analysis provides the expected number of days per year that firm load would be interrupted. Calculating the LOLE with and without the EPA NOx rules allows one to see the quantitative incremental impact of those rules.

8) There seems to be no disagreement among the players in the NOx reliability issue as to the time required (two weeks) to connect SNCR retrofits. However, there is significant disagreement on the amount of SCR required and the time it takes to integrate SCR facilities. For example, UARG estimates SCR retrofits for three times the amount of generating capacity, as does EPA. Also, UARG argues that some units take four weeks, some take ten weeks, and some will take 14 weeks or more. The different opinions as to the amount of SCR required results from different views as to the cost and performance of the various retrofit options. EPA says its sensitivity study for a nine-week retrofit integration period assumed all retrofit integrations were done in one year instead of three or more and the UARG argument of "three times the SCR requirement" is covered by that study.

9) EPA's assumption that the amount of maintenance is the same in each winter month is not realistic. This might overstate maintenance during some months, and understate maintenance during other months. This prevents RAS from drawing a conclusion about the relative reliability impacts for these months.

10) All of the players in the NOx reliability issue agree that there is no known material impact on the availability of generator units as a result of the retrofits having been made. Likewise, these players agree that there is no material impact on the net dependable capacity of these units.

11) The UARG study approach did not examine a wide enough range of sensitivities.

12) Since UARG's base case contains only the future generation additions that were presently permitted or under construction, the incremental reliability impact of the EPA NOx rules in this base case may be overstated.

13) Detailed review of the UARG study was difficult due to the lack of information contained in the presentation overheads provided to RAS by UARG. No report was provided.

14) UARG did not perform a statistical analysis to determine how much support would be available from systems outside ECAR, but instead assumed no such support would be available. This assumption overstates the reliability impact if such support is available.

15) UARG did not analyze how much more frequently interruptible loads would have to be interrupted as a result of the EPA NOx rules.

16) The first OAC study incorrectly assumed that each of ECAR's generating units would be maintained only once every three years instead of the once-per-year schedule traditionally used by ECAR members. This assumption was corrected in OAC's second study.

17) The second OAC study may understate the amount of capacity requiring SCR retrofits and the maintenance extension times required for such retrofits. The study did not analyze the increase in frequency of disruptions of interruptible load that would result from these extension times. There is a lack of sensitivity analyses and no quantitative impact (such as LOLE) analyses.

18) In viewing Figures 8 and 10 in OAC's May 1999 report, the reader should be aware that OAC's definition of "reserve margin" is not consistent with that of the industry because OAC includes 5,000 MW of Interconnection capability for ECAR in its calculation of "reserve margin." Although ECAR can usually import power in the event of emergencies over its interconnections, only firm sales and purchases over these interconnections (the net of which is far less than a 5,000 MW purchase) are included in the industry's standard definition of "reserve margin." Thus, the true "reserve margin" for ECAR is less than that reflected in the OAC study.

19) Only the OAC study considered the potential impact of amine enhanced fuel lean gas reburn, an emerging NOx control technology. If this emerging technology is proven to be more efficient and economical than the SNCR technology and is commercially available in time that it can be selected by utilities for retrofit purposes, then it could replace some of the SNCR technology assumed in these analyses and the resulting higher efficiencies would reduce the amount of SCR that is needed.

IV. RECOMMENDATIONS

The RAS NOx Task Force recommends that RAS conduct its own analysis of the reliability effects of EPA's NOx SIP Call using a probabilistic approach. This analysis should contain an adequate number of sensitivity studies for key study assumptions. RAS should determine the bounds of these assumptions. Further, RAS should make its best judgment as to the "most likely" values for these assumptions. The RAS NOx Task Force has identified the following key assumptions:

1) Load forecasts,

2) Amount of generation that will be added during the retrofit period,

3) Amount of generating capability that will be retrofitted with SCR,

4) Outage time required to integrate retrofits.

The key assumptions used by EPA, UARG, and OAC vary considerably. For example, the capacity needing SCR retrofits ranges from 73 GW (EPA estimate) to 163 GW (UARG estimate). Outage times for integration of SCR retrofits range from no extension of normal maintenance outage periods to four weeks extension of normal maintenance outage periods. The RAS NOx Task Force prepared a report (see Attachment 3) describing the reasons given by EPA, UARG, and OAC for their selection of these two key assumptions. Since there is a wide variation in the key assumptions used by EPA, UARG, and OAC, such variation could result in either little or considerable reliability impact and since a lack of sensitivity analyses were performed by these groups it is important that RAS perform its own study.

V. TASK FORCE ACTIVITIES

As a starting point, the RAS NOx Task Force determined the key parameters that influence a reliability analysis of EPA's SIP Call and divided among the task force members the review of how EPA addressed those parameters. John Osborn prepared a document *EPA Study Review from a Load and Capacity Perspective, November 5, 1998*, and Jim Bruggeman prepared a document dated November 5, 1998 on the outage period required for NOx retrofit and station power requirements for NOx retrofit equipment.

The task force reviewed several other documents in the course of its work. A list of those documents is contained in Attachment 1.

The task force met with the EPA, UARG, and OAC to obtain answers to questions the task force had on the assumptions and study models they employed. Most of these meetings were held during RAS meetings where other RAS members participated.

VI. SYNOPSIS OF EPA ANALYSIS

EPA hired ICF Kaiser Consulting Group (ICF) to conduct the analytical work associated with EPA's SIP Call. ICF used its Integrated Planning Model (IPM) in addressing, among other things, the potential effects of EPA's SIP Call on bulk power system reliability.

The IPM is an optimization model that uses a linear programming formulation to select investment options and to dispatch generation and load management resources to meet overall electricity demand and energy requirements. The model adds capacity to meet a reserve margin criterion. Plants are retired based on the expected life (or license in case of nuclear) of the plant which is categorized by plant type and size. Generation dispatch is optimized based on a five-segment load-duration curve representation for each period studied. The model results were originally intended to evaluate the cost effectiveness of the EPA NOx reduction proposal. For more information on the IPM model, please see Attachment 1 of *Analyzing Electric Power Generation under the CAAA*, March 1998.

The following are specific assumptions used in the IPM model for the analysis of the EPA SIP Call.

1) For its demand assumptions, ICF began with the internal net demand values in the *NERC Energy Supply and Demand 1997*. Energy and peak demand were adjusted downward in the model to account for EPA's representation of Climate Change Action Plan programs that it believes are not captured in the information supplied by the electric power industry.

2) Two periods were simulated: summer (May–September) and winter (October–April).

3) ICF assumed that enough capacity would be built in each NERC Region to meet a specified reserve margin criterion for that Region for each period (summer and winter) studied. If the EPA SIP Call reduced reserve margins to an unacceptable level, then the model would add capacity to meet the targeted reserve margin. The Region's own criterion for capacity or reserve margin was used. For Regions that use a reliability index in lieu of a percent margin, ICF used a percentage reserve that it felt was equivalent to that index. For example, the assumed reserve margin criteria for ECAR (which has a reliability index instead of a percent margin) was assumed to be 15%.

4) Generating unit maintenance was assumed to take place during the winter period (seven months). The amount of generating unit capacity out of service for maintenance was assumed to be the same during each hour of this winter study period. Such an assumption is contrary to actual practice where load plus maintenance, not just maintenance, is levelized. ICF states that this is a conservative assumption.

5) In its base-case analysis, EPA assumed that the retrofit integration period for each generating unit to be retrofitted was equal to or less than the normal maintenance period for that unit. Thus, the IPM model did not have to add capacity due to a reduction in reliability attributable to an extension of normal maintenance periods. For its two sensitivity studies, EPA assumed that SCR-retrofit integration times would be increased from five weeks to seven and from five weeks to nine weeks. Because the model did not add capacity over and above that added for the base case for these extended maintenance periods, EPA deduced that there would not be any reliability problems in the winter period due to such extensions of retrofit integration time.

6) For transfer capabilities within and between NERC Regions, ICF used 75% of the average of NERC summer and winter transfer capabilities, which EPA assumes represents reasonable long-term, sustainable interregional transfer capabilities. This assumption was based on ICF's judgment and discussions with various NERC Regions. Changes in the generating unit capacity factors indicated that some additional trading was occurring during retrofit outages.

7) In its base-case analysis, EPA assumed that a 3–5 week outage period is necessary to integrate the SCR equipment. This estimate was derived based on consultation with manufacturers that would install such equipment and on information of what occurred in Germany when it required the installation of similar equipment.

8) The model evaluated options for selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), and gas reburn. The option chosen for a plant was the most economic one for that plant based on EPA's assumptions of cost and performance characteristics of the various retrofit options. The model also considered outright replacement of capacity with alternative capacity that meets current New Source Performance Standards (NSPS).

9) It was assumed that interruptible load could be interrupted at any time and as frequently as needed. Depending on the number of interruptions and the contract terms for interruptible loads, this assumption could overstate the amount of capacity available to cover any potential generation outages resulting from unit retrofits.

For more information on the IPM model, please see Attachment 2 of *Analyzing Electric Power Generation under the CAAA*, March 1998.

On December 14, 1998, the RAS NOx Task Force (with Murty Bhavaraju substituting for Esam Khadr) and Bob Cummings met with Sam Napolitano and Peter Saragotta of EPA and John Blaney and Boddu Veskatesh of ICF. The purpose of the meeting was for the RAS NOx Task Force to get a better understanding of (1) the basis for the assumptions used by EPA and (2) how the IPM model works. The task force needed this information in order to judge whether the EPA analysis had adequately addressed the NOx retrofit reliability issue.

Prior to this meeting, the task force had provided to EPA a set of questions. At the meeting, EPA provided written answers to these questions and discussed the answers with the task force. These questions and answers are contained in Attachment 2.

VII. SYNOPSIS OF UARG ANALYSIS

The Utility Air Regulatory Group (UARG) is a utility trade association (composed of approximately 60 electric utilities, Edison Electric Institute, American Public Power Association, and National Rural Electric Cooperative Association) that represents a subset of utility interests in addressing emissions reduction programs. Membership in the association is mainly composed of several large utility companies in the Midwest and Southeast that rely heavily on coal-fired electricity generation.

UARG retained Applied Economic Research Company (AER) to help evaluate what impact EPA's proposed implementation schedule for SIP-call-driven NOx retrofits would have on the reliability of the electric power supply in the eastern United States. In particular, UARG asked AER to evaluate the impact of the SIP-Call-driven NOx retrofit program in the states of West Virginia, Pennsylvania, Ohio, Kentucky, Indiana, and Michigan — the states in ECAR where NOx controls, will have to be installed on approximately 81,000 MW of fossil-fired generation.

AER conducted it's analysis using the power supply and demand information from ECAR (NERC, *Electricity Supply Demand — 1998–2007*), and using information from the affected utilities concerning the control systems that they intend to use to meet the terms of EPA's SIP Call rule.

AER's assumptions regarding the extent of NOx controls needed in ECAR were those contained in a detailed technical analysis by H. Zinder & Associates and J. E. Cichanowicz, Inc. (*Evaluation of Alternative NOx Emission Caps in the 22-State SIP Region*, June 18, 1998), which assigned NOx control efficiencies to three NOx control options (SCR, SNCR for units 325 MW and smaller, and natural gas reburn) and estimated the resulting costs of complying with different levels of emission reductions.

AER used the Oak Ridge Competitive Electricity Dispatch Model (developed by DOE and EPA) to evaluate the impact of SIP-call-driven NOx reductions on reliability of power supply. The model was used to determine and compare the reserve margins and power availability in ECAR, with and without the impact of SIP-call-driven NOx retrofits. The RAS NOx Task Force has not fully examined how this model works.

AER concludes the following from its analyses:

- If EPA requires that all affected generation in ECAR retrofit NOx controls by May 1, 2003, then there will be serious power shortages in ECAR.

- If all 81,000 MW of affected ECAR generation must retrofit controls during the nonpeak demand months that occur between October 1, 2000 (when the first control systems can be installed) and May 1, 2003 (EPA's currently proposed compliance deadline), a period of 83 weeks, many units will have to be taken down for retrofits simultaneously, affecting the amount of electric power that will be available in affected areas.

- If all existing generation continues to operate, if all generation currently under construction is completed as scheduled, and if an additional 5,000 MW of generation is built in ECAR between now and 2001 (which AER says is optimistic), the calculated reserve margin will drop to minus 1.7 percent. UARG says this translates into voltage reductions, brownouts, and rolling blackouts in ECAR for close to 500 hours during each year that the retrofits are being done.

- If new construction totals 3,000 MW instead of 5,000 MW, there will be voltage reductions, brownouts, and rolling blackouts in ECAR for close to 500 hours during each year that the retrofits are being done.
- Using EPA's reduced growth-rate figures, the analysis predicts that power shortages in ECAR during each year when retrofits are done will range between 268 hours (for the 5,000 of additional generation scenario) and 800 hours (if no additional generation is operational in ECAR within the next three years).
- Shortages in ECAR cannot be "made up" by purchase of power from other Regions because these Regions will be faced with similar demands for power and will have similarly stretched reserve margins during the same periods.
- If SIP Call implementation deadline is extended to May 1, 2005, there are still reliability problems. Assuming all existing generation continues to operate, all generation currently under construction is completed as scheduled, and an additional 11,000 MW of generation is built in ECAR between now and 2004, the reliability situation would improve substantially. However, even with the two-year extension, there would be times in the off-peak season of each affected year that there will be power shortages in ECAR.

UARG disagrees with EPA's reduction in utility-provided demand and energy forecasts. EPA bases that reduction on the Administration's Climate Change Action Plan (CCAP). UARG says that the CCAP assumptions are overly optimistic. UARG says the broad range of actions taken or committed to have barely made a dent in the demand growth for electricity, and therefore, NERC demand and energy projections should be used.

UARG disagrees with EPA's base-case retrofit integration times (3–5 weeks) for SCR. UARG says that some SCR retrofits can be done in 4–6 weeks, the vast majority will take 8–12 weeks, and some will take greater than 14 weeks.

UARG disagrees with EPA's estimate of the amount of generation that will be retrofitted with SCR. UARG says some 177,000 MW (out of about 250,000 of fossil generation in the overall SIP Call Region) will be retrofitted with SCR as compared to EPA's estimate of 63,000 MW. UARG says its estimates are based on information from its member companies and they are supported by a recent report by NESCAUM. UARG says that the EPA should not set a deadline for completion of retrofits until it is known exactly which units will be retrofitted with SCR.

VIII. SYNOPSIS OF OAC ANALYSES

The Ozone Attainment Coalition (OAC) is composed of the following members:

- Audubon Society of New Hampshire
- Connecticut Fund for the Environment
- Consolidated Edison
- KeySpan Energy
- Merck & Company
- Natural Resources Defense Council
- Northeast Utilities
- PACE Energy project
- PECO Energy Company
- Public Service Electric & Gas
- PG&E Generating Company

The OAC has prepared two reports on the reliability impacts of the EPA NOx SIP Call. The first report is *Electric System Reliability: A Red Herring to Delay Clean Air Progress*, September 1998. The report states why OAC believes that NOx control retrofits under EPA's Section 110 SIP Call will not threaten electric system reliability. The report was produced jointly by M. J. Bradley & Associates and E^3 Ventures, Inc. and was a critique of UARG's analysis of the effects of the EPA SIP Call on reliability within ECAR.

The OAC report states that the most recent data ECAR has submitted to EIA projects enough capacity to cover extending scheduled maintenance outages for retrofits even under winter peak load conditions. OAC takes issue with UARG's assumptions for the outage times required for SCR retrofits. OAC says that the Oak Ridge model used by AER is not intended for evaluating reserve margins or reliability. The report concludes by saying that only with unexplained assumptions that project insufficient capacity without retrofits, does the UARG analysis illustrate a reliability problem due to installation of NOx controls.

In answer to one of our questions (see answer to Question 7 in Attachment 2), EPA referred to this OAC report. In addition, EPA said they endorsed this OAC report.

UARG issued a rebuttal to this OAC report revealing what it claimed to be errors and biases in the report. In this rebuttal, UARG said that the OAC analysis is in error by a wide margin, which changes OAC's assessment of reliability being ample to a situation of highly constrained supply posing potential danger to adequacy and reliability.

The second OAC study (*NOx SIP Call Compliance and Electric System Reliability: Compatible Goals for Achieving Needed Air Quality Benefits*, May 1999) was also performed jointly by M. J. Bradley & Associates and E^3 Ventures, Inc. and was more detailed than the first report.

This second report again concludes that the EPA NOx SIP Call will not result in reliability problems. OAC concludes there is sufficient time to schedule all the necessary SCR retrofits during the normal maintenance periods of the year. Further, OAC concludes that the SCR retrofits will reduce available capacity by a small amount — between one-half and one percent.

This second report examines the ECAR Region for the year 2001. OAC developed an algorithm for determining the units that require SCR retrofits. This algorithm is not explicitly based on economics like the algorithms used by EPA and UARG. Normal planned generating unit maintenance is allocated to levelize reserve margins in each month of the maintenance seasons. OAC assumes that normal generating unit maintenance outages would have to be extended two weeks to integrate SCR retrofits. OAC spreads these two-week periods evenly throughout the 83-week maintenance period between November 2000 and May 2003.

IX. OTHER ANALYSES

The MAIN Region has made a very preliminary analysis of the reliability impact of EPA's NOx rules on their Region. This preliminary analysis does not indicate a reliability concern. The MAIN Engineering Committee is not comfortable with some of the assumptions that were used in the analysis and has requested that follow-up studies be performed. The task force did not take the time to make a detailed review of MAIN's preliminary analysis since these follow-up studies are to be made. ECAR has undertaken reliability analyses for the ECAR Region. SERC has not done such a study and does not plan to do one. When made available to the RAS NOx Task Force, the task force plans to review these ECAR and follow-up MAIN studies.

ATTACHMENT I — MATERIALS REVIEWED

- *Analyzing Electric Power Generation under the CAAA*, Office of Air and Radiation. U.S Environmental Protection Agency, March 1998.
- *Feasibility of Installing NOx Control Technologies by May 2003*, prepared for the Office of Air and Radiation, U.S. Environmental Protection Agency by ICF Incorporated and ARCADIS Geraghty & Miller, September 1998.
- *Electric System Reliability: A Red Herring to Delay Clean Air Progress*, Ozone Attainment Coalition, September 1998.
- EPA's Response in the Record on the AER/UARG report.
- EPA's Comments on the NOx Control Costs: Focus on the Zinder Reports.
- Federal Register, *Environmental Protection Agency: Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone*, Tuesday, October 27, 1988, Vol. 63, No. 207, Selected Pages.
- *The NOx SIP Call and Reliability of the Power System*, Office of Air and Radiation, U.S. Environmental Protection Agency, October 21, 1998 (Presented to the NERC RAS).
- *Answers to NERC's Questions about the EPA Report: Analyzing Electric Power Generation under the CAAA And ICF's Integrated Planning Model (IPM)*, U.S. Environmental Protection Agency and ICF Resources Incorporated, December 14, 1998 (Presented to the RAS Task Force on the Impact of the EPA SIP Call on Electric Reliability).
- *The Impact of EPA's Regional SIP Call on the Reliability of the Electric Power Supply in the Eastern United States*, Prepared by Applied Economic Research for the Utility Air Regulatory Group, August 10, August 26, and September 11, 1998.
- *Supplemental Ozone Transport Rulemaking Regulatory Analysis*; Office of Air and Radiation, U.S. Environmental Protection Agency, April 7, 1998.
- EPA's Clean Air Power Initiative (CAPI) October 22, 1996.
- *The Impact of EPA's Regional SIP Call on the Reliability of the Electric Power Supply in the Eastern United States*, overview of comments previously submitted by the Utility Air Regulatory Group and overview chart presentation of Applied Economic Research Co., September 11, 1998.
- September 11, 1998 letter from Andrea Bear Field (on behalf of UARG) to Robert Perciasepe of EPA, Re: Additional Information on Electric Power Reliability Issues.
- *NOx SIP Call Compliance and Electric System Reliability: Compatible Goals for Achieving Needed Air Quality Benefits*, Ozone Attainment Coalition, May 1999

- .

ATTACHMENT II — ANSWERS TO NERC'S QUESTIONS ABOUT THE EPA REPORT:

Analyzing Electric Power Generation under the CAAA and ICF's Integrated Planning Model (IPM)

Prepared by

U.S. Environmental Protection Agency

And

ICF Resources Incorporated

December 14, 1998

Answers to NERC's Questions about the EPA Report: Analyzing Electric Power Generation under the CAAA and ICF's Integrated Planning Model (IPM)

Throughout these questions and answers, the report should be taken to mean the report; *Analyzing Electric Power Generation under the CAAA, March 1998* and model should be taken to mean; ICF's Integrated Planning Model (IPM).

Notably, many factors and several types of analysis have influenced EPA's position on the electric system reliability issue in the NOx SIP Call. The modeling that EPA did with IPM was just one element of the effort that the Agency has had to assess this issue. NERC should recognize this in reviewing the responses below. To thoroughly understand, how the Agency has reached its position on the reliability issue, NERC should begin with the preamble of the NOx SIP Call and then review the record of this rulemaking. Among the important documents that it should also consider is EPA's *Feasibility of Installing NOx Control Technologies by May 2003*, September 1998. Another important study to review in the record of the NOx SIP Call rulemaking is the report of the Ozone Attainment Coalition entitled *Electric System Reliability: A Red Herring to Delay Clean Air Progress*, September 1998. In conducting its review, EPA urges NERC to consider the full record that EPA has for the NOx SIP Call and the answers to the questions provided below.

Demand (Energy and Peak Load) Forecast

Question 1: Describe how the demand (energy and peak load) forecasts were developed. Explain the differences between these forecasts and those provided by the utility industry through the Energy Information Administration (EIA-411) reporting.

Answer: Details can be found on page A2-3 of the report on how the energy and peak load forecasts were developed. As described there, the demand forecast is based on NERC's Electricity Supply and Demand 1997 (ES&D 1997) forecast. The NERC and utility staffs that prepare this forecast would be the appropriate points of contact to describe how that forecast differs from the EIA-411 forecast.

Question 2: What adjustments were made to the North American Electric Reliability Council (NERC) Energy Supply and Demand 1997 Forecast?

Answer: The electric demand growth rate for the period 1996 through 2006 was taken from NERC's ES&D 1997 forecast of Net Energy for Load. The average annual NERC growth rate for 2000 through 2006 was used to extend the demand growth forecast through 2010. After 2010, EPA adopted a 1.3 percent growth rate, which was used by DRI in its 1995 forecast. A more detailed explanation can be found on page A2-3 of the report.

Question 3: Why were the Climate Change Action Programs subtracted from the NERC forecast?

Answer: EPA believes that it is appropriate to incorporate the impact of the voluntary measures in the Climate Change Action Plan (CCAP) on future electricity demand. The EPA has always believed that it is appropriate to incorporate any reasonable assumptions that the Agency can support that will affect future electricity demand, or electricity generation practices, into its Base Case forecast. For example, improvements in electric generation technology, fuel price changes, and other types of assumptions that are important elements of EPA's forecast of electricity generation and resulting air emissions are also not mandated by regulation. The Agency has considered the impact of the CCAP in using the IPM model for analysis since 1996, and documentation of the assumptions that the Agency has been making have been available for public review since 1996. Until the end of the rulemaking for the NOx SIP Call (summer of 1998), there was no challenge to this consideration in the numerous reviews that there have been of EPA's documentation of how it uses the IPM model. Also, no one has challenged EPA's specific approach to factoring the CCAP into its electricity generation forecast. (This can be confirmed by examination of the dockets for the Clean Air Power Initiative and the Phase II Title IV NOx Rule, records of EPA's Science Advisory Board, and the records of the Ozone Transport Assessment Group meetings.)

The EPA updated its assumptions in IPM for the CCAP at the beginning of 1998. The EPA updated its assumptions in the same manner as it has done in the past—by lowering the most recent NERC demand forecast by the amount of electricity demand between 2000 and 2010 that the best available analysis suggests will occur due to the activities in CCAP. The EPA used in the in-depth evaluation of the future implications of the CCAP for reducing electricity demand that was the basis for the findings in the Administration's *Climate Action Report*, July 1997. The amount of demand reduction that occurs appears in Analyzing Electric Power Generation under the CAAA, March 1998. The *Climate Action Report* analysis was reviewed extensively within the Federal Government by EPA, the Department of Energy, and other federal agencies, and the report was reviewed publicly before its publication. The EPA has not received public criticism that it has overstated the electricity demand reductions that are the basis for the carbon reductions under the CCAP.

Question 4: If the EPA forecast is low due to more conservation resulting from higher energy prices, is the forecast used prior to the 1990 CAAA for implementing SO2 available? Has EPA compared that forecast (if available) to what has actually occurred?

Answer: The electric demand forecast is input for IPM. Therefore, unless we are doing a sensitivity analysis concerning electric demand, the demand forecast remains constant in various runs. EPA inputs into IPM an electricity forecast that uses NERC's forecast from the *Electric Supply and Demand for 1997* after it has been adjusted to account for CCAP and extends that forecast out to 2025 using DRI's projections of electric demand growth (fully explained in the answers to Questions 2 and 3 above). No other changes are made to the NERC forecast. The Agency has not compared the electric generation forecast that the Agency used in considering provisions of the 1990 CAAA for SOx to what has occurred since 1990. This is because it's not relevant to the situation that exists today, where many determinants of generation load are different today than they were nine years ago.

Question 5: Does the demand forecast used include demand from interruptible customers? If not, how would including their demand effect EPA's results/conclusions?

Answer: The demand forecast used in the model includes electric energy consumed by interruptible customers. However, the peak demand is based on NERC's projected net internal demand, which does not include interruptible customers. The Agency has not analyzed cases where electricity demand associated with interruptible customers at the time of peak demand is included. However, including them would not alter the conclusions of the feasibility analysis because they are by definition customers who are willing to have their electric supply interrupted and therefore are not to be considered in reliability considerations.

Generating Capacity

Question 6: Explain the basis for the assumption that sufficient new generating unit capacity will be installed to maintain the reserve margins that are used in the report. What assurance and degree of comfort do you have that these amounts of capacity additions will take place during the electric industry's transition to a fully functioning competitive market? Did you consider potential construction of merchant plants in addition to generating unit expansions provided by the utility industry through EIA-411 reporting? Does the model differentiate between utility and merchant capacity expansion? If so, how? If not, why not?

Answer: The modeling analysis assumes that wholesale restructuring is occurring as embodied in FERC Order 888. Thus, we assume that there is a competitive market for electricity. Therefore, supply and demand interaction will be manifested in competitively set prices. Relative capacity shortfalls will be reflected in higher prices. As prices rise, as they did this past summer, additional capacity will be built in response. Implicit in the reserve margins used in the model is an assessment of future loss of load probabilities and the willingness to pay to avoid unserved energy. These reserve margins are derived from NERC reliability assessments. Based on work done by EIA recently which indicates that optimal reserve margins in many Regions, including ECAR, should be higher than the estimates used in the SIP Call analysis, EPA's reserve margin estimates are conservative.

For existing units, IPP plants are separated from utility owned plants. For new plants, IPM does not differentiate between utility and merchant plants. Firm capacity additions as reported by NERC are included in the model. In addition, the model endogenously adds capacity to maintain the Regional reserve margin requirements. Given that many power plants have changed owners in recent years and many more are likely to change hands in the future as restructuring continues, historical ownership of power plants is not particularly relevant.

Question 7: Is there a way of showing the reserve margin at various times throughout the year? Can you provide these values for the base case and extended retrofit outage case?

Answer: Yes, seasonal reserve margins can be calculated and displayed. Time given to us to respond to this list of questions did not enable ICF to do this. EPA questions whether the above referenced report by the Ozone Action Coalition provides the type of information that NERC is looking for and whether that report is adequate for NERC's need to consider the amount of time available for retrofitting electric generation units outside of the peak months.

Question 8: Explain the basis for the generator unit availabilities used in the analysis. Explain differences in those availabilities and those shown in NERC Generation Availability Data Set (GADS) – e.g., nuclear availability of 80.3% is higher than that actually experienced (equivalent availability of 73% for 1993-1997). Did you treat forced and maintenance outages separately?

Answer: The basis for EPA's assumptions on generation unit availabilities comes from different sources. The primary basis of the generator unit availabilities for those that rely primarily on fossil fuels is consideration of the trend reported in NERC's Generation Availability Data Set (GADS). The Federal Energy Regulatory Commission used the same approach to its analysis in Promoting Wholesale Competition through Open Access – Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities—Final Environmental Impact Statement, April 1996. Hydro units are assumed to operate the way they have recently done according to EIA Form 759 data for 1992 to 1995. Waste plants and other renewables are assumed to have a 90 percent availability.

In the relevant time period to installation of pollution control equipment (2000-2004), capacity availability for fossil plants is based on the trend found in the NERC's GADS data. For steam electric units (who install post-combustion NOx controls, the availability is assumed to be 83.5 percent. This assumption is consistent with availability assumptions used by FERC in the Order 888 Environmental Impact Assessment. See page A2-6 and A2-7 of the report for a discussion of the nuclear plant availability assumptions.

For nuclear units, EPA used the methodology that the Energy Information Administration used in the *Annual Energy Outlook for 1997* for estimating capacity available. In a unit level analysis, this approach considers: (1) the recent trend in improvements of the capacity factors of nuclear units throughout the country, (2) early retirements that are likely to occur (primarily at units with poor operating records that bring the current capacity availability average down), and (3) the likelihood that nuclear unit capacity availability will decline as units get very close to the end of their 40-year license period. This methodology was reviewed by the nuclear and power industries after the *AE097* publication. EIA staff report that they were not criticized on its application. In *AE098*, EIA staff estimated higher capacity factors in the future for nuclear units than they did in *AE097*. In an effort to be conservative, the Agency stayed with the *AE097* version of estimating capacity factors in the future for nuclear units.

In IPM annual forced outage rates and seasonal maintenance rates are specified as separate inputs. These annual forced outage rates and seasonal maintenance rates yield seasonal plant availability estimates.

Question 9: Explain how generating unit retirements were determined.

Answer: There are two different types of retirements used in the modeling analysis. First, assumptions are made about power plant lifetimes, see page A2-4 of the report. Second, IPM has the option to retire some power plants endogenously. Retirement dates for most nuclear plants are set to the expiration of their licenses. In addition, as state on page A2-6 of the report, EPA used retirement date assumptions for those units retired before their license expiration by EIA in their *AEO98.* In making the endogenous economic decision, IPM will retire those units whose discounted fixed operation and maintenance costs exceed the discounted future capacity and energy revenues.

Question 10: Did you evaluate the effect on reliability resulting from loss of capacity for the station power required for the retrofit? If so, explain your findings.

Answer: Yes, we did evaluate this issue. The results of EPA's analysis are explained in *Feasibility of Installing NOx Control Technologies by May 2003,* September 1998 (*Feasibility Study*).

Question 11: Did you evaluate the change in generating unit availability resulting from the retrofits (i.e., after the retrofits are complete)? If so, explain your findings.

Answer: The Agency did evaluate the issue of whether operating NOx controls electric generation units will lower their availability substantially and found that it would not. SCR and SNCR pollution control systems to not use that much electricity. The Agency estimates that SCR uses between .15 to .25 percent of a unit's electric generation. SNCR uses about 30 percent of the electric energy that SCR uses. These estimates are based on EPA's technical engineering analyses that support the NOx SIP Call and the earlier Title IV NOx rulemaking. Upon request, we can supply you the references for these estimates.

Question 12: What assumptions were used for the frequency and duration of planned outages? What were they for boiler plants versus turbines? Did the assumptions vary by type of plant, e.g., coal v. nuclear?

Answer: As explained in response to question 8, in IPM annual forced outage rates and seasonal maintenance rates are specified as separate inputs. These annual forced outage rates and seasonal maintenance rates yield seasonal plant availability estimates. It is this overall seasonal availability that is relevant for IPM in determining the maximum amount of electric energy that can be generated by a given plant. The seasonal availability for coal plants, as well as other fossil plants, for the years 2000 through 2004 are 82.4 percent for the winter and 85 percent for the summer which equates to an annual availability of 83.5 percent. Different estimates are used for nuclear units. See pages A2-5 through A2-7 for a discussion of the availability assumptions and segments of IPM runs posted at EPA's website: www.epa.gov/capi.

In considering the planned outage required for the installation of SCR for coal units of the size most commonly expected to install SCR, the Agency reviewed recent data on planned outages rates as reported in the NERC *Generating Availability Data System*, August 1997. The *GADS* data indicated recent planned outage and forced outage rates were different from the specific generic assumptions used in IPM, but consistent with the overall annual capacity availability assumptions in IPM of 83.5 percent. EPA's review of the *GADS* information in the size category of coal-fired unit units that the Agency believes contains most of the units that will install SCR indicated that the have an average planned maintenance period of 5 weeks.

Pollution Control Equipment

Question 13: What is the basis for selecting SCR versus the SNCR technology? What other factors effect the slate of SCR and SNCR used?

Answer: IPM is a dynamic linear programming production cost model that determines the least cost means for meeting electric demand subject to constraints on plant availability and operation emission limits, and other constraints. In examining the response of the power industry to the NOx SIP Call, the ozone season NOx emissions cap is specified as a constraint in the model. The model determines the least cost way to operate fossil units and other units to meet the demand and maintain NOx emissions at or below the specified constraint. Documentation of the cost and performance assumptions that EPA is using for SCR, SNCR, and gas reburn are explained on A5-6 through page A5-8 of the report. These cost and performance assumptions, along with the level of the NOx emissions cap, are the key parameters that affect the pollution control retrofit decision in IPM. In addition, IPM will also consider the plant's relative efficiency, variable cost, age, and the need to satisfy the SO_2 emission constraint in determining whether to apply SCR, SNCR, gas reburn or no technology on a given unit. EPA has set up IPM for consideration of the actions that power plant operators will take to comply with the NOx SIP Call with the installation of combustion controls already on coal-fired units greater than 25 MW (it used the type of controls that were considered in the Title IV NOx rules.) EPA's analysis in the past has shown that this is generally a cost-effective initial step to take before the application of post-combustion control systems such as SCR and SNCR. This approach was used in the cost estimation of the Ozone Transport Assessment Group and most recently used in the Zinder reports that industry prepared and submitted to EPA for consideration in the NOx SIP Call (these reports were submitted to EPA by the Utility Air Regulatory Group and the Alliance for Constructive Air Policy.)

Question 14: Explain how you derived the retrofit outage periods for selective catalytic reduction (SCR). Please explain the methodology employed for and results of your retrofit outage time sensitivity studies.

Answer: EPA derived the retrofit outage periods for selective catalytic reduction at coal-fired units (i.e., three to five weeks) based on its review of the U.S. experience, the experience in Germany, where the power industry installed SCR on 31 GW of capacity in a relatively short time period, and consultation with vendors and electric generation boiler experts. Many of the sources of information used to determine the outage period for installing selective catalytic reduction are listed in EPA's *Feasibility of Installing NOx Control Technologies by May 2003*, September 1998. Others can be found through the review of the NOx SIP Call record in EPA's rulemaking docket (we can forward these to you for your review upon request). We also considered the sensitivity of this determination for the outage period by extending it to 9 weeks in sensitivity analyses that the Agency prepared. In that analysis, which is also reported in EPA's Feasibility study, the Agency did not find a reliability problem arise.

In order to simulate the retrofit outage period in the sensitivity studies, the winter season maintenance rates for each unit installing SCR were lengthened to correspond to the assumed outage period. Changing the assumed maintenance rate lowered the plants winter season availability. Given that the winter season in the model includes the peak winter period means that some of the plants were assumed to be retrofitting during the winter peak period. Even with this conservative assumption about some SCR being installed during the winter peak period, there was sufficient capacity to meet winter energy demand in each case analyzed.

Question 15: Was an analysis made of the reliability during the spring and fall months that encompass the retrofit period? If yes, how was this done? Did you consider appropriate load reductions in these months? Did you consider increase in generating unit ratings in the non-summer months?

Answer: The sensitivity analysis that was conducted made the assumption that the SCR retrofits would be made during the October through April period. In all cases, there was sufficient capacity to maintain reliability. As stated in response to question 12, the analysis was undertaken by lengthening the assumed maintenance rate for each unit installing SCR to correspond to the assumed outage period. The modeling analysis does account for appropriate load reductions in the spring and fall. Hourly electric demand projections are used as input to the model. Theses hourly loads are converted to a seasonal load duration curve, which is then divided into 5 load segments. The model must dispatch enough energy to meet the load requirements for each of these load segments. The electric generation capacity estimates used in the model are net summer capacity estimates. Thus, the analysis provides a conservative assessment of reliability that does not take into account any increase in generating unit ratings in winter months.

Transmission

Question 16: Please explain the data source and rationale for the transmission constraints that were used. Were simultaneous transfer capabilities considered? Please explain how these numbers are used.

Answer: The transmission constraints used in the model are based on information provided by NERC and a methodology recommended by NERC staff. Discussions were held with NERC to determine the most appropriate way to apply their estimates in the model analysis. The estimates used are conservative estimates in the sense that they represent sustainable transfer capability between model Regions rather than maximum transfer capacity estimates. The methodology used to develop transmission capacity estimates was the same as the method adopted by FERC for its Environmental Impact Assessment of Order 888. Please see page A2-8 through page A2-11 for a detailed discussion of the transmission data used in the model.

Analysis Methodology

Question 17: Apparently, no studies were performed for 2000 and 2002, years critical for the actual retrofitting of capacity. Please explain why studies for these years were not necessary.

Answer: For ease in executing the analysis, the Agency selected 2003 to look at as opposed to looking at the entire time when SCR installation will occur – 1999, 2000, 2001, 2002, and 2003 before the NOx SIP Call goes into effect. This is a conservative choice, given that EPA: (1) considered all the SCR installation that EPA estimates should happen to occur in one year (about 63 GW of installation) and (2) electric demand in IPM is growing at a greater rate from 2001 to 2003 than is electric generation capacity to keep pace with it.7 The Agency has considered that its analysis can represent 62 GW of SCR installation in one year, or 186 GW of installation in a three year period and still remain conservative (given electric demand grows at a greater rate than capacity in IPM at this time through 2003.) Also, after EPA's analysis was completed, the Agency built in a one-year grace period that allows an additional year to install NOx control equipment, where a company shows that a reliability problem could result. EPA is authorizing states to award power plants facing this problem NOx allowances to cover their emissions for one ozone season (from a special compliance pool.) This was an extra safeguard that the Agency added to the NOx SIP Call during the last month of preparing the rule. This means that in reality, electric power companies will have from late 1999 through April 2005 to install SCR, if the time is needed -- not a one year period as EPA assumed in its analysis in the Feasibility Study.

Model Methodology

Question 18: Explain how the ICF model decides how much capacity to add for both the summer and winter periods. What criteria are used?

Answer: The model has a reserve margin constraint that requires that there must be enough capacity to meet the peak demand plus the reserve margin requirement. Thus, the sum of all capacity in a Region must be equal to or greater than the peak demand times 1 plus the Regional reserve margin. In addition, the model must have sufficient capacity to meet the electric energy demand in each seasonal load segment.

---

7 Note that after EPA completed its analysis, the NOx emissions cap was lowered in response to public comments and the amount of SCR that EPA estimates will need to be installed is now 73 GW on coal-fired units. The Agency does not see this as significant enough to make a difference its overall conclusion that the NOx SIP call will not jeopardize the reliability of the power system.

Question 19: Explain how the dispatch model works. How many load periods are used? Explain why the dispatch model adequately addresses the adequacy of supply issue. Is the model detailed enough to capture potential adequacy shortages in a given day or week? How are results about reliability derived for spring and fall if these seasons are not explicitly modeled?

Answer: In this analysis, hourly electric demand estimates are input into the model for each Region. The model converts this chronological hourly demand into seasonal load duration curves with five load segments per season. There are two seasons in the model. The summer ozone season covers the period from May through September. The remaining seven months of the year October through April are grouped into a single "winter" season. The model dispatches generating plants in such a way to ensure that the electric energy demand in each load segment and season is satisfied in a least cost fashion subject to constraints on plant availability, emission caps, fuel supply and transportation, and other constraints including operational constraints such as minimum turn down. The model ensures that there is enough energy dispatched to meet the seasonal load segment energy demand.

Using this approach for the cases analyzed in the feasibility study, the model results indicate that there would be sufficient generation capacity to meet the demand in all hours of the year.

Question 20: How are interregional trades represented? How are the time segments defined (by season and load slice)? How are they priced (shared savings or marginal cost)?

Answer: Interregional transmission of electric energy is simulated using the sustainable transmission estimates developed from NERC data (see response to question 14 above). The model keeps track of the hours in each load segment. The hours in each segment and season are used to determine factors that represent the distribution of hours across regions and load segments. There are two seasons in the model: winter, which corresponds to October through April; and summer, which corresponds to May through September. There are five load segments in each season with the following share of the load:

Segment	Share of Load
1	25%
2	30%
3	30%
4	10%
5	5%

Electric energy transactions are prices on a marginal cost basis.

Question 21: How are purchases from cogenerators and independent power producers represented?

Answer: As discussed on page A2-5 of the report, IPPs and cogenerators are explicitly represented in the model. All cogeneration capacity under firm contract to the grid is represented in the model. In addition, all non-firm cogeneration capacity above 25 MW is included in the model. Cogeneration for own use is not included in the model.

Question 22: Are renewables endogenously forecast?

Answer: Existing units are operated with capacity availability assumptions. New units are endogenously forecasted. See page A2-7 and A2-8 of the report for a discussion of how hydroelectric units and other renewables are modeled.

Question 23: How does IPM map renewable generation (hydro and intermittents) to the various load segments (horizontal time blocks)?

Answer: Hydro and other renewables are given an exogeneous capacity factor. These plants have zero fuel costs. The model determines how the plants will be dispatched up to their specified capacity factor limits. In general, the model will elect to dispatch the low cost hydro and renewable units in the peak periods when they will have the most value. See references in answer to question 20 for more details.

Question 24: How are electricity prices set?

Answer: The model does not endogenously forecast electricity demand so electricity prices are not relevant.

Question 25: What price does the consumer see in each region and how was it set?

Answer: The model does not endogenously forecast electricity demand so electricity prices are not relevant.

Question 26: What are the treatment of fuel, variable and fixed O&M, and capital components?

Answer: For a broad discussion of the fuel, variable and fixed O&M and capital component assumptions used in the model analysis see Appendices 2 and 3 of the report. EPA has placed on a website (http:www.epa.gov/capi) the resulting estimates of cost components for each model plant. For example, for the base case there is a file on the website named "sipjacr.t03" that has the plant-by-plant costs for the year 2003. Similarly, for the NOx SIP Call case there is a file called "sip2acr.t03."

Question 27: What is the relationship between the short-term prices and the cost of new plant construction?

Answer: Capacity marginal cost estimates are equal to the cost of building one more unit of capacity minus the forecasted net electric generation from that new capacity. If new generation capacity is the marginal plant operating in a given load segment, it will set the marginal cost in that load segment.

Question 28: What types of electricity price information are available from the model (customer class, generation, delivered, by time segment, etc.) and which are routinely reported?

Answer: The model does not endogenously forecast electricity demand so electricity prices are not relevant.

Question 29: Does the model have different ownership types (public, private)?

Answer: For existing units, IPP plants are separated from utility owned plants. For new plants, IPM does not differentiate between utility and merchant plants. Given that many power plants have changed owners in recent years and many more are likely to change hands in the future as restructuring continues, historical ownership of power plants is not particularly relevant.

Question 30: Describe the groupings of coal plants by type for the NOx control retrofits and retirement decisions.

Answer: The model uses a detailed list of criteria to guide the aggregation scheme including region, state, size, age, heat rate, NOx rate, firing and bottom type, mode for coal deliveries, and whether the plant was scrubbed or unscrubbed. ICF did the aggregation that was appropriate for providing reasonable pollution control cost estimates SO_2 and NOx.

Question 31: How do Phase I and Phase II decisions affect new State Implementation Plan (SIP) constraints? Does IPM directly compete combustion and post-combustion control technologies for both the CAAA and SIP requirements?

Answer: The CAAA Title IV Phase I and Phase II decisions covering most coal-fired units for NOx emissions are part of the Baseline. In examining the controls that units would select for compliance, EPA recognized that in general these controls offer a highly cost-effective first step in meeting the SIP Call. Therefore, in the NOx SIP Call model runs, the Agency has built these controls into the model plants in order to keep the model's consideration of NOx control options at a reasonable level for completing modeling runs. More details on this approach can be found in Appendix 4 of the report. EPA has used this type of approach since 1996 and it has not been criticized by the power industry. Notably, a similar type of approach was used in the recent reports by Zinder Associates (with support from Ed Cichanowicz) that were done for the Utility Air Regulatory Group and the Alliance for Constructive Air Policy.

Question 32: Are the coal plants retirements from NOx controls endogenously calculated?

Answer: IPM considers coal and oil/gas steam unit retirements. Initially, EPA found certain types of coal fired capacity did not retire early under stringent NOx and SO_2 controls and to save model run-time this option was removed for these units. Retirement of oil and gas steam units is specifically considered in the model.

ATTACHMENT III — GENERATING CAPACITY NEEDING SCR RETROFITS AND RETROFIT OUTAGE TIMES

NERC RAS NOx Task Force

October 1, 1999

TABLE OF CONTENTS

I. INTRODUCTION

The purpose of this report is to provide information to RAS to facilitate their determination of a range of most-likely values for:

1) The amount of generating capacity that will require SCR retrofits, and

2) the outage times required for these retrofits.

This report provides a discussion of the primary “drivers” that influence the amount of generating capacity requiring SCR retrofits. These primary drivers include the costs and efficiencies of the various retrofit options (SCR, SNCR, gas re-burn, etc.) and the models which use these cost and efficiency assumptions to determine the type of retrofit that each generating unit requires. Other key drivers include the projected capacity factor of units, baseline NOx emission rates assumed to be in compliance with the Title IV controls in 2000.

In this report, the RAS NOx Task Force (task force) includes a description and comparison of these cost and efficiency assumptions, models and resulting levels of required SCR retrofit that are contained in the analyses performed by EPA, EIA, OAC, UARG and Z/C (new). Z/C (new) is the work of Messrs. Zinder and Cichanowicz that was recently provided to PHB. In addition, the task force includes the SCR retrofit requirements determined through an ECAR survey (ECAR Survey) of its members.

The task force provides the bases for the cost and efficiency assumptions used by EPA, EIA, OAC, UARG and Z/C (new). The task force provides comments on these parameters and the models used by these groups.

The task force provides a comparison and discussion of the retrofit outage times (and the bases for these outage times) used by EPA, EIA, OAC, UARG and Z/C (new) and contained in the responses to the ECAR Survey.

Finally, the task force provides the conclusions that it has reached regarding the amount of capacity requiring SCR retrofit and the outage times required for those retrofits.

II. GENERATING CAPACITY NEEDING SCR RETROFITS

Table 1 is a comparison of the amounts of generating capacity requiring SCR retrofits. As explained in later sections of this report, the combination of (1) the assumptions used for cost and efficiency of the various retrofit technologies and (2) the model used to select the retrofit technology determine which generating units are assigned SCR and which ones are not.

TABLE 1

GENERATING CAPACITY (IN Net GW) REQUIRING SCR INSTALLATIONS

NERC REGION	EPA Draft	EPA Rule	OAC	EIA	UARG	PHB – Z/C	ECAR Survey
ECAR	**32.7**	**36.3**	**38.6**	**47.6**	**64.9 (2)**	**62.9**	**52.3 (1)**
MAAC	**9.4**	**9.4**	**10.1**	**12.4**	**18.5**	**14.1**	**NA**
MAIN	**5.4**	**5.3**	**8.2**	**12.6**	**21.4**	**20.4**	**NA**
NPCC	**0.2**	**0.7**	**1.8**	**5.6**	**6.5**	**0.7**	**NA**
SERC	**12.7**	**19.0**	**29.4**	**29.5**	**46.9**	**4.4**	**NA**
SPP	**2.2**	**2.2**	**2.8**	**2.5**	**4.1**	**45.3**	**NA**
MAPP	**0.0**	**0.0**	**NS**	**0.0**	**0.6**	**3.8**	**NA**
Total	**63.3**	**72.9**	**90.9**	**110.2**	**162.9**	**151.6**	**NA**

1) ECAR's has total coal capacity of 83.3 GW. ECAR received survey responses for 76.5 GW of coal capacity, which is 92% of its total coal capacity – 52.3 GW of that 76.5 GW of capacity is planned to be retrofitted using SCR. Extrapolated for all of ECAR's coal-fired capacity, this would result in an impact of 56.8 GW.

2) UARG indicated in a letter to EPA that its survey of ECAR members indicated a value of 51.2 GW. This is a different survey than the one reflected in the last column of the above table. Zinder and Cichanowicz determined the 64.9 GW value shown for ECAR in the above table.

NA – Not available. ECAR surveyed only the ECAR Region.

NS – Not studied.

The sources of the information shown on Table 1 are as follows:

EPA

A point of explanation is needed regarding the 72.9 GW value shown in Table 1 for "EPA Rule." In previous RAS meetings, the value attributed to the EPA work was 63.3 GW of generating capacity requiring SCR. The 63.3 GW value was based on the proposed NOx SIP Call. Since the proposal, EPA revised the NOx budgets for the affected jurisdictions. These distributions affect the distribution of post-combustion control technology retrofits. An addendum in EPA's *Feasibility of Installing NOx Control Technologies by May 2003,* September 1998, reflects this EPA revision. The effect of the revision was to increase the need for SCR from 63.3 GW to 72.9 GW.

OAC

Source: NOx SIP Call Compliance and Electric System Reliability: Compatible Goals for Achieving Needed Air Quality Benefits, May 1999 produced by M. J. Bradley & Associates and E^3 Ventures, Inc. for Ozone Attainment Coalition.

EIA

Sources:

1) *Annual Energy Outlook 1999*, December 1998 by Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy

2) Joseph (Alan) Beamon of EIA

UARG

Source: Provided by Jim Marchetti on May 5, 1999.

Z/C (new)

Source: Provided by PHB in September 1999.

III. COST AND EFFICIENCY ASSUMPTIONS FOR DETERMINING THE AMOUNT OF CAPACITY REQUIRING SCR RETROFIT

Table 2 is a comparison of the base case efficiency assumptions for **SCR**. See Z/C (new) section below for description of Z/C (new)'s sensitivity cases. Values for the ECAR Survey are not shown because they were not part of the survey.

TABLE 2

TECHNOLOGY COST/PERFORMANCE BASE CASE ASSUMPTIONS FOR SCR

Feature	EIA & EPA	OAC	**UARG & Z/C (new)**
Applicability	>100 MW	>100 MW	>100 MW
NOx Control	80% for high NOx rate 70% for low NOx rate	85% if at least 0.15 lb/MMBtu is achieved or whatever higher value is needed to achieve 0.15 lb/MMBtu	80-90%, averaging 83%
Capital Cost ($/kW)	$70-72/kW: per capacity, boiler type, inlet/outlet NOx for 200 MW unit. Economy of scale for units up to 500 MW.	Does not explicitly use economics to decide whether to use SCR	$65-100/kW: per capacity, boiler type, inlet/outlet NOx, fuel, age
Fixed & Variable O & M Cost	$6/kW/yr fixed $0.2-0.4/MWh variable	Does not explicitly use economics to decide whether to use SCR	No fixed $0.7-1.0/MWh variable

Table 3 is a comparison of the base case efficiency assumptions for **SNCR**. See Z/C (new) section below for description of Z/C (new)'s sensitivity cases. Values for the ECAR Survey are not shown because they were not part of the survey.

TABLE 3

TECHNOLOGY COST/PERFORMANCE BASE CASE ASSUMPTIONS FOR SNCR

Feature	EIA & EPA	OAC	UARG & Z/C (new)
Applicability	>100 MW	All	100-325 MW
NOx Removal	35% for high NOx rate 40% for low NOx rate	50% reduction, regardless of capacity(1)	20-35%, depending on capacity(2)
Capital Cost ($/kW)	**$10-19/kW: depending on boiler type, inlet/outlet NOx for 200 MW unit. Economy of scale for units up to 500 MW.**	Does not explicitly use economics to decide whether to use SNCR	$5-25/kW: depending on capacity, boiler type, inlet/outlet NOx
Operating Cost ($/MWh)	$0.8-1.3/MWh	Does not explicitly use economics to decide whether to use SNCR	$0.5-0.8/MWh

Notes to Table 3

1) This assumption applies to all non-SCR NOx control devices (including combinations of devices), not just SNCR.

2) UARG & Z/C (new) also used a gas-reburn option having a 40-50% NOx removal efficiency. The differences in these assumptions can significantly affect the amount of capacity that requires SCR retrofit. For example, the higher the assumed efficiency of SCR, the less SCR is needed because it takes fewer SCRs to remove the same amount of NOx. The same is true for the assumed efficiency of SNCR. The higher the assumed efficiency of SNCR, the less SCR is required to remove the same amount of NOx. More on the effect of efficiencies or SCR requirements is discussed later in this report.

In addition to SCR and SNCR, there are other technologies that can be considered to reduce NOx emissions. One source provided the following information on these alternative technologies:

- Low NOx Burners (LNBs) alone can reduce NOx emissions by 35 to 50 percent from pre-control levels. They have been used extensively either for new installations subject to EPA New Source Performance Standards, or as a retrofit to units for meeting Title IV of the 1990 Clean Air Act Amendments. While LNBs are among the most cost-effective options, the number of remaining units without LNBs is limited. LNB installation can require outages of 6-8 weeks.

- Reburn technologies reduce NOx by injecting either gas into the upper portions of a boiler furnace to burn out NOx. The effectiveness of these technologies can range between 30 and 50 percent. Natural gas reburn has a lower capital cost but a higher fuel cost due to the higher price of gas. Coal reburn is characterized by a higher capital cost and a lower fuel cost. Depending upon site specific economics, such as gas availability, these technologies may be less cost effective than SCR or SNCR. Depending upon the amount of equipment installed, such as additional coal pulverizers, or burner installation, these technologies could require additional outage time, using gas would probably require less than coal.

- An emerging combination technology is Amine Enhanced Fuel Lean Gas Reburn (AEFLGR). It combines SNCR technology and gas reburn. Recent demonstrations on a 320 MW unit showed 70% reduction at partial load and 50% at full load. The NOx retrofit application for this generating unit was designed for “load following,” but tests indicated if the generating unit had been a base-load unit and the retrofit so designed, then the NOx reduction percentage would be higher at full load. The efficiencies obtained through AEFLGR can vary significantly depending on the type of unit on which it is installed. For example, Fuel Tech has quoted 45% efficiency at full load for units on Cinergy’s system. The total amount of capacity using AEFLGR technology is limited, but there are plans for additional installations. In some cases, this technology could require some additional outage time beyond the normal maintenance outage time.

As can be seen on Table 2, EIA, EPA, OAC, UARG and Z/C (new) assume different NOx removal efficiencies for SCR. All other thing being equal, since OAC’s assumed NOx removal efficiency for SCR is the highest, it would result in the fewest megawatts of capacity requiring SCR. Regarding NOx removal with the SCR technology, the lower the pre-retrofit NOx emissions of a unit, the more costly it is to achieve a given percentage NOx removal.

As can be seen on Table 3, EIA and EPA assume 35% to 40% NOx removal for SNCR. OAC assumes a 50% NOx reduction for all non-SCR NOx control devices. UARG and Z/C (new) assume 20 to 35% NOx removal, depending on the size of the generating unit. Thus, all other things being equal, UARG and Z/C (new) would determine that SCR was needed for more capacity than would EIA and EPA.

Except for the capital costs for SCR, the capital and operating cost assumptions for SCR and SNCR used by EIA, EPA, UARG and Z/C (new) are similar. No capital and operating cost estimates are shown in Tables 2 and 3 for OAC because OAC’s model (discussed in the next section of this report) does not explicitly use economics to decide the type of retrofit a generating unit requires.

Since operating cost assumptions used by those that used such cost assumptions are similar, they will not be discussed further.

The capital cost for SCR used by UARG and Z/C (new) is significantly larger than that used by EPA and EIA. All other things being equal, and if the SCR option is chosen based on costs (as done in the EPA, EIA, UARG and Z/C (new) models), then the lower the capital cost assumption, the more SCR will tend to be chosen.

Since the efficiency assumptions used by these entities do significantly differ, let's take a look EIA, EPA, OAC, UARG and Z/C (new)'s bases for their efficiency assumptions. These assumptions are as follows:

EIA and EPA

The EIA analyses were performed after the EPA analysis. EIA decided to use the same assumptions, as did EPA. According to Sam Napolitano (Project Manager of EPA's analyses) EPA's efficiency assumptions for SCR and SNCR shown in Tables 2 and 3 were based on an analysis done by Bechtel and can be found on Table A5-5 of EPA's *Analyzing Electric Power Generation under the CAAA*, March 1998. The EPA report containing the amounts of capacity requiring SCR (*Feasibility of Installing NOx Control Technologies by May 2003*, September 1998) does not state what cost and efficiency assumptions were used. Ed Cichanowicz's January 6, 1999 presentation to RAS contained side-by-side comparisons of UARG and EPA's cost and efficiency assumptions for SCR and SNCR.

A sensitivity study performed by EPA sheds some light of the sensitivity of results to efficiency assumptions. EPA's base case assumed a 40% NOx reduction for low-emitting sources with baseline NOx emissions below 0.5 lb/MMBtu. Based on public comment, EPA did a sensitivity study using a 30% NOx reduction efficiency instead of the 40% value. This change increased the capacity requiring SCR from 63.3 GW to 93.6 GW, an increase of almost 50%. Using the 72.9 GW value developed by EPA to recognize EPA's revised NOx budgets (see Section II for more information), the 30% NOx reduction efficiency assumption would increase the SCR requirement from 72.9 GW to over 100 GW.

OAC

OAC's support for its 85% efficiency (and higher, if a higher efficiency is required to achieve a 0.15 lb/MMBtu emission level) assumption for SCR includes the statement, "SCR is capable of far greater than 90% control on a widespread basis, even when retrofit on gas-fired utility units as demonstrated in California." OAC also sites the Merrimack plant in New Hampshire meeting an 85% control at very high exhaust NOx concentration and loading. OAC says that installing a similar system on a unit with lower NOx emission rates would result in greater performance.

OAC does not provide strong support for its "50% reduction" assumption for non-SCR. OAC says NOx RACT efforts, the OTC MOU in the northeast United States and other initiatives in California have demonstrated significant reductions in NOx emission can be achieved. However, the 50% value is not justified by pointing to specific SNCR or other non-SCR installations.

UARG and Z/C (new)

Mr. Cichanowicz, consultant for UARG, sites several references on which he bases his NOx removal efficiency assumptions. The task force has not had sufficient time to review these references. Mr. Cichanowicz states that the June 1998 EPRI/Utility SCR Mission, which visited 14 generating stations and 23 units in Europe totaling 9,000 MW of capacity, verified that 90% SCR removal is rare. He goes on to say that the EPRI/Utility SCR Mission identified only one unit operating at 90% NOx removal, and six providing 85% or greater. These results seem to support UARG's assumptions on SCR efficiency. It should be pointed out that the German NOx reduction requirements involved a certain reduction in NOx emissions for each generating unit and thus there was no incentive to achieve reductions above the levels actually obtained on these units.

SNCR-type NOx removal was assumed to be inversely proportional to generating capacity, and based upon recent commercial demonstrations. NOx removal of up to 35% is achieved on the 170 MW furnaces at PSE&G's Mercer Station (Huhmann, 1977) and at the Penelec Seward Station (Urbis, 1998). NOx removal for larger units (200-350 MW capacity) was assumed to be 20-25%, depending on the inlet NOx rate. These estimates are based on the range of NOx predicted from computational flow dynamic (CFD) modeling for large furnaces (Hardman, 1998).

SNCR NOx removal is summarized as follows:

- 27-35%, for boilers smaller than 200 MW
- 20-25%, for boilers between 200-350 MW

In the their latest effort (Z/C (new)), Messrs. Zinder and Cichanowicz are performing sensitivity studies to the base case assumptions shown in Tables 2 and 3. One such sensitivity study assumes that SNCR will be installed on units greater than 325 MW in size. The Z/C (new) base case assumption was that SNCR would not be installed on units greater than 325 MW in size. Indeed, SNCR has been installed on units larger than 325 MW. For example, SNCR has been installed on PSE&G's 620 MW Hudson Unit 2 and AEP's 600 MW Cardinal Unit 1 and indications are that reduction efficiencies average about 30%.

Effects of assumptions other than cost and performance of retrofit technologies

The load forecast used in the analyses can significantly impact how much generating capacity requires SCR. EPA load forecast is lower than that used by the other entities. EPA began with the NERC ES&D load forecasts and lowered them for EPA's estimate of the effect of the Climate Change Action Plan. All other things being equal, a lower load forecast will result in a smaller amount of capacity needing SCR because, with a lower load forecast, the forecasted emissions are also lower. However, the actual coal-generated energy levels in the EPA analysis are similar to that in the other analyses.

IV. MODELS USED FOR DETERMINING THE AMOUNT OF CAPACITY REQUIRING SCR

Retrofit

The models were compared only focusing on the total megawatts of capacity needing SCR controls. Each model has identified the specific units to be retrofitted with SCR and the total megawatts in each Region, but the unit by unit data may not be dependable.

The significant factors that would influence the need for SCR are:

1) Generation output (heat input MMBtu) projected for year 2007 considering retirements and future generation additions

2) Baseline NOx rate (lbs/MMBtu) before controls to meet the SIP Call

3) Efficiency of controls to determine the new NOx rate after controls

4) Capital and operating costs of controls

5) Type of trading - intrastate or inter-state (among the 22 states)

Generation Output: EPA and EIA used macro system expansion models (e.g. IPM model used by EPA) to determine year 2007 generating unit outputs. These models consider committed retirements and unit additions, and add capacity needed to meet the reserve margin requirements. The OAC, UARG and Zinder studies used a somewhat simpler model to project 2007 generation for different groups of units considering the total generation projections. The second OAC study model did not explicitly address the economics of the retrofit options; however, the use of the same assumptions in the OAC, UARG, and Zinder models yields similar results. The task force did not study the reasonability of the models and the changes in the generation output from the current levels to 2007 levels.

Baseline NOx Rate: EPA/EIA/UARG/Zinder studies assumed that all affected units would comply with CAAA Title I- Phase I (NOx RACT) or Title IV- Phase I & II emission rates before the SIP Call. In its second study, OAC used the lesser of 1996 actual rates or Title IV emission rates. Baseline NOx rate is an extremely important factor, as a lower rate would result in a corresponding lower rate after controls and the amount of capacity that needs SCR would be less.

Efficiency of Controls: This is also an important factor in determining the need for SCR or other controls and is discussed in Section III. The product of 2007 heat input, baseline NOx rate, and control efficiency would provide an estimate of the tons of NOx produced by a unit after adding a control.

Costs of Controls: All the studies used generic cost data and these costs are probably adequate to determine total capacity that needs SCR vs. other controls. These generic costs are discussed in Section III. The results on controls on individual units may not be accurate as specific unit related control costs would be used by individual companies to make those decisions.

Trading: Analysis can be done based on either intrastate trading (all units in a state meet the NOx budget on the average) or on inter-state trading (all units in the 22 states will meet the budget on the average). This is done by proper grouping of units before checking for compliance.

Methodology: There are two types of analysis performed to determine the controls to be installed on different units. EPA and EIA used the system models mentioned earlier considering the costs of controls and the inter-state trading to meet the NOx budget based on 0.15 lbs/MMBtu rate. On the other hand, UARG/Zinder and OAC used spreadsheet analysis. Zinder refers to it as a least-cost analysis, but the details are not available. OAC approach sorts units with most effective to least effective SCR control and the detailed spreadsheets are available. Units with high NOx rate and high utilization are on the top of the list. OAC also used cost in $/ton NOx removed for sorting (the lowest cost unit on the top of the list) but not used in the final results. By adding up the remaining NOx for SCR or other controls a list of units with SCR can be identified for the system to comply (tons of NOx less than the budget).

The databases and models used in various studies are summarized in Table 4.

Table 4

Models Used to Estimate SCR Requirements

Data/Model	EPA	OAC	OAC (May 1999)	EIA	UARG	Z/C (new)
Heat Input Data	1996	1996	1996	1996	1996	1997
Heat Input Projected to 2007	Yes	No	Yes	Yes	Yes	Yes
Basis Used for Projection	IPM	N/A	EPA Data Used	NEMS	EPA Data Used	EPA data or ES&D forecast
Baseline NOx Rate	CAAA	1996	CAAA	CAAA	CAAA	CAAA
Trading Assumptions	Interstate	Interstate	Interstate	Interstate	Company	Company or Interstate
Use of Control Costs	Yes	Implicit	Implicit	Yes	Yes	Yes
Generation Expansion	Yes	No	EPA Data Used	Yes	No	No

V. OUTAGE TIMES FOR INTEGRATING EQUIPMENT RETROFITS

In the information that follows, the task force limited its examination of extended outage times to only those generating units for which SCR is required. The reason for this approach is as follows:

Regarding the installation of SNCR, there is general agreement that the outage time for SNCR integration is about two to three weeks and can be done during a normal planned outage. Thus, the task force did not investigate SNCR integration times any further.

There are retrofit options other than SNCR and SCR and options involving certain generating unit modifications in combination with either SNCR or SCR. The addition of low-NOx burners in combination with SNCR is the one such option that can result in extension of planned outage times. The ECAR survey responses indicated that this option can result in the need to extend planned maintenance outages; however, ECAR did not try to quantify this effect. None of the analyses reviewed by the task force addressed the extension of outage times required for low-NOx burner installations.

Regarding the integration time for SCR, there is considerable disagreement as to the outage time required to integrate this technology. Table 5 shows a comparison of the outage times for integrating SCR installations.

Table 5

Comparison of Expected Outage Times

Entity	Outage Times for SCR Integration
ECAR Survey	Additional outage time ranges from no additional outage time to as much as 15 weeks. In general 2-4 weeks of additional outage time is the average expected. This average is a weighted average, weighted by MW of capacity. Using RAS NOx Task Force assumption of four weeks for planned outages, the total outage time would range from 4 to 19 weeks and be a weighted (by MW unit size) average total outage time of 6-8 weeks.
EIA	Not applicable. EIA did not address outage times.
EPA	Total outage time of 5 weeks.
OAC	Total outage time of 6 weeks.
UARG & Z/C (new)	Total outage time varies. Considering three site categories: Moderate: 4-6 weeks Intermediate: 8-12 weeks Challenging: > 14 weeks See Table 6 below for more detail. The weighted average total outage time is 9 weeks.

The task force evaluated the bases for these assumptions. A brief description as to bases for these assumptions follows:

ECAR Survey (March 9, 1999 Summary Report)

Two of the questions posed to its member companies in the ECAR Survey were:

1) “What additional outage time will be required (per unit) for construction or cut-in (lengthening of existing planned outages)?”

2) “Will this vary by type of unit?”

For SCR, ECAR summarized the responses to these two questions as follows: “The range of responses goes from no additional outage time to as much as 15 weeks for a single unit. In general, 2–4 weeks of additional outage time is the average expected. A lot of SCR related outage work is expected to be accomplished during a scheduled turbine or major modification outage, but if no turbine or major modification outage is currently scheduled, then the existing boiler outage will have to be extended, sometimes by a significant number of weeks.” The average 2 – 4 weeks of additional outage time is a weighted average, weighted by MW of capacity.

In order to compare ECAR’s **additional** outage time results with the **total** outage times shown by the other entities (see Table 5), the task force assumed that the average planned outage that needed to be extended was four weeks.

EIA

No information on retrofit integration times is available because EIA did not use or discuss outage times in its analysis.

EPA

In its report, *Feasibility of Installing NOx Control Technologies by May 2003*), September 1998, EPA concludes from its review of papers by J. Philbrook, E. Zomorano and M. Gregory that, <u>*on average*</u>, it takes three to five weeks to connect SCR. EPA also states that a German SCR provider installed SCR on a significant portion of the German capacity within outage periods consisting of less than four weeks. This information was provided to EPA by Steag (Correspondence #2 in Appendix B of the September 1998 EPA report) and only discussed the situations where no outage extensions were required. The task force’s concern over using averages (discussed more later) and the desire to learn about German generating units requiring an extension of planned outage times, prompted the task force to try to contact the German SCR provider to see how many units needed extended outages. However, the provider did not return the phone calls made by the task force.

OAC

OAC cites the same German source, saying that Steag completed retrofits on 12 coal-fired boilers at five of its German plants (5,500 MW) all during planned maintenance outages. OAC goes on to list five specific U.S. generating units, four of which OAC says need SCR retrofits that can be done during normal outage periods and one SCR retrofit that requires a one-week extension. In OAC’s Conservative Scenario, it assumes SCR installations can occur with an average outage period of six weeks. OAC states that this assumption is conservative compared to experience to-date as well as to the position taken by the Institute for Clean Air Companies (ICAC), which asserted that SCR installations can be completed with outages of two to three weeks. OAC goes on to say that its six-week assumption is more conservative than EPA's four-week assumption. [Actually, EPA used a five-week assumption.]

UARG and Z/C (new)

Ed Cichanowicz has gathered outage requirements for SCR integration on some 60 units in the U.S. and abroad. The expected outages for SCR retrofit have been developed based on discussions with utilities that have received proposals for SCR installation, and site-specific analysis reported from studies conducted by process suppliers and architect/engineering firms. Table 6 prepared by Mr. Cichanowicz summarizes the expected outage as a function of unit generating capacity, and whether the unit is either a (1) "single" generator, (2) "outboard" generator in a multi-unit station, or (3) "inboard" unit in a multi-unit station.

An additional factor considered in the analysis is the need for Boiler/ESP Modifications. Units are assumed to require major boiler (and/or air heater modifications) depending on the fuel fired. Specifically, units with coal sulfur content >3% are assumed to (a) require more significant boiler economizer modifications to control low load flue gas temperature at the economizer exit, (b) upgrade air heater to resist SO3-induced corrosion, and (c) face limited construction access due to FGD equipment.

Units that retrofit ESPs in the 1970s for particulate control are assumed to provide an additional site complexity that will lengthen the outage due to limited construction access, or the need to demolish abandoned equipment.

Table 6

Cichanowicz's Summary of Expected Outages (Weeks)

Site Feature	100-350 MW		351-600 MW		>600 MW	
	With Boiler Mods, ESP retrofit	*w/o Boiler Mods*	*With Mods, ESP retrofit*	*w/o Boiler Mods*	*With Boiler Mods, ESP retrofit*	*w/o Boiler Mods*
Single, or "outboard" units in multi-unit station	6	4	10	8	14	10
Interior units in a multiple unit station	6	6	10	10	14	10

VI. TASK FORCE CONCLUSIONS

Task Force Conclusions on the Amount of Capacity Requiring SCR

The Task Force concludes there are significant variations in the assumptions, and it is difficult to determine which assumptions are appropriate. The information presented here is the best available at this time. There will be additional certainty as the compliance date draws closer. As a result it is prudent to continuously monitor developments.

The task force concludes that for the ECAR Region, the ECAR Survey information is better than the assumptions developed by the other analyses. ECAR's survey information is based on the current compliance plans of the plant owners. For example, one company (that the task force happened by chance to have talked to in performing its assignment) indicated that its plans for installing SCR provided in response to the survey are the ones that will soon be taken its Board of Directors for approval. That company also indicated that it had completed engineering for its NOx retrofits and is presently securing installation contracts.

Due to the inherent differences among generation fleets of the NERC Regions, the ECAR Survey results were not extrapolated to the other Regions.

Generally, the models used to determine how much capacity will be retrofitted by SCR do not take into account that utilities may put SCR on more capacity than the models indicate to ensure that they meet their emission requirements. Utilities may take into account hotter-than-normal summers and other factors (not recognized by these models) in determining how much capacity is retrofitted with SCR. Conversely, the requirements for SCR may be reduced from those presently expected if the alternative NOx removal technologies prove to be more effective than historical data indicates.

Regulatory considerations also significantly impact compliance planning. US EPA finalized the NOx SIP Call in the fall of 1998, which requires states to file their individual plans by the fall of 1999. EPA will then either approve these plans or impose a Federal Implementation Plan. There are still significant uncertainties:

- Certain states and areas in the northeast have more-stringent emission rules currently existing. How those programs will be coordinated with the state implementations of the EPA NOx SIP Call is unknown.
- In the allocation process, states may withhold or set aside allowances for energy efficiency programs or for new industrial and utility sources.
- States may issue a limited number of early reduction credits that could be used to delay installation of some control technology.
- EPA has encouraged the states to withhold 5% of their allowance pool for new sources and to withhold up to 20% of their allowance pool to encourage renewables. To the extent that these allowances become unavailable to sources for compliance purposes, the total compliance burden will increase. This in turn would increase the amount of SCR and other technologies that must be installed.

- Because of timing and the lack of final rules, the trading market has not yet developed outside a limited number of states in the northeast. The sooner this trading market forms, the more effect it will have in providing companies with a compliance pool.

- Sources could respond to this uncertainty in different ways. They could add additional control technology, use the emerging trading market, or seek other options.

These influences could serve to either increase or decrease the amount of control technology that will be installed.

Task Force Conclusions on SCR Retrofit Outage Times

As noted above, EPA and OAC rely on “average” outage times. The task force is concerned over the use “average” outage times because the need for an above-average extended outage period for a particular unit can be totally missed. For example, let’s assume a planned outage period of five weeks and seven generating units requiring outage periods of 3, 3, 4, 5, 5, 6, and 9 weeks, respectively. The average outage period is five weeks. By assigning this average outage period for each unit, the conclusion is reached by that no outage extensions are needed for any unit. However, two of the seven units will indeed need an extended outage. Such averaging also does not recognize the differences in the size of generating units. The best way to handle retrofit outage times is to use outage times for each individual unit.

There are considerable differences in the retrofit outage times used in the various studies that the task force reviewed. Utilities have had and will continue to have a financial incentive to minimize retrofit outage times.

As in the case of the amount of capacity requiring SCR, the task force feels that the ECAR Survey information is the most reliable set of retrofit outage assumptions for the ECAR Region because the information is unit-specific in nature. Due to the potential differences among NERC Regions, the task force is hesitant about applying the ECAR Survey results to the other Regions.

APPENDIX B — TABLES TO BE PROVIDED IN FINAL REPORT

APPENDIX C — RELIABILITY ASSESSMENT SUBCOMMITTEE

Frank J. Koza, Jr.
Subcommittee Chairman
General Manager, Ventures
PECO Energy Company

Edward P. Weber
Subcommittee Vice Chairman
Resources and Planning
Western Area Power Administration

Charles A. Roteck
ECAR Representative
Manager, Transmission Planning & Protection
FirstEnergy Corporation

Lloyd Pond
ERCOT Representative
Manager, Electric Systems Division and Control
Reliant Energy

Peter M. O'Neill
FRCC Representative
Staff Engineer, Transmission Planning
Florida Power Corporation

Esam A. F. Khadr
MAAC Representative
Manager-Transmission Planning and Technical Services
Public Service Electric and Gas Company

Donald R. Carlson
MAIN Representative
Manager - Energy Supply and Control
Wisconsin Public Service Company

Hoa Nguyen
MAPP Representative
Power Supply Coordinator
Montana-Dakota Utilities Company

John G. Mosier, Jr.
NPCC Representative
Manager, Operations
Northeast Power Coordinating Council

Gary P. Garrett
SERC Representative
Manager, Energy Resource Planning
Tennessee Valley Authority

James A. Bruggeman
SPP Representative
Senior Consultant
Central and SouthWest Services, Inc.

Christopher Oakley
WSCC Representative
Manager, Mid & Long Term Planning
ESBI Alberta Ltd.

Julien Gagnon
Canada Member-at-Large
Manager, System Control Scheduling
Hydro-Québec

George R. Bartlett
NERC Security Committee Representative
Director, Transmission Operations
Entergy

John Conti
DOE Liaison
Deputy Director, Office of Economics, Electricity and Natural Gas Analysis
U.S. Department of Energy

Tiffany Elliott
Independent Power Producer Representative
Manager of Policy
Electric Power Supply Association

John D. Osborn
ECAR Alternate
Manager, Transmission Services
East Central Area Reliability Coordination Agreement

Thomas Hallam
FRCC Alternate
Staff Engineer
Florida Reliability Coordination Council

Donald R. Volzka
MAIN Alternate
Manager of Transmission Planning
Wisconsin Electric Power Company

Robert W. Cummings
Staff Coordinator
Director-Transmission Services
North American Electric Reliability Council