State of California
AIR RESOURCES BOARD

Resolution 80-68

December 18, 1980

WHEREAS, Health and Safety Code Section 39003 provides that the Air Resources Board (the "Board") is the state agency charged with coordinating efforts to attain and maintain ambient air quality standards;

WHEREAS, Health and Safety Code Section 39002 provides that local and regional authorities have the primary responsibility for control of air pollution from all sources other than vehicular sources, and provides further that the Board shall undertake control activities in any area wherein it determines that the local or regional authority has failed to meet the responsibilities given to it by Division 26 of the Health and Safety Code or any other provision of law;

WHEREAS, Health and Safety Code Section 39500 provides that it is the intent of the Legislature that the Board shall coordinate, encourage and review the efforts of all levels of government as they affect air quality;

WHEREAS, Health and Safety Code Section 39600 provides that the Board shall do such acts as may be necessary for the proper execution of the powers and duties granted to, and imposed upon, the Board by Division 26 of the Health and Safety Code and by any other provision of law;

WHEREAS, Health and Safety Code Section 39602 designates the Board as the air pollution control agency for all purposes set forth in federal law; and provides further that the Board is responsible for preparation of the state implementation plan required by the Clean Air Act, and to this end shall coordinate the activities of all districts necessary to comply with that Act;

WHEREAS, Health and Safety Code Section 39605 provides that the Board may provide any assistance to any district;

WHEREAS, Health and Safety Code Section 40001 provides that the local districts shall adopt and enforce rules and regulations which assure that reasonable provision is made to achieve and maintain the state ambient air quality standards and shall also endeavor to achieve and maintain the federal ambient air quality standards;

WHEREAS, Health and Safety Code Section 40440, as presently in effect and as amended effective January 1, 1981, requires that the rules and regulations of the South Coast Air Quality Management District reflect the best available technological and administrative practices;

WHEREAS, Health and Safety Code Section 40462, as presently in effect and as amended effective January 1, 1981, requires that the South Coast Air Quality Management Plan provide for achievement of state ambient air quality standards at the earliest date achievable by application of all reasonable and available (or reasonably available) control measures and technologies;

WHEREAS, Health and Safety Code Section 40451 provides that on petition from any aggrieved person, the Board shall review any action or failure to act of the South Coast Air Quality Management District ("SCAQMD") Board of Directors, and provides further that if the Board finds that the action or inaction of the SCAQMD Board is inconsistent with the purposes of Division 26 of the Health and Safety Code, the Board may, inter alia, take appropriate action to implement and effectuate the purposes of Division 26;

WHEREAS, Section 107(a) of the Clean Air Act provides that it is the responsibility of each state to assure air quality within the entire geographic area of the state;

WHEREAS, Section 110(a)(1) of the Clean Air Act requires that each state adopt a plan which provides for the implementation, maintenance and enforcement of national primary ambient air quality standards within each air quality control region of the state;

WHEREAS, Section 110(a)(2) of the Clean Air Act requires that such plan provide for the attainment of such standards as expeditiously as practicable;

WHEREAS, Section 172(a)(1) of the Clean Air Act requires that an implementation plan for nonattainment areas provide for the attainment of national primary ambient air quality standards as expeditiously as practicable and no later than December 31, 1982;

WHEREAS, Section 172(b)(2) of the Clean Air Act requires the implementation of all reasonably available control measures as expeditiously as practicable;

WHEREAS, Section 172(b)(3) of the Clean Air Act requires that such nonattainment area plans require reasonable further progress (as defined in section 171(1)) including such reduction in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology;

WHEREAS, Health and Safety Code Section 41650 provides that the Board shall adopt the nonattainment area plan approved by a designated air quality planning agency as part of the state implementation plan unless the Board finds that the nonattainment area plan will not meet the requirements of the Clean Air Act;

WHEREAS, the California Environmental Quality Act and Board regulations require that an action not be adopted as proposed if significant environmental impacts have been identified and there exist within the jurisdiction of the Board feasible mitigation measures or alternatives which would substantially lessen, mitigate or avoid such impacts;

WHEREAS, in February 1978, the SCAQMD Board adopted Rule 475.1, pertaining to control of emissions of oxides of nitrogen (NOx) from power plants;

WHEREAS, the Southern California Edison Company ("SCE") and the Los Angeles Department of Water and Power ("LADWP") petitioned the Board pursuant to Health and Safety Code Section 40451 to review SCAQMD Rule 475.1;

WHEREAS, at hearings held from May to August 1978, the Board reviewed Rule 475.1 pursuant to Health and Safety Code Sections 40451 and 41504;

WHEREAS, on August 7, 1978, the Board adopted Resolution 78-48, in which it found Rule 475.1 to be inconsistent with the purposes of Division 26 for specified reasons, and in which it also found that:

The level of oxides of nitrogen emissions reduction required by Rule 475.1 is necessary to attain and maintain the federal and state ambient air quality standards for nitrogen dioxide, total suspended particulate matter, and visibility; and

The level of oxides of nitrogen emissions reduction required by Rule 475.1 is also likely to result in a net air quality benefit by causing reductions in peak ambient oxidant levels in the SCAQMD.

WHEREAS, the Board in Resolution 78-48 adopted amendments to Rule 475.1;

WHEREAS, in response to a petition for reconsideration filed by the SCAQMD, the Board on January 23, 1979, in Resolution 79-2, reaffirmed its decision adopting Resolution 78-48, and affirmed Rule 475.1 as adopted by its Executive Officer January 22, 1979, subject to such revisions as might be made by the SCAQMD consistent with the District's views expressed before the Board January 23, 1979;

WHEREAS, the SCAQMD did not adopt any changes to the Rule, but rather, by letter of its Executive Officer dated September 21, 1979, recommended that the Board hold hearings and adopt any amendments to the Rule;

WHEREAS, the Board, following notice and hearings held in January and March 1980, on March 27, 1980, adopted Resolution 80-22 in which it amended Rule 475.1 and recodified the Rule as Rule 1135.1;

WHEREAS, SCE petitioned the Board to reconsider Rule 1135.1 (475.1);

WHEREAS, the Board granted SCE's petition for reconsideration;

WHEREAS, public hearings have been held and the Board has considered all aspects of Rule 1135.1 and has received and considered the evidence presented to it;

WHEREAS, as specifically set forth in the Statement of Findings and Response to Opposing Considerations adopted herewith and made a part of this Resolution, the Board finds:

That the provisions of Rule 1135.1 as amended are technologically feasible and cost-effective;

That the provisions of Rule 1135.1 as amended are necessary to meet the requirements of the Clean Air Act;

That the provisions of Rule 1135.1 as amended assure that reasonable provision is made to achieve state ambient air quality standards;

That the provisions of Rule 1135.1 as amended are appropriate to implement and effectuate the purposes of Division 26 of the Health and Safety Code; and

That the provisions of Rule 1135.1 as amended reflect the best available technological and administrative practices.

WHEREAS, the Board further finds, in accordance with the requirements of CEQA and as set forth in detail in the Response to Significant Environmental Issues incorporated by reference herein:

That all adverse environmental effects found to be significant by the Board can be mitigated by the utilities pursuant to cost-effective operating procedures, are being minimized by improved catalyst design, or are within the jurisdiction of other public agencies which are currently regulating the activities generating such effects so as to mitigate any anticipated adverse impacts on the environment; and

That alternatives considered are either less effective in reducing NOx emissions and protecting public health and welfare, or are economically infeasible due to excessive increased costs to the utilities.

NOW, THEREFORE BE IT RESOLVED, that the Board amends SCAQMD Rule 1135.1 as set forth in Attachment A hereto.

BE IT FURTHER RESOLVED, that it is appropriate that the SCAQMD consider the adoption of regulations which provide for reductions in NOx emissions from power plants within the South Coast Air Basin not subject to Rule 1135.1.

BE IT FURTHER RESOLVED, that the Executive Officer is directed to transmit Rule 1135.1 as amended to the Environmental Protection Agency for inclusion in the California State Implementation Plan.

I certify that the above is a true and correct copy of Resolution 80-68, as adopted by the Air Resources Board.

Sally Rump

BOARD SECRETARY

Attachment A

Rule 1135.1 of the South Coast Air Quality Management District as Amended by the California Air Resources Board

December 18, 1980

I. Applicability

This rule shall apply to any electric utility with a system of electric generating units the total rated capacity of which is more than 500 megawatts.

II. Definitions

Available units are those electric generating units in the system which, except during periods of regularly scheduled maintenance, can be operated without incurring more than the normally acceptable risk to the system, unit, or personnel, and for which fuel can be supplied for at least the next day's operation.

Baseline emissions are emissions of oxides of nitrogen expressed in pounds of oxides of nitrogen (as nitrogen dioxide, NO_2) per hour at each of ten load points of equal increments from minimum load to 100 percent load for each unit of a utility as tested by the utility and as reported to the Executive Officer in 1979. In the case of units for which no such report was submitted in 1979, each affected utility shall submit to the Executive Officer source test data which show oxides of nitrogen (NOx) emission rates for 1979 at the load points specified herein.

Rated capacity is, for any electric generating unit, the lesser of the manufacturer's name-plate capacity in megawatts for the unit; or the capacity in megawatts to which a unit is restricted by a condition on the electric generating unit's permit to operate.

Steam generated electric capacity is the total rated electric capacity, as of January 1, 1978, of all units which produced electricity from electric generators driven by steam turbines located within the South Coast Air Basin. Steam generated electric capacity does not include electric generating capacity of simple or combined cycle gas turbine units.

III. Requirement for Least NOx Dispatch

A. The owner or operator of an electric power generating system shall at all times operate the available units in the system in a manner that minimizes the rate of emissions of oxides of nitrogen from the system ("least NOx dispatch"). Simple cycle gas turbines are exempted from the least NOx dispatch requirements.

B.1. A plan detailing the method for meeting the requirements in subsection III.A. shall be submitted to the Executive Officer for consideration no later than March 1, 1981. Within 60 days of receipt of such a plan, the Executive Officer shall approve or disapprove the plan. In the event the plan is disapproved, the Executive Officer shall notify the affected utility in writing, and shall state the grounds for the disapproval. Within 30 days of such notification, the affected utility shall submit a revised plan which eliminates the stated grounds of disapproval.

2. A revised plan shall also be submitted to the Executive Officer within 30 days after a new or modified unit is added to the system or a unit is removed from the system. A revised plan submitted when a unit is added to or removed from the system shall be subject to the requirements for review, approval and revision set forth in subsection III.B.1. for the original plan.

C. Effective 30 days after approval by the Executive Officer, the system shall be operated according to the approved plan.

D. Records relating to compliance with this section shall be kept in a manner and form specified by the Executive Officer.

IV. Requirements for Control

A. For a utility with a steam generated electric capacity of more than 500 megawatts and less than 5,000 megawatts:

Any owner or operator of an affected electric power generating system shall limit the emissions of oxides of nitrogen from the steam generators of individual generating units which have an aggregate steam generated electric capacity of at least 910 megawatts to a level not greater than 20 percent of the baseline emissions of each unit controlled. Such limit shall be achieved over the entire operating load range of each unit controlled.

B. For a utility with a steam generated electric capacity of more than 5,000 megawatts:

Any owner or operator of an affected electric power generating system shall limit the emissions of oxides of nitrogen from the steam generators of individual generating units which have an aggregate steam generated electric capacity of at least 1920 megawatts to a level not greater than 20 percent of the baseline emissions of each unit controlled. Such limit shall be achieved over the entire operating load range of each unit controlled.

V. Compliance Schedule

A.1. No later than December 1, 1983, each affected utility shall limit the emissions of one unit with a rated capacity greater than 300 megawatts to the levels specified in section IV, provided that this provision shall not require an affected utility to attain such limit by December 1, 1983 on more than one such unit within its total system.

2. Except for the requirements of subsection V.A.1., all controls necessary to meet the requirements of this rule shall be installed no later than during the first regularly scheduled shutdown after October 1, 1985, for each unit on which controls are to be installed as specified in the compliance plan required by section V.B.

3. All units on which controls are to be installed as specified in the compliance plan required by section V.B. shall be controlled by December 31, 1989.

B. A final compliance plan shall be submitted to the Executive Officer for consideration no later than March 1, 1981. The plan shall contain a list which identifies those units to be controlled and shall include a detailed description of the steps that will be taken to satisfy the requirements of subsections V.A.1., V.A.2, and V.A.3. The description shall contain a construction schedule for each unit on which controls are to be installed. Within 30 days of receipt of such a plan, the Executive Officer shall approve or disapprove the plan. In the event the plan is disapproved, the Executive Officer shall notify the affected utility in writing and state the grounds for the disapproval. Within 30 days of such notification, the affected utility shall submit a revised plan which eliminates the stated grounds for the disapproval.

VI. Review of Rule

Within ninety days after one year's operation on any unit of 300 megawatts or greater capacity of controls installed to achieve the emission reduction required by this rule, and upon request by an affected utility, the District Board shall conduct a hearing to consider the experience gained in meeting the requirements of the rule; and whether further implementation of the rule remains reasonable and necessary to attain the objective of a 90 percent overall reduction in power plant NOx emissions in the South Coast Air Shed. The rule shall remain in effect pending such consideration. Upon request by the District Board, the State Air Resources Board shall conduct the hearing.

VII. Severability

Except as otherwise provided in this Rule, if any portion of this Rule is found to be unenforceable, such finding shall have no effect on the enforceability of the remaining portions of the Rule. These remaining portions of the Rule shall continue to be in full force and effect.

State of California
AIR RESOURCES BOARD

Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants

Statement of Findings and Response
to Opposing Considerations

The Board has reviewed and considered all of the evidence and arguments presented to it in hearings on these two rules. This document is not intended to be exhaustive. It sets forth formal findings and the principal factors on which these findings rest, as well as a response to significant considerations raised in opposition to the Board's action.

December 18, 1980

1. Finding: Oxides of nitrogen (a mixture of nitric oxide, NO, and nitrogen dioxide, NO_2) are released from a multiplicity of sources that include fossil fueled power plants. Oxides of nitrogen (NOx) are rapidly converted to nitrogen dioxide (NO_2) in the atmosphere, either photochemically or by reaction with ozone (Staff Report,* pp 62-69).

   Basis: This finding is based on the Board's general knowledge of air quality and photochemistry. This issue has not been disputed during this hearing.

2. Finding: Concentrations of NO_2 in the ambient air in the South Coast Air Basin have persistently exceeded both state and national standards for NO_2 and will continue to exceed these standards unless control measures beyond those already existing are implemented.

   Basis: The facts on which this finding is based include the following:

   From 1972 to 1979, ambient concentrations of NO_2 in the South Coast Air Basin exceeded frequently and substantially both the national annual average standard and the state one-hour standard for NO_2 (Staff Report, Table IV. 1, 2, 3, pp 36-38).

   NO_2 concentrations in the South Coast Air Basin are the highest of any major metropolitan area in the world (NOx Abatement for Stationary Sources in Japan, Jumpei Ando, U.S. EPA, August 1979).

   The 1979 Air Quality Management Plan for the South Coast Air Basin projects that NO_2 concentrations will continue to exceed the national annual average standard even if all the control measures identified in the Plan are implemented. Based on the emissions projections contained in the Air Quality Management Plan, it is also expected that the state NO_2 standard will continue to be exceeded (see Finding 4, below).

3. Finding: Oxides of nitrogen emitted by gas and oil fired power plants make a substantial contribution to ground level concentrations of NO_2 in the South Coast Air Shed.

   Basis: The facts on which this finding is based include the following:

   Southern California Edison (SCE) has presented extensive technical information on tracer studies and meteorological analyses that lead it to conclude that stack height, buoyant plume rise and stable atmospheric conditions combine to reduce

*September 19, 1980 ARB Staff Report

substantially the influence of power plant emissions relative to ground level sources of NOx (Tr, Nov. 5, pp 130-155; Nov. 6, 9:30 a.m., pp 1-28; Nov. 6, 10:00 a.m., pp 52-142).

The ARB staff presented information, including the results of tracer releases and supporting meteorological analyses, that lead them to the conclusion that the ground level NO_2 impacts of power plant NOx are often large and contribute significantly to violations of both the hourly and annual average standards for NO_2. (Tr, Nov. 5, 9:15 a.m., pp 6-26; pp 27-36; pp 38-67)

a. Tracer Studies

SCE believes that power plant NOx emissions result in minimal ground level impacts based principally on two SF_6 tracer studies from the El Segundo Generating Station (ESGS). The first study was conducted by North American Weather Consultants on March 6, 7, and 8, 1979 (NAWC Report No. SBAQ-79-11, SCE January 23, 1980 Submittal). Among other conclusions, NAWC stated that "during periods of exceedances of the one-hour 0.25 parts per million (ppm) NO_2 standard, ESGS NOx contributions were at most 11 percent of the observed ambient NOx concentrations at any receptor."

From a series of SF_6 tracer tests made from the El Segundo Generating Station on September 3-5, 1980, SCE concluded that "the plume was diluted in the order of 10^5 - 10^7 times before it had an impact at ground level."

SCE concluded from these data that "the plume contributed a maximum impact of 2.5 parts per billion (ppb) of the (air monitoring) stations 50-100 ppb NOx concentration or a maximum of 5 percent." Although the Board believes SCE's analysis correctly represents the ground level impact of the one generating unit studied, subsequent SCE testimony (SCE Submittal, Nov. 3, 1980, pp 0200-0227; Tr, Nov. 6, 9:30 a.m., pp 7-10; p 27, ln 22, 23) indicated that this plume represents only one of four units in operation at El Segundo. The same testimony indicated that the other units at El Segundo and other large coastal power plants on the Santa Monica Bay are also expected to make significant contributions to the same receptor areas.

Other conclusions reached by SCE from this study are similarly based on the emissions from one unit (one-third of the generating capacity) of the ESGS and must be multiplied by at least a factor of three to represent the emissions from the entire ESGS complex, and by a still larger factor to account for adjacent power stations along the coastline.

Analysis presented by the ARB staff indicated that the additive ground level impacts from just one generating station (El Segundo) was near 20 percent in Lennox during the course of SCE's tests. (Tr, Nov. 6, 9:30 a.m., pp 21-23)

In a series of tests performed by Shair et al., at Haynes/Alamitos (Staff Report, pp 43-44 and Ref. 3) similar, though somewhat lower, dilution factors were measured (1.57×10^4 at Fullerton Fire Station Number Two on one test). Using the measured SF_6 values, the NO_2 impact due solely to the Haynes/Alamitos complex would be as high as .11 and .12 ppm, or nearly 50 percent of the state ambient air quality standard for NO_2 of 0.25 ppm for one hour. Shair also described a tracer study (Tr, Nov. 5, pp 38-47) in which SF_6 was released from the El Segundo Generating Station. The results of this test showed that the NOx emitted during night-time land-breeze conditions is widely spread along the coast, and that essentially all of the NOx is advected back across the shoreline at surface level and added to the following day's NOx burden.

b. Other Field Studies

A number of field studies were considered by the Board during the course of these hearings. For example, ambient measurements carried out in conjunction with the Haynes/Alamitos tracer studies done in 1974 clearly identified elevated ground level concentrations of NOx downwind of the power plant complex (Staff Report, p 44; Fig. IV.4, p 46). At the point of maximum ground level impact, some 9 kilometers downwind, NOx concentrations below the center line of the plume were elevated as much as 0.15 ppm (150 ppb) above the concentrations in areas adjacent to the plume. This finding is consistent with impacts inferred from the results of the tracer studies.

c. Meteorological Analysis

SCE's belief that, because the initial plume rise is at times sufficiently high to penetrate the base of the inversion layer, emissions from high stacks used by the power plants in the South Coast Air Shed prevent any impact on ground level NO_2 concentrations is contradicted by the results of the SF_6 tracer studies described above. SCE's beliefs are also contradicted by the meteorological analyses presented on pages 41-54 of the ARB Staff Report. These analyses show that, on 80 percent of the days, the base of the inversion as measured at Los Angeles International Airport, is at or above the power plant plume height, and that on 16 of the 21 days in the period 1972-1979 when NO_2 concentrations were equal to or greater than 0.45 ppm, the maximum mixing depth was greater than 984 feet. These data show that efficient mixing of the plume down to ground level would be expected on about 80 percent of all days and on 75 percent of those days when NO_2 concentrations are greater than 0.45 ppm. This finding is also supported by the SO_2/CO model study performed by TSC for SCE as interpreted by John Trijonis (John Trijonis, Review of the TSC Report "Impact of Power Plants on Ambient Nitrogen Dioxide in the South Coast Air Basin", May 1980) which shows that as much as 13.2 percent of the ground level NO_2 concentrations is due to NOx emissions from power plant stacks.

This conclusion is further supported by the testimony presented by Professor James Edinger (Tr, Nov. 5, pp 49 ff). Professor Edinger discussed the merging of the inversion layer into the mixing layer over the course of a day and presented data that show the mixing layer is deeper at inland locations where NO_2 maxima generally occur than it is at the shoreline where the power plants emit and where SCE's data on the height of the inversion base were gathered. Dr. Edinger's conclusions were graphically illustrated in a short time-lapse film that showed how pollutants trapped aloft in the inversion layer rapidly mix downward as surface heating occurs.

Another concern of the Board's is that the SCE witnesses have focused on NO_2 exceedances that occur early in the day, typically around 9:00 a.m. However, data presented in the ARB Staff Report (Staff Report, pp 51 and 52) show that the bulk of the NO_2 exceedances occur later in the day, well after the time when surface heating has caused the mixing layer to deepen and has produced the turbulence necessary to mix power plant emissions uniformly down to the ground.

On the basis of these facts -- tracer studies and meteorological analyses -- the Board believes that the idea of "suppressed mixing" put forward by SCE and their consultants (Tr, Nov. 6, 4:30 p.m., pp 114-119) is a misnomer. This phenomenon, which all the technical experts agree can sometimes occur because of initial plume rise, is more properly characterized as delayed mixing. The evidence before the Board clearly shows that pollutants transferred initially to the inversion layer do not simply disappear.

Thus, the Board concludes that during typical meteorological conditions associated with violations of ambient air quality standards, power plant NOx emissions contribute significantly to ground level NO_2 concentrations. Even in those instances when NOx emissions from elevated power plant stacks initially reach the inversion layer, under the meteorological conditions prevailing in the South Coast Air Shed, such emissions do impact at ground level and make a substantial contribution to ground level concentrations of NO_2.

4. Finding: Reductions of NOx emissions from power plants are needed to the maximum extent feasible and as early as practicable to meet state and national ambient air quality standards for NO_2.

Basis: The facts on which this finding is based include the following:

a. The nonattainment plan for the South Coast Air Basin consists of the Air Quality Management Plan adopted in January 1979 by the SCAQMD and Southern California Association of Governments as amended and approved by the Board. The plan contains a commitment to meet the national ambient air quality annual average for NO_2 and is based in part on and assumes the reduction in NOx emissions to be attained through implementation of Rule 475.1 or a similar rule. The plan has been submitted to the U.S. EPA, and EPA has proposed to conditionally approve the NO_2 portion of the plan (45 FR 21271 ff, April 1, 1980). The plan requires enforceable measures to control NOx emissions from power plants in the South Coast Air Shed.

b. The South Coast Air Quality Management Plan (AQMP) projects that in 1982, total NOx emissions in the South Coast Air Basin and Ventura County will be approximately 1340 tons per day.[1/] Of that total, approximately 660 tons per day[1/] will be from stationary sources and 680 tons per day will be from mobile sources (AQMP, p VII-50). According to the AQMP, a 470 tons per day[1/] emission reduction will be needed to attain the federal NO_2 standard in 1982 (AQMP, p VIII-33). If all suggested mobile and stationary source control measures included in the AQMP to be implemented by 1982 are adopted and are as effective as planned, approximately 120 tons per day of NOx emissions reductions will result (AQMP, p IV-2A). Consequently, an additional 350 tons per day NOx emission reduction (470 less 120) is needed to meet the standard, The

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1. The numbers presented above are different from the numbers reported in the 1979 AQMP in that the AQMP assumes that Rules 1135.1 and 59.1 will reduce power plant NOx emissions in the SCAB and Ventura County by 50 percent in 1982. The numbers above are based on the AQMP but have been changed to reflect what the emissions from power plants would have been if Rules 1135.1 and 59.1 were not in effect.

AQMP projects that in 1982, power plants will emit over 230 tons per day[1] of NOx emissions if left uncontrolled. Consequently, even if all emissions from power plants were eliminated, the AQMP shows that the NO_2 federal standard would not be attained by 1982.

c. Approximately 340 tons per day[2] of NOx emissions reductions basinwide (a 30 percent reduction) will be needed in 1985 if the national ambient air quality standard for NO_2 is to be met in the South Coast Air Basin by that date (460 tons per day[2] for the state one-hour NO_2 standard). Emission reductions of approximately 300[2] and 420 tons per day[2] will be needed to meet the national and state standards, respectively, in 1990. (The required reductions are based on the emission projections for 1985 and 1990 shown in the ARB Staff Report, Table V, p 95.) The number of tons per day of NOx emissions which must be reduced in order to meet the state and national standards is based on a rollback analysis which assumes proportionality between NOx emission rates and ambient NO_2 concentrations. The design or "baseline" values used in the rollback calculations, after adjustment for the hydrocarbon benefit and correction for NOx measurement, are 0.46 ppm for the state one-hour standard and 0.078 for the national annual average standard.

The hydrocarbon emission reduction benefit to ambient NO_2 concentrations was discussed on pages 45-46 of the May 25, 1978 ARB Staff Report. A 0.88 correction factor of NOx measured was used based on ARB laboratory findings (California Air Quality Data, Quarterly Summary, Vol. 9, No. 1, Jan-March 1977, p 2).

If no corrections were made, the design values would have been the maximum hourly average of 0.59 ppm NO_2 for the state one-hour standard and annual average of 0.089 ppm NO_2 for the national standard (California Air Quality Data, 1977 and 1978 Annual Summaries); these uncorrected concentrations would have resulted in an increase in needed reductions. Both sets of concentrations were measured in Pasadena. The maximum hourly average was measured in 1978, and the annual average was for 1977, and represent the highest concentrations observed during the last three years for which data are available.

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2. These numbers are not reported in any documents but have been calculated by the Board from numbers included in the references cited throughout this discussion. The calculation procedures are also discussed in the text of this finding.

d. This finding is consistent with findings made earlier by the Southern California Association of Governments, the South Coast Air Quality Management District, and the Air Resources Board in connection with the adoption and approval of the Air Quality Management Plan for the South Coast Air Basin (SCAG's Resolution No. 79-158-3, January 25, 1979; SCAQMD Resolution No. 79-4, January 26, 1979; ARB Resolution No. 79-27, May 10, 1979).

5. Finding: The reductions in power plant NOx emissions in Ventura County provided for in Ventura County Air Pollution Control District Rule 59.1 are required for the attainment and maintenance of ambient air quality standards in both Ventura County and in the South Coast Air Basin.

Basis: The facts upon which this finding is based include the following:

a. Ventura County's Air Quality Maintenance Plan calls for reductions in both reactive hydrocarbon and oxides of nitrogen emissions as a means of attaining the national ambient air quality standard for ozone. California's State Implementation Plan (Chapter 17, State Implementation Plan, 1979) applicable to Ventura County as revised in April and May 1979 contains a finding that Rule 59.1, which provided for a 90 percent reduction in power plant NOx emissions, would be effective in helping to attain the national ambient air quality standard for ozone. The finding also contains a commitment to include such a rule in the State Implementation Plan. Power plant NOx emissions accounted for 47 percent of the 1977 stationary source NOx emissions in the County, and these emissions represent a substantial fraction of the potential control available to the District for attainment of the ozone standard.

b. The County's plan for attainment of and state and federal standards for suspended particulate matter ("Plan for Attainment of Standards for Total Suspended Particulate in Ventura County", 1980) includes projected reductions in suspended nitrates of 3 $\mu g/m^3$ annual average. According to the plan the reductions are to be achieved, in part, by controlling NOx emissions from power plants located within the County.

c. The Air Resources Board resolved in 1976 (Resolution 76-29) that Ventura County must, in adopting regulations, consider the effects of emissions originating within the County on adjoining air basins when determining the degree of control required. This resolution was based on evidence considered at that June 26, 1976 hearing which showed mixing of the air masses between Ventura County and the rest of the South Coast Air Shed.

d. Tracer releases from SCE's Ormond Beach generating station (ARB Staff Report, pp 40-41; B. K. Lamb, A. Lorenzen and F. H. Shair, Tracer Study of Power Plant Emission, Transport and Dispersion from the Oxnard/Ventura Plain, prepared by the California Institute of Technology for the California Air Resources Board, Contract No. ARB-5-306) have demonstrated that emissions from that facility are transported to the South Coast Air Basin and impact significantly upon air quality in that air basin. In particular, NOx from the facility is clearly contributing to violations of ambient air quality standards for NO_2 at West Los Angeles, Lennox and Reseda.

e. A meteorological analysis prepared by Science Applications, Inc. ("An Estimate of the Degree of Mixing and Interaction Between Los Angeles and Ventura County Air Basins", June 1978) indicates that wind patterns favorable to interbasin transport over coastal and land-based routes are found on more than one-half of the days each year. Transport over the coastal route is common during the late fall and winter months when NO_2 exceedances are most likely in the South Coast Air Basin.

6. Finding: Reduced NOx emissions from power plants will result in slightly less of a reduction in ozone levels in the western portions of the SCAB and Ventura County than would be expected based solely on planned and adopted hydrocarbon control measures, and slightly greater reductions in ozone levels in the eastern portions of the Basin and County, in addition to providing a general reduction in NO_2 concentrations throughout the air shed.

Basis: The facts upon which this finding is based include the following:

a. Field Studies

Field studies in which the plumes of large power plants were traced over distances of 100 kilometers or more show that while NOx in the plume scavenges (decreases) ozone aloft in the immediate vicinity of the source, NOx ultimately increases ozone as the plume moves farther downwind and mixes with the surrounding air (ARB Staff Report, p 154 ff).

b. Air Quality Modeling

The modeling studies performed by SCE and their consultants, Environmental Research and Technology (ERT) and System Applications, Inc. (SAI) relied on both a trajectory and a grid (air shed) modeling approach. The analysis made by ERT used the ELSTAR trajectory model while SAI used a grid model (SAI Air Shed model). The following discussion briefly summarizes the use and applicability of these models with regard to the issues before the Board.

ERT stated that ELSTAR is ideally suited for examining potential impacts of these Rules on ground level concentrations of pollutants directly under the plume. In all cases where the model was used, the plume was assumed to disperse in the mixing layer in order to maximize calculated ground level impacts. In this model, the conservation of mass concept (mass balance) is applied to an air column as it undergoes vertical diffusion and chemical transformation, and receives primary emissions from surface and elevated sources, all as the column is advected through the basin. The model was used to investigate the effects of power plant NOx control measures during both ozone and NO_2 episodes. The ozone episode (July 21, 1977) simulates two trajectories starting from El Segundo and Los Alamitos at 0700 and 0800 PDT, respectively. The simulations were carried out through 1800 PDT when air columns driven by surface-level winds reach the eastern portion of the basin (Fontana-Upland). The NO_2 episode (December 6, 1977) simulates two trajectories from the same power plants, starting at the same times. However, because of low surface winds on this day, the trajectories during the 11-hour simulation reach only as far as the La Habra-Whittier-Anaheim area.

The major conclusions reached by SCE on the basis of the ERT modeling study with respect to NO_2 and O_3 impacts are the following:

- As a result of the implementation of Rules 1135.1 and 59.1 (in addition to SIP controls in 1987), peak NO_2 values will decrease in the range of 0.02 to 0.06 ppm. Due to implementation of the Rules, NO_2 concentrations are predicted to be consistently lower in all regions covered by the trajectory.

- The power plant NOx controls will also result in increased ozone concentrations, with the change in peak ozone values predicted to be in the range of 0.02 to 0.04 ppm, and with one trajectory predicting an increase of 0.10 ppm. Ozone values are predicted to be higher throughout the trajectory path (including Fontana-Upland) as a result of the power plant NOx controls.

The Board believes this analysis to be seriously flawed. All vertically resolved trajectory models, including ELSTAR, are based on the validity of one critical assumption: that the moving air column retains its integrity throughout the simulation. Verifying this critical assumption requires a knowledge of upper level wind data. Based on our general knowledge of meteorology, we believe it unlikely that all five vertical layers used in ELSTAR, which extends to a total height of 830 meters, are advected by the surface winds as was assumed in the model. In fact, the ARB staff testified that vertical wind shear has been found to be quite pronounced (Tr, Nov. 13, p 7 ff). It is especially unrealistic to assume that the air column retains its integrity over an entire eleven hour simulation run. This fundamental assumption regarding the vertical integrity of the air column, without a knowledge and investigation of upper winds for the days in question, makes trajectory models such as ELSTAR especially unsuitable for assessing the ground level impacts of a strategy for controlling the emissions from several elevated sources when long transport times and distances are involved, and when the emissions from these sources are mixed with significant emissions from other sources.

Furthermore, both SAI and the ARB staff testified that multi-day (at least 2 day) air quality simulations are required to assess the impact of control measures. This is necessary in order to minimize the influence of assumed initial conditions on conclusions drawn from model predictions. However, trajectory models, by the very nature of their formulation, are not suitable for multi-day runs. This is because it is extremely rare for an air parcel or air column to maintain its integrity over a 12-hour period, as discussed above, much less for 48 hours. The Board believes that this shortcoming also precludes the use of trajectory modeling as a tool for evaluating the air quality effects of individual control strategies.

The SAI modeling analysis used a 3-dimensional air shed model to simulate the photochemical reactions in the atmosphere. Although an early SAI analysis was based on a one-day simulation, later simulations were made by SAI for a multi-day ozone episode that occurred on June 26 and 27, 1974, when the highest ozone concentration measured at Upland was 0.51 ppm. The application of a 3-dimensional model, such as the SAI air shed model, is generally preferable to the trajectory modeling formulation used by ERT because it can more adequately treat temporal and spatial variations in winds at the surface and aloft, and can characterize more realistically the downwind transport and dispersion of elevated plumes.

The SAI modeling results for NO_2 (Tr, Nov. 5, p 16 ff) show that a general decrease in NO_2 concentrations -- at least 0.02 ppm -- directly downwind of the power plants in the Basin would have resulted from the Rules on these days. Dr. Philip Roth of SAI testified further that, because of the 5 kilometer grid size used, the model probably underestimates the near field impacts of the plumes on NO_2 air quality.

The results of the SAI analysis for 1987 show a slight decrease in ozone concentrations in the eastern portion of the South Coast Air Basin (in the range of 0.01 to 0.02 ppm) due to implementation of the Rules. These decreases occur some 45 to 100 kilometers downwind from the coastal power plants. A corresponding ozone increase of about 0.02 ppm is predicted to occur near the power plants for downwind distances up to 20 kilometers as a result of the Rules. The ozone increases generally occur to the west of a north-south line passing through Fontana.

Dr. Roth and Mr. Killus further testified (Tr, Nov. 6, 4:00 p.m., pp 8-9; pp 23-29) that their analysis showed significant reductions in ambient ozone concentrations in 1987 due to the implementation of other hydrocarbon and oxides of nitrogen control measures contained in the South Coast Air Quality Management Plan, and that these significant reductions in ozone concentrations would occur regardless of the implementation of Rules 1135.1 and 59.1.

Dr. Trijonis, in his review of the SAI modeling analysis (John Trijonis, Critique of the SCE Report: "Power Plant NOx Emissions and Ambient Air Quality in the South Coast Air Basin," May 1980), suggests that an analysis of historical air quality data tends to show the dividing line between ozone increases and decreases due solely to Rules 1135.1 and 59.1 to be farther to the west than indicated by the SAI modeling results. Dr. Trijonis believed that the Rules, considered alone, would produce slightly lower ozone levels in those populated areas where the ambient air quality standards for ozone are exceeded by the widest margin.

In addition, the ARB staff's rebuttal of the SAI analysis of the wind field on June 26-27, 1974, indicates that the wind field generated by the SAI model tends to advect pollutants out of the basin too quickly and does not adequately represent the effect of pollutants in the Basin carried over from one day to the next. If true, this flaw would result in the same errors noted by Dr. Trijonis and discussed in the preceding paragraph.

The ARB staff also performed an independent modeling analysis (ARB Staff Report, p 168 ff) using the EKMA and SMOG models. The Board believes that the results of these studies lead to essentially the same conclusion as the studies conducted by SAI. The EKMA analysis indicated that a regional reduction (which may be small) in peak ozone concentrations is to be expected due solely to NOx controls on power plants. The SMOG modeling analysis, using hypothetical input data to simulate a power plant plume advected through an urban area, showed slight ozone decreases of about 0.02 ppm at the downwind end of the grid without the power plant plume, as contrasted to the case with the plume. The SMOG modeling analysis also indicated an increase in the ground level NO_2 concentrations throughout the basin due to the addition of the plume. Since the ARB staff's modeling analysis was for a hypothetical situation, the results cannot be compared directly with the SAI results. However, the results agree qualitatively with the SAI analysis in that they show that power plants are producing elevated ozone concentrations in the eastern portion of the SCAB, and that reductions in power plant NOx emissions will result in slight increases in ozone concentrations in upwind areas, slight decreases in ozone concentrations in downwind areas, and significant decreases in NO_2 concentrations in both upwind and downwind areas.

7. Finding: The issue of the toxicity of ozone relative to the toxicity of nitrogen dioxide is not relevant to this proceeding.

Basis: The facts upon which this finding is based include the following:

The Board believes that it is necessary to limit ambient levels of both these pollutants, given the existence of federal and state ambient air quality standards for each pollutant, and of data showing clear exceedances for both pollutants (Tr, Nov. 6, 4:00 p.m., p 74, ln 10-21).

In making this finding the Board takes notice of SCE's undocumented assertion about relative toxicity (SCE Comments, page 00047; Tr, Nov. 6, 4:00 p.m., p 73, ln 15 - p 77, ln 13). The Board also takes notice of "Comments on Oxides of Nitrogen Controls" by William Innes. One of the comments of Mr. Innes refers to a previous presentation by Mr. Innes, at the American Industrial Hygiene Association, in which he discussed the issue of relative toxicity. In neither of these discussions of the issue of relative toxicity is there any recognition given the overriding issue of attainment of ambient air quality standards for both NO_2 and ozone.

8. Finding: Particulate nitrate matter is a significant contributor to the total suspended particulate burden in the South Coast Air Basin, especially in the downwind receptor areas in the eastern part of the Basin. The control of NOx emissions is an essential component of the strategy to reduce total suspended particulate matter.

Basis: The facts upon which this finding is based include the following:

In 1979, air monitoring stations measured violations of the state total suspended particulate matter standard on more than half of the samples. The California Air Quality Data Bank, the Board's ACHEX Field Study, and the study by Pitts and Grosjean (James N. Pitts, Jr., and Daniel Grosjean, Detailed Characterization of Gaseous and Size-Resolved Particulate Pollutants at a South Coast Air Basin Smog Receptor Site: Levels and Modes of Formation of Sulfate, Nitrate and Organic Particulates and Their Implications for Control Strategies, Final Report, California Air Resources Board, Contracts ARB-5-384 and A6-171-30 (1978)) show that nitrates frequently comprise one-third of the total particulate burden in the eastern part of the Basin. SCE introduced testimony to show that nitrate measurements are inaccurate and frequently dominated by artifact formation and that control of NOx emissions would be of little or no value in reducing total suspended particulate matter.

However, in his written testimony during the hearing on November 13, 1980, Dr. Bruce Appel showed that even when the influence of artifact nitrates is subtracted, ambient nitrate levels are still quite high. Dr. Appel also emphasized the fact that atmospheric acidity can lead to the removal of particulate nitrate from the surface of sampling filters. This "negative artifact" phenomenon can cause measured nitrate concentrations to be lower than actual concentrations. Dr. Appel concluded that particulate nitrate still accounts for a substantial contribution to the total suspended particulate burden. Dr. Appel's statement additionally shows that a substantial portion of the nitrate aerosol particles exist in the inhalable size range, which is also the size range that most efficiently scatters visible light and, hence, contributes most heavily to visibility degradation.

9. Finding: Particulate nitrate contributes to visibility degradation, and control of NO_2 is an important factor in the effort to improve visibility in the South Coast Air Basin.

Basis: The facts upon which this finding is based include the following:

In the eastern portion of the South Coast Air Basin, visibility was reduced to less than 3 miles by air pollution on 75 days during 1979 (ARB Staff Report, p 87; South Coast Air Quality Management District, Summary of Air Quality in the South Coast Air Basin in California 1979, June, 1980).

The Board's ACHEX Study (G.M. Hidy, Ed. Characterization of Aerosols in California, Vol. IV, ACHEX Final Report, California Air Resources Board, Contract 348, (1974)), Pitts and Grosjean (James N. Pitts, Jr., and Daniel Grosjean, Detailed Characterization of Gaseous and Size-Resolved Particulate Pollutants at a South Coast Air Basin Smog

Receptor Site: Levels and Modes of Formation of Sulfate, Nitrate and Organic Particulates and Their Implications for Control Strategies, Final Report, California Air Resources Board, Contracts ARB-5-384 and A6-171-30 (1978)), and Trijonis (John Trijonis, Visibility in California, Final Report, California Air Resources Board, Contract A7-181-30 (1980)) have performed analyses which show that visibility impairment is explained almost entirely by the sulfate and nitrate aerosol fractions (ARB Staff Report, p 171).

However, SCE believes that nitrate measurements are dominated by artifact nitrate formation and that there is very little nitrate aerosol to degrade visibility.

The artifact nitrate issue was discussed in Finding 8 above. In addition, Dr. Appel reported that 70 percent of the nitrate sampled by his group was below 3.5 microns in size, and that particles in this size range are extremely effective in scattering visible light and thus degrading visibility.

10. Finding: NOx emissions contribute to acid precipitation in the South Coast Air Basin.

Basis: The facts upon which this finding is based include the following:

Chemical analysis of rainfall samples from World Meteorological Organization background sites indicates that nitrate ion concentrations at these sites are not measurable. Even in urban areas, measurements taken at the end of rainstorms exhibit pH values close to the theoretical background value of 5.65 for water in equilibrium with atmospheric carbon dioxide (Tr, Nov. 6, 4:00 p.m., p 46 ff).

Recent studies (ARB Staff Report, p 175) in the South Coast Air Basin have shown that rainfall acidity is typically 10-100 times more acidic than unpolluted rain (ARB Staff Report, p 175), with maximum acidity nearly 1000 times the background unpolluted value. Nitrate and nitrite ion concentrations in rainfall from Pasadena show significant correlations with ambient nitric oxide concentrations.

SCE questioned the existence of an acid rain problem in the South Coast Air Shed (SCE Submittal, p 843), and presented data from "background" locations in remote areas to support their position. However, the ARB staff showed (Staff Rebuttal, Nov. 13, 1980, Att VI, pp 1-2) that the locations listed by SCE, although remote, are impacted by emissions from anthropogenic sources, and that acid precipitation at these sites is incorrectly interpreted as representing natural background values.

Since nitrate ions have been shown in the South Coast Air Basin studies to be in many cases at least as important as sulfate ions (ARB Staff Report, pp 88-89) and since the levels of nitrate and sulfate correlate well with rainfall acidity (J.J. Morgan, et al, Measurement and Interpretation of Acid Rainfall in the Los Angeles Basin, Final Report, California Air Resources Board, Contract No. A7-110-30), the Board finds that power plant NOx emissions are contributing significantly to acid precipitation in the South Coast Air Basin.

11. Finding: The above findings that power plant NOx emissions will have a significant impact on ground level NO_2 concentrations are generally applicable to other pollutants and to emissions from tall stacks in general.

Basis: This finding is based on the same information and same rationale as presented in Finding 3. The conclusions drawn from the SF_6 tracer studies and from the meteorological analyses apply equally to any gaseous or fine particulate pollutants emitted from elevated sources in the South Coast Air Shed.

Although pollutants other than NOx were not specifically discussed at these hearings, the findings regarding the effects of tall stacks in the air shed apply equally well to pollutants other than NOx, and the various modeling studies (see Basis for Finding 6) can similarly be applied to other pollutants by applying appropriate chemical transformations that occur while the pollutant is in transit. Inasmuch as power plant stacks produce the highest effective stack height of any stacks in the South Coast Air Shed, it must be concluded that any stack with a lower effective stack height will also significantly impact ground level air quality.

12. Finding: A strategy to achieve the maximum practicable reduction of NOx emissions from power plants should first consider the reduction in NOx from a 50 percent cutback in oil and gas burning, and then include adoption of a measure which will reduce by 80 percent the NOx emissions from six to seven of the largest SCE steam generating units and three of the largest LADWP steam generating units.

Basis: The facts upon which this finding is based include the following:

a. There are regulatory and economic pressures to significantly reduce the consumption of oil and gas by utilities.

Although it is impossible for anyone to predict precisely the energy future of the United States at this time, it is certain that great pressures do and will continue to exist to reduce fuel oil and natural gas burning. These pressures are reflected in the current provisions of the Powerplant and Industrial Fuel Use Act (42 U.S.C. 8301 et seq.), Section 301, which prohibits the use of natural gas as a primary energy source in an existing power plant after January 1, 1990. The likelihood of a future decrease in oil and gas burning to generate electricity is also seen in submissions by the utilities to the California Energy Commission. (Submissions to the California Energy Commission by SCE and LADWP for common forecasting methodology (CFM) II, July 1979, and CFM III, July 1980).

The record of the Board hearings on Rules 1135.1 and 59.1 in January and March 1980 contains abundant evidence presented by the utilities that because of an expected decrease in oil and natural gas availability, a substantial decrease in oil and gas generated electricity in the South Coast Air Shed could be expected (e.g., Tr, January 30, pp 72-80).

Additionally, even if natural gas and oil are available to California utilities, the price of these fuels may be expected with a considerable degree of certainty to increase throughout the 1980's and beyond, so that there will be a considerable economic incentive for utilities to reduce substantially their use of these fuels.

It is impossible to quantify precisely the reduction in future use of gas and oil for electrical generation, particularly for 1990 and beyond. Estimates have ranged from a 23 percent reduction to 50 percent reduction. (Tr, January 30, 1980, p 49; SCE CFM III, 1980; LADWP CFM III, 1980; ARB Staff Report, p 154.)

Based on the available evidence, the Board concludes that 50 percent is a reasonable upper limit for the expected reduction in oil and gas use by utilities in the South Coast Air Shed by 1990.

b. These pressures will also result in a decrease in the amount of electricity generated by existing units in the South Coast Air Shed.

A decrease of 50 percent in oil and gas burning by utilities in the South Coast Air Shed by 1990 will result in a substantial reduction in the amount of electricity generated from existing power plants in the Air Shed.

Virtually all of the gas and oil used by SCE and LADWP is used in the existing steam generating units which are located in the South Coast Air Shed. Therefore, a reduction in oil and gas consumption will result in a corresponding reduction in electrical generation from the steam generating units governed by the Rules. The submittals of SCE and LADWP to the California Energy Commission (CFM III, July 1980) show that the amount of electricity to be generated by these steam generating units in the Air Shed will decrease annually from 1980 to 1990.

c. The remaining demand for electricity in the South Coast Air Shed will be principally satisfied by the newer, larger, and more-efficient units in the utilities' systems.

With a 50 percent decrease in oil and gas burning by the utilities and the corresponding reduction in electricity generated in the South Coast Air Shed, the base load* capacity needed from steam generating units in the Air Shed after 1990 can be supplied by six or seven of SCE's largest steam generating units and three of LADWP's largest steam generating units.

The ARB staff testified at the March 27, 1980 hearing that with a 50 percent oil and gas cutback and the corresponding reduction in electricity generation in the Air Shed, only a relatively few steam generating units would be needed to supply the base electrical demand (Tr, March 27, 1980, pp 65-70). The ARB staff further indicated that it believed the aggregate rated capacity required to satisfy the base load demand under such a condition would be 3420 megawatts for SCE and 1003 megawatts for LADWP. Detailed data submitted to the ARB staff by the utilities on their steam generating units (Based on various letters from utilities, for example, letter from James Mulloy, LADWP to P. Venturini, January 27, 1978) show that generally the largest units are also among the newer, more efficient and least NOx emitting units. These points were not contested by the utilities. Therefore, the Board finds it reasonable to conclude that these larger units would be selected by the utilities to remain as base load units after 1990.

LADWP's submittals to the California Energy Commission generally support this conclusion. The Common Forecasting Methodology III (Submitted by LADWP to the CEC in July 1980) cites high projected capacity factors for the large units and low capacity factors for small units. (CFM III, Form No. R-5, pp 1-3.) However, SCE in its Common Forecasting Methodology III (Form No. R-5, p 254) shows increasing capacity factors for its units that are less than 100 megawatts of capacity. In fact, SCE projects for the year 2000, that the small, inefficient units will have higher capacity factors than all other steam generating units in the Air Shed. This does not support the conclusion that the small units will not be used as base load units.

*As used in these findings, base load means the relatively constant portion of electrical demand.

The reasons for SCE's projected high capacity factors for small units are unclear since operating these units at such high capacity factors is contrary to both economic dispatch and least NOx dispatch. Further, the ARB staff testified that at workshops conducted prior to this hearing, SCE agreed that with a 50 percent oil and gas cutback, the generating capacity of six of their largest units would adequately supply their base electrical needs after 1990 (Tr, March 27, 1980, pp 65-70). Based on the lack of any rational basis to support SCE's most recent projections and their inconsistency with previous SCE projections and recent LADWP projections, the Board concludes that the base load demand in 1990 can be met by six or seven of SCE's largest units.

d. A 50 percent reduction in oil and gas used will result in at least a 50 percent reduction in power plant NOx emissions, with 90 percent of the remaining NOx emitted by relatively few base loaded units.

Detailed data submitted by the utilities to the ARB staff show that the larger steam generating units are newer, more efficient and emit less NOx than the smaller units. (Based on various letters from utilities, for example, letter from James Mulloy, LADWP to P. Venturini, January 27, 1978). Operating the more efficient units at higher capacity factors and decreasing the capacity factors of the less efficient units would appear, on its face, to be consistent with the goal to reduce oil and gas consumption. Furthermore, operating the lower polluting units at higher capacity factors is also consistent with the least NOx dispatch requirements of the Rules. For these two reasons, the utilities are likely to operate their newer units more often in order to minimize fuel costs and to comply with least NOx dispatch. Thus, a 50 percent reduction in oil and gas consumption will likely result in a greater than 50 percent reduction in power plant NOx emissions.

Based on information provided by the staff the Board estimated the amount of emissions that would result from the uncontrolled operation of the base loaded units after 1990 (Staff Report, dated September 19, 1980, pp 244-252). With the assumption that there would be a 50 percent reduction in oil and gas use after 1990, and that this, combined with implementation of a least NOx dispatch plan, would result in at least a 50 percent reduction in NOx emissions, the ARB staff calculated that 90 percent of the remaining emissions would come from six of the largest SCE units and three of the largest LADWP units. This point was not disputed by the utilities.

e. With a 50 percent oil and gas cutback and the implementation of a least NOx dispatch plan, rules requiring an 80 percent decrease in the emissions from six or seven of the largest SCE steam generating units and from three of the largest LADWP steam generating units will result in an overall decrease in power plant NOx emissions in the South Coast Air Shed of nearly 90 percent.

The ARB staff prepared a scenario for SCE (ARB Staff Report, September 19, 1980, pp 244-252) based on the installation of selective catalytic reduction (SCR) systems achieving 90 percent control on two 800 megawatt units in Ventura County and four 480 megawatt units in the South Coast Air Basin. The ARB staff also prepared a scenario for LADWP (ARB Staff Report, pp 244-252) based on the retrofit of SCR on Haynes 5 and 6 (344 megawatts each) and Scattergood 3 (315 megawatts). The above nine units are among the largest, newest and most efficient units in the utilities' systems. The Board estimates that under these scenarios, but adjusted for only 80 percent control on those units, there would be an 89 percent reduction in annual power plant NOx emissions.

This analysis is based on the fact that a 50 percent cutback in oil and gas use by 1990, together with the implementation of a least NOx dispatch plan, can achieve as much as a 60 percent reduction in NOx emissions if capacity factors are higher for the base loaded units and low for the peaking units (ARB Staff Report, September 19, 1980, pp 244-252). Of the remaining 40 percent of the emissions, 90 percent will come from the nine or ten large base load units. Controlling these base load units by 80 percent will result in an additional reduction in emissions of 29 percent (90 percent times 40 percent times 80 percent). Therefore, the total reduction would be 89 percent (60 percent plus 29 percent).

SCE presented written testimony (SCE Written Testimony, Dec. 2, 1980, p 13) at the December 2, 1980 hearing describing a scenario based on the retrofit of SCR on slightly different units (two 800 megawatt units, two 480 megawatt units, and three 320 megawatt units, a total of seven units, as contrasted with the ARB staff's scenario of six units). LADWP also presented written testimony at the December 2, 1980 hearing describing a scenario based on the retrofit of SCR on Haynes units No. 1 (224 megawatts), 5 and 6 (both 344 megawatts). Although the scenarios developed by the ARB staff and the utilities call for the installation of SCR on some different units, the total steam generating capacity proposed to be retrofitted is similar in magnitude in each case. Consequently, the Board finds that the overall emissions reductions achieved in these scenarios will be similar if all retrofitted units are controlled by 80 percent, a 50 percent reduction in oil and gas consumption occurs, and least NOx dispatch is implemented.

f. A control strategy requiring the installation of 80 percent controls only on a limited number of base load units (or equivalent capacity) is prudent and reasonable because requiring controls on units which may not have significant use after 1990 would result in excessive costs.

SCE testified that the amount of replacement power that they will be able to obtain by 1990 is extremely uncertain due to delays in the construction of new electrical sources and loss of pending contracts (Tr, March 27, 1980, pp 104-117). Because of this, SCE testified that it is unable to guarantee that they will be able to reduce their oil and gas use by 50 percent by 1990. Because of such uncertainty, SCE developed a scenario for rule compliance which would require installation of SCR on 16 units and LADWP developed a scenario which would require installation of SCR on 11 units (SCE's Written Testimony, Nov. 5, 1980, pp 150-151; Tr, Nov. 13, 1980, p 62). This is in contrast to the ARB staff's scenario cited on pages 244-252 of the September 19, 1980 Staff Report which assumed the installation of SCR on six of SCE's units and three of LADWP's units. The basic reason for the difference between the ARB staff's estimate and the utilities' estimate of the number of units requiring the installation of SCR is the assumed amount of oil and gas cutback by 1990.

To minimize the uncertainty as to the number of units requiring retrofit by 1990, and, consequently, to minimize the financial risk to the utilities associated with achieving the maximum practicable NOx reductions, the Board believes it reasonable to require the installation of SCR only on those few units that are certain to remain as base load units with high capacity factors under the most optimistic oil and gas reduction scenarios. In the event that the reduction in the use of oil and gas in power plants by 1990 is less than 50 percent, and, consequently, units not controlled by 80 percent are used to supply base load demand, additional rules can be developed to require further control of NOx emissions from such units or from other NOx emitting sources. The advantage of this approach is that no units will be required to be retrofitted with 80 percent controls unless there is a substantial likelihood that these units will be operated to provide base load electricity after 1990.

13. Finding: Selective catalytic reduction (SCR) is a commercially available and proven technology to reduce NOx emissions from existing oil and gas fired electric utility boilers by 80 percent.

Basis: The facts upon which this finding is based include the following:

SCR has been retrofitted on existing, commercial size oil and gas fired electric utility boilers in Japan and is achieving NOx reductions in the range of 75-85 percent. (Testimony of William Ellison, NUS Corporation (consultant to LADWP), Tr, Nov. 13, 1980, p 68; testimony of James Sheehan, Stearns-Roger (consultant to LADWP), Tr, Nov. 13, 1980, pp 127-218; statement of Dan Waters, LADWP, Tr, Nov. 13, 1980, pp 106-107; ARB Staff Report, Sept. 19, 1980, pp 98-99.)

14. Finding: The cost per pound of NOx reduced to comply with the Rules is within the range of \$2.35 to \$2.90 per pound.

Basis: The facts upon which this finding is based include the following:

The cost-effectiveness of any proposed rule is determined by computing the total annual cost of compliance with the rule and dividing that cost by the annual reductions in emissions which result from the rule. The cost of compliance include both the capital cost (annualized) and the operating and maintenance costs. For these two Rules, the annual emissions reductions are dependent on the assumptions regarding capacity factors and fuel burned for the power plants equipped with controls, representing two other factors that must be taken into account. Each of these factors are discussed below.

a. The average capital costs of compliance with these Rules is within the range of \$70 to \$89 per kilowatt of capacity controlled for each utility, as expressed in 1980 dollars.

There is much data in the record regarding the cost of installing SCR on electric generating units of the affected utilities. SCE, LADWP, and the ARB staff have each presented to the Board their estimates of capital cost for retrofit of SCR. Because these estimates were presented in various ways, the Board has normalized the cost data when necessary to reflect only the 80 percent control actually required by the Rules, as expressed in 1980 dollars. The averages of these estimates range from \$70/kw to \$94/kw for each utility system in 1980 dollars.

SCE's latest capital cost estimates for 80 percent control range from \$89/kw to \$98/kw with an average of \$93.5/kw (SCE's Written Testimony, Dec. 2, 1980, Attachment 3). These cost estimates are based on conceptual cost estimates which have been consistently revised downwards as more detailed estimates have been made. For example, the amended version of SCE's estimates of cost shows a latest estimate of $111 per kilowatt (90 percent control), downwardly revised from SCE's previous estimate of $137 per kilowatt. Similarly, the latest SCE cost estimate is also based upon a conceptual (rather than preliminary or advanced) design. The Board believes, therefore, the current SCE estimate will likely be further reduced, as suggested by more detailed cost estimates by SCE for its demonstration (90 percent control) unit at Huntington Beach. Based on a conceptual design, SCR on the Huntington Beach unit (107.5 Mw) was originally estimated to cost about $129/kw (in 1980 dollars). However, preliminary and advanced engineering cost estimates prepared by SCE for this unit are $79/kw (in 1980 dollars). (SCE's Written Testimony, Nov. 5, 1980, p 00064, Attachment 1.)

The consultant for LADWP, Stearns-Roger, estimates the capital cost for retrofitting SCR systems for 80 percent emission controls on affected units to range from $77/kw to $124/kw with an average of $89/kw (LADWP's Supplemental Written Testimony, Dec. 2, 1980, Table 1). These estimates are the result of an analysis by Stearns-Roger of the difficulty of retrofit for individual units and the drafting of a conceptual design. Given the preliminary nature of the cost estimates, the Board finds that there is good general agreement between the ARB staff and LADWP estimates for capital cost.

The Board also finds that the major differences between the ARB staff and Stearns-Roger capital cost estimates is the assumed contingency cost. The Stearns-Roger estimate used a 25 percent contingency factor; consequently, the Stearns-Roger estimate of $89/kw should be considered an upper bound since SCE has used a much lower contingency of seven percent in its most recent cost for the Huntington Beach unit. The ARB staff estimate, on the other hand, should be considered a lower bound since it is based on the same basic assumptions as the Stearns-Roger estimate, but with a lower contingency cost.

b. The average annual operating and maintenance cost of compliance with the Rules is within the range of $9 - $10 per kilowatt of controlled capacity for each utility, as expressed in 1980 dollars.

The ARB staff, SCE, and LADWP have also presented to the Board their estimates of operating and maintenance costs for retrofit of SCR with 80 percent control on affected units. These estimates range from $9/kw/yr to $17/kw/yr in 1980 dollars.

Based on the ARB staff estimate of $10.82/kw/yr (ARB Staff Report, Sept. 19, 1980, p 120), adjusted downwardly to reflect 80 percent control and upwardly to reflect 1980 dollars, the Board estimates the cost to be $9/kw/yr. The Stearns-Roger estimate of $9/kw/yr to $10/kw/yr is in remarkably close agreement with this estimate (LADWP Written Supplemental Report, Dec. 2, 1980, Table 2).

SCE testified to the Board, however, that its estimate for operating and maintenance costs is $17/kw/yr (SCE Report, Dec. 2, 1980, p 16). This estimate is almost twice the estimate presented by the ARB staff and by Stearns-Roger. Both Stearns-Roger (Tr, Dec. 3, p 35) and SCE (SCE Written Testimony, Nov. 5, 1980, p 00068, Attachment 5) have identified and used in their estimates a catalyst cost of $875 per cubic foot. (Catalyst material must be replaced periodically.) Furthermore, Stearns-Roger and the ARB staff have both identified this catalyst cost as the single largest component of operating cost: approximately one-half (LADWP Written Testimony, Dec. 2, 1980, Table 2). Consequently, unspecified items (other than catalyst replacement) must account for the higher estimate by SCE, since all three estimates assumed the same cost and frequency of catalyst renewal. The Board finds SCE's estimate to be unsupported by its evidence, inconsistent with the estimates of LADWP, Stearns-Roger, and the ARB staff, and inconsistent with the fact that actual operating costs reported for SCR units in Japan are less than one-half the lowest estimates discussed above (Letters from Kitadada to Goodley, July 23, 1980; M. Kikkawa to Goodley, June 27, 1980).

Based on the analyses of all data in the record regarding operating and maintenance costs for retrofit of SCR with 80 percent effectiveness, the Board concludes that the approximate cost ranges from $9/kw/yr to $10/kw/yr.

c. The average capacity factors for each unit controlled with SCR will likely be in the range of 50-70 percent in 1990 and beyond.

The testimony presented to the Board has made it clear that estimates of cost-effectiveness are extremely dependent on the capacity factors assumed for units retrofitted with SCR. Therefore, in order to derive the cost of the Rules per pound of NOx reduced, it is important to determine a reasonable capacity factor for each unit. The average capacity factor for all units in the LADWP and SCE systems is presently over 40 percent, with newer units having capacity factors of over 50 percent (LADWP CFM III, Form R-5, pp 1-3 and SCE CFM III, Form R-5, p 254). Therefore, if electrical generation in the Air Shed were reduced by 50 percent, it is reasonable to assume that a few large units could and would be used to meet most of the demand (Finding 12 above). In addition, least NOx dispatch would require that units with lowest emissions (also the newest and most efficient) would be first added and last taken off the line, the result being an even greater likelihood that such units would be operated at high capacity factors.

Capacity factors at least as high as those found for these few units today (over 50 percent), and up to 70 percent, would be likely for the units to be considered for retrofit for the NOx controls.

d. Base load power plants in the South Coast Air Shed will likely be operating on oil, and not natural gas, beyond 1990.

There is much evidence in the record that there will be little natural gas available for utility use after 1990. Section 301 of the Powerplant and Industrial Fuel Use Act of 1978 (42 U.S.C. 8301 et seq.) requires that: (1) natural gas not be used as a primary energy source in an existing electric power plant on or after January 1, 1990; and (2) natural gas not be used as a primary energy source in an existing electric power plant for any calendar year before 1990 in greater proportions than the average yearly proportion of natural gas which such power plant used as a primary energy source in calendar years 1974-1976, unless an exemption is granted under Section 312 of the Act. The thrust of the Act is to limit the use of natural gas by power plants and industrial sources, particularly after 1990 (CEC 1979 Biennial Report, pp 8-9).

The California Energy Commission and the utilities have independently projected the amount of natural gas that will be available for utility use. The CEC's natural gas availability projections as of August 29, 1980, show that approximately half of the electrical demand in 1990 and 2000 will be met with the use of natural gas. The utilities' projections, as reported in their "1990 California Gas Report" to the Public Utilities Commission, on the other hand, show that no gas will be available for power plant use after 1990 ARB Staff Report, September 19, 1980, pp 225-229). Even if natural gas is available, and if legislation is changed to allow its use in power plants, most of the available natural gas will be used after 1990 on the uncontrolled peaking units, which operate most often on summer days when natural gas availability is highest.

Consequently, the Board finds it reasonable to assume that base load power plants in the South Coast Air Shed will not be operating to any significant extent on natural gas after 1990, and that the estimates of cost-effectiveness of controls should be based on the use of oil rather than natural gas as a fuel.

e. The cost-effectiveness of compliance with the Rules is within the range of \$2.35 to \$2.90 per pound of NOx reduced.

The cost-effectiveness estimates of the ARB staff and the utilities for Rules 1135.1 and 59.1 are included in Tables 1, 2 and 3 of this finding, normalized for 80 percent control and expressed in 1980 dollars. Because of the variations in the capital and operating and maintenance cost and capacity factor estimates of the ARB staff and the utilities, the cost-effectiveness estimates also vary.

Although the Board recognizes uncertainties in specific cost estimates, it finds that the evidence in the record supports finding that the average cost-effectiveness of compliance with Rules 1135.1 and 59.1 for each utility ranges from a lower bound of \$2.35 per pound to an upper bound of \$2.90 per pound of NOx reduced. The only estimates to exceed this amount are one presented by SCE and an estimate presented by LADWP the last day of the hearing. The Board finds the SCE estimate inappropriate for the same reasons discussed above regarding SCE's capital and operating and maintenance costs. The Board finds the last LADWP estimate inappropriate because it was based upon unusually low capacity factors for the retrofitted units. This latter estimate is discussed further in Finding 20 below.

15. Finding: The cost-effectiveness of the Rules is reasonable and comparable to that of other control measures adopted by the Board.

Basis: The facts upon which this finding is based include the following:

Based on a review of measures contained in the AQMPs for the South Coast and Ventura County, as well as of other NOx control measures the Board has considered or is aware of, the Board finds that there are no other measures or combinations of measures capable of achieving the same (or similar) NOx emissions reductions as Rules 1135.1 and 59.1 for less cost. The Rules are also comparable in cost-effectiveness to other control measures adopted by the Board, including the 0.4 gram per mile passenger car NOx standard cited by the utilities for comparison. The cost of that standard is currently estimated to be \$2.39 per pound, expressed in 1979 dollars, or \$2.63 per pound in 1980 dollars. The upper bound cost of the Rules is within 15 percent of the cost of this motor vehicle rule; this difference is reasonable given the uncertainties in the estimated cost of the Rules.

SUMMARY TABLE 1.

UTILITY COST ESTIMATE VS. ARB STAFF COST ESTIMATES

TO COMPLY WITH SCAQMD RULE 1135.1 AND VAPCD RULE 59.1

(1980 Dollars)

UTILITY	Overall Percent Reduction with th Proposed Rule	Total Capacity (Mw) Requiring SCR Retrofit	No. of Units Requiring SCR Retrofit to Achieve 80% Control	Utility Estimates			ARB Staff Estimates		
				Total Capital Cost (Million Dollars)	Total Annual Cost (Million Dollars)	Average Cost Effectiveness ($/lb.)	Total Capital Cost (Million Dollars)	Total Annual Cost (Million Dollars)	Average Cost Effectiveness ($/lb.)
SCE	89	3520	7	329	126	3.70	246	80	2.36
DWP	88	912	3	81	25	2.88	64	21	2.40

TABLE 2

COMPAR SCE Estimates .TAFF COST ESTIMATES TO COMPLY WITH THE PROPOSED RULE 1135.1 WITH 80 PERCENT CONTROL ON INDIVIDUAL UNITS (1980 Dollars)

Unit Number	Capacity Factor			ARB Staff Estimates	
		Capital Cost for 80% Control (million dollars)	Total Annual Cost (million dollars)	Capital Cost for 80% Control (million dollars)	Total Annual Cost (million dollars)
Ormond Beach 1	57	78.32	29.26	56.00	18.24
Ormond Beach 2	57	78.32	29.26	56.00	18.24
Alamitos 5	66	42.72	16.70	33.60	10.94
Alamitos 6	66	42.72	16.70	33.60	10.94
Alamitos 3	53	28.16	11.07	22.40	7.30
Alamitos 4	52	28.16	11.07	22.40	7.30
Etiwanda 3	52	30.98	11.64	22.40	7.30
Total		329.38	125.7	246.40	80.26

Note: Cost estimates have been adjusted to reflect 80 percent control and are expressed in 1980 dollars. Average capital cost estimates are $93.5 per kilowatt for SCE and $70 per kilowatt for the ARB staff estimates, although SCE's more detailed unit-by-unit costs are shows as well. The total annual costs include both annualized capital costs, and operating and maintenance costs of $27 per kilowatt for SCE and $9 per kilowatt for the ARB staff estimates.

16. Finding: The cost of Rules 1135.1 and 59.1, when allocated to the average residential customer of SCE, represents an increase of about 1.5 to 3 percent in the average residential customer's electricity bill over the period 1982-2007.

Basis: The facts upon which this finding is based include the following:

SCE, in its testimony submitted to the Board on December 2, 1980, included estimates (page 33) of the impact of Rules 1135.1 and 59.1 on its residential customers. Following discussions between the Board and Mr. Rodney Larson of SCE, it was agreed that the increase in average residential rates as a result of these rules would be about 1.5 to 3 percent. This would increase current average monthly residential bills of about $35.00 by about $0.50 to $1.00. The ARB staff presented an estimated bill increase of $0.55 per month, which is consistent with SCE's estimate.

17. Finding: LADWP's compliance with Rule 1135.1 will result in an increase of 2 to 3 percent in average LADWP electricity bills to residential customers.

Basis: The facts upon which this finding is based include the following:

Mr. Harrison Call testified on behalf of LADWP on December 3, 1980. According to Mr. Call's testimony, the increase in total revenues required by LADWP to comply with Rule 1135.1 would translate into a 2 to 3 percent increase in average monthly residential electricity bills. The ARB staff estimate was consistent with that of LADWP.

18. Finding: The capital costs of compliance with Rules 1135.1 and 59.1 represent a small fraction of both utilities' capital needs over the next ten years.

Basis: The facts on which this finding are based include the following:

a. SCE's testimony submitted to the Board on December 2, 1980, indicates that their capital needs through 1987 amount to about $7.5 billion. Based on SCE's estimates, the capital requirements for these Rules amount to about $374 million. The capital requirements for these Rules therefore amount to about 5 percent of their capital needs through 1987.

b. SCE indicated in their written testimony that the firm is currently experiencing a critical financial period and that the costs of these Rules would place an extreme financial burden upon them. While the Board recognizes that SCE may currently be experiencing cash flow problems, SCE's testimony indicated that they are transitory in nature, and are principally associated with ongoing construction projects which are nearing completion in the next few years.

Mr. McDaniel of SCE, during questioning, agreed with the Board's assessment that SCE's cash flow position has been difficult for the last couple of years and is expected to remain difficult for another couple of years, but that prospects for returning to financial health are favorable beyond that time.

c. Based on the testimony of Mr. Harrison Call of LADWP, the operation and maintenance costs (in 1980 dollars) of complying with Rule 1135.1 represent about 4.4 percent of LADWP's 1980 operation and maintenance costs, exclusive of fuel costs. Since fuel costs are normally included in operating and maintenance costs and comprise a large part of those costs, the operating and maintenance costs of complying with Rule 1135.1 would be considerably less than 4.4 percent of total operating and maintenance costs.

d. The testimony, on November 13, 1980, of Mr. Harrison Call of LADWP indicated that for the minimum case presented by LADWP where three units are controlled to the 90 percent level, the amount of debt financing required to comply with the Rule ($100 million), when compared to the levels of financing usually dealt with, should not present a serious problem to the Department. The Rule considered on December 2 and 3, 1980, requires only 80 percent control and according to LADWP testimony debt financing for this Rule will be about $75 million. This is $25 million less than that required for the 90 percent case and therefore should not present any serious financing problems.

19. Finding: The installation schedule, as included in the Rules adopted by the Board, is reasonable and technologically feasible.

Basis: The facts on which this finding is based include the following:

Maintenance schedules have been submitted by both utilities as part of their written testimony (Attachment 1 and p 20 of SCE's and Exhibit I of LADWP's Written Testimony of Dec. 2, 1980, and p 6-2 of LADWP's Nov. 5, 1980 Written Testimony). These schedules show the dates for scheduled outages to overhaul each of the units which would likely be controlled under the Rules. Since a major overhaul takes approximately nine to eleven weeks, the Board believes it is reasonable to require the installation of the control equipment at the time of such outages (SCE Supplemental Written Testimony, Dec. 2, 1980, pp 13-14). However, to avoid undue hardship on the utilities, it is also reasonable to ensure that not too many units are down for extended periods at the same time. The utilities indicated, and demonstrated by their submissions over time, that maintenance schedules are flexible and can generally be shifted by one to four months if necessary.

In written testimony, the utilities also provided an estimate of the total time required to install the controls. Both SCE and LADWP indicated that it would take up to 2-1/2 years to install the necessary controls on some units (SCE Supplemental Testimony, Dec. 2, 1980, pp 13-14 and LADWP Written Testimony, Nov. 5, 1980, p 6-2). Based on a review of the maintenance schedules and the testimony, the Board finds that in the case of at least one unit of more than 300 megawatts capacity of each utility, sufficient lead time exists that controls could be fully retrofitted by December 1, 1983. Additionally, prior to start-up of controls on such a unit, SCE will have an opportunity to gain operating experience with SCR through its Huntington Beach demonstration unit, which should facilitate its ability to operate SCR on a unit of larger size. Therefore, because of the need to move as expeditiously as practicable in this matter, the Board finds it is reasonable to require the installation of controls on at least one unit of each affected utility by that date.

The Board also finds that, based on the magnitude of the investment involved in complying with Rules 1135.1 and 59.1, it is prudent to include a provision that, following the installation and operation of one SCR unit on a unit of more than 300 megawatts by each major utility, the Board should require a review of the effectiveness and actual cost of that installation. The review should occur after sufficient operating experience but before any substantial expenditure of funds on subsequent units (Tr, Dec. 3, 1980, pp 55-71). Based on review of the maintenance schedules and construction schedules for SCR (Attachment 1 and p 20 of SCE's and Exhibit I of LADWP's Dec. 2, 1980 Written Testimonies and p 6-2 of LADWP's Nov. 5, 1980 Written Testimony), the Board concludes that a general requirement to install controls at the first regularly scheduled outage after October 1, 1985, provides for an adequate review period after the completion of the installation of SCR on one full-scale unit of each utility.

The purpose of this time period is two-fold: first, it provides an opportunity for the utilities to gain first-hand operating experience with a full-scale SCR unit, and then apply that experience to the final designs of subsequent units. Second, it provides an opportunity for the review of actual cost data and updated utility resource plans which could affect the number of subsequent units to be retrofitted. Although the utilities would always have the right to petition for review of the Rules on the basis of new information, the Board believes that the establishment of a specific time period for such a review would be helpful. It is the Board's intent, however, that the review result in substantive changes to the Rule only if information provided during that review indicate cost or cost-effectiveness estimates (specifically including capacity factor estimates) outside the range of the estimates found by the Board in the instant hearings.

The Board further finds that the maintenance schedules submitted by the utilities indicate that final retrofit of all units can be achieved by December 31, 1989, while still allowing the utilities to provide reliable electric services.

20. Finding: The alternative control strategy discussed by LADWP on December 3, 1980, does not achieve the maximum practicable reductions in power plant NOx emissions, is not supported by the evidence in the record, and contradicts previous LADWP testimony.

Basis: The facts on which this finding is based include the following:

At the close of his testimony on December 3, 1980, Mr. Dan Waters of LADWP introduced into the record three figures which resulted from a comparison by LADWP of the effect on NOx emissions and on cost of a NOx emissions control strategy which would require the installation of SCR on power plants and an alternative power plant control strategy. LADWP's alternative strategy would require the installation of Thermal DeNOx, instead of SCR, on certain units, plus the optimization of off-stoichiometric (O/S) firing on Scattergood units 1 and 2 and Haynes unit 2.

The Board has several major concerns regarding LADWP's presentation: First, LADWP's alternative strategy does not achieve or even come close to achieving the maximum practicable degree of control of NOx emissions from power plants or that degree of control which is required to achieve and maintain ambient air quality standards; second, because Thermal DeNOx is only effective over a small load range, LADWP's alternative strategy will not even achieve the limited reductions claimed for it; and third, the projected capacity factors on which these curves are based are new, have not been reviewed by state agencies with expertise in this area, and are not consistent with previous LADWP testimony. In addition, the figures were drafted by LADWP in a manner which misrepresented the effects of the strategy. A detailed analysis of these points follows:

a. The alternative strategy proposed by LADWP will not achieve the degree of NOx emissions control from power plants necessary to make reasonable progress towards attainment and maintenance of ambient air quality standards.

To achieve the air quality standards for nitrogen dioxide, emissions from power plants must be reduced by the maximum practicable amount. (Finding 4) SCR is a proven technology capable of achieving an 80 percent reduction in oxides of nitrogen emissions from oil and gas fired power plants, and thus represents the maximum practicable reductions which can be obtained from power plants in the South Coast Air Shed (Finding 13). However, the strategy proposed by LADWP would achieve a NOx reduction of only about half of that achieved by SCR, even if Thermal DeNOx could achieve the average 40 percent reduction assumed by LADWP.

The figures presented by LADWP were intended to represent the emissions of its power plants over the years 1982 through 2000 (Tr, Dec. 3, pp 121-122). LADWP assumed the use of Thermal DeNOx on Haynes units 1, 5, and 6, and off-stoichiometric (O/S) firing on Scattergood units 1 and 2 and Haynes unit 2 as an alternative control strategy. It asssumed that SCR would achieve an average 80 percent reduction and that Thermal DeNOx could achieve an average 40 percent reduction for each unit so controlled.

The manner in which LADWP drew the figures suggest that the NOx emissions reduction from the Thermal DeNOx scenario is about two-thirds of that from the SCR scenario. However, the Board believes the figures to be grossly inaccurate. In the first place, the reductions due to O/S firing are but a small part of the reductions achieved by 40 percent Thermal DeNOx and 80 percent SCR. For example, Table 2 (page 6) of the KVB report (C.E. Blakeslee, J.M. Robinson, D.E. Shore, <u>Cost-Effectiveness of NOx Reduction Techniques (Supplemental)</u>, prepared by KVB, Inc. for City of Los Angeles Department of Water and Power, October 1980) shows that for the year 1990 O/S firing reductions on Scattergood units 1 and 2 and Haynes unit 2 would be 172,000 pounds per year. However, the total reduction due to 40 percent Thermal DeNOx on Haynes units 1, 5 and 6 would be 2,685,000 pounds per year. Similarly, the 80 percent SCR reductions for Haynes units 1, 5 and 6 would be 5,375,000 pounds per year. Therefore, O/S firing reductions are only 3 percent of the total potential reductions.

Since Thermal DeNOx has been assumed by LADWP to be used on precisely the same generating units as SCR, and since LADWP assumed that Thermal DeNOx would achieve exactly one-half the reductions obtained with SCR, and since O/S firing represents only a small fraction of the total potential reductions, the reductions achieved under the Thermal DeNOx scenario must be approximately one-half the reductions achieved under the SCR scenario.

Consequently, notwithstanding the graphical techniques used by LADWP in presenting its data, the alternative strategy does not even approach the maximum practicable reductions which can be achieved from power plants in order to achieve and maintain ambient air quality standards.

b. The use of Thermal DeNOx will not likely result in the NOx emissions reductions assumed by LADWP, as evidenced by, among other things, prior testimony of both LADWP and SCE.

The alternative strategy discussed by LADWP (Tr, Dec. 3, 1980, pp 121-122) relies upon the use of Thermal DeNOx as an alternative to SCR. Thermal DeNOx is a process of injecting ammonia into the flue gas at a point where the temperature is about 1750°F. The ammonia reacts, in part, with the nitric oxide in the flue gas to form nitrogen and water. As the temperature of the flue gas differs from the optimum temperature, the effectiveness of the process rapidly falls off to zero. No catalyst is used in the Thermal DeNOx process.

The report of KVB (Blakeslee, Robinson, Short, October 1980) states that LADWP will install Thermal DeNOx on Haynes unit 4 as a demonstration project because of the uncertainties with the new Thermal DeNOx technology. The December 3, 1979 ARB Staff Report (page 22) contains a table which lists the control-effectiveness of Thermal DeNOx on Haynes unit 4 as ranging from zero at 60 percent load, to 24 percent at 90 percent load, and to 41 percent at full load. That same ARB Staff Report (page 21 ff) further states that the data are based on predictions by Exxon Research and Engineering Corporation (Exxon). The ARB staff also presented data from Exxon (Letter dated August 14, 1980, from Boyd E. Hurst of Exxon Research and Engineering Corporation to Francis DiGenova of the ARB) in which Exxon projects a reduction of 51 percent at full load if an improved mixing nozzle arrangement is used (no hydrogen case) and a reduction of only 24 percent at 90 percent load. Thus, the improvement in efficiency due to the new nozzles appears to occur only at 100 percent load. The injection of hydrogen improves the performance of Thermal DeNOx, but the utilities have expressed reluctance to use hydrogen (ARB Staff Report, December 31, 1979, p 34).

Electrical units are usually operated over a wide load range. For example, Table 5-2 of the Stearns-Roger testimony for LADWP shows the predicted 1990 loading schedule of LADWP units including Haynes unit 4. Haynes unit 4 is shown to have the following load schedule:

% Load	% Operating Time	Efficiency Thermal DeNOx
0	69	0
30	8	0
50	6	0
70	6	12
90	6	34
100	5	41

The efficiency of Thermal DeNOx is also listed in the above table. If the emissions are assumed to be linear with load, then the overall control of emissions from Haynes unit 4 using Thermal DeNOx would be 23 percent. This degree of control caused LADWP and SCE representatives and the ARB staff all to express concern regarding the viability of the Thermal DeNOx process (Mr. Waters for LADWP, Tr, March 27, 1980, p 180, ln 1-6; Mr. Bjorkland for SCE, Tr, January 30, 1980, p 68, ln 16-21; Mr. Johnson for SCE, Tr, January 30, 1980, pp 155-181; Mr. Goodley for ARB staff, Tr, January 30, 1980, pp 40-58). LADWP's suggestion that an alternative strategy be based on the less effective Thermal DeNOx process is inconsistent with the above evidence in the record, and is, itself, unsupported by any significant evidence.

c. The projected capacity factors which are critical assumptions to LADWP's alternative strategy are new, significantly different from previous LADWP submissions in this hearing, and are inconsistent with previous testimony.

The cost-effectiveness of both the Rules and LADWP's alternative strategy are inversely proportional to the capacity factors of the controlled units; emissions reductions due to each strategy are directly proportional to capacity factors. This is because the capacity factor is the amount of electrical energy that a unit produces in a year divided by the amount which it would produce if it operated at full load for the entire year. Therefore, the amount of annual emissions from a unit is directly proportional to the capacity factor, and since cost-effectiveness is annualized cost divided by annual emissions, the cost-effectiveness is inversely proportional to the capacity factor. If projected capacity factors are assumed to decrease, the calculated cost-effectiveness of controls increases.

The capacity factors assumed by LADWP in its December 3, 1980 testimony are inconsistent with the most recent estimates of the California Energy Commission, (California Energy Commission, LADWP Supply Plan Based on CEC Adopted Forecast and Biennial II Assumptions, December, 1979), the state agency responsible for the approval of utility resource plans for purposes of power plant need and siting decisions. Furthermore, these factors are inconsistent with previous LADWP submittals in this hearing as recent as November 5, 1980 (C.E. Blakeslee, J.M. Robinson, and D.E. Shore, Cost-Effectiveness of NOx Reduction Techniques, prepared by KVB, Inc. for City of Los Angeles Department of Water and Power, October 1980). In addition, these factors do not appear to reflect the application of a least NOx dispatch plan, since a unit without NOx controls (Haynes unit 3) is assumed to operate more frequently than a unit equipped with NOx controls (Haynes unit 1). For the above reasons, the Board finds LADWP's December 2 capacity factor projections unsupported by the evidence in the record.

Figure 1 shows the historical and projected emissions from the LADWP system for three scenarios: (1) no added controls; (2) Thermal DeNOx on Haynes units 1, 5 and 6; and (3) SCR on Haynes units 1, 5 and 6. All of the scenarios are based on the latest California Energy Commission projections of capacity factors, which are similar to LADWP's prior submissions in this hearing. All other assumptions used by LADWP were used by the Board. The cost-effectiveness calculated based upon these same latest California Energy Commission capacity factors for Thermal DeNox and SCR in 1990 are \$1.46 and \$2.97 per pound of NOx, respectively. The much larger estimates presented by LADWP for SCR are almost solely due to the significantly lower projections of capacity factors assumed for their latest submission.

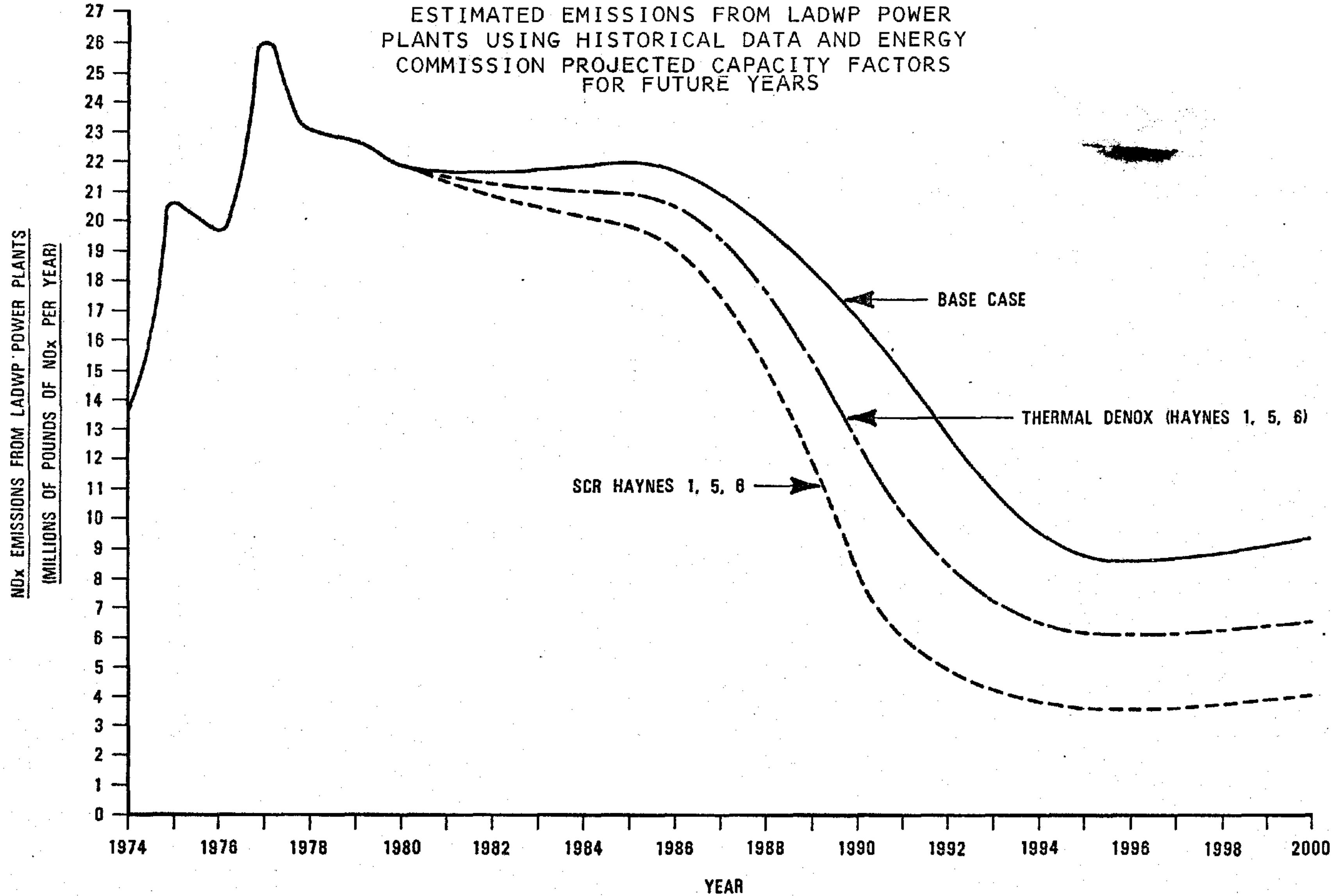
21. Finding: Rules 1135.1 and 59.1 have been developed through a thorough and adequate process of planning and analysis.

Basis: A consultant for SCE asserted that the procedure followed in the adoption of Rule 1135.1 was unsound and did not include sufficient analysis.

The Air Quality Management Plan for both Ventura County and the South Coast Air Basin are the result of a thorough planning process in which SCE was able to participate. That planning process included steps outlined by the SCE consultant. In hearings on the subject Rules and as set forth in these Findings, the Board has also made a complete analysis of factors relevant to the Rules' development.

FIGURE I

ESTIMATED EMISSIONS FROM LADWP POWER PLANTS USING HISTORICAL DATA AND ENERGY COMMISSION PROJECTED CAPACITY FACTORS FOR FUTURE YEARS



22. Finding: The Board, in Resolution 78-48, August 7, 1978, found Rule 475.1 adopted by the South Coast Air Quality Management District to be inconsistent with the purposes of Division 26. The failure of the SCAQMD to adopt a rule consistent with the purposes of Division 26 of the Health and Safety Code as found in Resolution 78-48 constitutes a failure to meet responsibilities under Division 26.

23. Finding: A major utility subject to the provisions of Rule 1135.1 has generating facilities within both the VCAPCD and the SCAQMD. Both the VCAPCD and the SCAQMD are within the South Coast Air Shed, and emissions of oxides of nitrogen from power plants in Ventura County are transported to and have an effect on air quality in the South Coast Air Basin (Finding 5). Therefore, it is necessary and appropriate that to coordinate the efforts of the VCAPCD and the SCAQMD the Board adopt for both Districts rules which provide a systematic approach to controlling power plant NOx emissions.

24. Finding: The SCAQMD has recommended that the Board consider and adopt amendments to Rule 1135.1 (Letter from J.A. Stuart to Thomas C. Austin, September 21, 1979; September 19, 1980 ARB Staff Report, Appendix E). Therefore, it is necessary and appropriate for the Board to take such action to provide assistance to the SCAQMD.

25. Finding: Ventura County Air Pollution Control District Rule 59.1 was originally adopted by the Air Resources Board in 1979 in response to an action by the Ventura County Board of Supervisors deferring to the Board the adoption of a rule for the control of NOx emissions from power plants. (Ventura County Resolution, September 19, 1978; Board Resolution 79-49, May 29, 1979.) Therefore, it is necessary and appropriate that the Board adopt amendments to Rule 59.1 to provide assistance to the VCAPCD.

26. Finding: The inclusion of Rule 1135.1 as amended in the nonattainment plan for the South Coast Air Basin is required and necessary for the nonattainment plan to meet the requirements in the Clean Air Act that the plan provide for the attainment of national primary ambient air quality standards as expeditiously as practicable and that, in the case of nonattainment areas, the plan provide for the implementation of all reasonably available control measures as expeditiously as practicable, and require reasonable further progress including emissions reductions from existing sources through the adoption of reasonably available control technology. (Sections 110(a)(2), 172(b)(2), and 172(b)(3); Findings 1-8, 12-14 above). In the absence of Rule 1135.1 as amended, the nonattainment plan for the South Coast Air Basin will not meet and does not comply with the requirements of the Clean Air Act.

27. Finding: The inclusion of Rule 59.1 as amended in the nonattainment plan applicable to Ventura County is required and necessary for the plan to meet the requirements in the Clean Air Act that the plan provide for the attainment of national primary ambient air quality standards as expeditiously as practicable and that, in the case of nonattainment areas, the plan provide for the implementation of all reasonably available control measures as expeditiously as practicable, and require reasonable further progress including emissions reductions from existing sources through the adoption of reasonably available control technology. (Sections 110(a)(2), 172(b)(2), and 172(b)(3); Findings 5 and 12-15 above). In the absence of Rule 59.1 as amended, the nonattainment plan applicable to Ventura County will not meet and does not comply with the requirements of the Clean Air Act.

28. Finding: The amendments to Rules 1135.1 and 59.1 adopted by Resolutions 80-68 and 80-69 are appropriate and necessary to simplify and clarify the Rules' requirements and to meet the concerns expressed by affected utilities that under the Rules as amended March 27, 1980, they would be required to control NOx emissions from virtually all their power generating units, even those expected to have very low capacity in 1990 and beyond. The amendments to the Rules are intended to achieve the same level of reductions in NOx emissions as the March 27 version (Staff Report, pp 157-165), while at the same time retaining the utilities' flexibility to designate which units to control and providing them with certainty regarding the capacity required to be controlled.

State of California
AIR RESOURCES BOARD

Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants

ARB Compliance with the California Environmental Quality Act (CEQA)

The following discussion is intended to explain how the ARB assures that any possible adverse environmental effects of its proposed actions will be identified and mitigated. As an environmental protection agency, the ARB is not required to prepare an Environmental Impact Report (EIR) on this project, but other written documentation prepared by the agency must describe the proposed activity with alternatives to the activity and mitigation measures to minimize any significant adverse environmental impact. Further, regulations adopted by the ARB require that the action will not be adopted by the Board as proposed if there are feasible alternatives or feasible mitigation measures which would substantially lessen any significant adverse impact of the activity on the environment. ARB regulations also require that prior to taking final action, the Board must respond in writing to significant environmental points raised during the evaluation process. Finally, CEQA requires that the ARB not adopt the activity for which significant adverse effects have been identified unless one or more of the following findings are made:

1. That changes have been incorporated into the project which mitigate the significant environmental impacts.

2. That such mitigation measures are within the responsibility and jurisdiction of another public agency and have been (or can and should be) adopted by such other agency.

3. That specific economic, social, or other considerations make the mitigation measures or alternatives infeasible.

Consequently, the ARB staff report discusses several possible environmental impacts of the proposed rule. Several other concerns were raised during the hearing process. These are identified and discussed in the following section. In addition, mitigation measures which could minimize any impacts found to be significant are examined, as are alternatives to the proposed action. In this case, since the proposal is the amendment of certain rules already in existence, the "no project" alternative is for the Board to take no action and to leave the current rules in place. Other alternatives discussed are the repeal of the subject rules in their entirety, amending the rules to be less stringent, and restoring the Districts' original Rules.

The Board, prior to taking final action, has adopted the attached responses to significant environmental issues. Further, in adopting the activity itself, the Board, in its resolution, has made findings relating to each significant environmental issue raised, either incorporating feasible mitigation measures and alternatives into the rules, indicating that other agencies are responsible for mitigation of these effects, or indicating the factors which prevent the imposition of mitigation measures or alternatives. If future experience reveals adverse environmental impacts not reasonably anticipated, corrective action can be taken by the Air Resources Board or other appropriate agency (e.g., the local air pollution control districts which will be implementing any adopted rule) to mitigate such effects.

State of California
AIR RESOURCES BOARD

Response to Significant Environmental Issues

Item: Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants

Public Hearing Dates: November 5, 6, 13, and December 2, 3, 18, 1980

Response Date: December 18, 1980

Issuing Authority: Air Resources Board

Introduction: Southern California Edison (SCE) and the Los Angeles Department of Water and Power (LADWP) have raised several concerns which they believe were not adequately addressed by the Air Resources Board (ARB) staff in the September 1980 report. Since the discussion of many of the issues raised by the utilities assumes an understanding of the selective catalytic reduction (SCR) process, it is appropriate to explain briefly the operation and performance of the process involved.

The utilities are being required to reduce NOx emissions on some of their steam generating boilers by 80 percent. This requirement will probably be satisfied by retrofitting utility boilers with the selective catalytic reduction (SCR) system to control oxides of nitrogen (NOx) emissions. The technology takes advantage of the preferential reaction of ammonia (NH_3) with NOx rather than with other flue gas constituents. Since oxygen (O_2) enhances the reduction, the reaction can be best expressed as

$$4NH_3 + 4NO + O_2 \longrightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \longrightarrow 3N_2 + 6H_2O \qquad (2)$$

Equation 1 represents the predominate reaction since approximately 95 percent of the NOx in combustion flue gas is in the form of nitric oxide (NO). Therefore, under ideal conditions a stoichiometric amount of NH_3 can be used to reduce NOx to harmless molecular nitrogen (N_2) and water vapor (H_2O).

In practice, an NH_3:NO mole ratio of about 1:1 has typically reduced NO emissions by 90 percent with a residual NH_3 concentration (also called "ammonia breakthrough") of less than 10 ppm. (1)*

The SCR process requires other auxiliary equipment such as a reactor, a catalyst, ammonia storage facilities and ammonia injection systems.

The optimum temperature for the NOx reduction reaction without a catalyst is about 1800^{o}F. However, the catalyst effectively reduces the optimum reaction temperature to approximately 600^{o}F to 850^{o}F.

*See reference list page 14.

Catalysts may be made with different chemical compounds; those with vanadium (V) compounds were found to promote the reduction of NOx with NH_3 and to be unaffected by the presence of sulfur oxides (SOx), another exhaust gas component which could interfere with the desirable reaction. (2)

Titanium dioxide (TiO_2) was found to be an acceptable carrier, since it is resistant to attack from SO_3. (2) Therefore, many SOx resistant catalysts are based on TiO_2 and vanadium pentoxide (V_2O_5).

The life of the catalyst depends upon the type of flue gases it is being used to treat. The catalysts to be used on power plants in the South Coast Air Basin should last for 2 years or longer. (3) Also, because of oil firing, catalysts will be most likely of the parallel flow type. It may have one of many shapes such as parallel plate, parallel tube or honeycomb type. It may be made of ceramic material such as TiO_2 or metal.

The catalyst may be of homogenous or of coated variety. In essence, the type of the catalyst to be used in the power plant depends upon the user and the process vendor. Figure 1 shows as an example of how, typically, a honeycomb type catalyst would be placed in a reactor. When the catalyst loses its reactivity, it is replaced.

The above explanation briefly summarizes the control methods that will likely be employed to retrofit the utility boilers to comply with Rules 1135.1 and 59.1. The discussion that follows addresses the concerns raised by SCE and LADWP and the Board's response to those concerns.

Comment 1: The LADWP has expressed concerns that disposal of spent catalyst in an environmentally sound manner is an unresolved problem and that because of the presence of vanadium in the catalyst, special disposal or reclamation methods will be required.

Response: The application of selective catalytic reduction to a total of 4432 MW of power plant capacity, as required to fully comply with Rules 1135.1 and 59.1, is expected to result in the use of about 1100 tons of catalyst per year.[1] The exact type and composition of catalyst would depend on the process vendor and the user, but typically a parallel flow, honeycomb type catalyst would contain V_2O_5 and titanium dioxide (TiO_2).

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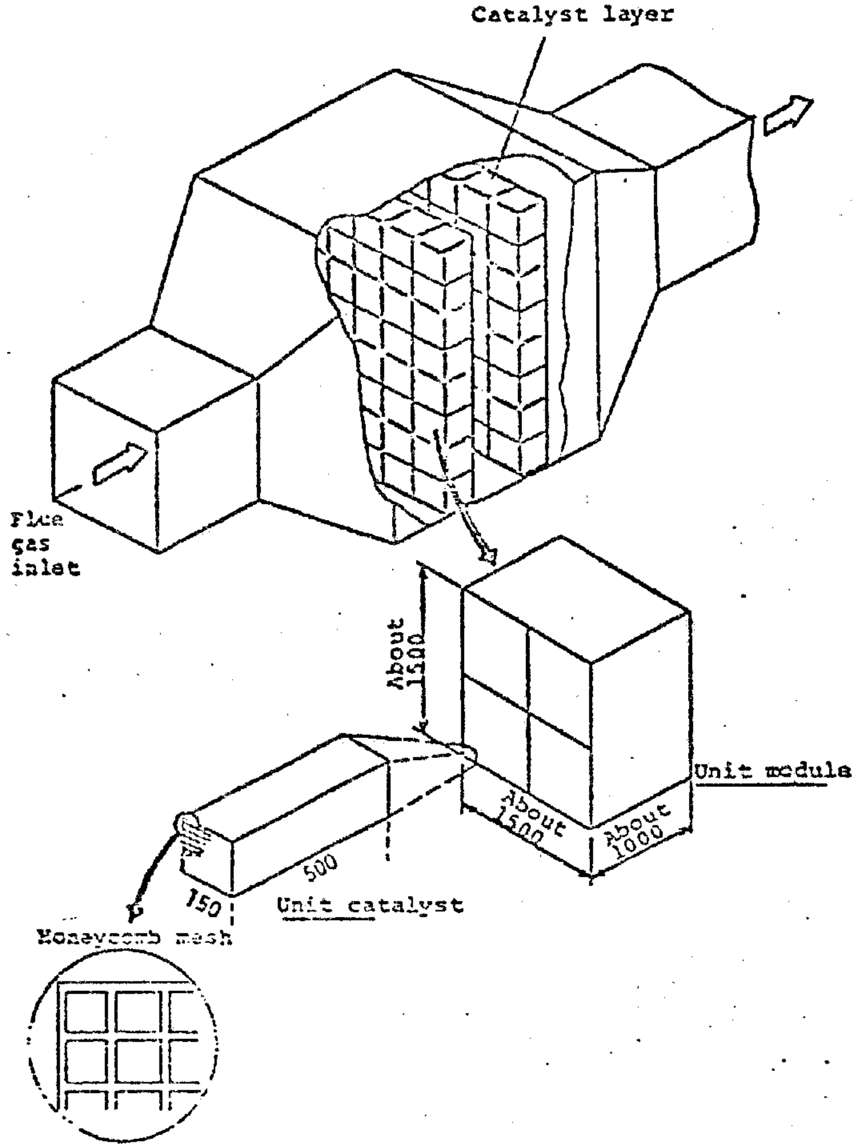
1. This estimate follows from a total generating capacity required to be controlled of 4432 megawatts (MW) and SCE's estimate (4) that control of its units larger than 175 MW (total of 24 units having 7720 MW) would require 1860 tons per year of catalyst, assuming a two year catalyst life:

$$4432 \text{ MW} \quad \times \quad \frac{1860 \text{ tons of catalyst/yr}}{7720 \text{ MW}} = 1068 \text{ tons catalyst/yr}$$

Based on commercial operating experience to date on SCR installations in Japan in which catalyst deterioration has not been significant (3) catalyst lifetimes are expected to equal or exceed 2 years with fuel oil firing and 3 years with natural gas firing. Requirements for catalyst are inversely related to catalyst lifetime, hence a catalyst lifetime of 3 years corresponds to a catalyst requirement of about 712 tons per year.



Example of a fixed bed reactor with honeycomb type catalyst (Ishikawajima-Harima Heavy Industries; sizes are in mm).

Source: J. Ando. NOx Attachment for Stationary Sources in Japan. August 1979.

Depending upon the specific type and material of the catalyst selected, valuable components may be recovered for reuse, just as used or "spent" automotive exhaust catalysts and refinery process catalysts are normally amenable to recovery or reprocessing prior to disposal. To the extent that spent catalyst cannot be recovered, and constitutes a potentially hazardous waste[2], treatment and/or disposal at a Class I or Class II-1 (hazardous waste) disposal site may be required. In such a worst case, the increment of potential hazardous waste generation due to Rules 1135.1 and 59.1 would be about 1100 tons per year, as compared with the current rate of generation of hazardous wastes in California of approximately 11,000,000 tons per year (5). Thus, full implementation of Rules 1135.1 and 59.1 is not expected to increase the production of potentially hazardous waste in California by more than about 0.01 percent, even in the worst case.

Mitigation of the above increments of hazardous waste disposal is accomplished by regulation of liquid and solid hazardous waste disposal in California by the State Water Resources Control Board (and Regional Boards), the Department of Health Services, and the Solid Waste Management Board. Through a system of hazardous waste generation reporting by the industry, and regulation by the above agencies to ensure environmentally sound disposal, the problem of hazardous waste disposal associated with the Board's action will be mitigated in the same manner as is the disposal of other toxic wastes.

Comment 2: Southern California Edison has expressed concerns that some of the toxic metals from catalysts that may be used in the SCR process can be released into the environment.

Response: The Board has received no evidence which demonstrates that catalysts which are used in the SCR process, as applied to oil or gas fired units to comply with Rules 1135.1 and 59.1, would result in significant increases in emissions of vanadium (V) or other potentially toxic metals from power plants.

Vanadium is a natural constituent of crude oil and is also contained in significant amounts in the (refined) residual oil burned in power plants in the South Coast Air Basin and Ventura County. (6) Thus, at the present time, combustion of fuel oil in the South Coast Air Basin and Ventura County is believed to result in significant release of vanadium into the environment. Based on data provided by SCE (6), and assuming 50 million barrels of oil per year burned in power plants (the minimum amount of oil burned by all utilities in any recent year), vanadium emissions are estimated to be about 120 tons per year[3] at the present time, i.e. absent further controls.

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2. Depending upon the specific composition of the catalyst selected, "spent" catalyst may or may not be classified as a hazardous waste.

3. $$\frac{50 \times 10^6 \text{ BBLS}}{\text{year}} \times \frac{320 \text{ lbs}}{\text{BBL}} \times \frac{15 \times 10^{-6} \text{ lbs V}}{\text{lb fuel oil}} \times \frac{\text{ton}}{2000 \text{ lbs}} = \frac{120 \text{ tons V}}{\text{yr}}$$

If this amount of vanadium is expressed as V_2O_5, an oxidized form, the amount of V_2O_5 is

$$\frac{120 \text{ tons V}}{\text{year}} \times \frac{182 \text{ tons } V_2O_5}{51 \text{ tons of V}} = 429 \text{ tons } V_2O_5/\text{yr}.$$

The Board is not aware of any other source of vanadium emissions, due to fuel burning, SCR, or any other source, which is larger than the above current emissions from power plants. Furthermore, the Board is not aware of any data which show that the retrofit of SCR to an oil or gas fired power plant would result in significantly increased emissions of vanadium or other components of the catalyst. To the contrary, available information from Japan indicates good catalyst performance over long periods (in excess of 2 years), suggesting that vanadium, the principal active component in the catalyst bed, remains essentially intact and continues to perform at, or near, full design efficiency. (3) Vanadium or vanadium compounds could potentially present risks as toxic compounds at elevated levels of human exposure; however, such compounds have not been identified as high priority toxic compounds at the present time,(9, 10) and evidence received by the Board does not support the concern that Rules 1135.1 and 59.1 would result in significant environmental impacts. If vanadium or vanadium compounds are identified as a significant threat or potential threat to human health or the environment at some future time, such compound(s) would be regulated in accordance with the statewide programs to control airborne toxic substances, including existing and future ARB and local district programs.

Comment 3: Southern California Edison has raised concerns that nitrosamines can be formed as a result of ammonia injection in flue gases for Thermal DeNOx and SCR processes.

Response: Representatives of SCE testified that with a model system using a propane/air flame, they have found a potential for formation of nitrosamines when ammonia is injected in the flue gases. Subsequent testimony by SCE indicated that the company's concerns regarding the formation of nitrosamines was based on injection of ammonia in a propane enriched flame. However, this situation would occur only during a boiler upset condition. It is standard operating practice at the present time to avoid any such possible upsets in order to ensure system safety and reliability. Consequently, since the utility boilers are carefully operated with excess air and are not fuel enriched, the hydrocarbon radical (essential to the formation of nitrosamines) would be completely oxidized and would not be available for the formation of nitrosamines in the presence of ammonia. Thus, no nitrosamines are expected to be formed if ammonia is injected in a normal operating mode of an electric utility boiler. Mitigation of possible impacts during boiler upset conditions consists of the utilities continuing current standard operating practices to avoid unsafe fuel-rich operation of a boiler.

Comment 4: LADWP has raised concerns regarding ammonia breakthrough to the atmosphere as a result of its injection in the noncatalytic and catalytic deNOx methods.

Response: As explained in the introduction, ammonia (NH_3) is injected in the flue gases to reduce NOx emissions through chemical reactions leading to the formation of harmless materials. Ideally, a stoichiometric (chemically correct) amount of NH_3 can be used to reduce 100 percent of the NOx to harmless molecular nitrogen and water vapor, with no ammonia breakthrough. However, in practice, the stoichiometric NH_3:NO mole ratio of 1:1, in the presence of a catalyst, will typically reduce NOx emissions by 90 percent with a residual NH_3 concentration of less than 10 parts per million (ppm). (1) In processes which reduce NOx without use of a catalyst, higher NH_3:NO mole ratios may be required for less than 90 percent reduction, resulting in slightly higher residual NH_3.

This residual NH_3 is commonly known as "NH_3 slip", "breakthrough", "carryover", or "release". This ammonia breakthrough is minimized by optimizing the design and operation of the catalytic and noncatalytic deNOx processes, as illustrated by the attached Figure 2. The attached figure shows that an SCR system, when operated for 90 percent NOx removal efficiency, is expected to result in NH_3 breakthrough in the range of 5-10 ppm in stack gases. However, SCR systems which are designed and operated for 80 percent NOx removal efficiency are expected to result in stack gas concentrations of less than 5 ppm of NH_3 carryover. As discussed in the ARB Staff Report of September 19, 1980 (7), ground level NH_3 concentrations at the point of maximum plume impact would be expected to be 1/1000 of the stack concentrations, resulting in ground level NH_3 concentrations below natural background levels and far below the level of any adverse health impacts which have been identified.

Because optimum operation of an SCR system to reduce NH_3 breakthrough would also minimize the consumption of NH_3 and the deposition of NH_3-based reaction products on components such as air preheaters, system design and operation to minimize NH_3 carryover is also in the economic interest of the system owner/operator, as this would minimize operating and maintenance expenditures. Thus, any remaining impact of NH_3 breakthrough would be fully mitigated by the utilities by system design and operation to minimize NH_3 emissions.

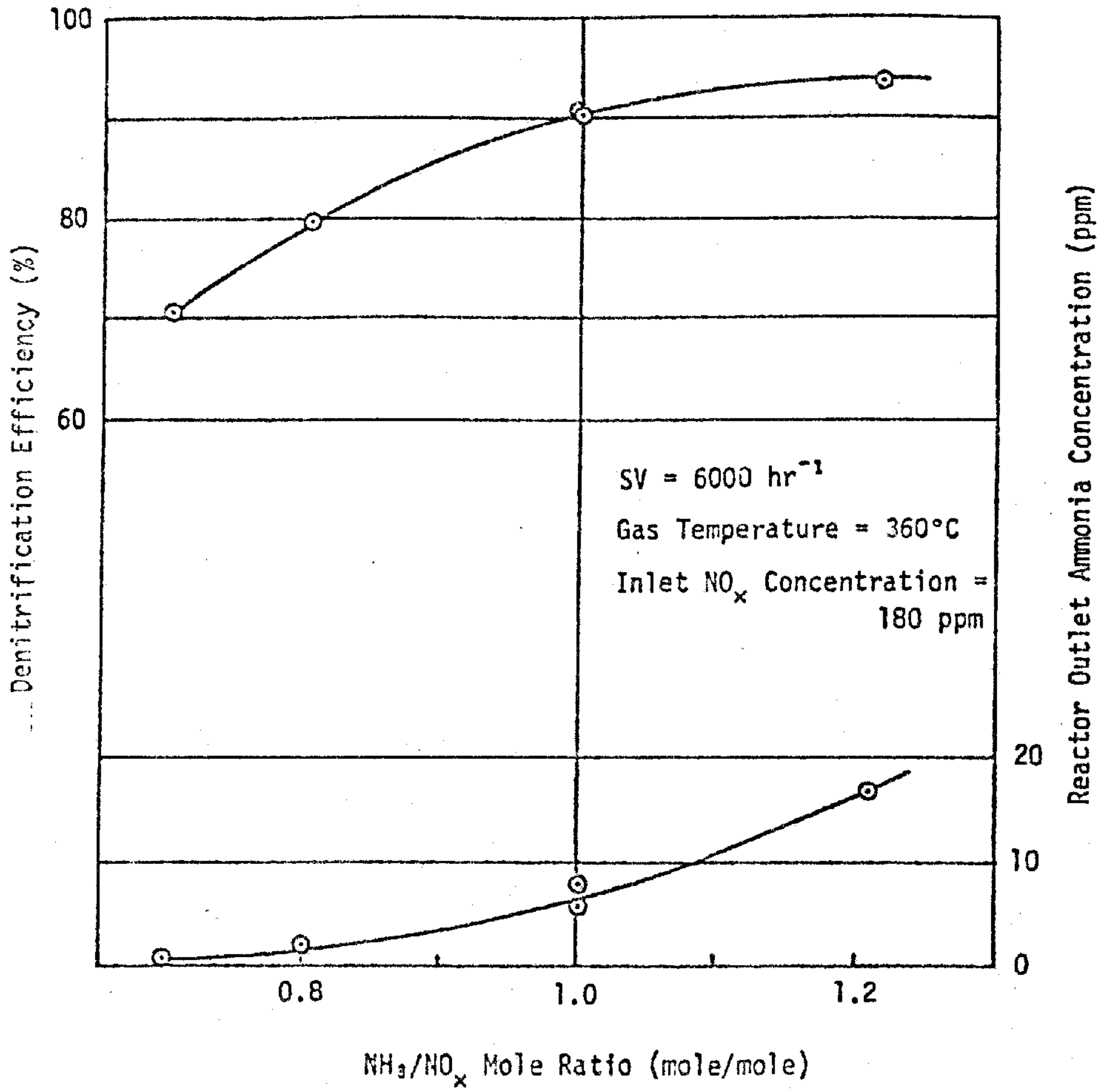
Comment 5: LADWP has expressed concerns that SCR systems promote the oxidation of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) and that therefore the total sulfate concentration in the flue gas would be increased by the proposed rules. Furthermore, LADWP believes that increased sulfate emissions may adversely affect our ability to attain and maintain applicable ambient air quality standards and the public health and welfare which these standards are designed to protect.

Response: As explained in the introduction, SCR systems are used to facilitate NOx emission control. In addition to the two chemical reactions that convert NOx to N_2 and H_2O (see introduction), a third reaction also occurs, simultaneously. This third reaction is the oxidation of sulfur dioxide, a compound produced during the combusion of any fuel containing sulfur, to sulfur trioxide, and can be expressed as follows:

$$2\ SO_2 + O_2 \longrightarrow 2\ SO_3 \quad (3)$$

In the absence of an SCR system, this reaction will occur naturally in the atmosphere, but at a slower rate. Because of the corrosive nature of SO_3 and its potential to combine with NH_3 to form ammonium sulfates and other potentially condensible compounds most of the process vendors have improved their catalysts to minimize the conversion of SO_2 to SO_3. SCR systems which are currently in use convert from 1.5 to 2.5 percent or higher of SO_2 to SO_3 (1) whereas new catalysts are developed and tested to suppress conversion to less than one-half percent of the SO_2 to SO_3. (4) As in the case of the minimization of NH_3 breakthrough, the minimization of SO_3 formation is also in the economic interest of utilities, since it would minimize maintenance costs. Consequently, utilities can design SCR systems using catalysts which minimize SO_3 formation to substantially mitigate any potential adverse impacts of SCR on sulfate emissions.

Figure 2



NH_3/NO_x mole ratio versus denitrification efficiency versus reactor outlet ammonia concentration for the honeycomb catalyst at Taketoyo Power Station.

Source: Reference 1.

Comment 6: LADWP has expressed concerns that the use of enough ammonia to effect a 90 percent NOx emission removal could result in the formation of ammonium sulfate ($(NH_4)_2SO_4$) and ammonium bisulfate (NH_4HSO_4) deposits which could foul the air preheater. Furthermore, LADWP believes that aerosols of these compounds could cause environmental problems, and their presence in the stack plume may cause opacity problems due to the presence of condensed particles.

Response: The formation of ammonium sulfate and ammonium bisulfate depends upon the concentrations of NH_3 and SO_3 in flue gas and also on the temperature of the flue gas. Ammonium bisulfate is formed as a result of the reaction between NH_3, SO_3, and water vapor as described in the following reaction:

$$NH_3 \text{ (gas)} + SO_3 \text{ (gas)} + H_2O \text{ (gas)} \longrightarrow NH_4HSO_4 \text{ (liquid)}$$

In the presence of excess ammonia, ammonium bisulfate may further react to form ammonium sulfate (solid) as follows:

$$NH_4HSO_4 \text{ (liquid)} + NH_3 \text{ (gas)} \longrightarrow (NH_4)_2SO_4 \text{ (solid)}$$

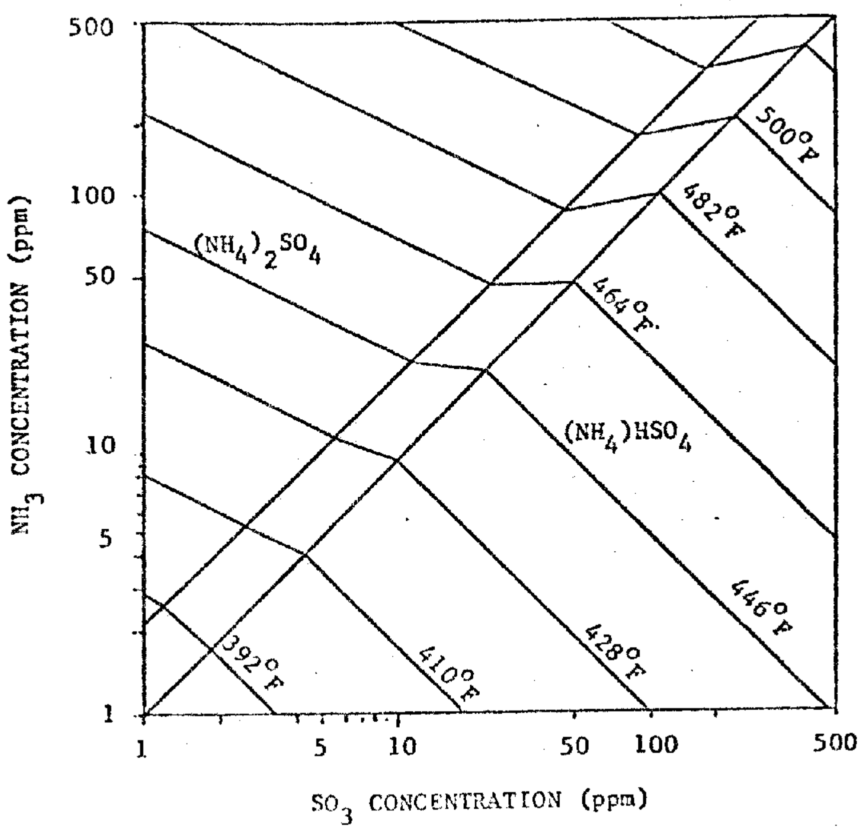
The conditions under which these compounds will be formed are shown in Figure 3.

As can be seen in Figure 3, actions which reduce both NH_3 carryover concentrations and SO_3 concentrations (as discussed in the responses to comments 4 and 5) will also result in lower temperatures of formation of ammonia-sulfur compounds, and thus would be expected to reduce the formation of such compounds. As discussed above, these actions, both individually and collectively, are expected to reduce potential operating and maintenance costs to the utilities. Therefore, minimization of NH_3 carryover concentrations and SO_3 concentrations are available mitigation actions which are expected to be fully implemented by the utilities and are in the economic interests of the utilities.

With regard to potential opacity problems, of the more than seventy commercial installations operating with SCR in Japan (7), the Board is unaware of any data noting opacity problems on any of these units. Furthermore, opacity (the darkness and visibility of stack emissions) is regulated by state law (Health and Safety Code Section 41701) and local air pollution control district regulations, and any adverse impacts will have to be mitigated by the utilities pursuant to these requirements.

Comment 7: LADWP has expressed concerns that ammonium sulfates formed as a result of the SCR process may produce deposits on the air preheater and force more frequent washings than would otherwise occur. An air preheater wash will create a large volume of waste water for disposal. LADWP estimates that depending upon the washing period, the additional waste water may range from 300,000 to 1,000,000 gallons and is concerned about the potential adverse environmental impact of disposal of such waste water. (LADWP did not specify whether the additional waste water use was projected on an annual basis or for some other time period.)

Figure 3



FORMATION OF AMMONIUM SULFATE
HIGH TEMPERATURE RANGE

Source: D.R. Swann, G.D. Drissel. Feasibility of Retrofitting Catalytic Post Combustion NOx Controls on an 80 MW Coal-Fired Utility Boiler. February 1980 (8)

Response: The LADWP estimate apparently applies to an annual generation rate for waste water under the assumption that 11 of its units, comprising 2593 MW, would be required to install SCR units designed for 90 percent NOx removal. The final version of Rules 1135.1 and 59.1 requires that only 3 units of LADWP, comprising 912 MW, would be required to be retrofit with SCR designed for 80 percent NOx removal. Consequently, the actual quantities of additional waste water generated due to the adopted rules will be significantly less than that estimated by LADWP. Furthermore, as explained above, the potential for formation of ammonium compounds can be minimized by techniques which are in the economic interest of utilities and which minimize NH_3 breakthrough emissions as well as the conversion of SO_2 to SO_3.

In addition, because air preheaters are periodically washed at the present time (without SCR installed), any additional waste water generated would be treated and disposed of in a manner similar to that currently used, and in accordance with requirements imposed by the State and Regional Water Quality Control Boards. Accordingly, any potential adverse environmental effects due to additional waste water disposal would thus be mitigated in accordance with regulations of those agencies having jurisdiction over water quality.

Comment 8: SCE expressed concerns regarding potential hazards of ammonia storage, handling, and transport and the possibility of accidental releases of ammonia. LADWP also expressed concerns regarding storage of ammonia.

Response: In order to evaluate the potential hazards of ammonia storage, handling and transportation, the ammonia-related hazardous materials incidents have been compared to all the hazardous materials incidents[4] in the U.S. in 1978. In addition, the amount of NH_3 required as a result of Rules 1135.1 and 59.1 is small compared with national statistics for ammonia shipments.

Table 1 compares ammonia related incidents with all hazardous materials incidents in the U.S. in 1978. As shown in this table, shipment of about 9 million tons of ammonia in 1978 resulted in spillage of about 188 tons (0.002%) in 95 incidents. These incidents resulted in 2 deaths, 58 injuries, and $98,000 in damages. By comparison, all hazardous materials incidents, totalling 17,750 in 1978 resulted in 46 deaths, 1072 injuries, and $16 million in damage. Table 1 also compares ammonia requirements of Rules 1135.1 and 59.1 with national average shipments and data on incidents. These data suggest a relatively low probability of incidents with relatively very low or negligible expected impacts.

Table 2 shows that the mean mortality index for ammonia is 0.02 as compared to the mean mortality index of hydrocarbons which ranges from 0.1-0.6. These data indicate that ammonia, which is commonly used in many household, commercial and industrial cleaning applications and which is used in agriculture in significant

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4. A hazardous materials incident is defined in 49 CFR 171.15 (1977) according to criteria established by the U.S. Department of Transportation. Basically, these criteria include: accidental deaths or injuries, property damage in excess of $50,000, or other specified damages.

TABLE 1

ANHYDROUS AMMONIA STATISTICS

Total amounts of shipments of anhydrous ammonia in the U.S. in 1978		8.7 million tons
Total amount spilled of those shipments in the U.S. in 1978		188 tons
Statistics of the 17,750 incidents* in 1978 in the U.S.	Deaths Injuries Damages	46 1072 $16 million
Statistics of the 95 incidents involving anhydrous ammonia in 1978 in the U.S.	Deaths Injuries Damages	2 58 $98,000
Total amount of anhydrous ammonia used by agriculture in the U.S. in 1978		4.5 million tons
Total amount of anhydrous ammonia required to comply with the Rules		15,000 tons per year

*An incident is as defined in 49 CFR 171.15 (1977).

Source: U.S. Department of Transportation, National Fertilizer Association and ARB/SSCD

TABLE 2

ESTIMATE OF MEAN MORTALITY INDEX OF AMMONIA AND ITS COMPARISON WITH OTHER GASES

LOCATION	DATE	AREA/SITE	SOURCE OF LEAKAGE	QUANTITY METRIC TON	NUMBER OF FATALITIES
Floral, Ark.	June 5, 1971	Rural	Pipeline	600 tons	0
Enid, Oklahoma	May 7, 1976	Urban	Pipeline	500	0
Conway, Kansas	December 6, 1973	Rural	Pipeline	277	0
Landskrona, Sweden	January 16, 1976	Port	Ship-storage connection	180	2
Blair, Nebraska	November 15, 1970	Rural	Storage tank	160	0
Crete, Nebraska	February 18, 1969	Urban	Rail tanker	90	9
Belle, West Va.	January 21, 1970	Urban	Rail tanker	75	0
Texas, Tx City	September 13, 1975	Urban	Pipeline	50	0
Potschefstroom, South Africa	July 13, 1973	Urban	Storage tank	38	18+
Houston, Texas	November 15, 1976	Urban	Road tanker	19	6
Lievin, France	August 21, 1968	Urban	Road tanker	19	6

$$\text{Mean mortality index} = \frac{\text{total number fatalities}}{\text{total amount lost}} = \frac{41}{2008} = 0.02$$

+Without this incident the mean mortality index = 0.01

Mean mortality index of chlorine = 0.3
" " " of flammable gases or vapor = 0.1 -0.6
" " " of Ammonium Nitrate = 0.1

Source: A report on Major Hazards by Advisors Committee, Health and Safety Commission, Great Britain, 1979.

quantities, is not particularly dangerous when handled with proper caution. Accordingly, mitigation measures expected to be taken by utilities to ensure minimization of potential hazards due to ammonia spillage, which would consist of implementation of standard safe operating practices for potentially hazardous materials, are expected to reduce potential hazards to very low or negligible levels.

Comment 9: LADWP, in its written testimony, expressed concerns regarding formation of hydrogen cyanide (HCN) by ammonia injection.

Response: Brown and Sawyer were not able to detect either HCN or other nitrogenous species (other than NOx, NH_3, or N_2) in the stack gas from a laboratory combustor burning No. 1 diesel doped with pyridine. (Quarterly Progress Report for ARB Contract A8-146-31 for 1 May - 1 July 1980). Based upon minimum detection limits associated with the various analytical procedures used, Brown and Sawyer estimated conservative upper limit concentration values of 5 ppm for all nitrogenous species (other than NOx, NH_3, and N_2) and 1 ppm for HCN in the laboratory combustor stack gas.

These data, taken along with SCE's and ARB's tracer studies, which show that emissions from tall stacks are diluted by a factor of 10^{-4} to 10^{-6} (7), show that the maximum surface level concentration of all nitrogenous species (other than NOx, NH_3, and N_2) is in the range of 5 to 500 parts per trillion and 1 to 100 parts per trillion for HCN, and may be substantially less.

A threshold limit value (TLV) of 10 parts per million has been designated for hydrogen cyanide (HCN), according to Multimedia Environmental Goals for Environmental Assessment, Volume 11, MEG Charts and Background Information, J.G. Cleland and G.L. Kingsbury, November, 1977; EPA-600/7-77-136b. The ambient level goal recommended in that same work is 24 parts per billion, based on health effects. Documentation of the Threshold Limit Values for Substances in Workplace Air, (American Conference of Governmental Industrial Hygienists, Third Edition 1971), shows that the TLV of 10 parts per million "contains a two-fold margin of safety against mild symptoms of HCN response."

Thus, according to the test data, the highest ambient concentration expected would be a factor of more than 200 below EPA recommended environmental goals for the atmosphere.

Comment 10: SCE expressed concern that the Board's action would exacerbate ozone and oxidant air quality problems in the South Coast Air Basin.

Response: This concern is dealt with at length in the Board's Findings and Basis for decision, which is incorporated by reference herein.

CERTIFIED: Sally Rump
Sally Rump
Board Secretary

Date: Dec 23, 1980

References

1. Dr. Jumpei Ando, NOx Abatement for Stationary Sources in Japan, rpt. (Japan: Chou University, August 1979).

2. Proceedings of the Joint Symposium on Stationary Combustion NOx Control, Volume II, Utility Boiler NOx Control by Flue Gas Treatment, "Assessment of NOx Flue Gas Treatment Technology" by J. D. Moholey, U.S. EPA, IERL-RTP-1084, October 1980.

3. Sengoku Tadamasa, et al, The Development of a Catalytic NOx Reduction System For Coal-Fired Steam Generators (Tokyo, Japan; Mitsubishi Heavy Industries, October 6-9, 1980).

4. Proceedings of the Joint Symposium on Stationary Combustion NOx Control, Volume II, Utility Boiler NOx Control by Flue Gas Treatment, "Status of SCR Retrofit at Southern California Edison Huntington Beach Generating Station Unit 2", L. Johnson et al; U.S. EPA IERL-RTP-1084 October 1980.

5. Solid Waste Management in California: A Status Report, State of California, Solid Waste Management Board, February 1980.

6. A document from SCE titled "Emission of Vanadium and Organics from SCE Oil-Fired Generating Stations," November 24, 1980.

7. The Air Resources Board staff report entitled "Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants." (September 1980)

8. D. R. Swann, G. D. Drissel. Feasibility of Retrofitting Catalytic Post Combustion NOx Controls on an 80 MW Coal-Fired Utility Boiler, rpt. (Denver, Colorado: Stearns-Roger Inc., February 1980).

9. State of California Air Resources Board Final Report of the Ad Hoc Panel on Atmospheric Carcinogens, April 1979.

10. Science Applications, Inc., Vol. I., Final Report, An Inventory of Carcinogenic Substances Released Into the Ambient Air of California, February 1979.

There are five basic alternatives which the Board could adopt in reconsidering SCAQMD Rule 1135.1 and VCAPCD Rule 59.1. Following are descriptions and discussions of these alternatives.

Alternative 1: Take no action; that is, the "no project" alternative. This alternative would, in effect, reaffirm the versions of SCAQMD Rule 1135.1 and VCAPCD Rule 59.1, currently stayed, both of which the Board adopted on March 27, 1980. This alternative would neither prevent nor mitigate the environmental and other concerns raised by the petitioner, SCE, and LADWP, the intervenor. It is with regard to the existing versions of these two rules that the environmental questions have been raised.

Alternative 2: Rescind SCAQMD Rule 1135.1 and VCAPCD 59.1. Under this alternative, further NOx emission reductions would not be required, and power plants would continue to be subject to the control prescribed by SCAQMD Rule 464 (125-225 ppm for gas-fired units and 225-325 ppm for oil-fired units) and by a comparable VCAPCD rule. Although this alternative would eliminate the concerns raised by SCE and LADWP, it would forego emission reductions of almost 60 tons per day of NOx by 1990. Currently, NOx emissions from stationary sources in the South Coast Air Shed are slightly over 450 tons per day. The nonattainment area plans for the South Coast Air Basin and the Ventura County Air Pollution Control District rely on these emission reductions to attain and maintain the national ambient air quality standards for nitrogen dioxide and suspended particulate matter and, in the case of Ventura, for ozone as well. Also, such reductions in the emissions of NOx are necessary if the state ambient air quality standards for nitrogen dioxide, suspended particulate matter, and visibility are to be attained and maintained. If those standards are not attained and maintained, the adverse effects on the public health and welfare that the standards are intended to prevent will not be prevented.

Because the federal Clean Air Act and the California Health and Safety Code require that the ambient air quality standards be attained and maintained in order to protect public health and welfare, withdrawal of Rules 1135.1 and 59.1 would require that new measures be adopted to effect equivalent reductions from other sources. That is, NOx control measures would have to be adopted for sources for which control methods have not yet been identified, or for which controls cost more for each pound of NOx reduction than those required by Rules 1135.1 and 59.1. Since all of the significant adverse environmental effects expected to result from the proposal can be mitigated, the benefit of achieving the 60 tons per day NOx emission reductions by controlling power plants is preferable to controlling other sources at this time because control of other sources may be accompanied by unknown environmental impacts.

If other, more costly or unidentified rules were not quickly adopted, this alternative would be inconsistent with state and federal laws, and would result in pollutant concentrations in the South Coast Air Shed which would be detrimental to the public health and welfare. This alternative is therefore infeasible, with significant adverse impacts on the environment.

Alternative 3: Amend Rules 1135.1 and 59.1 to be less stringent. Concerns raised by SCE and LADWP (such as increased environmental burdens of heavy metals from catalysts and emissions of ammonia) could be partially mitigated by making the existing rules less stringent. Although this alternative would still provide some cost-effective reductions in emissions of NOx, these emission reductions

would be less than the reductions that would result from the current rules. Therefore, the same problems discussed under Alternative 2 would apply, albeit to a lesser degree, to this alternative. Overall, the air quality benefit expected by implementation of the rules would be lost while the adverse impacts of the rules would not be commensurably reduced. This is especially true since all such impacts can be mitigated without loss of environmental benefits, or have been found not to be a problem.

Alternative 4: Rescind Rules 1135.1 and 59.1 and restore the South Coast Air Quality Management District's original Rule 475.1. This rule required a 90 percent reduction in emissions from every unit, a far more costly alternative since the utilities would not have the flexibility of selecting units to be controlled. This alternative would undoubtedly be unacceptable to SCE and LADWP because they petitioned the Board to set this rule aside in 1978. After hearing testimony on the rule, the Board found the rule to be inconsistent with Division 26 of the Health and Safety Code for several reasons and amended the rule on August 7, 1978. The Board found at that time that the rule imposed an unreasonable financial and engineering burden on the affected utilities and did not require best available technological and administrative practices. Nothing has changed in the interim to affect these findings; as a result, adoption of this alternative would result in a rule which would be in conflict with the Health and Safety Code. Furthermore, this alternative would exacerbate the environmental concerns raised by the two utilities. While from an air quality point of view this rule would achieve greater NOx reductions than the proposal, economic impacts of this alternative would render its application infeasible.

It also should be noted that the Ventura County Air Pollution Control District did not adopt a rule to control NOx emissions from power plants similar to Rule 475.1 adopted by the SCAQMD. Therefore, for consistency, the Board would have to consider adopting a similar rule for the VCAPCD.

Alternative 5: Amend Rules 1135.1 and 59.1 as proposed.

CONCLUSION

The Board finds that Alternative 5 is the most desirable of the alternatives listed.

Alternative 5 offers the potential of reducing emissions of NOx in the South Coast Air Shed by an amount nearly equivalent to the reductions that would result from the current versions of Rules 1135.1 and 59.1, while effectively lessening the significant environmental concerns raised by SCE and LADWP. This conclusion is based on the following:

1. The requirements of the amended Rules are clear, easily understood, and not subject to uncertainty.

2. The amended Rules require the utilities to install controls only on units that are certain to be in use as base-load units through 1990, and units which will have high capacity factors under <u>any</u> realistic oil and gas reduction scenario likely to occur.

3. The emission reductions resulting from implementing the amended Rules are needed to attain and maintain the state and national ambient air quality standards for nitrogen dioxide and total suspended particulate matter in the South Coast Air Basin, and for nitrogen dioxide, total suspended particulate matter, and ozone in the Ventura County Air Pollution Control District. These reductions are also needed to attain and maintain the state visibility standard.

4. Compliance with the amended rules can be achieved through installation of SCR on a limited number of units.

In addition, weakening of the rules would only partially mitigate the environmental concerns raised, while creating new, more serious concerns (e.g., increases in NOx emissions or NH_3). Most of the environmental concerns raised have been determined not to pose significant problems. Further, all legitimate concerns can be mitigated. The mitigation measures identified are either within the jurisdiction of other agencies, which are currently regulating the subject utilities, or are within the direct control of the utilities that raised the concerns. Further, the utilities have an economic interest in assuring that the measures are carried out. Finally, for the reasons identified in items 1 through 4 above, Alternative 5 will result in fewer potential adverse environmental impacts compared to Alternative 1, the no action alternative.

State of California

Memorandum

To : Huey D. Johnson
Secretary

Date : December 23, 1980

Subject : Filing of Notice of Decision of the Air Resources Board

From : **Air Resources Board**

Pursuant to Title 17, Section 60007(b), and in compliance with Air Resources Board certification under section 21080.5 of the Public Resources Code, the Air Resources Board hereby forwards for posting the attached notice of decision and response to environmental comments raised during the comment period.

Sally Rump

Sally Rump
BOARD SECRETARY

attach: ~~Resolution 80-68~~ f
Resolution 80-69

RECEIVED BY
Office of the Secretary

DEC 23 1980

Resources Agency of California

State of California
AIR RESOURCES BOARD

RECEIVED BY
Office of the Secretary

DEC 23 1980

Resources Agency of California

Resolution 80-68

December 18, 1980

WHEREAS, Health and Safety Code Section 39003 provides that the Air Resources Board (the "Board") is the state agency charged with coordinating efforts to attain and maintain ambient air quality standards;

WHEREAS, Health and Safety Code Section 39002 provides that local and regional authorities have the primary responsibility for control of air pollution from all sources other than vehicular sources, and provides further that the Board shall undertake control activities in any area wherein it determines that the local or regional authority has failed to meet the responsibilities given to it by Division 26 of the Health and Safety Code or any other provision of law;

WHEREAS, Health and Safety Code Section 39500 provides that it is the intent of the Legislature that the Board shall coordinate, encourage and review the efforts of all levels of government as they affect air quality;

WHEREAS, Health and Safety Code Section 39600 provides that the Board shall do such acts as may be necessary for the proper execution of the powers and duties granted to, and imposed upon, the Board by Division 26 of the Health and Safety Code and by any other provision of law;

WHEREAS, Health and Safety Code Section 39602 designates the Board as the air pollution control agency for all purposes set forth in federal law; and provides further that the Board is responsible for preparation of the state implementation plan required by the Clean Air Act, and to this end shall coordinate the activities of all districts necessary to comply with that Act;

WHEREAS, Health and Safety Code Section 39605 provides that the Board may provide any assistance to any district;

WHEREAS, Health and Safety Code Section 40001 provides that the local districts shall adopt and enforce rules and regulations which assure that reasonable provision is made to achieve and maintain the state ambient air quality standards and shall also endeavor to achieve and maintain the federal ambient air quality standards;

WHEREAS, Health and Safety Code Section 40440, as presently in effect and as amended effective January 1, 1981, requires that the rules and regulations of the South Coast Air Quality Management District reflect the best available technological and administrative practices;

WHEREAS, Health and Safety Code Section 40462, as presently in effect and as amended effective January 1, 1981, requires that the South Coast Air Quality Management Plan provide for achievement of state ambient air quality standards at the earliest date achievable by application of all reasonable and available (or reasonably available) control measures and technologies;

State of California
AIR RESOURCES BOARD

Resolution 80-69

December 18, 1980

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WHEREAS, Health and Safety Code Section 39500 provides that it is the intent of the Legislature that the Board shall coordinate, encourage and review the efforts of all levels of government as they affect air quality;

WHEREAS, Health and Safety Code Section 39600 provides that the Board shall do such acts as may be necessary for the proper execution of the powers and duties granted to, and imposed upon, the Board by Division 26 of the Health and Safety Code and by any other provision of law;

WHEREAS, Health and Safety Code Section 39602 designates the Board as the air pollution control agency for all purposes set forth in federal law; and provides further that the Board is responsible for preparation of the state implementation plan required by the Clean Air Act, and to this end shall coordinate the activities of all districts necessary to comply with that Act;

WHEREAS, Health and Safety Code Section 39605 provides that the Board may provide any assistance to any district;

WHEREAS, Health and Safety Code Section 40001 provides that the local districts shall adopt and enforce rules and regulations which assure that reasonable provision is made to achieve and maintain the state ambient air quality standards and shall also endeavor to achieve and maintain the federal ambient air quality standards;

WHEREAS, Section 107(a) of the Clean Air Act provides that it is the responsibility of each state to assure air quality within the entire geographic area of the state;

WHEREAS, Section 110(a)(1) of the Clean Air Act requires that each state adopt a plan which provides for the implementation, maintenance, and enforcement of national primary ambient air quality standards within each air quality control region of the state;

WHEREAS, Section 110(a)(2) of the Clean Air Act requires that such plan provide for the attainment of such standards as expeditiously as practicable;

WHEREAS, Section 172(a)(1) of the Clean Air Act requires that an implementation plan for nonattainment areas provide for the attainment of national primary ambient air quality standards as expeditiously as practicable and no later than December 31, 1982;

WHEREAS, Section 172(b)(2) of the Clean Air Act requires the implementation of all reasonably available control measures as expeditiously as practicable;

WHEREAS, Section 172(b)(3) of the Clean Air Act requires that such nonattainment area plans require reasonable further progress (as defined in section 171(1)) including such reduction in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology;

WHEREAS, Health and Safety Code Section 41650 provides that the Board shall adopt the nonattainment area plan approved by a designated air quality planning agency as part of the state implementation plan unless the Board finds that the nonattainment area plan will not meet the requirements of the Clean Air Act;

WHEREAS, the California Environmental Quality Act and Board regulations require that an action not be adopted as proposed if significant environmental impacts have been identified and there exist within the jurisdiction of the Board feasible mitigation measures or alternatives which would substantially lessen, mitigate or avoid such impacts;

WHEREAS, the Board, in Resolution 79-49, May 29, 1979, adopted Rule 59.1 for the Ventura County Air Pollution Control District in response to action of the Ventura County Board of Supervisors deferring such action to the Board;

WHEREAS, the Board, following notice and hearings held in January and March 1980, on March 27, 1980, adopted Resolution 80-23 in which it amended Rule 59.1;

WHEREAS, Southern California Edison ("SCE") petitioned the Board to reconsider Rule 59.1;

WHEREAS, public hearings have been held and the Board has considered all aspects of Rule 59.1 and has received and considered the evidence presented to it;

WHEREAS, as specifically set forth in the Statement of Findings and Response to Opposing Considerations adopted herewith and made a part of this Resolution, the Board finds:

That the provisions of Rule 59.1 are technologically feasible and cost-effective;

That the provisions of Rule 59.1 as amended are necessary to meet the requirements of the Clean Air Act;

That the provisions of Rule 59.1 as amended assure that reasonable provision is made to achieve state ambient air quality standards; and

That the provisions of Rule 59.1 as amended are appropriate to implement and effectuate the purposes of Division 26 of the Health and Safety Code.

WHEREAS, the Board further finds, in accordance with the requirements of CEQA and as set forth in detail in the Response to Significant Environmental Issues incorporated by reference herein:

That all adverse environmental effects found to be significant by the Board can be mitigated by the utilities pursuant to cost-effective operating procedures, are being minimized by improved catalyst design, or are within the jurisdiction of other public agencies which are currently regulating the activities generating such effects so as to mitigate any anticipated adverse impacts on the environment; and

That alternatives considered are either less effective in reducing NOx emissions and protecting public health and welfare, or are economically infeasible due to excessive increased costs to the utilities.

NOW, THEREFORE BE IT RESOLVED, that the Board amends VCAPCD Rule 59.1 as set forth in Attachment A hereto.

BE IT FURTHER RESOLVED, that the Executive Officer is directed to transmit Rule 59.1 as amended to the Environmental Protection Agency for inclusion in the California State Implementation Plan.

I certify that the above is a true and correct copy of Resolution 80-69, as adopted by the Air Resources Board.

Sally Rump

BOARD SECRETARY

Attachment A

Rule 59.1 of the Ventura County Air Pollution Control District as Amended by the California Air Resources Board

December 18, 1980

A. Applicability

This rule shall apply to any electric utility with a system of electric generating units the total rated capacity of which is more than 500 megawatts.

B. Definitions

Available units are those electric generating units in the system which, except during periods of regularly scheduled maintenance, can be operated without incurring more than the normally acceptable risk to the system, unit, or personnel, and for which fuel can be supplied for at least the next day's operation.

Baseline emissions are of oxides of nitrogen expressed in pounds of oxides of nitrogen (as nitrogen dioxide, NO_2) per hour at each of ten load points of equal increments from minimum load to 100 percent load for each unit of a utility as tested by the utility and as reported to the Air Pollution Control Officer in 1979. In the case of units for which no such report was submitted in 1979, each affected utility shall submit to the Air Pollution Control Officer source test data which show oxides of nitrogen (NOx) emission rates for 1979 at the load points specified herein.

Rated capacity is, for any electric generating unit, the lesser of the manufacturer's name-plate capacity in megawatts for the unit; or the capacity in megawatts to which a unit is restricted by a condition on the electric generating unit's permit to operate.

Steam generated electric capacity is the total rated electric capacity, as of January 1, 1978, of all units which produced electricity from electric generators driven by steam turbines located within the Ventura County Air Pollution Control District. Steam generated electric capacity does not include electric generating capacity of simple or combined cycle gas turbine units.

C. Requirement for Least NOx Dispatch

1. The owner or operator of an electric power generating system shall at all times operate the available units in the system in a manner that minimizes the rate of emissions of oxides of nitrogen from the system ("least NOx dispatch"). Simple cycle gas turbines are exempted from the least NOx dispatch requirements.

2.a. A plan detailing the method for meeting the requirements in subsection C.1. shall be submitted to the Air Pollution Control Officer for consideration no later than March 1, 1981. Within 60 days of receipt of such a plan, the Air Pollution Control Officer shall approve or disapprove the plan. In the event the plan is disapproved, the Air Pollution Control Officer shall notify the affected utility in writing, and shall state the grounds for the disapproval. Within 30 days of such notification, the affected utility shall submit a revised plan which eliminates the stated grounds of disapproval.

b. A revised plan shall also be submitted to the Air Pollution Control Officer within 30 days after a new or modified unit is added to the system or a unit is removed from the system. A revised plan submitted when a unit is added to or removed from the system shall be subject to the requirements for review, approval and revision set forth in subsection C.2.a. for the original plan.

3. Effective 30 days after approval by the Air Pollution Control Officer, the system shall be operated according to the approved plan.

4. Records relating to compliance with this section shall be kept in a manner and form specified by the Air Pollution Control Officer.

D. Requirements for Control

Any owner or operator of an affected electric power generating system shall limit the emissions of oxides of nitrogen from the steam generator of each electric generating unit with a rated capacity of 500 megawatts or more to not more than 20 percent of the baseline emissions. Such limit shall be achieved over the entire operating load range of each unit controlled.

E. Compliance Schedule

1.a. No later than December 1, 1983, each affected utility shall limit the emissions of one unit with a rated capacity greater than 300 megawatts to the levels specified in section D, provided that this provision shall not require an affected utility to attain such limit by December 1, 1983 on more than one such unit within its total system.

b. Except for the requirements of subsection E.1.a., all controls necessary to meet the requirements of this rule shall be installed no later than during the first regularly scheduled shutdown after October 1, 1985, for each unit on which controls are to be installed as specified in the compliance plan required by section E.2.

c. All units on which controls are to be installed as specified in the compliance plan required by section E.2. shall be controlled by December 31, 1989.

2. A final compliance plan shall be submitted to the Air Pollution Control Officer for consideration no later than March 1, 1981. The plan shall contain a list which identifies those units to be controlled and shall include a detailed description of the steps that will be taken to satisfy the requirements of subsections E.1.a., E.1.b., and E.1.c. The description shall contain a construction schedule for each unit on which controls are to be installed. Within 30 days of receipt of such a plan, the Air Pollution Control Officer shall approve or disapprove the plan. In the event the plan is disapproved, the Air Pollution Control Officer shall notify the affected utility in writing and state the grounds for the disapproval. Within 30 days of such notification, the affected utility shall submit a revised plan which eliminates the stated grounds for the disapproval.

F. Review of Rule

Within ninety days after one year's operation on any unit of 300 megawatts or greater capacity within an affected utility's electric power steam generating system of controls installed to achieve the emission reduction required by this rule and upon request by an affected utility, the District Board shall conduct a hearing to consider the experience gained in meeting the requirements of the rule; and whether further implementation of the rule remains reasonable and necessary to attain the objective of a 90 percent overall reduction in power plant NOx emissions in the South Coast Air Shed. The rule shall remain in effect pending such consideration. Upon request by the District Board, the State Air Resources Board shall conduct the hearing.

G. Severability

Except as otherwise provided in this Rule, if any portion of this Rule is found to be unenforceable, such finding shall have no effect on the enforceability of the remaining portions of the Rule. These remaining portions of the Rule shall continue to be in full force and effect.

State of California
AIR RESOURCES BOARD

Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants

ARB Compliance with the California Environmental Quality Act (CEQA)

The following discussion is intended to explain how the ARB assures that any possible adverse environmental effects of its proposed actions will be identified and mitigated. As an environmental protection agency, the ARB is not required to prepare an Environmental Impact Report (EIR) on this project, but other written documentation prepared by the agency must describe the proposed activity with alternatives to the activity and mitigation measures to minimize any significant adverse environmental impact. Further, regulations adopted by the ARB require that the action will not be adopted by the Board as proposed if there are feasible alternatives or feasible mitigation measures which would substantially lessen any significant adverse impact of the activity on the environment. ARB regulations also require that prior to taking final action, the Board must respond in writing to significant environmental points raised during the evaluation process. Finally, CEQA requires that the ARB not adopt the activity for which significant adverse effects have been identified unless one or more of the following findings are made:

1. That changes have been incorporated into the project which mitigate the significant environmental impacts.

2. That such mitigation measures are within the responsibility and jurisdiction of another public agency and have been (or can and should be) adopted by such other agency.

3. That specific economic, social, or other considerations make the mitigation measures or alternatives infeasible.

Consequently, the ARB staff report discusses several possible environmental impacts of the proposed rule. Several other concerns were raised during the hearing process. These are identified and discussed in the following section. In addition, mitigation measures which could minimize any impacts found to be significant are examined, as are alternatives to the proposed action. In this case, since the proposal is the amendment of certain rules already in existence, the "no project" alternative is for the Board to take no action and to leave the current rules in place. Other alternatives discussed are the repeal of the subject rules in their entirety, amending the rules to be less stringent, and restoring the Districts' original Rules.

The Board, prior to taking final action, has adopted the attached responses to significant environmental issues. Further, in adopting the activity itself, the Board, in its resolution, has made findings relating to each significant environmental issue raised, either incorporating feasible mitigation measures and alternatives into the rules, indicating that other agencies are responsible for mitigation of these effects, or indicating the factors which prevent the imposition of mitigation measures or alternatives. If future experience reveals adverse environmental impacts not reasonably anticipated, corrective action can be taken by the Air Resources Board or other appropriate agency (e.g., the local air pollution control districts which will be implementing any adopted rule) to mitigate such effects.

State of California
AIR RESOURCES BOARD

Response to Significant Environmental Issues

Item: Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants

Public Hearing Dates: November 5, 6, 13, and December 2, 3, 18, 1980

Response Date: December 18, 1980

Issuing Authority: Air Resources Board

Introduction: Southern California Edison (SCE) and the Los Angeles Department of Water and Power (LADWP) have raised several concerns which they believe were not adequately addressed by the Air Resources Board (ARB) staff in the September 1980 report. Since the discussion of many of the issues raised by the utilities assumes an understanding of the selective catalytic reduction (SCR) process, it is appropriate to explain briefly the operation and performance of the process involved.

The utilities are being required to reduce NOx emissions on some of their steam generating boilers by 80 percent. This requirement will probably be satisfied by retrofitting utility boilers with the selective catalytic reduction (SCR) system to control oxides of nitrogen (NOx) emissions. The technology takes advantage of the preferential reaction of ammonia (NH_3) with NOx rather than with other flue gas constituents. Since oxygen (O_2) enhances the reduction, the reaction can be best expressed as

$$4NH_3 + 4NO + O_2 \longrightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \longrightarrow 3N_2 + 6H_2O \qquad (2)$$

Equation 1 represents the predominate reaction since approximately 95 percent of the NOx in combustion flue gas is in the form of nitric oxide (NO). Therefore, under ideal conditions a stoichiometric amount of NH_3 can be used to reduce NOx to harmless molecular nitrogen (N_2) and water vapor (H_2O).

In practice, an NH_3:NO mole ratio of about 1:1 has typically reduced NO emissions by 90 percent with a residual NH_3 concentration (also called "ammonia breakthrough") of less than 10 ppm. (1)*

The SCR process requires other auxiliary equipment such as a reactor, a catalyst, ammonia storage facilities and ammonia injection systems.

The optimum temperature for the NOx reduction reaction without a catalyst is about 1800^{o}F. However, the catalyst effectively reduces the optimum reaction temperature to approximately 600^{o}F to 850^{o}F.

*See reference list page 14.

Catalysts may be made with different chemical compounds; those with vanadium (V) compounds were found to promote the reduction of NOx with NH_3 and to be unaffected by the presence of sulfur oxides (SOx), another exhaust gas component which could interfere with the desirable reaction. (2)

Titanium dioxide (TiO_2) was found to be an acceptable carrier, since it is resistant to attack from SO_3. (2) Therefore, many SOx resistant catalysts are based on TiO_2 and vanadium pentoxide (V_2O_5).

The life of the catalyst depends upon the type of flue gases it is being used to treat. The catalysts to be used on power plants in the South Coast Air Basin should last for 2 years or longer. (3) Also, because of oil firing, catalysts will be most likely of the parallel flow type. It may have one of many shapes such as parallel plate, parallel tube or honeycomb type. It may be made of ceramic material such as TiO_2 or metal.

The catalyst may be of homogenous or of coated variety. In essence, the type of the catalyst to be used in the power plant depends upon the user and the process vendor. Figure 1 shows as an example of how, typically, a honeycomb type catalyst would be placed in a reactor. When the catalyst loses its reactivity, it is replaced.

The above explanation briefly summarizes the control methods that will likely be employed to retrofit the utility boilers to comply with Rules 1135.1 and 59.1. The discussion that follows addresses the concerns raised by SCE and LADWP and the Board's response to those concerns.

Comment 1: The LADWP has expressed concerns that disposal of spent catalyst in an environmentally sound manner is an unresolved problem and that because of the presence of vanadium in the catalyst, special disposal or reclamation methods will be required.

Response: The application of selective catalytic reduction to a total of 4432 MW of power plant capacity, as required to fully comply with Rules 1135.1 and 59.1, is expected to result in the use of about 1100 tons of catalyst per year.[1] The exact type and composition of catalyst would depend on the process vendor and the user, but typically a parallel flow, honeycomb type catalyst would contain V_2O_5 and titanium dioxide (TiO_2).

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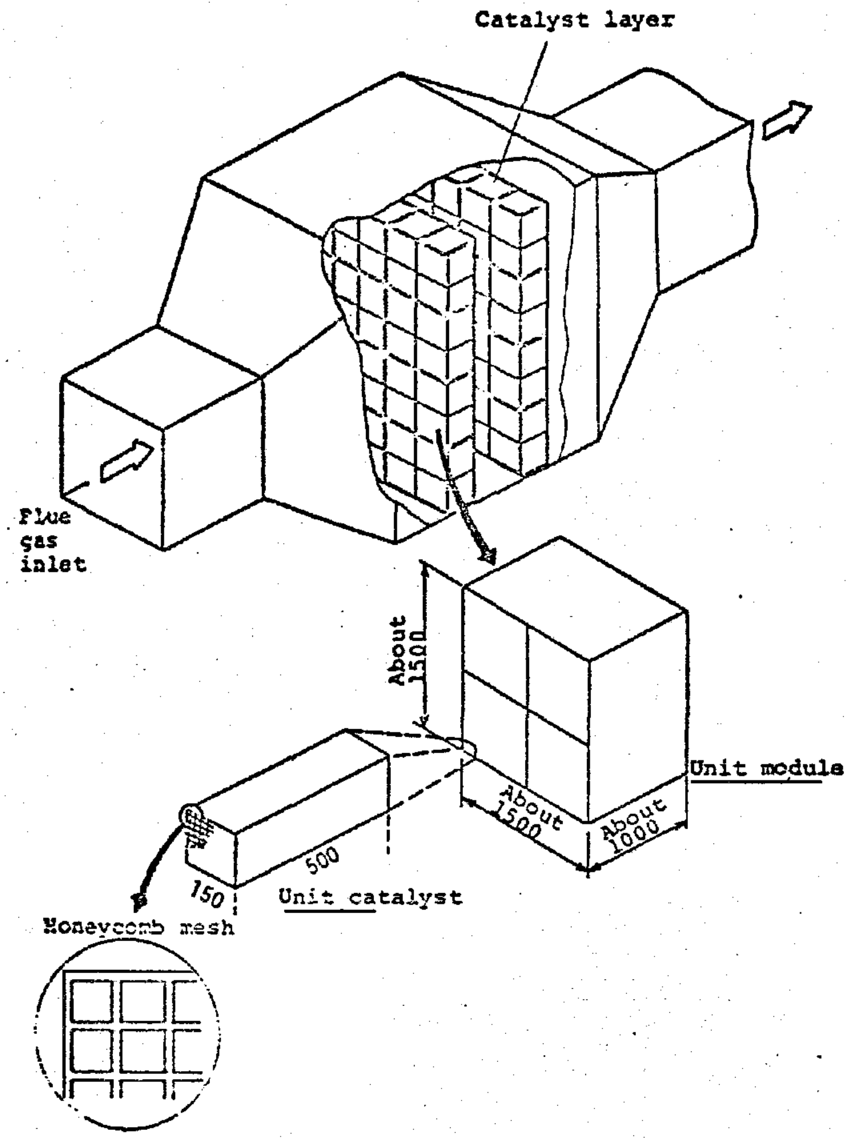
1. This estimate follows from a total generating capacity required to be controlled of 4432 megawatts (MW) and SCE's estimate (4) that control of its units larger than 175 MW (total of 24 units having 7720 MW) would require 1860 tons per year of catalyst, assuming a two year catalyst life:

$$4432 \text{ MW} \quad \times \quad \frac{1860 \text{ tons of catalyst/yr}}{7720 \text{ MW}} = 1068 \text{ tons catalyst/yr}$$

Based on commercial operating experience to date on SCR installations in Japan in which catalyst deterioration has not been significant (3) catalyst lifetimes are expected to equal or exceed 2 years with fuel oil firing and 3 years with natural gas firing. Requirements for catalyst are inversely related to catalyst lifetime, hence a catalyst lifetime of 3 years corresponds to a catalyst requirement of about 712 tons per year.

FIGURE 1



Example of a fixed bed reactor with honeycomb type catalyst (Ishikawajima-Harima Heavy Industries; sizes are in mm).

Source: J. Ando. NOx Attachment for Stationary Sources in Japan. August 1979.

Depending upon the specific type and material of the catalyst selected, valuable components may be recovered for reuse, just as used or "spent" automotive exhaust catalysts and refinery process catalysts are normally amenable to recovery or reprocessing prior to disposal. To the extent that spent catalyst cannot be recovered, and constitutes a potentially hazardous waste[2], treatment and/or disposal at a Class I or Class II-1 (hazardous waste) disposal site may be required. In such a worst case, the increment of potential hazardous waste generation due to Rules 1135.1 and 59.1 would be about 1100 tons per year, as compared with the current rate of generation of hazardous wastes in California of approximately 11,000,000 tons per year (5). Thus, full implementation of Rules 1135.1 and 59.1 is not expected to increase the production of potentially hazardous waste in California by more than about 0.01 percent, even in the worst case.

Mitigation of the above increments of hazardous waste disposal is accomplished by regulation of liquid and solid hazardous waste disposal in California by the State Water Resources Control Board (and Regional Boards), the Department of Health Services, and the Solid Waste Management Board. Through a system of hazardous waste generation reporting by the industry, and regulation by the above agencies to ensure environmentally sound disposal, the problem of hazardous waste disposal associated with the Board's action will be mitigated in the same manner as is the disposal of other toxic wastes.

Comment 2: Southern California Edison has expressed concerns that some of the toxic metals from catalysts that may be used in the SCR process can be released into the environment.

Response: The Board has received no evidence which demonstrates that catalysts which are used in the SCR process, as applied to oil or gas fired units to comply with Rules 1135.1 and 59.1, would result in significant increases in emissions of vanadium (V) or other potentially toxic metals from power plants.

Vanadium is a natural constituent of crude oil and is also contained in significant amounts in the (refined) residual oil burned in power plants in the South Coast Air Basin and Ventura County. (6) Thus, at the present time, combustion of fuel oil in the South Coast Air Basin and Ventura County is believed to result in significant release of vanadium into the environment. Based on data provided by SCE (6), and assuming 50 million barrels of oil per year burned in power plants (the minimum amount of oil burned by all utilities in any recent year), vanadium emissions are estimated to be about 120 tons per year[3] at the present time, i.e. absent further controls.

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2. Depending upon the specific composition of the catalyst selected, "spent" catalyst may or may not be classified as a hazardous waste.

3. $$\frac{50 \times 10^6 \text{ BBLS}}{\text{year}} \times \frac{320 \text{ lbs}}{\text{BBL}} \times \frac{15 \times 10^{-6} \text{ lbs V}}{\text{lb fuel oil}} \times \frac{\text{ton}}{2000 \text{ lbs}} = \frac{120 \text{ tons V}}{\text{yr}}$$

If this amount of vanadium is expressed as V_2O_5, an oxidized form, the amount of V_2O_5 is

$$\frac{120 \text{ tons V}}{\text{year}} \times \frac{182 \text{ tons } V_2O_5}{51 \text{ tons of V}} = 429 \text{ tons } V_2O_5/\text{yr}.$$

The Board is not aware of any other source of vanadium emissions, due to fuel burning, SCR, or any other source, which is larger than the above current emissions from power plants. Furthermore, the Board is not aware of any data which show that the retrofit of SCR to an oil or gas fired power plant would result in significantly increased emissions of vanadium or other components of the catalyst. To the contrary, available information from Japan indicates good catalyst performance over long periods (in excess of 2 years), suggesting that vanadium, the principal active component in the catalyst bed, remains essentially intact and continues to perform at, or near, full design efficiency. (3) Vanadium or vanadium compounds could potentially present risks as toxic compounds at elevated levels of human exposure; however, such compounds have not been identified as high priority toxic compounds at the present time,(9, 10) and evidence received by the Board does not support the concern that Rules 1135.1 and 59.1 would result in significant environmental impacts. If vanadium or vanadium compounds are identified as a significant threat or potential threat to human health or the environment at some future time, such compound(s) would be regulated in accordance with the statewide programs to control airborne toxic substances, including existing and future ARB and local district programs.

Comment 3: Southern California Edison has raised concerns that nitrosamines can be formed as a result of ammonia injection in flue gases for Thermal DeNOx and SCR processes.

Response: Representatives of SCE testified that with a model system using a propane/air flame, they have found a potential for formation of nitrosamines when ammonia is injected in the flue gases. Subsequent testimony by SCE indicated that the company's concerns regarding the formation of nitrosamines was based on injection of ammonia in a propane enriched flame. However, this situation would occur only during a boiler upset condition. It is standard operating practice at the present time to avoid any such possible upsets in order to ensure system safety and reliability. Consequently, since the utility boilers are carefully operated with excess air and are not fuel enriched, the hydrocarbon radical (essential to the formation of nitrosamines) would be completely oxidized and would not be available for the formation of nitrosamines in the presence of ammonia. Thus, no nitrosamines are expected to be formed if ammonia is injected in a normal operating mode of an electric utility boiler. Mitigation of possible impacts during boiler upset conditions consists of the utilities continuing current standard operating practices to avoid unsafe fuel-rich operation of a boiler.

Comment 4: LADWP has raised concerns regarding ammonia breakthrough to the atmosphere as a result of its injection in the noncatalytic and catalytic deNOx methods.

Response: As explained in the introduction, ammonia (NH_3) is injected in the flue gases to reduce NOx emissions through chemical reactions leading to the formation of harmless materials. Ideally, a stoichiometric (chemically correct) amount of NH_3 can be used to reduce 100 percent of the NOx to harmless molecular nitrogen and water vapor, with no ammonia breakthrough. However, in practice, the stoichiometric NH_3:NO mole ratio of 1:1, in the presence of a catalyst, will typically reduce NOx emissions by 90 percent with a residual NH_3 concentration of less than 10 parts per million (ppm). (1) In processes which reduce NOx without use of a catalyst, higher NH_3:NO mole ratios may be required for less than 90 percent reduction, resulting in slightly higher residual NH_3.

This residual NH_3 is commonly known as "NH_3 slip", "breakthrough", "carryover", or "release". This ammonia breakthrough is minimized by optimizing the design and operation of the catalytic and noncatalytic deNOx processes, as illustrated by the attached Figure 2. The attached figure shows that an SCR system, when operated for 90 percent NOx removal efficiency, is expected to result in NH_3 breakthrough in the range of 5-10 ppm in stack gases. However, SCR systems which are designed and operated for 80 percent NOx removal efficiency are expected to result in stack gas concentrations of less than 5 ppm of NH_3 carryover. As discussed in the ARB Staff Report of September 19, 1980 (7), ground level NH_3 concentrations at the point of maximum plume impact would be expected to be 1/1000 of the stack concentrations, resulting in ground level NH_3 concentrations below natural background levels and far below the level of any adverse health impacts which have been identified.

Because optimum operation of an SCR system to reduce NH_3 breakthrough would also minimize the consumption of NH_3 and the deposition of NH_3-based reaction products on components such as air preheaters, system design and operation to minimize NH_3 carryover is also in the economic interest of the system owner/operator, as this would minimize operating and maintenance expenditures. Thus, any remaining impact of NH_3 breakthrough would be fully mitigated by the utilities by system design and operation to minimize NH_3 emissions.

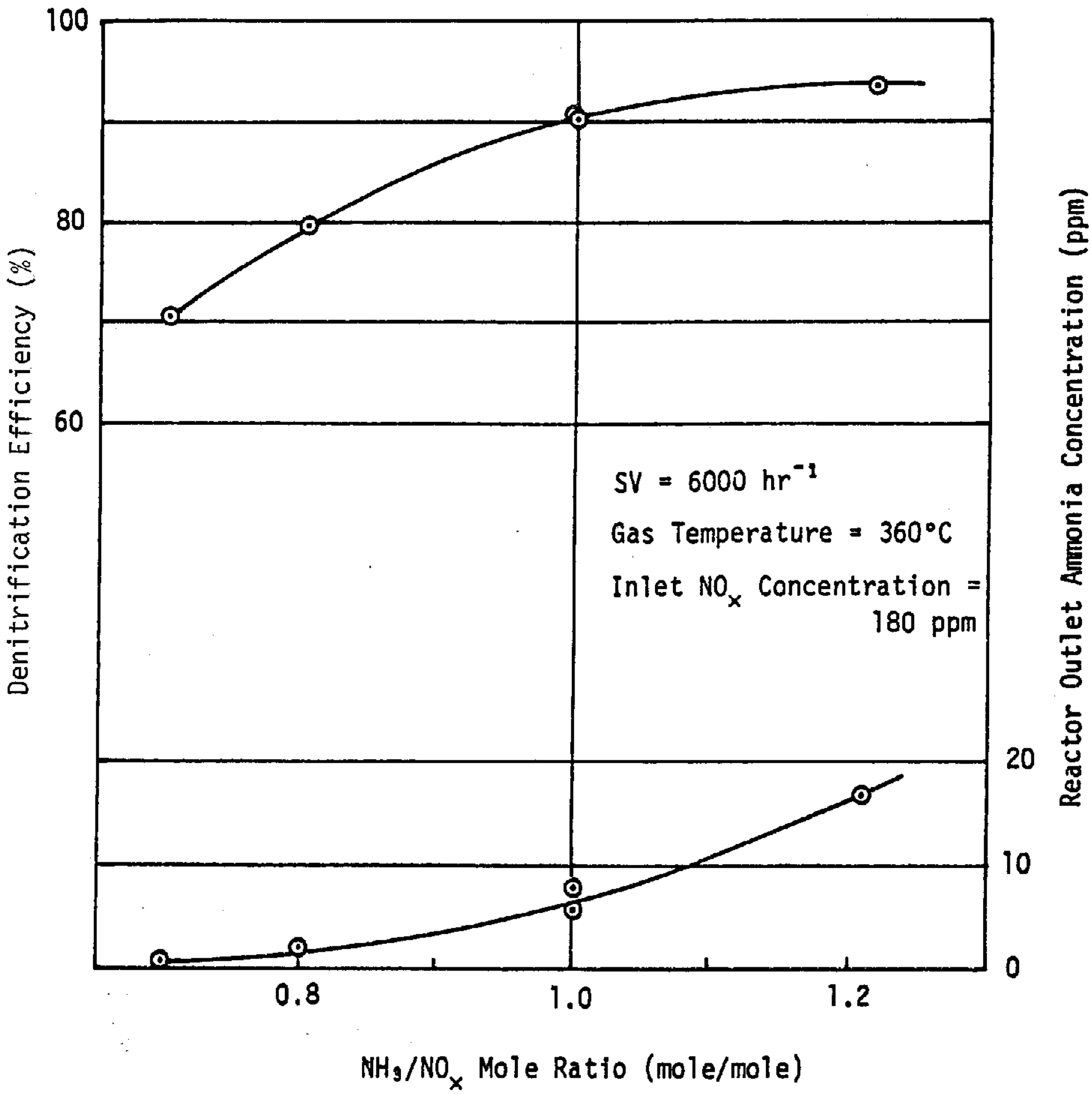
Comment 5: LADWP has expressed concerns that SCR systems promote the oxidation of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) and that therefore the total sulfate concentration in the flue gas would be increased by the proposed rules. Furthermore, LADWP believes that increased sulfate emissions may adversely affect our ability to attain and maintain applicable ambient air quality standards and the public health and welfare which these standards are designed to protect.

Response: As explained in the introduction, SCR systems are used to facilitate NOx emission control. In addition to the two chemical reactions that convert NOx to N_2 and H_2O (see introduction), a third reaction also occurs, simultaneously. This third reaction is the oxidation of sulfur dioxide, a compound produced during the combusion of any fuel containing sulfur, to sulfur trioxide, and can be expressed as follows:

$$2\ SO_2 + O_2 \longrightarrow 2\ SO_3 \quad (3)$$

In the absence of an SCR system, this reaction will occur naturally in the atmosphere, but at a slower rate. Because of the corrosive nature of SO_3 and its potential to combine with NH_3 to form ammonium sulfates and other potentially condensible compounds most of the process vendors have improved their catalysts to minimize the conversion of SO_2 to SO_3. SCR systems which are currently in use convert from 1.5 to 2.5 percent or higher of SO_2 to SO_3 (1) whereas new catalysts are developed and tested to suppress conversion to less than one-half percent of the SO_2 to SO_3. (4) As in the case of the minimization of NH_3 breakthrough, the minimization of SO_3 formation is also in the economic interest of utilities, since it would minimize maintenance costs. Consequently, utilities can design SCR systems using catalysts which minimize SO_3 formation to substantially mitigate any potential adverse impacts of SCR on sulfate emissions.

Figure 2



NH_3/NO_x mole ratio versus denitrification efficiency versus reactor outlet ammonia concentration for the honeycomb catalyst at Taketoyo Power Station.

Source: Reference 1.

Comment 6: LADWP has expressed concerns that the use of enough ammonia to effect a 90 percent NOx emission removal could result in the formation of ammonium sulfate ($(NH_4)_2SO_4$) and ammonium bisulfate (NH_4HSO_4) deposits which could foul the air preheater. Furthermore, LADWP believes that aerosols of these compounds could cause environmental problems, and their presence in the stack plume may cause opacity problems due to the presence of condensed particles.

Response: The formation of ammonium sulfate and ammonium bisulfate depends upon the concentrations of NH_3 and SO_3 in flue gas and also on the temperature of the flue gas. Ammonium bisulfate is formed as a result of the reaction between NH_3, SO_3, and water vapor as described in the following reaction:

$$NH_3\ (gas) + SO_3\ (gas) + H_2O\ (gas) \longrightarrow NH_4HSO_4\ (liquid)$$

In the presence of excess ammonia, ammonium bisulfate may further react to form ammonium sulfate (solid) as follows:

$$NH_4HSO_4\ (liquid) + NH_3\ (gas) \longrightarrow (NH_4)_2SO_4\ (solid)$$

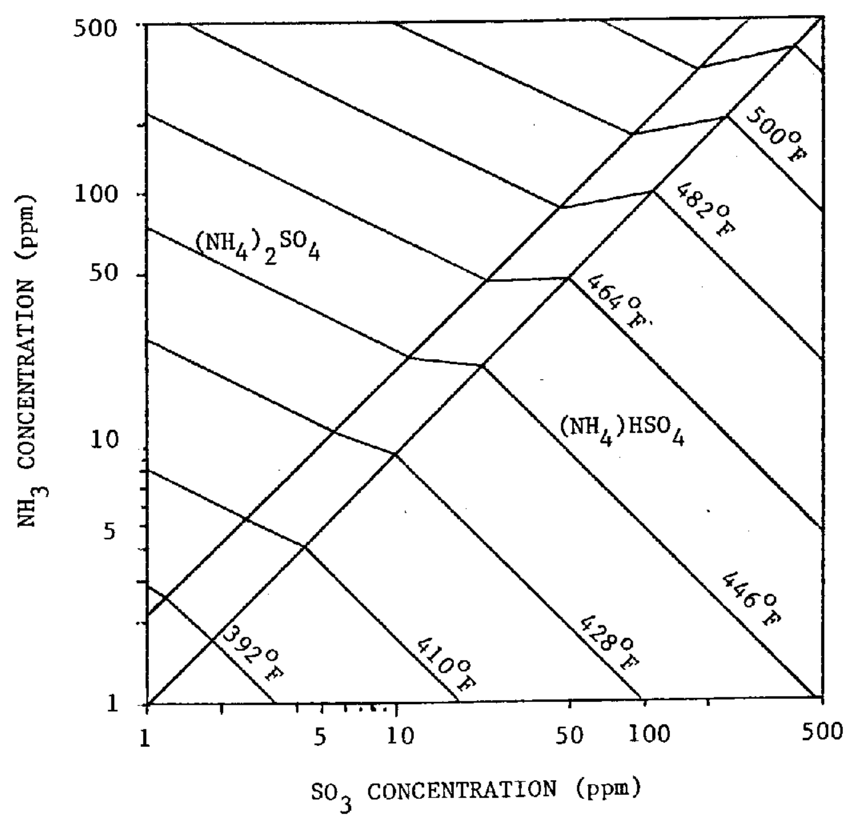
The conditions under which these compounds will be formed are shown in Figure 3.

As can be seen in Figure 3, actions which reduce both NH_3 carryover concentrations and SO_3 concentrations (as discussed in the responses to comments 4 and 5) will also result in lower temperatures of formation of ammonia-sulfur compounds, and thus would be expected to reduce the formation of such compounds. As discussed above, these actions, both individually and collectively, are expected to reduce potential operating and maintenance costs to the utilities. Therefore, minimization of NH_3 carryover concentrations and SO_3 concentrations are available mitigation actions which are expected to be fully implemented by the utilities and are in the economic interests of the utilities.

With regard to potential opacity problems, of the more than seventy commercial installations operating with SCR in Japan (7), the Board is unaware of any data noting opacity problems on any of these units. Furthermore, opacity (the darkness and visibility of stack emissions) is regulated by state law (Health and Safety Code Section 41701) and local air pollution control district regulations, and any adverse impacts will have to be mitigated by the utilities pursuant to these requirements.

Comment 7: LADWP has expressed concerns that ammonium sulfates formed as a result of the SCR process may produce deposits on the air preheater and force more frequent washings than would otherwise occur. An air preheater wash will create a large volume of waste water for disposal. LADWP estimates that depending upon the washing period, the additional waste water may range from 300,000 to 1,000,000 gallons and is concerned about the potential adverse environmental impact of disposal of such waste water. (LADWP did not specify whether the additional waste water use was projected on an annual basis or for some other time period.)

Figure 3



FORMATION OF AMMONIUM SULFATE
HIGH TEMPERATURE RANGE

Source: D.R. Swann, G.D. Drissel. Feasibility of Retrofitting Catalytic Post Combustion NOx Controls on an 80 MW Coal-Fired Utility Boiler. February 1980 (8)

Response: The LADWP estimate apparently applies to an annual generation rate for waste water under the assumption that 11 of its units, comprising 2593 MW, would be required to install SCR units designed for 90 percent NOx removal. The final version of Rules 1135.1 and 59.1 requires that only 3 units of LADWP, comprising 912 MW, would be required to be retrofit with SCR designed for 80 percent NOx removal. Consequently, the actual quantities of additional waste water generated due to the adopted rules will be significantly less than that estimated by LADWP. Furthermore, as explained above, the potential for formation of ammonium compounds can be minimized by techniques which are in the economic interest of utilities and which minimize NH_3 breakthrough emissions as well as the conversion of SO_2 to SO_3.

In addition, because air preheaters are periodically washed at the present time (without SCR installed), any additional waste water generated would be treated and disposed of in a manner similar to that currently used, and in accordance with requirements imposed by the State and Regional Water Quality Control Boards. Accordingly, any potential adverse environmental effects due to additional waste water disposal would thus be mitigated in accordance with regulations of those agencies having jurisdiction over water quality.

Comment 8: SCE expressed concerns regarding potential hazards of ammonia storage, handling, and transport and the possibility of accidental releases of ammonia. LADWP also expressed concerns regarding storage of ammonia.

Response: In order to evaluate the potential hazards of ammonia storage, handling and transportation, the ammonia-related hazardous materials incidents have been compared to all the hazardous materials incidents[4] in the U.S. in 1978. In addition, the amount of NH_3 required as a result of Rules 1135.1 and 59.1 is small compared with national statistics for ammonia shipments.

Table 1 compares ammonia related incidents with all hazardous materials incidents in the U.S. in 1978. As shown in this table, shipment of about 9 million tons of ammonia in 1978 resulted in spillage of about 188 tons (0.002%) in 95 incidents. These incidents resulted in 2 deaths, 58 injuries, and $98,000 in damages. By comparison, all hazardous materials incidents, totalling 17,750 in 1978 resulted in 46 deaths, 1072 injuries, and $16 million in damage. Table 1 also compares ammonia requirements of Rules 1135.1 and 59.1 with national average shipments and data on incidents. These data suggest a relatively low probability of incidents with relatively very low or negligible expected impacts.

Table 2 shows that the mean mortality index for ammonia is 0.02 as compared to the mean mortality index of hydrocarbons which ranges from 0.1-0.6. These data indicate that ammonia, which is commonly used in many household, commercial and industrial cleaning applications and which is used in agriculture in significant

4. A hazardous materials incident is defined in 49 CFR 171.15 (1977) according to criteria established by the U.S. Department of Transportation. Basically, these criteria include: accidental deaths or injuries, property damage in excess of $50,000, or other specified damages.

TABLE 1

ANHYDROUS AMMONIA STATISTICS

Total amounts of shipments of anhydrous ammonia in the U.S. in 1978		8.7 million tons
Total amount spilled of those shipments in the U.S. in 1978		188 tons
Statistics of the 17,750 incidents* in 1978 in the U.S.	Deaths	46
	Injuries	1072
	Damages	$16 million
Statistics of the 95 incidents involving anhydrous ammonia in 1978 in the U.S.	Deaths	2
	Injuries	58
	Damages	$98,000
Total amount of anhydrous ammonia used by agriculture in the U.S. in 1978		4.5 million tons
Total amount of anhydrous ammonia required to comply with the Rules		15,000 tons per year

*An incident is as defined in 49 CFR 171.15 (1977).

Source: U.S. Department of Transportation, National Fertilizer Association and ARB/SSCD

TABLE 2

ESTIMATE OF MEAN MORTALITY INDEX OF AMMONIA
AND ITS COMPARISON WITH OTHER GASES

LOCATION	DATE	AREA/SITE	SOURCE OF LEAKAGE	QUANTITY METRIC TON	NUMBER OF FATALITIES
Floral, Ark.	June 5, 1971	Rural	Pipeline	600 tons	0
Enid, Oklahoma	May 7, 1976	Urban	Pipeline	500	0
Conway, Kansas	December 6, 1973	Rural	Pipeline	277	0
Landskrona, Sweden	January 16, 1976	Port	Ship-storage connection	180	2
Blair, Nebraska	November 15, 1970	Rural	Storage tank	160	0
Crete, Nebraska	February 18, 1969	Urban	Rail tanker	90	9
Belle, West Va.	January 21, 1970	Urban	Rail tanker	75	0
Texas, Tx City	September 13, 1975	Urban	Pipeline	50	0
Potschefstroom, South Africa	July 13, 1973	Urban	Storage tank	38	18^{+}
Houston, Texas	November 15, 1976	Urban	Road tanker	19	6
Lievin, France	August 21, 1968	Urban	Road tanker	19	6

$$\text{Mean mortality index} = \frac{\text{total number fatalities}}{\text{total amount lost}} = \frac{41}{2008} = 0.02$$

+Without this incident the mean mortality index = 0.01

Mean mortality index of chlorine = 0.3
" " " of flammable gases or vapor = 0.1 -0.6
" " " of Ammonium Nitrate = 0.1

Source: A report on Major Hazards by Advisors Committee, Health and Safety Commission, Great Britain, 1979.

quantities, is not particularly dangerous when handled with proper caution. Accordingly, mitigation measures expected to be taken by utilities to ensure minimization of potential hazards due to ammonia spillage, which would consist of implementation of standard safe operating practices for potentially hazardous materials, are expected to reduce potential hazards to very low or negligible levels.

Comment 9: LADWP, in its written testimony, expressed concerns regarding formation of hydrogen cyanide (HCN) by ammonia injection.

Response: Brown and Sawyer were not able to detect either HCN or other nitrogenous species (other than NOx, NH_3, or N_2) in the stack gas from a laboratory combustor burning No. 1 diesel doped with pyridine. (Quarterly Progress Report for ARB Contract A8-146-31 for 1 May - 1 July 1980). Based upon minimum detection limits associated with the various analytical procedures used, Brown and Sawyer estimated conservative upper limit concentration values of 5 ppm for all nitrogenous species (other than NOx, NH_3, and N_2) and 1 ppm for HCN in the laboratory combustor stack gas.

These data, taken along with SCE's and ARB's tracer studies, which show that emissions from tall stacks are diluted by a factor of 10^{-4} to 10^{-6} (7), show that the maximum surface level concentration of all nitrogenous species (other than NOx, NH_3, and N_2) is in the range of 5 to 500 parts per trillion and 1 to 100 parts per trillion for HCN, and may be substantially less.

A threshold limit value (TLV) of 10 parts per million has been designated for hydrogen cyanide (HCN), according to Multimedia Environmental Goals for Environmental Assessment, Volume 11, MEG Charts and Background Information, J.G. Cleland and G.L. Kingsbury, November, 1977; EPA-600/7-77-136b. The ambient level goal recommended in that same work is 24 parts per billion, based on health effects. Documentation of the Threshold Limit Values for Substances in Workplace Air, (American Conference of Governmental Industrial Hygienists, Third Edition 1971), shows that the TLV of 10 parts per million "contains a two-fold margin of safety against mild symptoms of HCN response."

Thus, according to the test data, the highest ambient concentration expected would be a factor of more than 200 below EPA recommended environmental goals for the atmosphere.

Comment 10: SCE expressed concern that the Board's action would exacerbate ozone and oxidant air quality problems in the South Coast Air Basin.

Response: This concern is dealt with at length in the Board's Findings and Basis for decision, which is incorporated by reference herein.

CERTIFIED: Sally Rump
Sally Rump
Board Secretary

Date: Nov 23, 1980

References

1. Dr. Jumpei Ando, NOx Abatement for Stationary Sources in Japan, rpt. (Japan: Chou University, August 1979).

2. Proceedings of the Joint Symposium on Stationary Combustion NOx Control, Volume II, Utility Boiler NOx Control by Flue Gas Treatment, "Assessment of NOx Flue Gas Treatment Technology" by J. D. Moholey, U.S. EPA, IERL-RTP-1084, October 1980.

3. Sengoku Tadamasa, et al, The Development of a Catalytic NOx Reduction System For Coal-Fired Steam Generators (Tokyo, Japan; Mitsubishi Heavy Industries, October 6-9, 1980).

4. Proceedings of the Joint Symposium on Stationary Combustion NOx Control, Volume II, Utility Boiler NOx Control by Flue Gas Treatment, "Status of SCR Retrofit at Southern California Edison Huntington Beach Generating Station Unit 2", L. Johnson et al; U.S. EPA IERL-RTP-1084 October 1980.

5. Solid Waste Management in California: A Status Report, State of California, Solid Waste Management Board, February 1980.

6. A document from SCE titled "Emission of Vanadium and Organics from SCE Oil-Fired Generating Stations," November 24, 1980.

7. The Air Resources Board staff report entitled "Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants." (September 1980)

8. D. R. Swann, G. D. Drissel. Feasibility of Retrofitting Catalytic Post Combustion NOx Controls on an 80 MW Coal-Fired Utility Boiler, rpt. (Denver, Colorado: Stearns-Roger Inc., February 1980).

9. State of California Air Resources Board Final Report of the Ad Hoc Panel on Atmospheric Carcinogens, April 1979.

10. Science Applications, Inc., Vol. I., Final Report, An Inventory of Carcinogenic Substances Released Into the Ambient Air of California, February 1979.

Alternatives

There are five basic alternatives which the Board could adopt in reconsidering SCAQMD Rule 1135.1 and VCAPCD Rule 59.1. Following are descriptions and discussions of these alternatives.

Alternative 1: Take no action; that is, the "no project" alternative. This alternative would, in effect, reaffirm the versions of SCAQMD Rule 1135.1 and VCAPCD Rule 59.1, currently stayed, both of which the Board adopted on March 27, 1980. This alternative would neither prevent nor mitigate the environmental and other concerns raised by the petitioner, SCE, and LADWP, the intervenor. It is with regard to the existing versions of these two rules that the environmental questions have been raised.

Alternative 2: Rescind SCAQMD Rule 1135.1 and VCAPCD 59.1. Under this alternative, further NOx emission reductions would not be required, and power plants would continue to be subject to the control prescribed by SCAQMD Rule 464 (125-225 ppm for gas-fired units and 225-325 ppm for oil-fired units) and by a comparable VCAPCD rule. Although this alternative would eliminate the concerns raised by SCE and LADWP, it would forego emission reductions of almost 60 tons per day of NOx by 1990. Currently, NOx emissions from stationary sources in the South Coast Air Shed are slightly over 450 tons per day. The nonattainment area plans for the South Coast Air Basin and the Ventura County Air Pollution Control District rely on these emission reductions to attain and maintain the national ambient air quality standards for nitrogen dioxide and suspended particulate matter and, in the case of Ventura, for ozone as well. Also, such reductions in the emissions of NOx are necessary if the state ambient air quality standards for nitrogen dioxide, suspended particulate matter, and visibility are to be attained and maintained. If those standards are not attained and maintained, the adverse effects on the public health and welfare that the standards are intended to prevent will not be prevented.

Because the federal Clean Air Act and the California Health and Safety Code require that the ambient air quality standards be attained and maintained in order to protect public health and welfare, withdrawal of Rules 1135.1 and 59.1 would require that new measures be adopted to effect equivalent reductions from other sources. That is, NOx control measures would have to be adopted for sources for which control methods have not yet been identified, or for which controls cost more for each pound of NOx reduction than those required by Rules 1135.1 and 59.1. Since all of the significant adverse environmental effects expected to result from the proposal can be mitigated, the benefit of achieving the 60 tons per day NOx emission reductions by controlling power plants is preferable to controlling other sources at this time because control of other sources may be accompanied by unknown environmental impacts.

If other, more costly or unidentified rules were not quickly adopted, this alternative would be inconsistent with state and federal laws, and would result in pollutant concentrations in the South Coast Air Shed which would be detrimental to the public health and welfare. This alternative is therefore infeasible, with significant adverse impacts on the environment.

Alternative 3: Amend Rules 1135.1 and 59.1 to be less stringent. Concerns raised by SCE and LADWP (such as increased environmental burdens of heavy metals from catalysts and emissions of ammonia) could be partially mitigated by making the existing rules less stringent. Although this alternative would still provide some cost-effective reductions in emissions of NOx, these emission reductions

would be less than the reductions that would result from the current rules. Therefore, the same problems discussed under Alternative 2 would apply, albeit to a lesser degree, to this alternative. Overall, the air quality benefit expected by implementation of the rules would be lost while the adverse impacts of the rules would not be commensurably reduced. This is especially true since all such impacts can be mitigated without loss of environmental benefits, or have been found not to be a problem.

Alternative 4: Rescind Rules 1135.1 and 59.1 and restore the South Coast Air Quality Management District's original Rule 475.1. This rule required a 90 percent reduction in emissions from every unit, a far more costly alternative since the utilities would not have the flexibility of selecting units to be controlled. This alternative would undoubtedly be unacceptable to SCE and LADWP because they petitioned the Board to set this rule aside in 1978. After hearing testimony on the rule, the Board found the rule to be inconsistent with Division 26 of the Health and Safety Code for several reasons and amended the rule on August 7, 1978. The Board found at that time that the rule imposed an unreasonable financial and engineering burden on the affected utilities and did not require best available technological and administrative practices. Nothing has changed in the interim to affect these findings; as a result, adoption of this alternative would result in a rule which would be in conflict with the Health and Safety Code. Furthermore, this alternative would exacerbate the environmental concerns raised by the two utilities. While from an air quality point of view this rule would achieve greater NOx reductions than the proposal, economic impacts of this alternative would render its application infeasible.

It also should be noted that the Ventura County Air Pollution Control District did not adopt a rule to control NOx emissions from power plants similar to Rule 475.1 adopted by the SCAQMD. Therefore, for consistency, the Board would have to consider adopting a similar rule for the VCAPCD.

Alternative 5: Amend Rules 1135.1 and 59.1 as proposed.

CONCLUSION

The Board finds that Alternative 5 is the most desirable of the alternatives listed.

Alternative 5 offers the potential of reducing emissions of NOx in the South Coast Air Shed by an amount nearly equivalent to the reductions that would result from the current versions of Rules 1135.1 and 59.1, while effectively lessening the significant environmental concerns raised by SCE and LADWP. This conclusion is based on the following:

1. The requirements of the amended Rules are clear, easily understood, and not subject to uncertainty.

2. The amended Rules require the utilities to install controls only on units that are certain to be in use as base-load units through 1990, and units which will have high capacity factors under <u>any</u> realistic oil and gas reduction scenario likely to occur.

3. The emission reductions resulting from implementing the amended Rules are needed to attain and maintain the state and national ambient air quality standards for nitrogen dioxide and total suspended particulate matter in the South Coast Air Basin, and for nitrogen dioxide, total suspended particulate matter, and ozone in the Ventura County Air Pollution Control District. These reductions are also needed to attain and maintain the state visibility standard.

4. Compliance with the amended rules can be achieved through installation of SCR on a limited number of units.

In addition, weakening of the rules would only partially mitigate the environmental concerns raised, while creating new, more serious concerns (e.g., increases in NOx emissions or NH_3). Most of the environmental concerns raised have been determined not to pose significant problems. Further, all legitimate concerns can be mitigated. The mitigation measures identified are either within the jurisdiction of other agencies, which are currently regulating the subject utilities, or are within the direct control of the utilities that raised the concerns. Further, the utilities have an economic interest in assuring that the measures are carried out. Finally, for the reasons identified in items 1 through 4 above, Alternative 5 will result in fewer potential adverse environmental impacts compared to Alternative 1, the no action alternative.

State of California
AIR RESOURCES BOARD

Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants

ARB Compliance with the California Environmental Quality Act (CEQA)

The following discussion is intended to explain how the ARB assures that any possible adverse environmental effects of its proposed actions will be identified and mitigated. As an environmental protection agency, the ARB is not required to prepare an Environmental Impact Report (EIR) on this project, but other written documentation prepared by the agency must describe the proposed activity with alternatives to the activity and mitigation measures to minimize any significant adverse environmental impact. Further, regulations adopted by the ARB require that the action will not be adopted by the Board as proposed if there are feasible alternatives or feasible mitigation measures which would substantially lessen any significant adverse impact of the activity on the environment. ARB regulations also require that prior to taking final action, the Board must respond in writing to significant environmental points raised during the evaluation process. Finally, CEQA requires that the ARB not adopt the activity for which significant adverse effects have been identified unless one or more of the following findings are made:

1. That changes have been incorporated into the project which mitigate the significant environmental impacts.

2. That such mitigation measures are within the responsibility and jurisdiction of another public agency and have been (or can and should be) adopted by such other agency.

3. That specific economic, social, or other considerations make the mitigation measures or alternatives infeasible.

Consequently, the ARB staff report discusses several possible environmental impacts of the proposed rule. Several other concerns were raised during the hearing process. These are identified and discussed in the following section. In addition, mitigation measures which could minimize any impacts found to be significant are examined, as are alternatives to the proposed action. In this case, since the proposal is the amendment of certain rules already in existence, the "no project" alternative is for the Board to take no action and to leave the current rules in place. Other alternatives discussed are the repeal of the subject rules in their entirety, amending the rules to be less stringent, and restoring the Districts' original Rules.

The Board, prior to taking final action, has adopted the attached responses to significant environmental issues. Further, in adopting the activity itself, the Board, in its resolution, has made findings relating to each significant environmental issue raised, either incorporating feasible mitigation measures and alternatives into the rules, indicating that other agencies are responsible for mitigation of these effects, or indicating the factors which prevent the imposition of mitigation measures or alternatives. If future experience reveals adverse environmental impacts not reasonably anticipated, corrective action can be taken by the Air Resources Board or other appropriate agency (e.g., the local air pollution control districts which will be implementing any adopted rule) to mitigate such effects.

State of California
AIR RESOURCES BOARD

Response to Significant Environmental Issues

Item: Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants

Public Hearing Dates: November 5, 6, 13, and December 2, 3, 18, 1980

Response Date: December 18, 1980

Issuing Authority: Air Resources Board

Introduction: Southern California Edison (SCE) and the Los Angeles Department of Water and Power (LADWP) have raised several concerns which they believe were not adequately addressed by the Air Resources Board (ARB) staff in the September 1980 report. Since the discussion of many of the issues raised by the utilities assumes an understanding of the selective catalytic reduction (SCR) process, it is appropriate to explain briefly the operation and performance of the process involved.

The utilities are being required to reduce NOx emissions on some of their steam generating boilers by 80 percent. This requirement will probably be satisfied by retrofitting utility boilers with the selective catalytic reduction (SCR) system to control oxides of nitrogen (NOx) emissions. The technology takes advantage of the preferential reaction of ammonia (NH_3) with NOx rather than with other flue gas constituents. Since oxygen (O_2) enhances the reduction, the reaction can be best expressed as

$$4NH_3 + 4NO + O_2 \longrightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \longrightarrow 3N_2 + 6H_2O \qquad (2)$$

Equation 1 represents the predominate reaction since approximately 95 percent of the NOx in combustion flue gas is in the form of nitric oxide (NO). Therefore, under ideal conditions a stoichiometric amount of NH_3 can be used to reduce NOx to harmless molecular nitrogen (N_2) and water vapor (H_2O).

In practice, an NH_3:NO mole ratio of about 1:1 has typically reduced NO emissions by 90 percent with a residual NH_3 concentration (also called "ammonia breakthrough") of less than 10 ppm. (1)*

The SCR process requires other auxiliary equipment such as a reactor, a catalyst, ammonia storage facilities and ammonia injection systems.

The optimum temperature for the NOx reduction reaction without a catalyst is about 1800°F. However, the catalyst effectively reduces the optimum reaction temperature to approximately 600°F to 850°F.

*See reference list page 14.

Catalysts may be made with different chemical compounds; those with vanadium (V) compounds were found to promote the reduction of NOx with NH_3 and to be unaffected by the presence of sulfur oxides (SOx), another exhaust gas component which could interfere with the desirable reaction. (2)

Titanium dioxide (TiO_2) was found to be an acceptable carrier, since it is resistant to attack from SO_3. (2) Therefore, many SOx resistant catalysts are based on TiO_2 and vanadium pentoxide (V_2O_5).

The life of the catalyst depends upon the type of flue gases it is being used to treat. The catalysts to be used on power plants in the South Coast Air Basin should last for 2 years or longer. (3) Also, because of oil firing, catalysts will be most likely of the parallel flow type. It may have one of many shapes such as parallel plate, parallel tube or honeycomb type. It may be made of ceramic material such as TiO_2 or metal.

The catalyst may be of homogenous or of coated variety. In essence, the type of the catalyst to be used in the power plant depends upon the user and the process vendor. Figure 1 shows as an example of how, typically, a honeycomb type catalyst would be placed in a reactor. When the catalyst loses its reactivity, it is replaced.

The above explanation briefly summarizes the control methods that will likely be employed to retrofit the utility boilers to comply with Rules 1135.1 and 59.1. The discussion that follows addresses the concerns raised by SCE and LADWP and the Board's response to those concerns.

Comment 1: The LADWP has expressed concerns that disposal of spent catalyst in an environmentally sound manner is an unresolved problem and that because of the presence of vanadium in the catalyst, special disposal or reclamation methods will be required.

Response: The application of selective catalytic reduction to a total of 4432 MW of power plant capacity, as required to fully comply with Rules 1135.1 and 59.1, is expected to result in the use of about 1100 tons of catalyst per year.[1] The exact type and composition of catalyst would depend on the process vendor and the user, but typically a parallel flow, honeycomb type catalyst would contain V_2O_5 and titanium dioxide (TiO_2).

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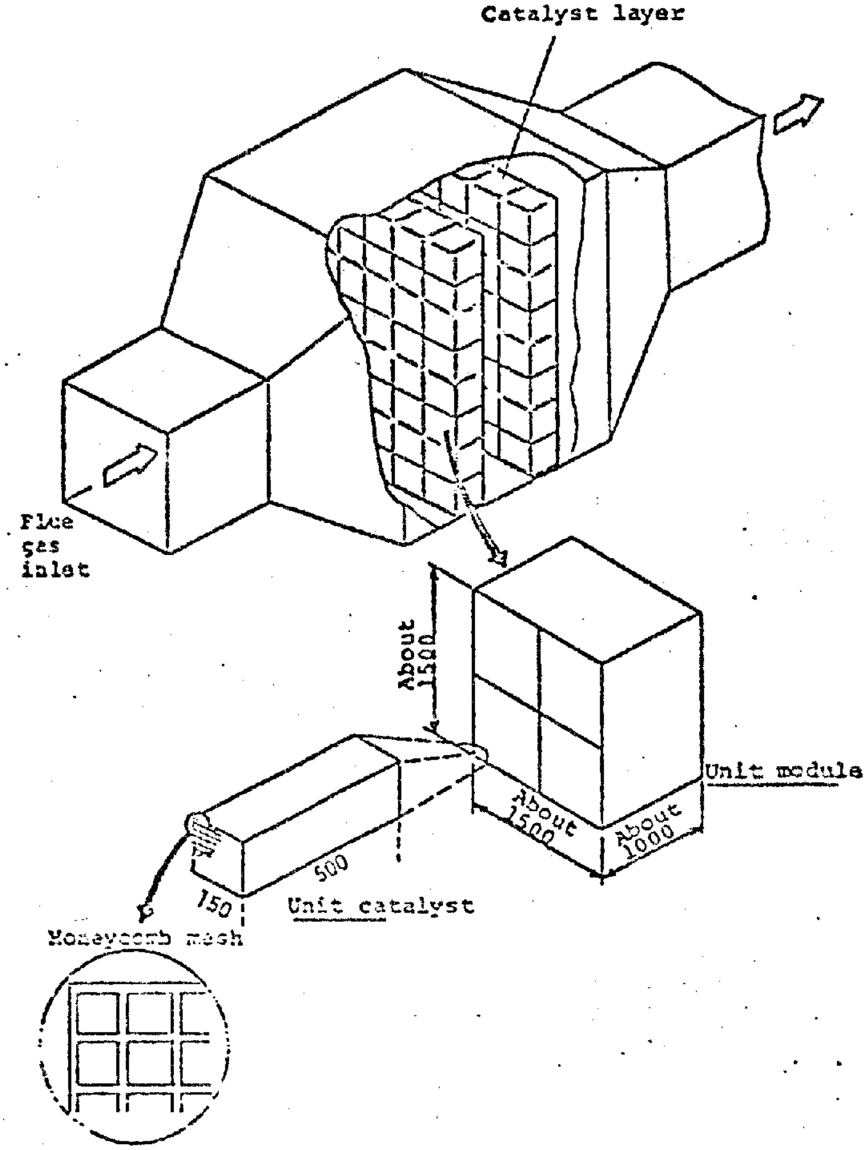
1. This estimate follows from a total generating capacity required to be controlled of 4432 megawatts (MW) and SCE's estimate (4) that control of its units larger than 175 MW (total of 24 units having 7720 MW) would require 1860 tons per year of catalyst, assuming a two year catalyst life:

$$4432 \text{ MW} \quad \times \quad \frac{1860 \text{ tons of catalyst/yr}}{7720 \text{ MW}} = 1068 \text{ tons catalyst/yr}$$

Based on commercial operating experience to date on SCR installations in Japan in which catalyst deterioration has not been significant (3) catalyst lifetimes are expected to equal or exceed 2 years with fuel oil firing and 3 years with natural gas firing. Requirements for catalyst are inversely related to catalyst lifetime, hence a catalyst lifetime of 3 years corresponds to a catalyst requirement of about 712 tons per year.



Example of a fixed bed reactor with honeycomb type catalyst (Ishikawajima-Harima Heavy Industries; sizes are in mm).

Source: J. Ando. NOx Attachment for Stationary Sources in Japan. August 1979.

Depending upon the specific type and material of the catalyst selected, valuable components may be recovered for reuse, just as used or "spent" automotive exhaust catalysts and refinery process catalysts are normally amenable to recovery or reprocessing prior to disposal. To the extent that spent catalyst cannot be recovered, and constitutes a potentially hazardous waste[2], treatment and/or disposal at a Class I or Class II-1 (hazardous waste) disposal site may be required. In such a worst case, the increment of potential hazardous waste generation due to Rules 1135.1 and 59.1 would be about 1100 tons per year, as compared with the current rate of generation of hazardous wastes in California of approximately 11,000,000 tons per year (5). Thus, full implementation of Rules 1135.1 and 59.1 is not expected to increase the production of potentially hazardous waste in California by more than about 0.01 percent, even in the worst case.

Mitigation of the above increments of hazardous waste disposal is accomplished by regulation of liquid and solid hazardous waste disposal in California by the State Water Resources Control Board (and Regional Boards), the Department of Health Services, and the Solid Waste Management Board. Through a system of hazardous waste generation reporting by the industry, and regulation by the above agencies to ensure environmentally sound disposal, the problem of hazardous waste disposal associated with the Board's action will be mitigated in the same manner as is the disposal of other toxic wastes.

Comment 2: Southern California Edison has expressed concerns that some of the toxic metals from catalysts that may be used in the SCR process can be released into the environment.

Response: The Board has received no evidence which demonstrates that catalysts which are used in the SCR process, as applied to oil or gas fired units to comply with Rules 1135.1 and 59.1, would result in significant increases in emissions of vanadium (V) or other potentially toxic metals from power plants.

Vanadium is a natural constituent of crude oil and is also contained in significant amounts in the (refined) residual oil burned in power plants in the South Coast Air Basin and Ventura County. (6) Thus, at the present time, combustion of fuel oil in the South Coast Air Basin and Ventura County is believed to result in significant release of vanadium into the environment. Based on data provided by SCE (6), and assuming 50 million barrels of oil per year burned in power plants (the minimum amount of oil burned by all utilities in any recent year), vanadium emissions are estimated to be about 120 tons per year[3] at the present time, i.e. absent further controls.

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2. Depending upon the specific composition of the catalyst selected, "spent" catalyst may or may not be classified as a hazardous waste.

3. $$\frac{50 \times 10^{6}\,\text{BBLS}}{\text{year}} \times \frac{320\ \text{lbs}}{\text{BBL}} \times \frac{15 \times 10^{-6}\ \text{lbs V}}{\text{lb fuel oil}} \times \frac{\text{ton}}{2000\ \text{lbs}} = \frac{120\ \text{tons V}}{\text{yr}}$$

If this amount of vanadium is expressed as V_2O_5, an oxidized form, the amount of V_2O_5 is

$$\frac{120\ \text{tons V}}{\text{year}} \times \frac{182\ \text{tons}\ V_2O_5}{51\ \text{tons of V}} = 429\ \text{tons}\ V_2O_5/\text{yr}.$$

The Board is not aware of any other source of vanadium emissions, due to fuel burning, SCR, or any other source, which is larger than the above current emissions from power plants. Furthermore, the Board is not aware of any data which show that the retrofit of SCR to an oil or gas fired power plant would result in significantly increased emissions of vanadium or other components of the catalyst. To the contrary, available information from Japan indicates good catalyst performance over long periods (in excess of 2 years), suggesting that vanadium, the principal active component in the catalyst bed, remains essentially intact and continues to perform at, or near, full design efficiency. (3) Vanadium or vanadium compounds could potentially present risks as toxic compounds at elevated levels of human exposure; however, such compounds have not been identified as high priority toxic compounds at the present time,(9, 10) and evidence received by the Board does not support the concern that Rules 1135.1 and 59.1 would result in significant environmental impacts. If vanadium or vanadium compounds are identified as a significant threat or potential threat to human health or the environment at some future time, such compound(s) would be regulated in accordance with the statewide programs to control airborne toxic substances, including existing and future ARB and local district programs.

Comment 3: Southern California Edison has raised concerns that nitrosamines can be formed as a result of ammonia injection in flue gases for Thermal DeNOx and SCR processes.

Response: Representatives of SCE testified that with a model system using a propane/air flame, they have found a potential for formation of nitrosamines when ammonia is injected in the flue gases. Subsequent testimony by SCE indicated that the company's concerns regarding the formation of nitrosamines was based on injection of ammonia in a propane enriched flame. However, this situation would occur only during a boiler upset condition. It is standard operating practice at the present time to avoid any such possible upsets in order to ensure system safety and reliability. Consequently, since the utility boilers are carefully operated with excess air and are not fuel enriched, the hydrocarbon radical (essential to the formation of nitrosamines) would be completely oxidized and would not be available for the formation of nitrosamines in the presence of ammonia. Thus, no nitrosamines are expected to be formed if ammonia is injected in a normal operating mode of an electric utility boiler. Mitigation of possible impacts during boiler upset conditions consists of the utilities continuing current standard operating practices to avoid unsafe fuel-rich operation of a boiler.

Comment 4: LADWP has raised concerns regarding ammonia breakthrough to the atmosphere as a result of its injection in the noncatalytic and catalytic deNOx methods.

Response: As explained in the introduction, ammonia (NH_3) is injected in the flue gases to reduce NOx emissions through chemical reactions leading to the formation of harmless materials. Ideally, a stoichiometric (chemically correct) amount of NH_3 can be used to reduce 100 percent of the NOx to harmless molecular nitrogen and water vapor, with no ammonia breakthrough. However, in practice, the stoichiometric NH_3:NO mole ratio of 1:1, in the presence of a catalyst, will typically reduce NOx emissions by 90 percent with a residual NH_3 concentration of less than 10 parts per million (ppm). (1) In processes which reduce NOx without use of a catalyst, higher NH_3:NO mole ratios may be required for less than 90 percent reduction, resulting in slightly higher residual NH_3.

This residual NH_3 is commonly known as "NH_3 slip", "breakthrough", "carryover", or "release". This ammonia breakthrough is minimized by optimizing the design and operation of the catalytic and noncatalytic deNOx processes, as illustrated by the attached Figure 2. The attached figure shows that an SCR system, when operated for 90 percent NOx removal efficiency, is expected to result in NH_3 breakthrough in the range of 5-10 ppm in stack gases. However, SCR systems which are designed and operated for 80 percent NOx removal efficiency are expected to result in stack gas concentrations of less than 5 ppm of NH_3 carryover. As discussed in the ARB Staff Report of September 19, 1980 (7), ground level NH_3 concentrations at the point of maximum plume impact would be expected to be 1/1000 of the stack concentrations, resulting in ground level NH_3 concentrations below natural background levels and far below the level of any adverse health impacts which have been identified.

Because optimum operation of an SCR system to reduce NH_3 breakthrough would also minimize the consumption of NH_3 and the deposition of NH_3-based reaction products on components such as air preheaters, system design and operation to minimize NH_3 carryover is also in the economic interest of the system owner/operator, as this would minimize operating and maintenance expenditures. Thus, any remaining impact of NH_3 breakthrough would be fully mitigated by the utilities by system design and operation to minimize NH_3 emissions.

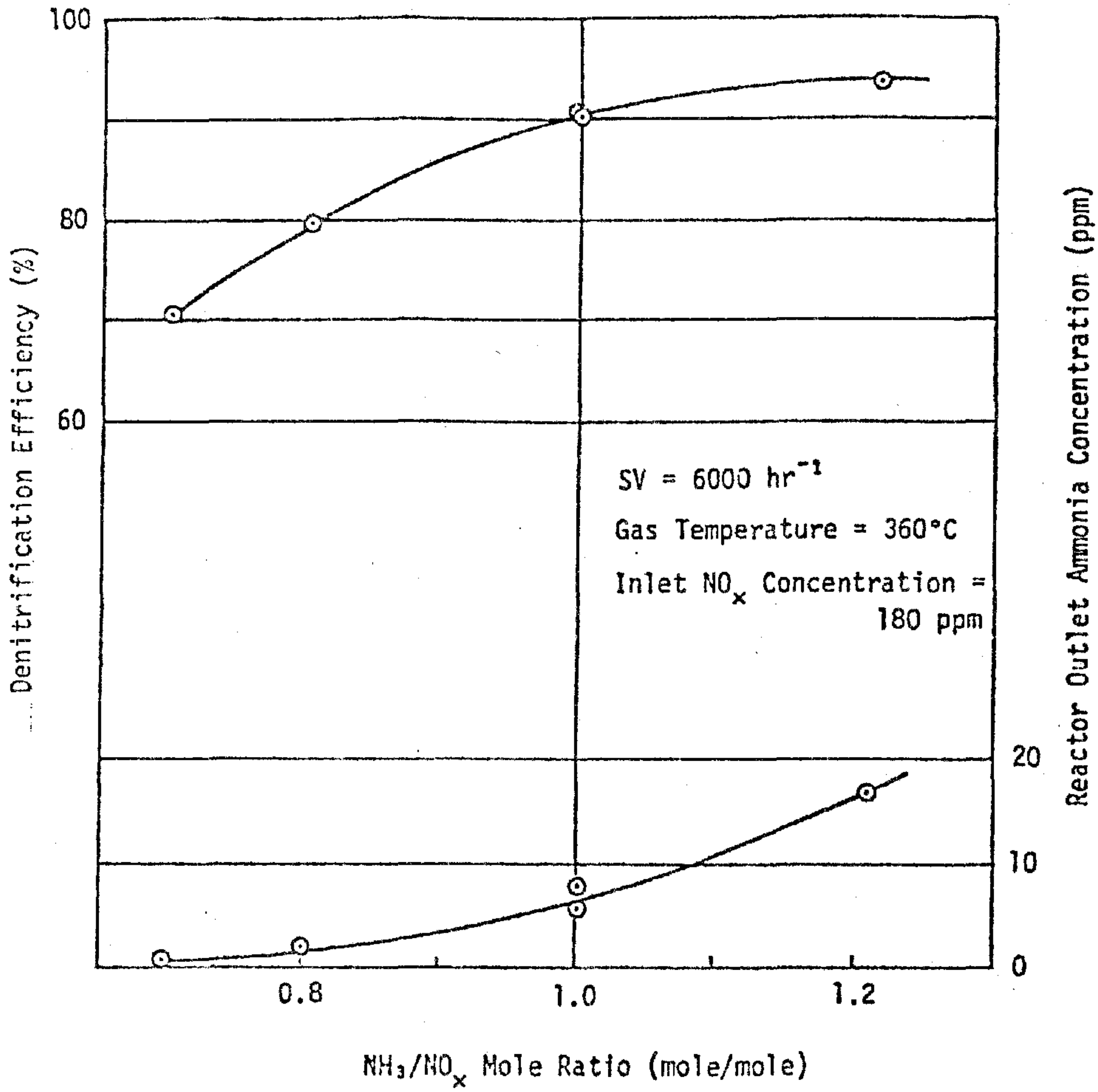
Comment 5: LADWP has expressed concerns that SCR systems promote the oxidation of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) and that therefore the total sulfate concentration in the flue gas would be increased by the proposed rules. Furthermore, LADWP believes that increased sulfate emissions may adversely affect our ability to attain and maintain applicable ambient air quality standards and the public health and welfare which these standards are designed to protect.

Response: As explained in the introduction, SCR systems are used to facilitate NOx emission control. In addition to the two chemical reactions that convert NOx to N_2 and H_2O (see introduction), a third reaction also occurs, simultaneously. This third reaction is the oxidation of sulfur dioxide, a compound produced during the combusion of any fuel containing sulfur, to sulfur trioxide, and can be expressed as follows:

$$2\ SO_2 + O_2 \longrightarrow 2\ SO_3 \qquad (3)$$

In the absence of an SCR system, this reaction will occur naturally in the atmosphere, but at a slower rate. Because of the corrosive nature of SO_3 and its potential to combine with NH_3 to form ammonium sulfates and other potentially condensible compounds most of the process vendors have improved their catalysts to minimize the conversion of SO_2 to SO_3. SCR systems which are currently in use convert from 1.5 to 2.5 percent or higher of SO_2 to SO_3 (1) whereas new catalysts are developed and tested to suppress conversion to less than one-half percent of the SO_2 to SO_3. (4) As in the case of the minimization of NH_3 breakthrough, the minimization of SO_3 formation is also in the economic interest of utilities, since it would minimize maintenance costs. Consequently, utilities can design SCR systems using catalysts which minimize SO_3 formation to substantially mitigate any potential adverse impacts of SCR on sulfate emissions.

Figure 2



NH_3/NO_x mole ratio versus denitrification efficiency versus reactor outlet ammonia concentration for the honeycomb catalyst at Taketoyo Power Station.

Source: Reference 1.

Comment 6: LADWP has expressed concerns that the use of enough ammonia to effect a 90 percent NOx emission removal could result in the formation of ammonium sulfate ($(NH_4)_2SO_4$) and ammonium bisulfate (NH_4HSO_4) deposits which could foul the air preheater. Furthermore, LADWP believes that aerosols of these compounds could cause environmental problems, and their presence in the stack plume may cause opacity problems due to the presence of condensed particles.

Response: The formation of ammonium sulfate and ammonium bisulfate depends upon the concentrations of NH_3 and SO_3 in flue gas and also on the temperature of the flue gas. Ammonium bisulfate is formed as a result of the reaction between NH_3, SO_3, and water vapor as described in the following reaction:

$$NH_3\ (\text{gas}) + SO_3\ (\text{gas}) + H_2O\ (\text{gas}) \longrightarrow NH_4HSO_4\ (\text{liquid})$$

In the presence of excess ammonia, ammonium bisulfate may further react to form ammonium sulfate (solid) as follows:

$$NH_4HSO_4\ (\text{liquid}) + NH_3\ (\text{gas}) \longrightarrow (NH_4)_2SO_4\ (\text{solid})$$

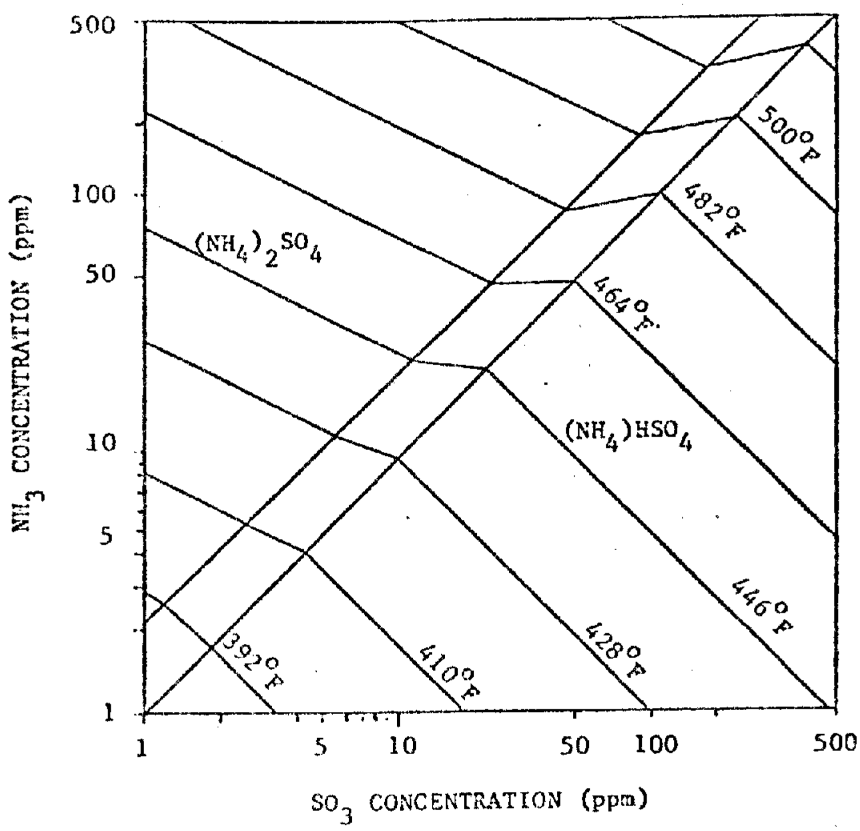
The conditions under which these compounds will be formed are shown in Figure 3.

As can be seen in Figure 3, actions which reduce both NH_3 carryover concentrations and SO_3 concentrations (as discussed in the responses to comments 4 and 5) will also result in lower temperatures of formation of ammonia-sulfur compounds, and thus would be expected to reduce the formation of such compounds. As discussed above, these actions, both individually and collectively, are expected to reduce potential operating and maintenance costs to the utilities. Therefore, minimization of NH_3 carryover concentrations and SO_3 concentrations are available mitigation actions which are expected to be fully implemented by the utilities and are in the economic interests of the utilities.

With regard to potential opacity problems, of the more than seventy commercial installations operating with SCR in Japan (7), the Board is unaware of any data noting opacity problems on any of these units. Furthermore, opacity (the darkness and visibility of stack emissions) is regulated by state law (Health and Safety Code Section 41701) and local air pollution control district regulations, and any adverse impacts will have to be mitigated by the utilities pursuant to these requirements.

Comment 7: LADWP has expressed concerns that ammonium sulfates formed as a result of the SCR process may produce deposits on the air preheater and force more frequent washings than would otherwise occur. An air preheater wash will create a large volume of waste water for disposal. LADWP estimates that depending upon the washing period, the additional waste water may range from 300,000 to 1,000,000 gallons and is concerned about the potential adverse environmental impact of disposal of such waste water. (LADWP did not specify whether the additional waste water use was projected on an annual basis or for some other time period.)

Figure 3



FORMATION OF AMMONIUM SULFATE
HIGH TEMPERATURE RANGE

Source: D.R. Swann, G.D. Drissel. Feasibility of Retrofitting Catalytic Post Combustion NOx Controls on an 80 MW Coal-Fired Utility Boiler. February 1980 (8)

Response: The LADWP estimate apparently applies to an annual generation rate for waste water under the assumption that 11 of its units, comprising 2593 MW, would be required to install SCR units designed for 90 percent NOx removal. The final version of Rules 1135.1 and 59.1 requires that only 3 units of LADWP, comprising 912 MW, would be required to be retrofit with SCR designed for 80 percent NOx removal. Consequently, the actual quantities of additional waste water generated due to the adopted rules will be significantly less than that estimated by LADWP. Furthermore, as explained above, the potential for formation of ammonium compounds can be minimized by techniques which are in the economic interest of utilities and which minimize NH_3 breakthrough emissions as well as the conversion of SO_2 to SO_3.

In addition, because air preheaters are periodically washed at the present time (without SCR installed), any additional waste water generated would be treated and disposed of in a manner similar to that currently used, and in accordance with requirements imposed by the State and Regional Water Quality Control Boards. Accordingly, any potential adverse environmental effects due to additional waste water disposal would thus be mitigated in accordance with regulations of those agencies having jurisdiction over water quality.

Comment 8: SCE expressed concerns regarding potential hazards of ammonia storage, handling, and transport and the possibility of accidental releases of ammonia. LADWP also expressed concerns regarding storage of ammonia.

Response: In order to evaluate the potential hazards of ammonia storage, handling and transportation, the ammonia-related hazardous materials incidents have been compared to all the hazardous materials incidents[4] in the U.S. in 1978. In addition, the amount of NH_3 required as a result of Rules 1135.1 and 59.1 is small compared with national statistics for ammonia shipments.

Table 1 compares ammonia related incidents with all hazardous materials incidents in the U.S. in 1978. As shown in this table, shipment of about 9 million tons of ammonia in 1978 resulted in spillage of about 188 tons (0.002%) in 95 incidents. These incidents resulted in 2 deaths, 58 injuries, and $98,000 in damages. By comparison, all hazardous materials incidents, totalling 17,750 in 1978 resulted in 46 deaths, 1072 injuries, and $16 million in damage. Table 1 also compares ammonia requirements of Rules 1135.1 and 59.1 with national average shipments and data on incidents. These data suggest a relatively low probability of incidents with relatively very low or negligible expected impacts.

Table 2 shows that the mean mortality index for ammonia is 0.02 as compared to the mean mortality index of hydrocarbons which ranges from 0.1-0.6. These data indicate that ammonia, which is commonly used in many household, commercial and industrial cleaning applications and which is used in agriculture in significant

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4. A hazardous materials incident is defined in 49 CFR 171.15 (1977) according to criteria established by the U.S. Department of Transportation. Basically, these criteria include: accidental deaths or injuries, property damage in excess of $50,000, or other specified damages.

TABLE 1

ANHYDROUS AMMONIA STATISTICS

Total amounts of shipments of anhydrous ammonia in the U.S. in 1978		8.7 million tons
Total amount spilled of those shipments in the U.S. in 1978		188 tons
Statistics of the 17,750 incidents* in 1978 in the U.S.	Deaths Injuries Damages	46 1072 $16 million
Statistics of the 95 incidents involving anhydrous ammonia in 1978 in the U.S.	Deaths Injuries Damages	2 58 $98,000
Total amount of anhydrous ammonia used by agriculture in the U.S. in 1978		4.5 million tons
Total amount of anhydrous ammonia required to comply with the Rules		15,000 tons per year

*An incident is as defined in 49 CFR 171.15 (1977).

Source: U.S. Department of Transportation, National Fertilizer Association and ARB/SSCD

TABLE 2

ESTIMATE OF MEAN MORTALITY INDEX OF AMMONIA
AND ITS COMPARISON WITH OTHER GASES

LOCATION	DATE	AREA/SITE	SOURCE OF LEAKAGE	QUANTITY METRIC TON	NUMBER OF FATALITIES
Floral, Ark.	June 5, 1971	Rural	Pipeline	600 tons	0
Enid, Oklahoma	May 7, 1976	Urban	Pipeline	500	0
Conway, Kansas	December 6, 1973	Rural	Pipeline	277	0
Landskrona, Sweden	January 16, 1976	Port	Ship-storage connection	180	2
Blair, Nebraska	November 15, 1970	Rural	Storage tank	160	0
Crete, Nebraska	February 18, 1969	Urban	Rail tanker	90	9
Belle, West Va.	January 21, 1970	Urban	Rail tanker	75	0
Texas, Tx City	September 13, 1975	Urban	Pipeline	50	0
Potschefstroom, South Africa	July 13, 1973	Urban	Storage tank	38	18+
Houston, Texas	November 15, 1976	Urban	Road tanker	19	6
Lievin, France	August 21, 1968	Urban	Road tanker	19	6

$$\text{Mean mortality index} = \frac{\text{total number fatalities}}{\text{total amount lost}}$$

$$= \frac{41}{2008}$$

$$= 0.02$$

+Without this incident the mean mortality index = 0.01

Mean mortality index of chlorine = 0.3
" " " of flammable gases or vapor = 0.1 -0.6
" " " of Ammonium Nitrate = 0.1

Source: A report on Major Hazards by Advisors Committee, Health and Safety Commission, Great Britain, 1979.

quantities, is not particularly dangerous when handled with proper caution. Accordingly, mitigation measures expected to be taken by utilities to ensure minimization of potential hazards due to ammonia spillage, which would consist of implementation of standard safe operating practices for potentially hazardous materials, are expected to reduce potential hazards to very low or negligible levels.

Comment 9: LADWP, in its written testimony, expressed concerns regarding formation of hydrogen cyanide (HCN) by ammonia injection.

Response: Brown and Sawyer were not able to detect either HCN or other nitrogenous species (other than NOx, NH_3, or N_2) in the stack gas from a laboratory combustor burning No. 1 diesel doped with pyridine. (Quarterly Progress Report for ARB Contract A8-146-31 for 1 May - 1 July 1980). Based upon minimum detection limits associated with the various analytical procedures used, Brown and Sawyer estimated conservative upper limit concentration values of 5 ppm for all nitrogenous species (other than NOx, NH_3, and N_2) and 1 ppm for HCN in the laboratory combustor stack gas.

These data, taken along with SCE's and ARB's tracer studies, which show that emissions from tall stacks are diluted by a factor of 10^{-4} to 10^{-6} (7), show that the maximum surface level concentration of all nitrogenous species (other than NOx, NH_3, and N_2) is in the range of 5 to 500 parts per trillion and 1 to 100 parts per trillion for HCN, and may be substantially less.

A threshold limit value (TLV) of 10 parts per million has been designated for hydrogen cyanide (HCN), according to Multimedia Environmental Goals for Environmental Assessment, Volume II, MEG Charts and Background Information, J.G. Cleland and G.L. Kingsbury, November, 1977; EPA-600/7-77-136b. The ambient level goal recommended in that same work is 24 parts per billion, based on health effects. Documentation of the Threshold Limit Values for Substances in Workplace Air, (American Conference of Governmental Industrial Hygienists, Third Edition 1971), shows that the TLV of 10 parts per million "contains a two-fold margin of safety against mild symptoms of HCN response."

Thus, according to the test data, the highest ambient concentration expected would be a factor of more than 200 below EPA recommended environmental goals for the atmosphere.

Comment 10: SCE expressed concern that the Board's action would exacerbate ozone and oxidant air quality problems in the South Coast Air Basin.

Response: This concern is dealt with at length in the Board's Findings and Basis for decision, which is incorporated by reference herein.

CERTIFIED: Sally Rump
Sally Rump
Board Secretary

Date: Dec 23, 1980

References

1. Dr. Jumpei Ando, NOx Abatement for Stationary Sources in Japan, rpt. (Japan: Chou University, August 1979).

2. Proceedings of the Joint Symposium on Stationary Combustion NOx Control, Volume II, Utility Boiler NOx Control by Flue Gas Treatment, "Assessment of NOx Flue Gas Treatment Technology" by J. D. Moholey, U.S. EPA, IERL-RTP-1084, October 1980.

3. Sengoku Tadamasa, et al, The Development of a Catalytic NOx Reduction System For Coal-Fired Steam Generators (Tokyo, Japan; Mitsubishi Heavy Industries, October 6-9, 1980).

4. Proceedings of the Joint Symposium on Stationary Combustion NOx Control, Volume II, Utility Boiler NOx Control by Flue Gas Treatment, "Status of SCR Retrofit at Southern California Edison Huntington Beach Generating Station Unit 2", L. Johnson et al; U.S. EPA IERL-RTP-1084 October 1980.

5. Solid Waste Management in California: A Status Report, State of California, Solid Waste Management Board, February 1980.

6. A document from SCE titled "Emission of Vanadium and Organics from SCE Oil-Fired Generating Stations," November 24, 1980.

7. The Air Resources Board staff report entitled "Public Hearing to Reconsider Rule 1135.1 of the South Coast Air Quality Management District and Rule 59.1 of the Ventura County Air Pollution Control District Controlling Emissions of Oxides of Nitrogen from Power Plants." (September 1980)

8. D. R. Swann, G. D. Drissel. Feasibility of Retrofitting Catalytic Post Combustion NOx Controls on an 80 MW Coal-Fired Utility Boiler, rpt. (Denver, Colorado: Stearns-Roger Inc., February 1980).

9. State of California Air Resources Board Final Report of the Ad Hoc Panel on Atmospheric Carcinogens, April 1979.

10. Science Applications, Inc., Vol. I., Final Report, An Inventory of Carcinogenic Substances Released Into the Ambient Air of California, February 1979.

Alternatives

There are five basic alternatives which the Board could adopt in reconsidering SCAQMD Rule 1135.1 and VCAPCD Rule 59.1. Following are descriptions and discussions of these alternatives.

Alternative 1: Take no action; that is, the "no project" alternative. This alternative would, in effect, reaffirm the versions of SCAQMD Rule 1135.1 and VCAPCD Rule 59.1, currently stayed, both of which the Board adopted on March 27, 1980. This alternative would neither prevent nor mitigate the environmental and other concerns raised by the petitioner, SCE, and LADWP, the intervenor. It is with regard to the existing versions of these two rules that the environmental questions have been raised.

Alternative 2: Rescind SCAQMD Rule 1135.1 and VCAPCD 59.1. Under this alternative, further NOx emission reductions would not be required, and power plants would continue to be subject to the control prescribed by SCAQMD Rule 464 (125-225 ppm for gas-fired units and 225-325 ppm for oil-fired units) and by a comparable VCAPCD rule. Although this alternative would eliminate the concerns raised by SCE and LADWP, it would forego emission reductions of almost 60 tons per day of NOx by 1990. Currently, NOx emissions from stationary sources in the South Coast Air Shed are slightly over 450 tons per day. The nonattainment area plans for the South Coast Air Basin and the Ventura County Air Pollution Control District rely on these emission reductions to attain and maintain the national ambient air quality standards for nitrogen dioxide and suspended particulate matter and, in the case of Ventura, for ozone as well. Also, such reductions in the emissions of NOx are necessary if the state ambient air quality standards for nitrogen dioxide, suspended particulate matter, and visibility are to be attained and maintained. If those standards are not attained and maintained, the adverse effects on the public health and welfare that the standards are intended to prevent will not be prevented.

Because the federal Clean Air Act and the California Health and Safety Code require that the ambient air quality standards be attained and maintained in order to protect public health and welfare, withdrawal of Rules 1135.1 and 59.1 would require that new measures be adopted to effect equivalent reductions from other sources. That is, NOx control measures would have to be adopted for sources for which control methods have not yet been identified, or for which controls cost more for each pound of NOx reduction than those required by Rules 1135.1 and 59.1. Since all of the significant adverse environmental effects expected to result from the proposal can be mitigated, the benefit of achieving the 60 tons per day NOx emission reductions by controlling power plants is preferable to controlling other sources at this time because control of other sources may be accompanied by unknown environmental impacts.

If other, more costly or unidentified rules were not quickly adopted, this alternative would be inconsistent with state and federal laws, and would result in pollutant concentrations in the South Coast Air Shed which would be detrimental to the public health and welfare. This alternative is therefore infeasible, with significant adverse impacts on the environment.

Alternative 3: Amend Rules 1135.1 and 59.1 to be less stringent. Concerns raised by SCE and LADWP (such as increased environmental burdens of heavy metals from catalysts and emissions of ammonia) could be partially mitigated by making the existing rules less stringent. Although this alternative would still provide some cost-effective reductions in emissions of NOx, these emission reductions

would be less than the reductions that would result from the current rules. Therefore, the same problems discussed under Alternative 2 would apply, albeit to a lesser degree, to this alternative. Overall, the air quality benefit expected by implementation of the rules would be lost while the adverse impacts of the rules would not be commensurably reduced. This is especially true since all such impacts can be mitigated without loss of environmental benefits, or have been found not to be a problem.

Alternative 4: Rescind Rules 1135.1 and 59.1 and restore the South Coast Air Quality Management District's original Rule 475.1. This rule required a 90 percent reduction in emissions from every unit, a far more costly alternative since the utilities would not have the flexibility of selecting units to be controlled. This alternative would undoubtedly be unacceptable to SCE and LADWP because they petitioned the Board to set this rule aside in 1978. After hearing testimony on the rule, the Board found the rule to be inconsistent with Division 26 of the Health and Safety Code for several reasons and amended the rule on August 7, 1978. The Board found at that time that the rule imposed an unreasonable financial and engineering burden on the affected utilities and did not require best available technological and administrative practices. Nothing has changed in the interim to affect these findings; as a result, adoption of this alternative would result in a rule which would be in conflict with the Health and Safety Code. Furthermore, this alternative would exacerbate the environmental concerns raised by the two utilities. While from an air quality point of view this rule would achieve greater NOx reductions than the proposal, economic impacts of this alternative would render its application infeasible.

It also should be noted that the Ventura County Air Pollution Control District did not adopt a rule to control NOx emissions from power plants similar to Rule 475.1 adopted by the SCAQMD. Therefore, for consistency, the Board would have to consider adopting a similar rule for the VCAPCD.

Alternative 5: Amend Rules 1135.1 and 59.1 as proposed.

CONCLUSION

The Board finds that Alternative 5 is the most desirable of the alternatives listed.

Alternative 5 offers the potential of reducing emissions of NOx in the South Coast Air Shed by an amount nearly equivalent to the reductions that would result from the current versions of Rules 1135.1 and 59.1, while effectively lessening the significant environmental concerns raised by SCE and LADWP. This conclusion is based on the following:

1. The requirements of the amended Rules are clear, easily understood, and not subject to uncertainty.

2. The amended Rules require the utilities to install controls only on units that are certain to be in use as base-load units through 1990, and units which will have high capacity factors under any realistic oil and gas reduction scenario likely to occur.

3. The emission reductions resulting from implementing the amended Rules are needed to attain and maintain the state and national ambient air quality standards for nitrogen dioxide and total suspended particulate matter in the South Coast Air Basin, and for nitrogen dioxide, total suspended particulate matter, and ozone in the Ventura County Air Pollution Control District. These reductions are also needed to attain and maintain the state visibility standard.

4. Compliance with the amended rules can be achieved through installation of SCR on a limited number of units.

In addition, weakening of the rules would only partially mitigate the environmental concerns raised, while creating new, more serious concerns (e.g., increases in NOx emissions or NH_3). Most of the environmental concerns raised have been determined not to pose significant problems. Further, all legitimate concerns can be mitigated. The mitigation measures identified are either within the jurisdiction of other agencies, which are currently regulating the subject utilities, or are within the direct control of the utilities that raised the concerns. Further, the utilities have an economic interest in assuring that the measures are carried out. Finally, for the reasons identified in items 1 through 4 above, Alternative 5 will result in fewer potential adverse environmental impacts compared to Alternative 1, the no action alternative.

State of California

Memorandum

To : Huey D. Johnson
Secretary

Date : December 23, 1980

Subject : Filing of Notice of Decision of the Air Resources Board

From : **Air Resources Board**

Pursuant to Title 17, Section 60007(b), and in compliance with Air Resources Board certification under section 21080.5 of the Public Resources Code, the Air Resources Board hereby forwards for posting the attached notice of decision and response to environmental comments raised during the comment period.

Sally Rump

Sally Rump
BOARD SECRETARY

attach: Resolution 80-68
[redacted]

RECEIVED BY
Office of the Secretary
DEC 23 1980
Resources Agency of California

RECEIVED BY
Office of the Secretary

DEC 23 1980

Resources Agency of California

State of California
AIR RESOURCES BOARD

Resolution 80-69

December 18, 1980

WHEREAS, Health and Safety Code Section 39003 provides that the Air Resources Board (the "Board") is the state agency charged with coordinating efforts to attain and maintain ambient air quality standards;

WHEREAS, Health and Safety Code Section 39002 provides that local and regional authorities have the primary responsibility for control of air pollution from all sources other than vehicular sources, and provides further that the Board shall undertake control activities in any area wherein it determines that the local or regional authority has failed to meet the responsibilities given to it by Division 26 of the Health and Safety Code or any other provision of law;

WHEREAS, Health and Safety Code Section 39500 provides that it is the intent of the Legislature that the Board shall coordinate, encourage and review the efforts of all levels of government as they affect air quality;

WHEREAS, Health and Safety Code Section 39600 provides that the Board shall do such acts as may be necessary for the proper execution of the powers and duties granted to, and imposed upon, the Board by Division 26 of the Health and Safety Code and by any other provision of law;

WHEREAS, Health and Safety Code Section 39602 designates the Board as the air pollution control agency for all purposes set forth in federal law; and provides further that the Board is responsible for preparation of the state implementation plan required by the Clean Air Act, and to this end shall coordinate the activities of all districts necessary to comply with that Act;

WHEREAS, Health and Safety Code Section 39605 provides that the Board may provide any assistance to any district;

WHEREAS, Health and Safety Code Section 40001 provides that the local districts shall adopt and enforce rules and regulations which assure that reasonable provision is made to achieve and maintain the state ambient air quality standards and shall also endeavor to achieve and maintain the federal ambient air quality standards;

WHEREAS, Section 107(a) of the Clean Air Act provides that it is the responsibility of each state to assure air quality within the entire geographic area of the state;

WHEREAS, Section 110(a)(1) of the Clean Air Act requires that each state adopt a plan which provides for the implementation, maintenance, and enforcement of national primary ambient air quality standards within each air quality control region of the state;