AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

DATE: December 12, 1995

TO: Air Pollution Control Board

SUBJECT: Continued Public Hearing on Amendments to Rule 69 (Electrical Generating Steam Boilers, Replacement Units and New Units)

SUMMARY:

On November 14, 1995, the Air Pollution Control Board was scheduled to consider adopting changes to Rule 69 (Electrical Generating Steam Boilers, Replacement Units and New Units) proposed by San Diego Gas and Electric Company (SDG&E) to allow greater flexibility in complying with NOx emission control requirements. The amendments would have removed current oxides of nitrogen emission rate limits (e.g. 0.15 pounds of NOx per megawatt-hour of electricity produced) applicable to each utility boiler subject to the rule and instead required that annual oxides of nitrogen (NOx) emissions from all such boilers, as well as replacement units and new units under common ownership or control, be reduced to not more than 2100 tons per year starting in 1997, and not more than 800 tons per year starting in 2001. The hearing was continued to December 12 (2:00 p.m.) to resolve concerns expressed by the California Air Resources Board (ARB) regarding whether the proposed amendments represent Best Available Retrofit Control Technology as required by state law.

SDG&E, the ARB and the District have met and held conference calls. As a result, additional changes are proposed to make Rule 69 consistent with state Best Available Retrofit Control Technology requirements. These changes add an additional emission reduction requirement to the rule by specifying that annual NOx emissions from all utility boilers (including replacement units and new units under common ownership or control) be reduced to not more than 650 tons per year starting in 2005. This is in addition to the reduction requirements in the current rule of not more than 2100 tons per year starting in 1997 and not more than 800 tons per year starting in 2001. The ARB does not agree the 650 tons per year NOx limit guarantees SDG&E will implement Best Available Retrofit Control Technology but will withhold final judgment until SDG&E submits its required Compliance Plans.

The additional changes to the proposed amendments also require NOx control equipment be operated at maximum control performance at all times during boiler operation; delete the restriction that yearly NOx limits not be exceeded unless due to an unforeseen event or a disruption in the supply of imported power; and allow exceedances of annual NOx limits if the District has approved the exceedance in advance (and modified permits accordingly) and offsetting emission reductions are provided in advance at a 1.0 to 1.0 ratio. The changes also make minor revisions to Compliance Report requirements; add specified data recording requirements; and allow the banking of excess NOx emission reductions from any boilers subject to emission rate limits and not subject to annual NOx limits.

SDG&E, the only company currently affected, has estimated possible compliance cost savings from these amendments of up to $34 million. However, these savings are dependent upon future electrical generation levels and resources, and development and performance of less

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costly NOx emission controls. Rule 69 has not been submitted to the U.S. Environmental Protection Agency (EPA) for inclusion in the State Implementation Plan since it goes beyond federal requirements. Therefore, EPA is not involved with the proposed amendments.

The amendments are also consistent with the Board's direction of February 2, 1993 regarding implementation of new or revised regulations because amended Rule 69 satisfies the requirement for Best Available Retrofit Control Technology mandated by state law, and because the amendments have been requested by SDG&E.

Issue

Should the Board adopt the proposed amendments to Rule 69 (Electrical Generating Steam Boilers, Replacement Units and New Units) to meet the requirements of the California Clean Air Act for Best Available Retrofit Control Technology and provide SDG&E additional flexibility in meeting the emission reduction goals of the rule and the opportunity to significantly reduce the costs of implementing the rule.

Recommendation

AIR POLLUTION CONTROL OFFICER:

1. Adopt the resolution dated December 12, 1995 amending Rule 69 and make the appropriate findings:

   (i) of necessity, authority, clarity, consistency, non-duplication and reference, as required by Section 40727 of the State Health and Safety Code;

   (ii) that the amendments will alleviate a problem and will promote attainment of ambient air quality standards (Section 40001 of the State Health and Safety Code);

   (iii) that an assessment of socioeconomic impacts of the proposed amendments has been prepared and, after actively considering the socioeconomic impact of the proposed amendments in accordance with Section 40728.5 of the State Health and Safety Code, a finding be made that there will be no adverse socioeconomic impacts resulting from the adoption of the proposed amendments; and,

   (iv) that the proposed amendments to Rule 69 will not have a significant effect on the environment and that the proposed amendments are exempt from the requirements of the California Environmental Quality Act.

2. Direct the Air Pollution Control Officer to execute the proposed Memorandum of Understanding with San Diego Gas and Electric Company regarding indemnification of the District with regard to any litigation that may arise from adoption of the proposed amendments.

3. Direct the Air Pollution Control Officer to consider and recommend, if appropriate, future amendments to Rule 69 if the Air Pollution Control Officer finds that additional emission reductions from electrical generating steam boilers, replacement units and new units are achievable, are cost-effective and are necessary to further progress towards attainment of ambient air quality standards.

Advisory Statement

The Air Pollution Control District Advisory Committee recommended adopting the proposed amendments to Rule 69 at its October 25, 1995 meeting. The Committee also recommended that any additional changes which would be more inclusive or prescriptive be resisted. The Committee has not reviewed the changes made to Rule 69 after the October 25 meeting.

Fiscal Impact

Adopting the proposed amendments will have no fiscal impact on the District.

Alternatives

- Not adopt the proposed amendments. This alternative would retain current Rule 69 and require SDG&E to retrofit one electrical generating steam boiler to comply with the emission rate limits of the rule by 1997, and at least one additional boiler each calendar year thereafter. All affected boilers would be required to be retrofit by January 1, 2001 (except for specified circumstances), and annual NOx reduced to not more than 2100 tons per year starting in 1997 and not more than 800 tons per year starting in 2001. SDG&E has estimated that compliance with current Rule 69 will require a capital investment in NOx controls of approximately $87 million.

  This alternative is not recommended because it would not provide SDG&E flexibility in meeting the emission reduction objectives of Rule 69 nor an opportunity to reduce Rule 69 compliance costs, nor to evaluate and implement alternative NOx control technologies (e.g. low NOx burners) and strategies (e.g. import additional electricity).

- Adopt other amendments to Rule 69. Such amendments could include an overall electric utility system oxides of nitrogen emission rate limit, a delay in final compliance with the current boiler specific emission rate limits, or an annual NOx limit that varies depending on electrical generation levels.

  Although these alternatives would provide some additional compliance flexibility for SDG&E, they are not recommended because they would not provide the full opportunities for compliance cost savings as the proposed amendments would provide nor the same opportunities for evaluating and implementing alternative emission controls.

BACKGROUND:

Current Rule 69 was adopted by the Board on January 18, 1994 to meet California Clean Air Act requirements for Best Available Retrofit Control Technology (BARCT). The Air Resources Board (ARB) determined the rule met BARCT requirements. It requires oxides of nitrogen (NOx) emissions from electrical generating steam boilers and new and replacement electrical generating units be controlled to specified levels. At least one existing boiler must be controlled each year beginning in 1997 and all existing boilers must be in compliance by 2001, with the exception of replacement units and associated boilers that may be scheduled for initial startup between January 1, 2001 and January 1, 2003. Replacement units and associated boilers are required to be in compliance by January 1, 2003 or initial startup, whichever is sooner. The current rule also requires annual NOx emissions from all boilers, replacement units and new units under common ownership not exceed 2100 tons starting in 1997, and 800 tons starting in

2001. Electrical generating steam boilers operated by the San Diego Gas and Electric Company (SDG&E) are the only existing boilers in San Diego County affected by Rule 69. Other future electrical energy generators who may assume ownership or operation of one or more boilers currently operated by SDG&E, or who may enter into joint ventures with SDG&E for operating new or replacement electrical generating units will also be affected.

Current Rule 69 was developed in collaboration with SDG&E, in coordination with the ARB and with technical assistance from the California Energy Commission. When adopted, Rule 69 was supported by SDG&E and ARB. BARCT requirements were met by requiring NOx emissions from existing electrical generating steam boilers be controlled by approximately 85 percent on a system-wide basis using combinations of emission control technologies, including selective catalytic reduction (SCR), for eight of the nine operating utility boilers subject to the rule. The rule prescribed emission rate limits (e.g. 0.15 pounds of NOx per megawatt-hour of electricity produced) for each affected boiler to ensure NOx emission reductions would be achieved from each boiler regardless of its level of use or annual emissions.

Establishing an annual system-wide oxides of nitrogen emissions limit (cap) in conjunction with a waiver from the New Source Review rule requirement to provide offsetting emission reductions for emission increases from modified, replacement and new units provides for expected increases in electrical generation levels in the future and helps to preserve scarce emission offsets needed for other industrial growth projects. The annual emission limits in current Rule 69 apply to total NOx emissions from all existing SDG&E boilers, as well as any replacement or new units that might be built to meet projected increases in electrical energy demand. The annual limits also ensure NOx emissions from SDG&E utility boilers will be reduced by a minimum of approximately 36 percent by the year 1997, and 75 percent by the year 2001 and thereafter, compared to recent average annual system emissions even if additional electrical generating capacity were to be added. Current average NOx emissions from SDG&E boilers subject to the rule are approximately 3260 tons per year.

With the exception of the annual NOx limit (cap) and related waiver for emission offset requirements, rules similar to current Rule 69 have been adopted over the past several years in the South Coast Air Quality Management District, Ventura County Air Pollution Control District, Bay Area Air Quality Management District, Monterey Bay Unified Air Pollution Control District and San Luis Obispo County Air Pollution Control District. Since then, amendments delaying full implementation of selective catalytic reduction control technologies have been proposed and approved in San Luis Obispo and Monterey Bay to allow low-NOx burner control technology to develop. Amendments to provide greater operational and compliance flexibility for affected utility boilers have been proposed in the Bay Area. While these amended rules would eventually require the most stringent emission rate limits be applied to large utility boilers, they do not incorporate an annual NOx emission cap.

Recently, the Regional Clean Air Incentives Market (RECLAIM) open-market emissions trading program specified emissions for Southern California Edison Company. Southern California Edison must meet annual NOx emission caps that are established based on historic peak annual emissions, reductions required by the South Coast BARCT rule, and further reductions needed to meet the South Coast attainment plan for the federal ozone standard. The annual NOx emission caps went into effect in 1994 and decline annually to the year 2003. Edison can comply with the annual caps by installing emission controls at varying levels of effectiveness, by importing more electrical power from outside their electrical generating facilities in the South Coast District, by replacing existing boilers with more efficient electrical generating units, and by purchasing emission reduction credits. Edison is not required to install specific emission control technologies, such as SCR, nor is it required to limit emissions on a daily basis.

On July 24, 1995, SDG&E requested Rule 69 be amended to allow complete flexibility in implementing the NOx emission control requirements. SDG&E requested both the boiler specific NOx emission rate limits of the rule and the requirement to retrofit at least one existing boiler with NOx emission controls each year starting in 1997 be deleted and requested other clarifications to the rule. The NOx emission control requirement would then become the annual NOx caps of 2100 tons per year starting in 1997, and 800 tons per year starting in 2001. SDG&E stated that such amendments would provide an opportunity to significantly reduce the costs of compliance and to evaluate and implement alternative, less costly NOx emission control technologies.

With these proposed amendments, SDG&E would be allowed to choose levels of emission controls required for each boiler, import more electrical energy to reduce local NOx emissions (and reduce the need for and cost of final emission controls), and replace existing boilers with more energy efficient electrical generating units, so long as total system-wide NOx emissions from SDG&E's units do not exceed the prescribed annual caps. Basing the rule on NOx caps alone is a significant departure from current Rule 69 which mandates that each affected boiler be equipped with emission reduction technology that will meet the daily NOx emission rate limits (e.g. 0.15 pounds of NOx per megawatt-hour of electricity produced) specified for each boiler.

When current Rule 69 was adopted, the estimated initial capital cost to comply were approximately $110 million (the $73 million included as backup information when Rule 69 was adopted reflects 1987 dollars). Recently, SDG&E estimated capital costs of compliance with the current Rule 69 to be approximately $87 million, the decrease being primarily due to lower costs of NOx emission control technologies. Under the proposed amendments to Rule 69, SDG&E estimates capital cost savings of approximately $34 million resulting from additional opportunities to implement less costly NOx emission control technologies, to import additional electrical energy, and to optimize more cost-effective electricity generation in NOx controlled boilers. Savings may also result from construction of new or replacement electrical generating units with higher energy efficiencies.

The California Air Resources Board (ARB) objected to the November 14, 1995 proposed changes primarily because the 800 ton annual cap did not reflect BARCT requirements as mandated by state law. The ARB did not believe the 800 ton annual cap was equivalent to the emission reductions that would be achieved under current Rule 69 for reasonably expected operating conditions. ARB also stated the 800 ton annual cap was not consistent with the methodology used to establish an emissions cap for Southern California Edison under the RECLAIM program which ARB determined met BARCT requirements. ARB also expressed concern that the rule would allow SDG&E the option of burning fuel oil at certain times instead of cleaner burning natural gas, and would not require NOx control equipment be operated at maximum control performance at all times during boiler operation.

SDG&E, the ARB and the District met on November 6 to discuss the ARB's concerns. Conference calls were held on November 21 and December 1. The District agrees that using the RECLAIM methodology would result in a cap for SDG&E of about 550 tons per year and therefore, a cap lower than 800 tons per year is appropriate. However, the District believes that consistency with rather than equivalence to the RECLAIM program is what is required, and that differences in the operating characteristics between the SDG&E and Southern California Edison systems need to be considered in establishing an appropriate cap. As a result, further changes have been proposed, including an additional final emissions cap of 650 tons per year starting in the year 2005. The ARB does not agree the 650 ton per year NOx limit guarantees SDG&E will implement BARCT but will withhold judgment until the required Compliance Plans are submitted by SDG&E and the proposed control technologies can be evaluated.

Specifically, the additional changes accomplish the following:

Additional Rule Amendments

- Delete provisions [Section (d)(3)] requiring NOx control equipment be operated at maximum control performance only on days when an exceedance of the state standard for ozone is predicted and instead require NOx control equipment be operated at maximum control performance at all times during boiler operation.

- Add a further level of NOx reduction [Section (d)(4)(C)] requiring NOx emissions not exceed 650 tons per year on and after January 1, 2005. This is in addition to the 2100 tons per year NOx reduction requirement on and after January 1, 1997 and the 800 tons per year NOx reduction requirement on and after January 1, 2001.

- Delete the restriction [Section (d)(5)] that annual NOx limits (e.g. 650 tons per year) not be exceeded unless the exceedance is due to an unforeseen event or a disruption in the supply of imported power. Exceedances of annual NOx limits will be allowed if the District has approved the exceedance in advance, modified permits accordingly and offsetting emission reductions are provided in advance at a 1.0 to 1.0 ratio. This change is consistent with the provisions of SB 456 which was recently signed by the Governor and allows emission reduction credits to be used in lieu of any requirement for BARCT if the credit complies with District rules. If the Air Pollution Control Board adopts a rule allowing emission reduction credits in the South Coast AQMD to be used in lieu of BARCT-required emission reductions, this change would avoid the need to again revise Rule 69. The South Coast AQMD Board would also be required to approve any such out-of-air-basin emission reduction credits before they can be used in San Diego County.

- Delete provisions [Section (e)(3)(i)] requiring emissions rate data and/or key emissions control device or boiler operating data for each day an exceedance of the state ozone standard is predicted during the preceding calendar year be included in the required Compliance Report.

- Add requirements [Section (e)(3)(i)] that the Compliance Report submitted in year 2001 and thereafter include a forecast of total NOx emissions through the year 2005 and a demonstration of how compliance will be achieved with the final NOx cap.

- Add provisions [Section (f)(1)(vi)(F)] requiring any emissions control device and boiler operational data specified by the District be recorded as specified.

- Add provisions [Section (f)(9)] to allow banking excess emission reductions from boilers subject to the emission rate limits specified in Section (d)(7) and not subject to a NOx cap. This would only apply to existing boilers sold by SDG&E to an independent operator which would no longer be regulated under SDG&E's emissions cap.

Best Available Retrofit Control Technology Justification

The proposed amended rule with a final annual NOx limit of 650 tons is consistent with BARCT requirements based on the following:

The amended rule is consistent with Health and Safety Code Section 40406 defining BARCT as an emission limitation based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source. It is also consistent with state requirements concerning incremental cost effectiveness. It allows a mix of possible emission control technologies, including technology currently under development, be used to meet BARCT emission levels as do rules in the South Coast AQMD and Bay Area AQMD.

ARB has not developed BARCT guidance for electrical utility boilers as for other VOC and NOx emission source categories. This is because of the significant differences in electricity generating resource characteristics and operating practices among the different California electric utilities.

The 650 tons per year final cap in year 2005 represents an 80 percent reduction from average SDG&E emissions in the last five emissions inventory years, an 83 percent reduction from SDG&E's 1989 emission levels, and a 93 percent reduction from SDG&E's 1980 levels. By comparison, under the BARCT portion of the Regional Clean Air Incentive Market (RECLAIM) program in the South Coast AQMD, Southern California Edison must reduce annual emissions by 80 percent from 1989 levels and 94 percent from 1980 levels. The ARB has accepted the RECLAIM program as BARCT in the South Coast.

The NOx emission reductions achieved are equal to or greater than emission reductions required by District rules implementing BARCT for stationary sources of NOx and volatile organic compounds (VOC). For example, District Rule 67.10 reduces overall VOC emissions from the single largest stationary source of VOC emissions in the county by approximately 81 percent.

Based on the average of the California Energy Commission (CEC) electrical generation forecasts for SDG&E, the proposed rule would achieve 94 percent of the cumulative emission reductions achieved by the current rule, and 95 percent of the cumulative emission reductions achieved if RECLAIM were applied to SDG&E, over the ten years from 1997 to 2006. Using the highest CEC electrical generation forecast for SDG&E, the proposed rule would achieve 100 percent of the cumulative emission reductions achieved by current Rule 69, and 96 percent of the cumulative emission reductions achieved if RECLAIM were applied to SDG&E, over the ten years from 1997 to 2006.

The proposed rule will result in cumulative emissions reductions from the year 1997 through the year 2010 comparable to or somewhat greater than what would be obtained under the recently amended Bay Area AQMD Rule 9-11 which implements BARCT for Pacific Gas and Electric Company's boilers. The final compliance date of 2005 is consistent with that of the Bay Area AQMD in Rule 9-11, and will allow the utilities to work together and take advantage of promising new emission control technologies.

The proposed amendments to Rule 69 are consistent with the 1991 Regional Air Quality Strategy. Should future updates to the RAQS or attainment demonstrations for the state ozone standard indicate that annual or peak day NOx emissions from electrical generating units need to be further reduced, additional amendments to Rule 69 should be evaluated and appropriate recommendations made.

To meet the annual NOx cap requirements, SDG&E has stated boilers will likely be retrofit with emission control technology as follows:

Existing Unit	Expected NOx Controls	Schedule
South Bay Unit 1	Selective Catalytic Reduction	January, 1997
Encina Unit 5	Flue Gas Recirculation	January, 1997
	Low-NOx Burners	January, 1998
Encina Unit 4	Flue Gas Recirculation	January, 1997
	Low-NOx Burners	January, 1999

Existing Unit	Expected NOx Controls	Schedule
South Bay Unit 2	Selective Catalytic Reduction	January, 2000
South Bay Unit 3	Selective Catalytic Reduction	January, 2001
Encina Unit 1	Urea Injection	January, 2001
	Selective Catalytic Reduction	January, 2003
Encina Unit 2	Urea Injection/In-duct SCR	January, 2001
	Selective Catalytic Reduction	January, 2004
Encina Unit 3	Selective Catalytic Reduction	January, 2005
South Bay Unit 4	No additional controls	N/A

Alternative emission control technologies such as urea injection or low-NOx burners with flue gas recirculation for the Encina Units 1, 2, and 3 may be possible depending on the effectiveness of the low-NOx burners planned for the larger Encina Units 4 and 5, future electrical energy demand, and availability of other electrical energy resources.

Cost-Effectiveness

Section 40406 of the Health and Safety Code defines BARCT as, "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source." Recent changes to the Health and Safety Code (SB456, Kelley) provide, in part, that in determining BARCT after January 1, 1996, air districts must identify several control options, determine the cost-effectiveness of each, determine the incremental cost-effectiveness of each option, and consider this information in adopting rules or regulations to implement BARCT.

Several emission control options and associated NOx emission reductions have been considered for Rule 69. The first is for current Rule 69 reflecting emission rates from 0.15 - 0.18 pounds of NOx per megawatt-hour of electricity produced, limited oil burning allowance, and a final NOx cap of 800 tons per year. The second is for a variable NOx cap proposed by ARB ranging from 390 to 790 tons per year depending on electricity production; the greater the production, the higher the cap. The third is for a cap constructed using the same methodology for Southern California Edison under the South Coast AQMD's RECLAIM program. The fourth is for the currently proposed final cap of 650 tons per year (2005) and the fifth is for the 800 tons per year cap in the current Rule 69. The estimated capital cost of each option, and total projected annual average emission reductions for SDG&E over the years 1997 through 2010, is as follows:

Control Option	Emission Reductions Tons/Yr	Capital Cost $/Yr
Current Rule 69	2,442	87,000,000
ARB variable cap proposal	2,382	93,000,000
RECLAIM Rule @ 550 tpy	2,389	73,000,000
Cap-Only Rule @ 650 tpy	2,273	53,000,000
Cap-Only Rule @ 800 tpy	2,209	38,000,000

The individual cost-effectiveness and incremental cost-effectiveness of each control option is estimated as follows (listed least to most stringent based on the average of future energy and resource forecasts):

Control Option (least to most stringent)	Cost-Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Cap-Only Rule @ 2100/800 tpy	3,800	N/A
Cap-Only Rule @ 2100/800/650 tpy	4,800	16,700
RECLAIM Rule @ 550 tpy	5,990	34,000
Current Rule 69	6,670	33,300
ARB variable cap proposal	7,300	81,200[1]

[1] Referenced to the proposed 2100/800/650 tons per year cap only rule.

Based on the above, all of the above options are cost-effective compared to current Rule 69, which was estimated at the time of adoption to be from $8,800 to $14,000 per ton of NOx emissions reduced. However, a cap-only rule with a final cap of 650 tons will result in capital costs savings of approximately $34 million over current Rule 69, annual cost savings of approximately $5.4 million and achieve approximately 93 percent of the emission reductions that would be achieved by current Rule 69 from the years 1997 to 2010.

Issues

Potential for Fewer Emission Reductions

The Air Resources Board has questioned whether the 650 tons per year final NOx cap is comparable to the emissions reductions required by current Rule 69 and, therefore, whether the proposed amended Rule 69 reflects BARCT.

Annual NOx Emissions:
For reasonably expected future SDG&E electrical generating scenarios, the annual NOx reductions achieved under the proposed amendments are comparable to those achieved under current Rule 69. The District agrees there are some possible future generating scenarios where NOx emissions under current Rule 69 could be less than the 650 tons per year final limit of proposed amended Rule 69. However, it is uncertain whether these scenarios would actually occur because a prerequisite would be that demand for electricity in the county not increase, or that demand increases be substantially met by existing electrical generating capacity or by construction of new or replacement electrical generating units and/or by additional import energy delivered over existing electrical transmission lines. It is unlikely these situations would reasonably occur because energy demand will continue to increase, recent proposals for construction of new generation projects have not gone forward, and existing transmission lines are limited in number and capacity.

In addition, the 650 ton annual cap is comparable to a 550 ton annual cap that would result if the cap were constructed using the emission reduction calculation methodologies used in determining an annual NOx cap for Southern California Edison under the RECLAIM program. ARB has determined the RECLAIM NOx cap is BARCT.

Maximum Daily NOx Emissions:
It is possible that under the proposed amendments maximum daily NOx emissions could be higher than under current Rule 69. This is because the current rule requires each boiler be in compliance with specified NOx emission rates each calendar day. Although the proposed amendments would require NOx controls be operated at maximum emissions control performance to ameliorate this issue, the emissions control performance will reflect the control technologies chosen by SDG&E to meet the 650 ton annual cap. If those NOx control technologies are not as efficient as those mandated by the current rule, maximum daily NOx emissions after January 1, 2001 could be higher under the amended rule compared to the current rule.

The difference in maximum daily NOx emissions will be small if the control technologies required to meet the 650 ton cap under the proposed amendments are equally effective as those required to meet the current NOx emission rate limits of Rule 69. SDG&E has estimated that under conservative control efficiency assumptions, maximum daily NOx emissions under the amended rule would be 6.5 tons per day. This is significantly less than current actual maximum daily emissions of approximately 15 tons per day but more than the projected maximum daily emissions of approximately 2.6 tons per day under current Rule 69.

Maximum daily and annual NOx emissions under the proposed amendments are consistent with current state and federal ozone attainment plans for San Diego and with the 1994 attainment demonstration for the federal ozone standard. However, if additional annual or maximum daily NOx emission reductions from electrical generating steam boilers are determined to be available, cost-effective and needed to further progress towards attainment of ambient air quality standards for ozone, Rule 69 will be reconsidered and appropriate additional amendments recommended.

While the ARB does not agree the 650 tons per year NOx limit guarantees implementation of BARCT, ARB has agreed to withhold final judgment until SDG&E submits its required Compliance Plans and the proposed control technology can be reviewed. The District will conduct this review in consultation with ARB.

Restriction on Fuel Oil Burning

The Air Resources Board stated that allowing fuel oil to be burned is not consistent with BARCT requirements contained in the rules of other California air districts. The District believes the current restriction prohibiting fuel oil burning when an exceedance of the state ozone standard is forecast is adequate.

Final NOx Cap at 2005

The Air Resources Board has questioned the need for allowing until 2005 to require the 650-ton annual NOx cap. The final compliance date of January 1, 2005 for the final emission cap is consistent with the Bay Area Air Quality Management District in its recently amended Regulation 9, Rule 11, and will allow the utilities to work together and take advantage of developing technologies.

California Energy Commission Issues

The California Energy Commission (CEC) provided written comments to the District regarding the proposed amendments to Rule 69 that raise the following issues:

1. The elimination of the hourly emission rate limits causes concern that new power plant additions, either directly or cumulatively with existing power plant emissions, could result in otherwise unmitigated hourly, daily or quarterly emission increases. Such emission increases could contribute to violations of the state's one-hour ozone standard.

   Response: Current Rule 69 specifies daily rather than hourly emission rate limits for utility boilers. Under the proposed amendments to Rule 69, the daily emission rate limits would be removed and compliance based on annual NOx caps. However, new electrical generating projects such as combined-cycle units and repowers of existing boilers will still be subject to Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) project-specific emission limits. These limits will likely be based on maximum instantaneous or hourly average emissions rates. Thus, new projects that will be subject to CEC review will likely be subject to clock-hour or more stringent emission limits. Moreover, such projects will tend to shift electrical generation and, thus, emissions from existing boilers not subject to hourly or daily emission rate limits.

2. To reflect most current energy emission control technology status, the District may wish to review the BACT level assumed in the analysis.

   Response: Both current and proposed Rule 69 require new and repowered units to apply BACT or LAER emission controls, as applicable. This requirement has not changed. BACT or LAER will be determined at the time a new or repowered unit is permitted. It should be noted that many of the electrical energy generation forecasts prepared by the CEC for the District to assist in the evaluation of the SDG&E system and future potential operating scenarios included operation of one or more new or repowered units. Over the last few years, several such projects for SDG&E have been considered by the CEC, yet none have gone forward, for a variety of reasons. Given the uncertainty associated with reliance on such projects, the District believes it prudent to retain its current assumed emission rates for purposes of estimating future emissions.

3. The District should address whether SDG&E's request for reduced compliance costs in light of increased regulatory uncertainty has the inadvertent effect of relaxing SDG&E's current obligations under the District's attainment plan.

   Response: None of these emission reductions associated with the proposed rule are obligated under the District's attainment plan for the national ozone standard. Moreover, the rule is consistent with the District's attainment plan for the state one-hour standard.

4. There is a broad range of cost reducing opportunities which are consistent with continued achievement of District emission reduction goals. These include a system-wide emission rate limit similar to that in South Coast Rule 1135 and proposed amended Bay Area Rule 9-11. A more comprehensive option would be a "RECLAIM" strategy applicable to all large NOx sources. This would include a declining annual emissions allocation, a marketable emissions trading program, and a quarterly compliance demonstration requirement.

   Response: Proposed amended Rule 69 will result in emission reductions comparable to those which would result under a RECLAIM approach and to those that would be achieved under a rule similar to the Bay Area Rule 9-11.

Socioeconomic Impact Assessment

Section 40728.5 of the State Health and Safety Code requires that, to the extent data are available, the socioeconomic impacts of rule amendments and new rules be evaluated and actively considered by the Air Pollution Control Board, and that good faith efforts be made to minimize adverse socioeconomic impacts. The proposed amendments to Rule 69 will have impacts as follows:

- The proposed amendments will affect only one company, SDG&E. No other businesses currently have equipment subject to the current rule or the proposed amendments, and no small businesses will be affected by the proposed amendments.

- Due to the uncertainty of how SDG&E would choose to comply with the annual NOx caps under the proposed amendments, no data are available on the impact the proposed amendments will have on employment and the economy of the region. The socioeconomic impact assessment (which may be conservatively high) prepared for the adoption of the original version of Rule 69 predicted slight job growth and slight improvement in the overall economy in the first two years of purchase and installation of the control systems required by current Rule 69, but long-term negative effects on employment and the economy of the region thereafter as a result of higher electricity rates. Both positive and negative impacts are small compared to total employment growth between 1994 and 2010. SDG&E's proposed amendments to Rule 69 would likely moderate both the short-term positive impacts on employment and the economy and the long-term negative impacts on employment and the economy predicted to result from the current Rule 69.

- There are no probable additional costs to SDG&E and its customers if the proposed amendments are adopted. SDG&E estimates it could save up to $34 million in capital costs as a result of the amendments.

- There are alternatives to the proposed amendments to Rule 69 (650-ton annual cap). The first would retain the current rule, without amendment. The cost effectiveness of this alternative ($6,670 per ton of NOx reduced) was determined and considered by the Board when the rule was adopted. The cost effectiveness of establishing a 550-ton annual cap is $5,990 per ton and the cost effectiveness of an 800 ton annual cap is $3,800 per ton. The cost effectiveness of a variable cap (390 to 790 ton annual cap) proposed by ARB and which is dependent on the level of local electricity generation is $7,300 per ton.

- The proposed amendments will not result in additional emission reductions, unless future electrical generation grows to the extent that the final emission cap of 650 tons per year limits emissions beyond current Rule 69.

- The proposed amendments to Rule 69 are not necessary to attain the federal ambient air quality standard for ozone.

Environmental Impacts

The California Environmental Quality Act (CEQA) requires an environmental review for certain actions, including rule adoptions which may result in environmental impacts. The proposed amendments to Rule 69 will not have a significant effect on the environment and are exempt from the requirements of CEQA because the proposed amendments will require significant reduction in daily and annual emissions of NOx to the environment compared to emissions currently occurring from boilers subject to the rule. Current emissions from affected boilers average approximately 3260 tons per year. Under the proposed amended Rule 69, emissions from these boilers, and any new or replacement electrical generating units, will be reduced to 2100 tons per year by 1997, to 800 tons by 2001 and to 650 tons by 2005.

The potential environmental impacts associated with NOx emission controls for electrical generating steam boilers and current Rule 69 were considered in the Environmental Impact Report prepared for the 1991 San Diego Regional Air Quality Strategy, and in conjunction with adoption of Rule 69 in January, 1994. It was determined that, although Rule 69 does not specify which oxides of nitrogen emission control technologies must be used to comply, it was likely that at least some of the existing SDG&E boilers located at the Encina and South Bay power plants would be equipped with selective catalytic reduction technology. This technology uses ammonia injected in the flue gas ahead of a catalyst to reduce oxides of nitrogen emissions. The use of selective catalytic reduction creates the potential for adverse environmental impacts, specifically associated with the handling of ammonia, a toxic gas, and the handling of spent catalyst, a potential hazardous waste.

In adopting Rule 69, the Board found that the Final Environmental Impact Report for the 1991 San Diego Regional Air Quality Strategy, prepared in October, 1991 and approved by the Board on June 30, 1992, discussed potential environmental impacts that may result from the emission reduction measures upon which Rule 69 is based and concluded that the impacts would not be significant after mitigation. The amendments to Rule 69 may provide greater opportunities to implement NOx emission controls other than selective catalytic reduction technologies and, therefore, may reduce the potential significant (although mitigated) environmental impacts that were identified with the use of such technologies to comply with current Rule 69. There are no known significant environmental impacts associated with alternative NOx emission controls that could be applied under the proposed amendments to Rule 69.

Since the proposed amendments to Rule 69 have been requested by SDG&E, SDG&E has agreed to indemnify the District from any costs associated with any litigation that might arise regarding adopting the proposed amendments. A proposed memorandum of understanding documenting this indemnification is attached. The District is recommending that the Air Pollution Control Officer be directed to execute this memorandum of understanding if the proposed amendments to Rule 69 are adopted.

Section 40001 of the Health and Safety Code requires the District to determine, prior to adopting any rule to reduce criteria pollutants, that the rule will alleviate a problem and promote the attainment or maintenance of state or federal air quality standards. The proposed amendments may save SDG&E and its customers up to $34 million in capital costs. The proposed amendments will still promote attainment of the state and federal ambient air quality standards.

On February 2, 1993, the Air Pollution Control Board directed that, with the exception of a regulation requested by business or a regulation for which a socioeconomic impact assessment is not required, no new or revised regulation shall be implemented during the 1993 calendar year unless specifically required by federal or state law. The proposed amendments to Rule 69 were requested by SDG&E, the only business currently impacted by the rule, to be adopted on an expeditious schedule. They meet the California Clean Air Act requirement for expeditious implementation of the 1991 San Diego Regional Air Quality Strategy.

Concurrence: Respectfully submitted,

Richard J. Smith

DAVID E. JANSSEN
Chief Administrative Officer

for R. J. SOMMERVILLE
Air Pollution Control Officer

AIR POLLUTION CONTROL BOARD
AGENDA ITEM
INFORMATION SHEET

SUBJECT: Continued Public Hearing on Amendments to Rule 69 (Electrical Generating Steam Boilers, Replacement Units and New Units)

SUPV DIST.: All

11 12/12/95

COUNTY COUNSEL APPROVAL: Form and Legality [X] Yes [ ] N/A
[ ] Standard Form [ ] Ordinance [X] Resolution

CHIEF FINANCIAL OFFICER/AUDITOR REVIEW: [X] N/A [ ] Yes
4 VOTES: [ ] Yes [X] No

CONTRACT REVIEW PANEL: [ ] Approved ______________________ [X] N/A

CONTRACT NUMBER(S): N/A

PREVIOUS RELEVANT BOARD ACTION: January 18, 1994 (APCB Item #1)
November 14, 1995 (APCB Item #1)

BOARD POLICIES APPLICABLE: N/A

CITIZEN COMMITTEE STATEMENT: The Air Pollution Control District Advisory Committee recommended adoption of the proposed amendments at its October 25, 1995 meeting and that any additional changes which would be more inclusive or prescriptive be resisted. The Committee has not reviewed the additional changes.

CONCURRENCES: N/A

ORIGINATING DEPARTMENT: Air Pollution Control District

CONTACT PERSON: Richard J. Smith, Deputy Director 750-3303 MS: 0-176

Richard J. Smith
for R. J. SOMMERVILLE
DEPARTMENT AUTHORIZED REPRESENTATIVE

DECEMBER 12, 1995
MEETING DATE

Re Rules and Regulations of the)
Air Pollution Control District)
of San Diego County . . . .)

NO. 95-461 TUESDAY, DECEMBER 12, 1995

RESOLUTION AMENDING RULE 69
OF REGULATION IV
OF THE RULES AND REGULATIONS OF THE
SAN DIEGO COUNTY AIR POLLUTION CONTROL DISTRICT

On motion of Member Slater, seconded by Member Roberts the following resolution is adopted:

WHEREAS, the San Diego County Air Pollution Control Board, pursuant to Section 40702 of the Health and Safety Code, adopted Rules and Regulations of the Air Pollution Control District of San Diego County; and

WHEREAS, said Board now desires to amend said Rules and Regulations; and

WHEREAS, notice has been given and a public hearing has been had relating to the amendment of said Rules and Regulations pursuant to Section 40725 of the Health and Safety Code.

NOW THEREFORE IT IS RESOLVED AND ORDERED by the San Diego County Air Pollution Control Board that the Rules and Regulations of the Air Pollution Control District of San Diego County be and hereby are amended as follows:

Proposed amendments to Rule 69 are to read as follows:

RULE 69. ELECTRICAL GENERATING STEAM BOILERS, REPLACEMENT UNITS AND NEW UNITS

(a) APPLICABILITY

(1) Except as provided in Section (b) or otherwise specified in this rule, this rule is applicable to the following existing electrical generating steam boilers, and to all replacement units and to all new units, including any auxiliary boiler used in conjunction with such electrical generating steam boilers, replacement units or new units:

(i) Encina Power Plant Units 1, 2, 3, 4 and 5

(ii) South Bay Power Plant Units 1, 2, 3 and 4

(iii) Silvergate Power Plant Units

(2) Equipment subject to this rule shall also comply with the emission limitations and exemptions set forth in Rule 68.

(b) EXEMPTIONS

(1) The provisions of Sections (d), (e), (f) and (g) shall not apply to:

(i) Any electrical generating steam boiler with a maximum heat input capacity of less than 100 million Btu's per hour.

(ii) Boilers which generate steam used exclusively for space heat or process heat and not used for electrical generation.

(c) DEFINITIONS

For the purposes of this rule, the following definitions shall apply:

(1) **"Boiler"** means any combustion equipment fired with solid, liquid and/or gaseous fuels and used to produce steam, excluding electrical generating gas turbines.

(2) **"Calendar Day"** means the 24-hour period starting on the 00:00 hour and ending on the 24:00 hour.

(3) **"Calendar Year"** means the consecutive 12-month period beginning January 1 and ending December 31.

(4) **"Compliance Emissions Testing"** means any emissions or continuous emissions monitor (CEM) quality assurance/quality control (QA/QC) testing required by federal, state, or local regulations.

(5) **"Clock Hour"** means every 60-minute period starting on the hour.

(6) **"Electrical Generating Steam Boiler"** means any boiler used to produce steam to be expanded in a turbine generator used for the generation of electric power.

(7) **"Electrical Generating Gas Turbine"** means any combustion turbine fired with solid, liquid and/or gaseous fuels and used to provide direct shaft work for the generation of electric power.

(8) **"Force Majeure Natural Gas Curtailment"** means an interruption in natural gas service such that the daily fuel needs of a boiler or replacement unit subject to this rule cannot be met with the natural gas available due to:

(i) Unforeseeable natural disaster or other cause resulting in the failure or malfunction of natural gas supply, delivery or storage system facilities, not resulting from an intentional or negligent act or omission on the part of an owner or operator of a boiler, a new unit or a replacement unit, or

(ii) A supply restriction resulting from a California Public Utilities Commission priority allocation ruling, or

(iii) Delivery restrictions due to pipeline capacity limitations of the natural gas supplier or upstream transports or within a gas utility's delivery system.

(9) **"Heat Input"** means the heat derived from combustion of fuel in an electrical generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal com-

bustion engines, kilns, etc. The maximum heat input rating means the lesser of the steady state heat input capacity of an electrical generating unit, as limited by its design and construction or as limited by an Authority to Construct or Permit to Operate.

(10) **"Megawatt-hour (MW-hr)"** means the total electrical energy generation of a boiler, new unit or replacement unit subject to this rule.

(11) **"New Unit"** means any electrical generating steam boiler or electrical generating gas turbine for which the first Authority to Construct is issued on or after January 18, 1994.

(12) **"Oxides of Nitrogen (NOx)"** means the sum of all compounds containing at least one atom of nitrogen and one atom of oxygen, measured as nitrogen dioxide, except nitrous oxide.

(13) **"Reasonable Further Progress"** means annual incremental reductions in emissions of the applicable air pollutant which are sufficient, in the judgment of the Air Pollution Control Officer, to provide for attainment of the applicable National Ambient Air Quality Standard by the date required by law.

(14) **"Reasonably Available Control Technology"** means the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available, considering technological and economic feasibility and any technology findings made by the U. S. Environmental Protection Agency.

(15) **"Replacement Unit"** means any electrical generating steam boiler or electrical generating gas turbine which permanently replaces or augments, on or after January 18, 1994 , an existing electrical generating steam boiler subject to this rule. For purposes of this rule, a replacement unit need not be limited to the same electrical generating capacity as the existing boiler being replaced.

(16) **"SIP Control Measures"** means those emission control measures approved by the Air Pollution Control Board for inclusion in the State Implementation Plan (SIP) required by federal law or contained in the SIP approved by the U.S. Environmental Protection Agency.

(d) STANDARDS

A person shall not operate an existing electrical generating steam boiler, replacement unit or new unit subject to this rule unless only natural gas, alternative fuel and/or fuel oil is burned and the following requirements are met. If an alternative fuel is burned in an existing boiler subject to the provisions of Subsection (d)(7), the operator shall have previously demonstrated to the satisfaction of the Air Pollution Control Officer that the emissions of oxides of nitrogen (NOx) per megawatt-hour of electricity generated is not greater than would be the emissions from the burning of natural gas in the same boiler, replacement unit or new unit.

(1) Fuel Oil Firing

A person shall not operate an electrical generating steam boiler, replacement unit or new unit when burning fuel oil on or after January 1, 1997 unless: the Air Pollution Control Officer has determined that an exceedance of the state ambient air quality standard for ozone is not predicted at any location in the air basin at any time during the fuel oil burning. This paragraph shall not apply when burning of fuel oil is required due to a force majeure natural gas curtailment. Prior to January 1, 1998, this paragraph shall not apply to fuel oil burning in the existing South Bay Power Plant Unit 4 boiler on days when fuel oil burning is needed to meet peak electrical generation demand.

(2) Replacement Units and New Units NOx Emission Limits

A person shall not operate a replacement unit or new unit subject to this rule unless such unit has been built with, and is operated in conjunction with, the Lowest Achievable Emission Rate or Best Available Control Technology as applicable and defined in Rule 20.1 for emissions of oxides of nitrogen.

(3) Maximum NOx Emissions Control Performance

On and after January 1, 1997, a person shall not operate an electrical generating steam boiler, replacement unit or new unit unless all NOx emissions controls associated with such boiler, replacement unit or new unit are operated in a manner that achieves the maximum NOx emission control performance, taking into consideration the electrical generation load, for that boiler or unit. The Air Pollution Control Officer shall specify allowable NOx emission rates and/or key emission control device and boiler or unit operating parameters in the Authority to Construct and/or Permit to Operate for NOx emission controls proposed by the owner or operator to be used on each such boiler, replacement unit or new unit as necessary to ensure compliance with this requirement.

(4) Aggregate NOx Emission Limit

(i) Except as provided in Subsection (d)(5), no person who owned or operated an ~~electrical-generating~~ steam boiler subject to this rule on January 18, 1994 shall operate any existing electrical generating steam boiler, replacement unit or new unit subject to this rule unless such person has demonstrated that the aggregate emissions of oxides of nitrogen, expressed as nitrogen dioxide, from all such boilers, replacement units and new units located in San Diego County and owned or operated by such person and any electrical generating steam boilers, replacement units and new units located in San Diego County that are owned or operated by another entity in which such person has a controlling interest, are not greater than:

(A) On and after January 1, 1997, 2100 tons during every calendar year.

(B) On and after January 1, 2001, 800 tons during every calendar year.

(C) On and after January 1, 2005, 650 tons during every calendar year.

(ii) The aggregate NOx emission limits specified in Subsections (d)(4)(i)(A), (d)(4)(i)(B) and (d)(4)(i)(C) shall be adjusted if any existing boiler replacement unit or new unit subject to the aggregate limit is transferred to another entity in which the person who owned or operated an existing boiler on January 18, 1994 does not have a controlling interest. The transferred existing boiler, replacement unit or new unit shall not be subject to an aggregate NOx emission limit pursuant to this rule, but shall be subject to unit specific emission limits, as applicable, specified in Subsections (d)(2) and (d)(7) of this rule.

(iii) The aggregate NOx emission limits shall be adjusted when boilers or units are transferred by reducing the limits by an amount equal to the annual average megawatt-hours generated over the five years preceding transfer when burning natural gas, fuel oil, and any combination of natural gas and fuel oil, for each such boiler or unit, multiplied by a NOx emission rate of 0.15 pounds per megawatt-hour when burning natural gas, a NOx emission rate of 0.40 pounds per megawatt-hour when burning fuel oil and, when burning a combination of natural gas and fuel oil, a NOx emission rate prorated for the relative heat input from natural gas and fuel oil, as specified in Subsection (d)(7) of this rule. For boilers, replacement units or new units that have operated less than five years prior to transfer, the annual average megawatt-hours generated shall be based on the most representative years of operation preceding transfer, as determined by the Air Pollution Control Officer.

(iv) The annual oxides of nitrogen emission limits specified in this subsection shall be adjusted to account for fuel oil burning that results from a force majeure natural gas curtailment, or is due to compliance emissions testing, using methods approved by the Air Pollution Control Officer. The adjustment shall be made by adding to the applicable limit the difference between the total pounds of oxides of nitrogen emissions occurring during such fuel oil burning and the total pounds of oxides of nitrogen emissions which would have occurred during the same period had natural gas been fired in that boiler, replacement unit or new unit. The adjustment shall be prorated for the relative heat inputs of fuel oil and natural gas when co-firing both fuels.

(5) Exceedances of an Aggregate NOx Emission Limit

An owner or operator subject to the requirements of Subsection (d)(4) may operate its electrical generating steam boilers, replacement units and new units when aggregate oxides of nitrogen emissions exceed the calendar year limits specified in Subsection (d)(4) provided:

(i) The Air Pollution Control Officer has approved the exceedance in advance and has issued modified permits to operate for the affected equipment adding conditions that establish a new, enforceable calendar year aggregate emission limit, and

(ii) Such owner or operator has provided, in advance, offsetting emission reductions, on an annual basis and at a 1.0 to 1.0 offset ratio, for all emissions of oxides of nitrogen in excess of the calendar year limits specified in Subsection (d)(4).

The new calendar year aggregate oxides of nitrogen emission limit established pursuant to the above shall be based on the sum of the aggregate emission limit specified in Subsection (d)(4) and the emission offsets provided pursuant to Subsection (d)(5). Offsetting emission reductions shall conform to the criteria for emission offsets specified in Rule 20.1.

(6) Waiver from New Source Review NOx Offset Requirements

On and after January 1, 1997, oxides of nitrogen emission increases from any new, modified or replacement unit subject to and in compliance with Subsections (d)(4) and (d)(5) of this rule, shall not be subject to the offset provisions of Regulation II, Rules 20.1 through 20.3, and 20.9 (New Source Review) of these Rules and Regulations provided that:

(i) The owner or operator of the new, modified or replacement unit has demonstrated, using methods approved by the Air Pollution Control Officer and the U.S. Environmental Protection Agency, the extent to which the NOx emission reductions that have been achieved by the owner or operator from electrical generating steam boilers existing prior to January 18, 1994 by compliance with this rule are in excess of the NOx emission reductions required to demonstrate compliance with Reasonably Available Control Technology, any NOx emission reductions from electrical generating steam boilers contained in SIP Control Measures and any NOx emission reductions from electrical generating steam boilers necessary to demonstrate compliance with Reasonable Further Progress, and

(ii) The excess NOx emission reductions determined in Subsection (d)(6)(i) are greater than 1.2 times the NOx emissions increases from the new, modified or replacement unit that would otherwise be subject to the offset provisions of Regulation II, Rules 20.1 through 20.3, and 20.9 (New Source Review) of these Rules and Regulations, and

(iii) The excess NOx emission reductions determined in Subsection (d)(6)(i) are reduced by 1.2 times the NOx emissions increases from the new, modified or replacement unit that would otherwise be subject to the offset provisions of Regulation II, Rules 20.1 through 20.3, and 20.9 (New Source Review) of these Rules and Regulations.

Only oxides of nitrogen emission increases associated with generating capacity which the California Energy Commission or the California Public Utilities Commission or their successor, as applicable, has determined a need for shall be eligible for this waiver.

(7) NOx Emission Rate Limits for Existing Boilers Not Subject to an Aggregate NOx Emission Limit

The emissions of oxides of nitrogen from any existing electrical generating steam boiler that has been transferred to another entity in which the person who owned or operated the boiler on January 18, 1994 does not have a controlling interest, shall not exceed 0.15 pounds per megawatt-hour when burning exclusively natural gas, 0.40 pounds per megawatt-hour when burning exclusively fuel oil, and a prorated emissions limit, determined as follows, when burning a combination of natural gas and fuel oil:

$$EL = \frac{[(Lo)(Qo)(HHVo)] + [(Lg)(Qg)(HHVg)]}{(Qo)(HHVo) + (Qg)(HHVg)}$$

where,

EL	=	Emission limit, pounds per megawatt-hour
Lo	=	0.40 pounds per megawatt-hour
Qo	=	Quantity of fuel oil burned, barrels per hour
HHVo	=	Higher heating value of fuel oil, Btu's per barrel
Lg	=	0.15 pounds per megawatt-hour
Qg	=	Quantity of natural gas burned, scf per hour
HHVg	=	Higher heating value of natural gas, Btu per scf,

Compliance with the standards of this subsection shall be based on emissions of oxides of nitrogen from an affected boiler averaged over each calendar day of operation, or portion thereof.

(8) Emission Standards for Ammonia

The emissions of ammonia from any electrical generating steam boiler, replacement unit or new unit subject to the requirements of this rule, or from any emissions control device used to achieve compliance with this rule, shall not be greater than the lowest emission rate achievable, consistent with the requirements of this rule, taking into consideration the costs of achieving that emission rate and the potential public health impacts associated with such emissions.

(9) Banking of Excess Emission Reductions

No person shall be eligible to obtain emission reduction credits for emissions of oxides of nitrogen below the limits specified in this Section (d), with the exception of any boiler subject to and in compliance with the emission limits specified in Subsection (d)(7).

(e) COMPLIANCE SCHEDULE, PLAN AND REPORT

(1) Compliance Schedule

A person subject to the provisions of Section (d) shall comply with the following increments of progress:

(i) Any replacement unit or any new unit shall be in compliance with the applicable requirements of Section (d) on and after initial startup.

(ii) Any existing electrical generating steam boiler subject to the requirements of Subsection (d)(7) shall be in compliance with the requirements of this rule within two years after the first transfer of such boiler that occurs after (*date of adoption*), but not later than January 1, 2001.

(iii) The owner or operator of an existing electrical generating steam boiler, replacement unit or new unit subject to the provisions of Subsection (d)(4) shall be in compliance with the applicable aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5) beginning with calendar year 1997, and each calendar year thereafter.

(2) Initial Compliance Plan

The owner or operator of any equipment subject to the provisions of this rule shall submit to the Air Pollution Control Officer, for approval, by (*date of adoption + 180 days*) a Compliance Plan describing the actions, and contingencies, which are proposed by the owner or operator to meet the requirements of Section (d). The Compliance Plan shall be approved if it demonstrates that the requirements of this rule will be met. The Compliance Plan shall contain, at a minimum, the following applicable information for each electrical generating steam boiler, replacement unit and new unit subject to this rule:

- District Permit to Operate number.
- Equipment location.
- Manufacturer.
- Model number.
- Maximum permitted heat input rating.
- Primary and backup fuels to be used.
- Proposed methods to measure, record and report emissions of oxides of nitrogen, measured as parts per million by volume (ppmv) as nitrogen dioxide at 3% O_2, as pounds per million Btu's of fuel heat input, as pounds per day, as tons per calendar month and as tons per calendar year.

- For existing boilers subject to the provisions of Subsection (d)(7), proposed methods to measure, record and report megawatt-hours generated and watt transducer calibration method with supporting documentation.
- Maximum hourly, daily and annual pre-controlled NOx emission rates.
- Method and type of emission controls to be used.
- Expected performance of the emission controls.
- Proposed schedule for applications for Authorities to Construct, issuing purchase orders for emission controls, commencing construction of emission controls, completing construction, conducting compliance tests and demonstrating compliance with the provisions of this rule.
- For boilers and replacement units and new units subject to the aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5), a forecast of aggregate emissions of oxides of nitrogen, in tons, for each calendar month of the next calendar year, a forecast of aggregate emissions of oxides of nitrogen, in tons, for each calendar year through the year 2001, and a demonstration of how compliance will be achieved with the aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5).
- All analyses, operating data, emission factors, assumptions and calculations used to develop the forecast of aggregate calendar month and calendar year emissions of oxides of nitrogen.

The initial Compliance Plan submittal need not contain detailed information regarding emission control specifications, performance and schedules, but must contain at least preliminary information regarding the type of control equipment and the anticipated date for installation of any planned emission controls for each affected unit. A copy of the Compliance Plan shall be kept at each affected site and shall be made available for District inspection upon request. Adherence to a Compliance Plan does not relieve the owner or operator from complying with any other provisions of this rule. The owner or operator of any boiler, replacement unit or new unit subject to this rule shall update the Compliance Plan annually.

(3) Compliance Reporting

(i) Annual Compliance Report

The owner or operator of any equipment subject to the provisions of this rule shall submit by the submittal date in 1997 of the Emissions Statement Form(s) required by Rule 19.3, and each year thereafter, a Compliance Report which describes the measures taken in the preceding calendar year to achieve compliance with the requirements of Section (d). The Compliance Report shall contain, at a minimum, the following information for the preceding calendar year for each electrical generating steam boiler, replacement unit and new unit subject to Section (d) of this rule:

- District Permit to Operate number.
- Number of hours of operation.
- Types and amounts of fuels consumed, and the number of hours on each fuel type.
- Dates and times of any force majeure natural gas curtailments that occurred.

- Mass emissions of oxides of nitrogen for each calendar month and for the calendar year for each such boiler and unit and for the aggregate emissions of such boilers and units under common ownership or control.
- Megawatt-hours generated and total mass emissions of NOx each calendar day and for the calendar year for each boiler subject to the NOx emission rate limits of Subsection (d)(7).
- Indication of whether the owner or operator is on schedule to meet the Compliance Plan(s) submitted pursuant to Subsection (e)(1).
- Identification of each exceedance of the applicable requirements of Section (d).

The Compliance Report submitted in 1998 for calendar year 1997, and each annual compliance report thereafter, shall contain a demonstration by the owner or operator, in the manner and form prescribed by the Air Pollution Control Officer, that the applicable requirements of Section (d) were met in the preceding calendar year. The Compliance Report shall be certified by the owner or operator as to its accuracy and completeness.

Where the Air Pollution Control Officer has approved emissions monitoring on a common stack that serves more than one electrical generating steam boiler, replacement unit, or new unit subject to this rule, the annual Compliance Report may contain aggregate emissions data from such boilers or units in lieu of emissions data for each such boiler or unit.

The Compliance Report shall also contain any proposed revisions to the Compliance Plan. These revisions shall include the justification for the changes and a demonstration that the changes will ensure compliance with the requirements of Section (d) and Subsection (e)(1). The Compliance Report submitted in year 2001, and each year thereafter, shall include a forecast of aggregate emissions of oxides of nitrogen, in tons, for each calendar year through the year 2005, and a demonstration of how compliance will be achieved with the aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5).

Documentation and calculations used to prepare the material presented in the Compliance Report shall be maintained by the owner or operator for at least two years and shall be made available to the District upon request.

(ii) Monthly Compliance Reporting

The owner or operator of any boiler, replacement unit or new unit subject to the provisions of Subsections (d)(4)and (d)(5) shall submit monthly, by the 15th day of the calendar month, a report of the aggregate oxides of nitrogen emissions for the preceding calendar month and cumulatively for the current calendar year from each and all such boilers, replacement units and new units under the control of the owner or operator, and a comparison of oxides of nitrogen emissions during the preceding calendar months for the current calendar year to that forecast in the current Compliance Plan.

Where the Air Pollution Control Officer has approved emissions monitoring on a common stack that serves more than one electrical generating steam boiler, replacement unit or new unit subject to this rule, the monthly Compliance Report may contain aggregate emissions data from such boilers or units in lieu of emissions data for each such boiler or unit.

If the actual monthly or cumulative aggregate emissions exceed that forecast in the current Compliance Plan, the owner or operator shall submit an explanation of the exceedance, a description of all emission control and operational steps to be taken to ensure that the applicable calendar year aggregate emission limit of Section (d) will not be exceeded, and a revised forecast of the aggregate oxides of nitrogen emissions from each and all electrical generating steam boilers, replacement units and new units for each calendar month for the remainder of the calendar year.

(f) RECORDKEEPING

(1) On and after January 1, 1997, no person shall operate any electrical generating steam boiler, replacement unit or new unit subject to this rule unless such boiler or unit is equipped with continuous monitors, and associated data collection, processing and storage systems, which record and preserve, on a daily basis and in the manner and form prescribed by the Air Pollution Control Officer, all of the information needed to demonstrate compliance with Subsections (d)(1) through (d)(5) and (d)(7) of this rule, as applicable, including but not limited to:

(i) The daily emissions, in pounds, of oxides of nitrogen from each boiler, replacement unit, or new unit.

(ii) The aggregate daily emissions, in pounds, of oxides of nitrogen from all such boilers, replacement units or new units under common ownership or control.

(iii) The cumulative calendar month and annual emissions, in tons, of oxides of nitrogen, commencing with January 1 of the current calendar year, for each such boiler, replacement unit or new unit.

(iv) The cumulative calendar month and annual emissions, in tons, of oxides of nitrogen, commencing with January 1 of the current calendar year, for the aggregate of all such boilers, replacement units or new units under common ownership or control.

(v) The hours of operation for each such boiler, replacement unit or new unit.

(vi) For each such boiler, replacement unit or new unit, the following, averaged over each clock hour or portion thereof:

(A) NOx emission concentration, in parts per million by volume (ppmv) as nitrogen dioxide at three percent oxygen on a dry basis.

(B) Diluent concentration (CO_2 or O_2), in percent on a dry basis.

(C) NOx emission rate, in pounds per million Btu's of fuel heat input.

(D) Fuel heat input, in millions of Btu's.

(E) NOx mass emission, in pounds.

(F) For boilers subject to the provisions of Subsection (d)(7), NOx emissions per unit of electrical energy generated, in pounds per megawatt-hour, megawatt-hours of electrical energy generated, and the type and amount of fuel being burned.

(G) Any emission control device and boiler or unit key operating parameters specified by the Air Pollution Control Officer pursuant to Subsection (d)(3).

Oxides of nitrogen emission concentrations shall be measured at equally spaced intervals, not to be less frequent than once every five minutes, or such other period determined by the Air Pollution Control Officer to be necessary to determine compliance with this rule and not inconsistent with monitoring requirements imposed under these rules or state or federal law, and averaged up to each clock hour, or portion thereof. Only the clock hour average data, or portion thereof, must be recorded and preserved.

(2) For each electrical generating steam boiler, replacement unit or new unit, emissions of oxides of nitrogen, and megawatt-hours of electrical energy produced, if applicable, shall be measured, and the resultant data processed and reported, in accordance with a protocol prepared by the owner or operator of such boiler or unit and approved by the Air Pollution Control Officer. The protocol shall specify the maintenance, calibration and quality assurance procedures to be followed for each emission or energy measurement device and all data processing and associated equipment.

The Air Pollution Control Officer may approve continuous emissions monitoring on a common stack that serves more than one electrical generating steam boiler, replacement unit, or new unit subject to this rule provided that the owner or operator of such boilers or units demonstrates, to the satisfaction of the Air Pollution Control Officer, that such monitoring will be sufficient to determine compliance with the applicable requirements of this rule.

The records required by this section shall be retained on site for at least three years and shall be made available to the District upon request. Records of aggregate daily emissions required by Subsection (f)(1)(ii) shall be available within two working days of a request. Records of cumulative emissions required by Subsections (f)(1)(iii) and (f)(1)(iv) shall be available within 15 working days of a request.

(g) TEST METHODS

The following methods shall be used to determine compliance with the requirements of this rule:

(1) Oxides of nitrogen emissions shall be measured utilizing District Method 100 as it exists on *(date of adoption)*. This method shall not apply to continuous emission monitors required by Subsection (f)(1).

(2) The oxides of nitrogen (NOx) emission rate, in pounds, in pounds per megawatt-hour, if applicable, and in pounds per million Btu's of fuel heat input for each clock hour of operation, or portion thereof, for each boiler, replacement unit or new unit subject to the requirements of Section (d), shall be calculated in accordance with procedures approved by the Air Pollution Control Officer.

IT IS FURTHER RESOLVED AND ORDERED that the subject amendments to Rule 69 of Regulation IV shall take effect upon adoption.

PASSED AND ADOPTED by the Air Pollution Control Board of the San Diego County Air Pollution Control District, State of California, this 12th day of December, 1995 by the following votes:

AYES: Cox, Slater, Roberts, Horn
NOES: None
ABSENT: None
ABSTAIN: Jacob

This is a true certified copy of the original document on file or of record in my office. It bears the seal of the County of San Diego and signature of the Clerk of the Board of Supervisors, imprinted in purple ink.

Thomas J. Pastuszka

Clerk of the Board, San Diego County, California

Date: 1/16/96 By Deputy: Dora Cisena

APPROVED AS TO FORM AND LEGALITY
COUNTY COUNSEL

BY Dutton
DEPUTY

BOARD OF SUPERVISORS SAN DIEGO COUNTY, CALIFORNIA COUNTY OF SAN DIEGO

STATE OF CALIFORNIA) ss
County of San Diego)

I hereby certify that the foregoing is a full, true, and correct copy of the Original Resolution which is now on file in my office.

BOARD OF SUPERVISORS SAN DIEGO COUNTY, CALIFORNIA COUNTY OF SAN DIEGO

THOMAS J. PASTUSZKA
Clerk of the San Diego County
Air Pollution Control Board

By A. Gomez
Adair Gomez, Deputy

AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

CHANGE COPY

PROPOSED AMENDMENTS TO RULE 69

Proposed amendments to Rule 69 are to read as follows:

RULE 69. ELECTRICAL GENERATING STEAM BOILERS, REPLACEMENT UNITS AND NEW UNITS

(a) APPLICABILITY

(1) Except as provided in Section (b) or otherwise specified in this rule, this rule is applicable to ~~all~~ the following existing electrical generating steam boilers, and to all replacement units and to all new units, including any auxiliary boiler used in conjunction with ~~an~~ such electrical generating steam boilers, ~~and to~~ replacement units ~~and~~ or new units:

(i) Encina Power Plant Units 1, 2, 3, 4 and 5

(ii) South Bay Power Plant Units 1, 2, 3 and 4

(iii) Silvergate Power Plant Units

(2) Equipment subject to this rule shall also comply with the emission limitations and exemptions set forth in Rule 68.

(b) EXEMPTIONS

(1) The provisions of Sections (d), (e), (f) and (g) shall not apply to:

(i) Any electrical generating steam boiler with a maximum heat input capacity of less than 100 million Btu's per hour.

(ii) Boilers which generate steam used exclusively for space heat or process heat and not used for electrical generation.

(c) DEFINITIONS

For the purposes of this rule, the following definitions shall apply:

(1) **"Boiler"** means any combustion equipment fired with solid, liquid and/or gaseous fuels and used to produce steam, excluding electrical generating gas turbines.

(2) **"Calendar Day"** means the 24-hour period starting on the 00:00 hour and ending on the 24:00 hour.

(3) **"Calendar Year"** means the consecutive 12-month period beginning January 1 and ending December 31.

~~(4) **"Capacity Factor"** means the fraction of an electrical generating steam boiler's, replacement unit's or new unit's maximum electrical generating capacity that is actually utilized during a calendar year. The maximum electrical generating capacity shall be determined by multiplying the maximum rated capacity of a boiler, replacement unit or~~

~~new unit, in megawatts, by 8760 maximum operating hours per year (8784 hours for a leap year).~~

(4) **"Compliance Emissions Testing"** means any emissions or continuous emissions monitor (CEM) quality assurance/quality control (QA/QC) testing required by federal, state, or local regulations.

(5) **"Clock Hour"** means every 60-minute period starting on the hour.

(6) **"Electrical Generating Steam Boiler"** means any boiler used to produce steam to be expanded in a turbine generator used for the generation of electric power.

(7) **"Electrical Generating Gas Turbine"** means any combustion turbine fired with solid, liquid and/or gaseous fuels and used to provide direct shaft work for the generation of electric power.

(8) **"Force Majeure Natural Gas Curtailment"** means an interruption in natural gas service such that the daily fuel needs of a boiler or replacement unit subject to this rule cannot be met with the natural gas available due to:

(i) Unforeseeable natural disaster or other cause resulting in the failure or malfunction of natural gas supply, delivery or storage system facilities, not resulting from an intentional or negligent act or omission on the part of an owner or operator of a boiler, a new unit or a replacement unit, or

(ii) A supply restriction resulting from a California Public Utilities Commission priority allocation ruling, or

(iii) Delivery restrictions due to pipeline capacity limitations of the natural gas supplier or upstream transports or within a gas utility's delivery system.

(9) **"Heat Input"** means the heat derived from combustion of fuel in an electrical generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc. The maximum heat input rating means the lesser of the steady state heat input capacity of an electrical generating unit, as limited by its design and construction or as limited by an Authority to Construct or Permit to Operate.

(10) **"Megawatt-hour (MW-hr)"** means the total electrical energy generation of a boiler, new unit or replacement unit subject to this rule.

(11) **"New Unit"** means any electrical generating steam boiler or electrical generating gas turbine for which the first Authority to Construct is issued on or after January 18, 1994.

(12) **"Oxides of Nitrogen (NOx)"** means the sum of all compounds containing at least one atom of nitrogen and one atom of oxygen, measured as nitrogen dioxide~~.~~, except nitrous oxide.

(13) **"Reasonable Further Progress"** means annual incremental reductions in emissions of the applicable air pollutant which are sufficient, in the judgment of the Air Pollution Control Officer, to provide for attainment of the applicable National Ambient Air Quality Standard by the date required by law.

(14) **"Reasonably Available Control Technology"** means the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available, considering technological and economic feasibility and any technology findings made by the U. S. Environmental Protection Agency.

(15) **"Replacement Unit"** means any electrical generating steam boiler or electrical generating gas turbine which permanently replaces or augments, on or after January 18, 1994 , an existing electrical generating steam boiler subject to this rule. For purposes of this rule, a replacement unit need not be limited to the same electrical generating capacity as the existing boiler being replaced.

(16) **"SIP Control Measures"** means those emission control measures approved by the Air Pollution Control Board for inclusion in the State Implementation Plan (SIP) required by federal law or contained in the SIP approved by the U.S. Environmental Protection Agency.

~~(16) **"Startup"** means the period of time during which a boiler, replacement unit or new unit, and associated emissions control device(s), are being heated to the minimum functional operating temperatures of the emission control device(s), or when electrical generation equals or exceeds 25 percent of rated capacity, whichever is sooner.~~

~~(17) **"Shutdown"** means the period of time during which a boiler, replacement unit or new unit, and its associated emissions control device(s), are allowed to cool from the minimum functional operating temperatures of the emission control device(s) or when electrical generation drops below 25 percent of rated capacity, whichever is later.~~

(d) STANDARDS

A person shall not operate an existing electrical generating steam boiler, replacement unit or new unit subject to this rule unless only natural gas, alternative fuel and/or fuel oil is burned and the following requirements are met. If an alternative fuel is burned in an existing boiler subject to the provisions of Subsection (d)(7), the operator shall have previously demonstrated to the satisfaction of the Air Pollution Control Officer that the emissions of oxides of nitrogen (NOx) per megawatt-hour of electricity generated is not greater than would be the emissions from the burning of natural gas in the same boiler, replacement unit or new unit.

~~(1) Except as provided in Subsections (d)(2) through (d)(6), a person shall not operate an electrical generating steam boiler unless:~~

~~(i) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the boiler do not exceed 0.15 pounds per megawatt-hour, and~~

~~(ii) The person has met the compliance schedule specified in Section (e).~~

~~(2) Except as provided in Subsections (d)(3), (d)(4) and (d)(5), no person shall operate one or more of the electrical generating steam boilers listed below unless the emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the boiler do not exceed 0.18 pounds per megawatt-hour and such person has met the compliance schedule specified in Section (e).~~

~~Encina Power Plant Units 1, 2, 3 and 4~~
~~South Bay Power Plant Units 1,2 and 4~~

~~(3) The provisions of Subsection (d)(2) shall not apply and the provisions of Subsection (d)(1) shall apply if the capacity factor of an electrical generating boiler with a maximum heat input rating of equal to or greater than 2100 million Btu's per hour is greater than 0.15 over any calendar year.~~

~~(4)~~ (1) Fuel Oil Firing ~~NOx Emission Rate Limits~~

A person shall not operate an electrical generating steam boiler, replacement unit or new unit when burning fuel oil on or after January 1, 1997 unless~~:~~

~~(i) The requirements of Subsection (d)(1), (d)(2) or (d)(3), as applicable, are met by the operator of an affected boiler when burning natural gas exclusively in that boiler, and~~

~~(ii) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from an affected boiler do not exceed 0.40 pounds per megawatt-hour when burning fuel oil exclusively in that boiler, and~~

~~(iii) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the boiler when fired on a mixture of fuel oil and natural gas do not exceed the limits prescribed in Subsections (d)(4)(i) and (d)(4)(ii), prorated for the relative heat input from fuel oil and natural gas, as follows:~~

$$\cancel{EL = \frac{[(Lo)(Qo)(HHVo)] + [(Lg)(Qg)(HHVg)]}{(Qo)(HHVo) + (Qg)(HHVg)}}$$

~~where,~~

~~EL~~	~~=~~	~~Emission limit, pounds per megawatt-hour~~
~~Lo~~	~~=~~	~~0.40 pounds per megawatt-hour~~
~~Qo~~	~~=~~	~~Quantity of fuel oil burned, barrels per hour~~
~~HHVo~~	~~=~~	~~Higher heating value of fuel oil, Btu's per barrel~~
~~Lg~~	~~=~~	~~0.15 or 0.18 pounds per megawatt-hour, as applicable~~
~~Qg~~	~~=~~	~~Quantity of natural gas burned, scf per hour~~
~~HHVg~~	~~=~~	~~Higher heating value of natural gas, Btu per scf,~~

~~and~~

~~(iv)~~ the Air Pollution Control Officer has determined that an exceedance of the state ambient air quality standard for ozone is not predicted at any location in the air basin at any time during the fuel oil burning. This paragraph shall not apply when burning of fuel oil is required due to a force majeure natural gas curtailment. Prior to January 1, 1998 ~~7~~, this paragraph shall not apply to fuel oil burning in the existing South Bay Power Plant Unit 4 boiler on days when fuel oil burning is needed to meet peak electrical generation demand.

~~(5) Low Capacity Factor Boiler NOx Emission Rate Limits~~

~~The provisions of Subsections (d)(1)(i), (d)(2) and (d)(4)(i), (ii) and (iii), shall not apply to the operation of the existing electrical generating steam boilers located at the Silvergate Power Plant nor to the existing Unit 4 boiler at the South Bay Power Plant provided:~~

~~(i) The capacity factor for each such boiler, over each calendar year, does not exceed 0.10, and~~

~~(ii) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, do not exceed 0.60 pounds per megawatt-hour when burning natural gas, and~~

~~(iii) Fuel oil shall not be burned in the Silvergate Power Plant boilers, and may only be burned in the South Bay Unit 4 boiler during force majeure natural gas curtailments on and after January 1, 1997. Prior to January 1, 1997, this limitation shall not apply to fuel oil burning in the South Bay Power Plant Unit 4 boiler on days when fuel oil burning is needed to meet peak electrical generation demand. The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the South Bay Unit 4 boiler when burning fuel oil shall not exceed 1.20 pounds per megawatt-hour and when fired on a mixture of fuel oil and natural gas shall not exceed the limits prescribed in Subsections (d)(5)(ii) and (d)(5)(iii), prorated for the relative heat input from fuel oil and natural gas, as follows:~~

$$\cancel{EL = \frac{[(Lo)(Qo)(HHVo)] + [(Lg)(Qg)(HHVg)]}{(Qo)(HHVo) + (Qg)(HHVg)}}$$

~~where,~~

~~EL~~	~~=~~	~~Emission limit, pounds per megawatt-hour~~
~~Lo~~	~~=~~	~~1.20 pounds per megawatt-hour~~
~~Qo~~	~~=~~	~~Quantity of fuel oil burned, barrels per hour~~
~~HHVo~~	~~=~~	~~Higher heating value of fuel oil, Btu's per barrel~~
~~Lg~~	~~=~~	~~0.60 pounds per megawatt-hour~~
~~Qg~~	~~=~~	~~Quantity of natural gas burned, scf per hour~~
~~HHVg~~	~~=~~	~~Higher heating value of natural gas, Btu per scf,~~

~~and~~

~~(iv) The Air Pollution Control Officer has determined that an exceedance of the state ambient air quality standard for ozone is not predicted at any location in the air basin at any time during the fuel oil burning. This paragraph shall not apply when burning of fuel oil is required due to a force majeure natural gas curtailment.~~

~~(6) Compliance with the standards of Subsections (d)(1) through (d)(5) shall be based on emissions of oxides of nitrogen from an affected boiler averaged over each calendar day of operation, or portion thereof, excluding periods of startups and shutdowns.~~

~~(7) Startups and Shutdowns~~

~~The provisions of Subsections (d)(1)(i), (d)(2)(i), (d)(3), (d)(4) and (d)(5) shall not apply to electrical generating steam boilers during periods of startup or shutdown provided the startup or shutdown does not exceed fifteen hours.~~

~~(8)~~ (2) Replacement Units and New Units NOx Emission Limits

~~Notwithstanding the requirements of Subsections (d)(1) through (d)(7), no~~ A person shall not operate a replacement unit or new unit subject to this rule unless such unit has been built with, and is operated in conjunction with, the Lowest Achievable Emission Rate or Best Available Control Technology as applicable and defined in Rule 20.1 for emissions of oxides of nitrogen. ~~Emissions of oxides of nitrogen from any replacement unit or new unit shall not be greater than the emission rate limit of Subsection (d)(1)(i). For a cogeneration unit which generates process steam as well as electricity, the emissions of oxides of nitrogen per megawatt-hour of electrical energy generated shall be determined by prorating the total unit emissions of oxides of nitrogen by the ratio of the gross electrical energy generated to the total energy produced by the unit.~~

(3) Maximum NOx Emissions Control Performance

On and after January 1, 1997~~7~~, a person shall not operate an electrical generating steam boiler, replacement unit or new unit ~~on any calendar day for which the Air Pollution Control Officer has predicted an exceedance of the state ambient air quality standard for ozone at any location in the air basin at any time during that day~~ unless all NOx emissions controls associated with such boiler, replacement unit or new unit are operated in a manner that achieves the maximum NOx emission control performance, taking into consideration the electrical generation load, for that boiler or unit. The Air Pollution Control Officer shall specify ~~maximum~~ allowable NOx emission rates and/or key emission control device and boiler or unit operating parameters~~, to be applicable on days predicted to exceed the state ambient air quality standard for ozone,~~ in the Authority to Construct and/or Permit to Operate for NOx emission controls proposed by the owner or operator to be used on each such boiler, replacement unit or new unit as necessary to ensure compliance with this requirement.

~~(9)~~ (4) Aggregate NOx Emission Limit

(i) Except as provided in Subsection (d)(5), ~~(10),~~ no person who owned or operated an electrical generating steam boiler subject to this rule on January 18, 1994 ~~or company which qualifies for the NOx offset waiver provisions of Subsection (d)(11)~~ shall operate any existing electrical generating steam boiler, replacement unit or new unit subject to this rule unless such person ~~or company~~ has demonstrated that the aggregate emissions of oxides of nitrogen, expressed as nitrogen dioxide, from all such boilers, replacement units and new units located in San Diego County and owned or operated by such person ~~or company~~ and any electrical generating steam boilers, replacement units and new units located in San Diego County that are owned or operated by ~~a company~~ another entity in which such person ~~or company~~ has a controlling interest, are not greater than:

~~(i)~~ (A) On and after January 1, 1997, 2100 tons during every calendar year.

(B) On and after January 1, 2001, 800 tons during every calendar year.

(C) On and after January 1, 2005, 650 tons during every calendar year.

(ii) The aggregate NOx emission limits specified in Subsections (d)(4)(i)(A), ~~and~~ (d)(4)(i)(B) and (d)(4)(i)(C) shall be adjusted if any existing boiler replacement unit or new unit subject to the aggregate limit is transferred to another entity in which the person who owned or operated an existing boiler on January 18, 1994 does not have a controlling interest. The transferred existing boiler, replacement unit or new unit shall not be subject to an aggregate NOx emission limit pursuant to this rule, but shall be subject to unit specific emission limits, as applicable, specified in Subsections (d)(2) and (d)(7) of this rule.

(iii) The aggregate NOx emission limits shall be adjusted when boilers or units are transferred by reducing the limits by an amount equal to the annual average megawatt-hours generated over the five years preceding transfer when burning natural gas, fuel oil, and any combination of natural gas and fuel oil, for each such boiler or unit, multiplied by a NOx emission rate of 0.15 pounds per megawatt-hour when burning natural gas, a NOx emission rate of 0.40 pounds per megawatt-hour when burning fuel oil and, when burning a combination of natural gas and fuel oil, a NOx emission rate prorated for the relative heat input from natural gas and fuel oil, as specified in Subsection (d)(7) of this rule. For boilers, replacement units or new units that have operated less than five years prior to transfer, the annual average megawatt-hours generated shall be based on the most representative years of operation preceding transfer, as determined by the Air Pollution Control Officer.

(iv) The annual oxides of nitrogen emission limits specified in this subsection shall be adjusted to account for fuel oil burning that results from a force majeure natural gas curtailment, or is due to compliance emissions testing, using methods approved by the Air Pollution Control Officer. The adjustment shall be made by adding to the applicable limit the difference between the total pounds of oxides of nitrogen emissions occurring during such fuel oil burning and the total pounds of oxides of nitrogen emissions which would have occurred during the same period had natural gas been fired in that boiler, replacement unit or new unit. ~~product of the megawatt-hours generated by each boiler, replacement unit, or new unit during such fuel oil burning and the difference between the applicable oxides of nitrogen emission rate limits for fuel oil burning and natural gas burning in that boiler, replacement unit or new unit.~~ The adjustment shall be prorated for the relative heat inputs of fuel oil and natural gas when co-firing both fuels.

~~(10)~~ (5) Exceedances of an Aggregate NOx Emission Limit

An ~~person or company~~ owner or operator subject to the requirements of Subsection (d)(4)~~(9)~~ may operate its electrical generating steam boilers, replacement units and new units when aggregate oxides of nitrogen emissions exceed the calendar year limits specified in Subsection (d)(4)~~(9)~~ provided:

~~(i) Such person or company owner or operator has demonstrated, to the satisfaction of the Air Pollution Control Officer, that the exceedance is due to an unforeseen event, such as a forced outage of one or more generating units boilers, replacement units or new units or a disruption in the supply of imported power, and is not due to an intentional or negligent act or omission on the part of such person or company, and~~

~~(ii)~~(i) The Air Pollution Control Officer has approved the exceedance in advance and has issued modified permits to operate for the affected equipment adding conditions that establish a new, enforceable calendar year aggregate emission limit, and

~~(iii)~~(ii) Such ~~person or company~~ owner or operator has provided, in advance, offsetting emission reductions, on an annual basis and at a ~~1.3~~ 1.0 to 1.0 offset ratio, for all emissions of oxides of nitrogen in excess of the calendar year limits specified in Subsection (d)(4)~~(9)~~.

The new calendar year aggregate oxides of nitrogen emission limit established pursuant to ~~Subsection (d)(10)(ii)~~ the above shall be based on the sum of the aggregate emission limit specified in Subsection (d)(4) and the emission offsets provided pursuant to Subsection (d)(5). ~~maximum expected calendar year emissions in compliance with this rule. The quantity of offsetting emission reductions required shall be 1.3 times the difference between the new calendar year aggregate oxides of nitrogen emission limit and the applicable calendar year limit specified in Subsection (d)(9).~~ Offsetting emission reductions shall conform to the criteria for emission offsets specified in Rule 20.1.

~~(11)~~ (6) Waiver from New Source Review NOx Offset Requirements

On and after January 1, 1997, oxides of nitrogen emission increases from any new, modified or replacement unit subject to and in compliance with Subsections (d)(4)~~(9)~~ and (d)(5)~~(10)~~ of this rule, shall not be subject to the offset provisions of Regulation II, Rules 20.1 through ~~20.4~~ 20.3, and 20.9 (New Source Review) of these Rules and Regulations provided that:

(i) The owner or operator of the new, modified or replacement unit has demonstrated, using methods approved by the Air Pollution Control Officer and the U.S. Environmental Protection Agency, the extent to which the NOx emission reductions that have been achieved by the owner or operator from electrical generating steam boilers existing prior to January 18, 1994 by compliance with this rule are in excess of the NOx emission reductions required to demonstrate compliance with Reasonably Available Control Technology, any NOx emission reductions from electrical generating steam boilers contained in SIP Control Measures and any NOx emission reductions from electrical generating steam boilers necessary to demonstrate compliance with Reasonable Further Progress, and

(ii) The excess NOx emission reductions determined in Subsection (d)(6)(i) ~~(11)(i)~~ are greater than ~~1.3~~ 1.2 times the NOx emissions increases from the new, modified or replacement unit that would otherwise be subject to the offset provisions of Regulation II, Rules 20.1 through ~~20.4~~ 20.3, and 20.9 (New Source Review) of these Rules and Regulations, and

(iii) The excess NOx emission reductions determined in Subsection (d)(6)(i) ~~(11)(i)~~ are reduced by ~~1.3~~ 1.2 times the NOx emissions increases from the new, modified or replacement unit that would otherwise be subject to the offset provisions of Regulation II, Rules 20.1 through ~~20.4~~ 20.3, and 20.9 (New Source Review) of these Rules and Regulations.

Only oxides of nitrogen emission increases associated with generating capacity which the California Energy Commission or the California Public Utilities Commission or their successor, as applicable, has determined a need for shall be eligible for this waiver.

(7) NOx Emission Rate Limits for Existing Boilers Not Subject to an Aggregate NOx Emission Limit

The emissions of oxides of nitrogen from any existing electrical generating steam boiler that has been transferred to another entity in which the person who owned or operated the boiler on January 18, 1994 does not have a controlling interest, shall not exceed 0.15 pounds per megawatt-hour when burning exclusively natural gas, 0.40 pounds per megawatt-hour when burning exclusively fuel oil, and a prorated emissions limit, determined as follows, when burning a combination of natural gas and fuel oil:

$$EL = \frac{[(Lo)(Qo)(HHVo)] + [(Lg)(Qg)(HHVg)]}{(Qo)(HHVo) + (Qg)(HHVg)}$$

where,

EL	=	Emission limit, pounds per megawatt-hour
Lo	=	0.40 pounds per megawatt-hour
Qo	=	Quantity of fuel oil burned, barrels per hour
HHVo	=	Higher heating value of fuel oil, Btu's per barrel
Lg	=	0.15 pounds per megawatt-hour
Qg	=	Quantity of natural gas burned, scf per hour
HHVg	=	Higher heating value of natural gas, Btu per scf.

Compliance with the standards of this subsection shall be based on emissions of oxides of nitrogen from an affected boiler averaged over each calendar day of operation, or portion thereof.

~~(12)~~ (8) Emission Standards for Ammonia

The emissions of ammonia from any electrical generating steam boiler, replacement unit or new unit subject to the requirements of this rule, or from any emissions control device used to achieve compliance with this rule, shall not be greater than the lowest emission rate achievable, consistent with the requirements of this rule, taking into consideration the costs of achieving that emission rate and the potential public health impacts associated with such emissions.

~~(13)~~ (9) Banking of Excess Emission Reductions

No person shall be eligible to obtain emission reduction credits for emissions of oxides of nitrogen below the limits specified in this Section (d), with the exception of any boiler subject to and in compliance with the emission limits specified in Subsection (d)(7).

(e) **COMPLIANCE SCHEDULE, PLAN AND REPORT**

(1) ~~Increments of Progress~~ Compliance Schedule

A person subject to the provisions of Section (d) shall comply with the following increments of progress:

(i) Any replacement unit or any new unit shall be in compliance with the applicable requirements of Section (d) on and after initial startup.

(ii) ~~Not later than January 18, 1997, be in compliance with the applicable requirements of Section (d) for not fewer than one electrical generating steam boiler, replacement unit or new unit and each calendar year thereafter bring into compliance a minimum of one additional boiler, replacement unit or new unit owned or operated by such person.~~ Any existing electrical generating steam boiler subject to the requirements of Subsection (d)(7) shall be in compliance with the requirements of this rule within two years after the first transfer of such boiler that occurs after *(date of adoption)*, but not later than January 1, 2001.

(iii) ~~Except as provided in Subsection (e)(1)(iv) below, on and after January 1, 2001, be in compliance with the requirements of Section (d) for all operating electrical generating steam boilers, replacement units and new units owned or operated by such person.~~ The owner or operator of an existing electrical generating steam boiler, replacement unit or new unit subject to the provisions of Subsection (d)(4) shall be in compliance with the applicable aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5) beginning with calendar year 1997, and each calendar year thereafter.

~~(iv) Be in compliance with Section (d) by January 1, 2003, or upon initial startup, whichever is sooner, for all replacement units, and associated boiler(s), scheduled for initial startup between January 1, 2001 and January 1, 2003.~~

(2) Initial Compliance Plan~~/Report~~

~~(i)~~ The owner or operator of any equipment subject to the provisions of this rule shall submit to the Air Pollution Control Officer, for approval, by ~~July 18, 1994~~ *(date of adoption + 180 days)* a Compliance Plan describing the actions, and contingencies, which are proposed by the owner or operator to meet the requirements of Section (d) ~~and Subsection (e)(1)~~. The Compliance Plan shall be approved if it demonstrates that the requirements of this rule will be met. The Compliance Plan shall contain, at a minimum, the following applicable information for each electrical generating steam boiler, replacement unit and new unit subject to this rule:

- District Permit to Operate number.
- Equipment location.
- Manufacturer.
- Model number.
- Maximum permitted heat input rating.
- Primary and backup fuels to be used.
- Proposed methods to measure, ~~and~~ record and report ~~megawatt-hours~~ emissions of oxides of nitrogen, measured as parts per million by volume (ppmv) as nitrogen dioxide at 3% O_2, as pounds per million Btu's of fuel heat input, as pounds per day, as tons per calendar month and as tons per calendar year ~~generated and watt transducer calibration method with supporting documentation~~.
- For existing boilers subject to the provisions of Subsection (d)(7), proposed methods to measure, ~~and~~ record and report megawatt-hours generated and watt transducer calibration method with supporting documentation.
- Maximum hourly, daily and annual pre-controlled NOx emission rates.
- Method and type of emission controls to be used.
- Expected performance of the emission controls.
- Proposed schedule for applications for Authorities to Construct, issuing purchase orders for emission controls, commencing construction of emission controls, completing construction, conducting compliance tests and demonstrating compliance with the provisions of this rule.
- For boilers and replacement units and new units subject to the aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5), a forecast of aggregate emissions of oxides of nitrogen, in tons, for each calendar month of the next calendar year, a forecast of aggregate emissions of oxides of nitrogen, in tons, for each calendar year through the year 2001, and a demonstration of how compliance will be achieved with the aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5).
- All analyses, operating data, emission factors, assumptions and calculations used to develop the forecast of aggregate calendar month and calendar year emissions of oxides of nitrogen.

The initial Compliance Plan submittal need not contain detailed information regarding emission control specifications, performance and schedules, but must contain at least preliminary information regarding the type of control equipment and the anticipated ~~final compliance~~ date for installation of any planned emission controls for each affected unit. A copy of the Compliance Plan shall be kept at each affected site and shall be made available for District inspection upon request. Adherence to a Compliance Plan does not relieve the owner or operator from complying with any other provisions of this rule. The owner or operator of any boiler, replacement unit or new unit subject to this rule shall update the Compliance Plan ~~shall be updated~~ annually.

(3) Compliance Reporting

(i) Annual Compliance Report

~~(ii)~~ The owner or operator of any equipment subject to the provisions of this rule shall submit by the submittal date in 1997 of the Emissions Statement Form(s) required by Rule 19.3, and each year thereafter, a Compliance Report which describes the measures taken in the preceding calendar year to achieve compliance with the requirements of Section (d) ~~and Subsection (e)(1)~~. The Compliance Report shall contain, at a minimum, the following information for the preceding calendar year for each electrical generating steam boiler, replacement unit and new unit subject to Section (d) of this rule:

- District Permit to Operate number.
- Number of hours of operation.
- Types and amounts of fuels consumed, and the number of hours on each fuel type.
- Dates and times of any force majeure natural gas curtailments that occurred.
- Mass emissions of oxides of nitrogen for each calendar ~~day~~ month and for the calendar year for each such boiler and unit and for the aggregate emissions of such boilers and units under common ownership or control.
- Megawatt-hours generated and total mass emissions of NOx each calendar day and for the calendar year for each boiler subject to the NOx emission rate limits of Subsection (d)(7).
- Indication of whether the ~~unit~~ owner or operator is on schedule to meet the Compliance Plan(s) submitted pursuant to Subsection (e)(1).
- ~~Emissions rate data and/or key emissions control device or boiler or unit operating parameter data, as required pursuant to Subsection (d)(3), for each day that the Air Pollution Control Officer predicted an exceedance of the state ambient air quality standard for ozone during the preceding calendar year.~~
- Identification of each exceedance of the applicable requirements of Section (d).

The Compliance Report submitted in 1998 for calendar year 1997, and each annual compliance report thereafter, shall contain a demonstration by the owner or operator, in the manner and form prescribed by the Air Pollution Control Officer, that the applicable requirements of Section (d) were met in the preceding calendar year. The Compliance Report shall be certified by the owner or operator as to its accuracy and completeness.

Where the Air Pollution Control Officer has approved emissions monitoring on a common stack that serves more than one electrical generating steam boiler, replacement unit, or new unit subject to this rule, the annual Compliance Report may contain aggregate emissions data from such boilers or units in lieu of emissions data for each such boiler or unit.

The Compliance Report shall also contain any proposed revisions to the Compliance Plan. These revisions shall include the justification for the changes and a demonstration that the changes will ensure compliance with the requirements of Section (d) and Subsection (e)(1). The Compliance Report submitted in year 2001, and each year thereafter, shall include a forecast of aggregate emissions of oxides of nitrogen, in tons, for each calendar year through the year 2005, and a demonstration of how compliance will be achieved with the aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5).

Documentation and calculations used to prepare the material presented in the Compliance Report shall be maintained by the owner or operator for at least two years and shall be made available to the District upon request.

(ii) Monthly Compliance Reporting

The owner or operator of any boiler, replacement unit or new unit subject to the provisions of Subsections (d)(4)and (d)(5) shall submit monthly, by the 15th day of the calendar month, a report of the aggregate oxides of nitrogen emissions for the preceding calendar month and cumulatively for the current calendar year from each and all such boilers, replacement units and new units under the control of the owner or operator, and a comparison of oxides of nitrogen emissions during the preceding calendar months for the current calendar year to that forecast in the current Compliance Plan.

Where the Air Pollution Control Officer has approved emissions monitoring on a common stack that serves more than one electrical generating steam boiler, replacement unit or new unit subject to this rule, the monthly Compliance Report may contain aggregate emissions data from such boilers or units in lieu of emissions data for each such boiler or unit.

If the actual monthly or cumulative aggregate emissions exceed that forecast in the current Compliance Plan, the owner or operator shall submit an explanation of the exceedance, a description of all emission control and operational steps to be taken to ensure that the applicable calendar year aggregate emission limit of Section (d) will not be exceeded, and a revised forecast of the aggregate oxides of nitrogen emissions from each and all electrical generating steam boilers, replacement units and new units for each calendar month for the remainder of the calendar year.

(f) RECORDKEEPING

(1) On and after January 1, 1997, no person ~~or company subject to the requirements of Subsection (d)(9)~~ shall operate any electrical generating steam boiler, replacement unit or new unit subject to this rule unless such boiler or unit is equipped with continuous ~~emission~~ monitors, and associated data collection, processing and storage systems, which

record and preserve, on a daily basis and in the manner and form prescribed by the Air Pollution Control Officer, all of the information needed to demonstrate compliance with Subsections (d)(1), (~~d)~~(4)~~(9) and~~ through (d)(5)~~(10)~~ and (d)(7) of this rule, as applicable, including but not limited to:

(i) The daily emissions, in pounds, of oxides of nitrogen from each boiler, replacement unit, or new unit.

(ii) The aggregate daily emissions, in pounds, of oxides of nitrogen from all such boilers, replacement units or new units under common ownership or control.

(iii) The cumulative calendar month and annual emissions, in tons, of oxides of nitrogen, commencing with January 1 of the current calendar year, for each such boiler, replacement unit or new unit.

(iv) The cumulative calendar month and annual emissions, in tons, of oxides of nitrogen, commencing with January 1 of the current calendar year, for the aggregate of all such boilers, replacement units or new units under common ownership or control.

(v) The hours of operation for each such boiler, replacement unit or new unit.

(vi) For each such boiler, replacement unit or new unit, the following, averaged over each clock hour or portion thereof:

(A) NOx emission concentration, in parts per million by volume (ppmv) as nitrogen dioxide at three percent oxygen on a dry basis.

(B) Diluent concentration (CO_2 or O_2), in percent on a dry basis.

(C) NOx emission rate, in pounds per million Btu's of fuel heat input.

(D) Fuel heat input, in millions of Btu's.

(E) NOx mass emission, in pounds.

(F) For boilers subject to the provisions of Subsection (d)(7), NOx emissions per unit of electrical energy generated, in pounds per megawatt-hour, megawatt-hours of electrical energy generated, and the type and amount of fuel being burned.

(G) Any emission control device and boiler or unit key operating parameters specified by the Air Pollution Control Officer pursuant to Subsection (d)(3).

Oxides of nitrogen emission concentrations shall be measured at equally spaced intervals, not to be less frequent than once every five minutes, or such other period determined by the Air Pollution Control Officer to be necessary to determine compliance with this rule and not inconsistent with monitoring requirements imposed under these rules or state or federal law, and averaged up to each clock hour, or portion thereof. Only the clock hour average data, or portion thereof, must be recorded and preserved.

~~(2) On and after the final compliance date specified in the Compliance Plan, a person shall not operate any electrical generating steam boiler, replacement unit or new unit subject to this rule unless such boiler or unit is equipped with continuous monitors, approved by the Air Pollution Control Officer, which record and preserve all of the information needed to determine compliance with Subsections (d)(1) through (d)(5) and (d)(7), including but not limited to:~~

~~(i) The hours of operation of the unit.~~

~~(ii) The emission concentration of oxides of nitrogen, calculated as parts per million by volume (ppmv) of nitrogen dioxide at three percent oxygen on a dry basis, averaged over every clock hour of operation, or portion thereof. The emission concentration shall be measured at equally spaced intervals, not to be less frequent than once every five minutes, or such other period determined by the Air Pollution Control Officer to be necessary to determine compliance with this rule and not inconsistent with monitoring requirements imposed under these rules or state or federal law, and averaged up to each clock hour, or portion thereof. Only the clock hour average data, or portion thereof, must be recorded and preserved.~~

~~(iii) The unit exhaust flue gas flow rate, calculated as cubic feet per hour at standard conditions and at three percent oxygen on a dry basis, averaged over every clock hour of operation, or portion thereof. The exhaust flue gas flow rate shall be measured at the same interval as emission concentration measurements. If unit exhaust flue gas flow rate is not measured directly but instead calculated from fuel flow rate or other operating parameter, such parameter shall be measured at the specified concentration measurement interval, the parameter measurement shall be recorded, and the exhaust flue gas flow rate shall be calculated for each such interval. The exhaust flue gas flow rate measurements shall be averaged up to each clock hour, or portion thereof. Only the clock hour average data, or portion thereof, must be recorded and preserved.~~

~~(iv) The emissions of oxides of nitrogen shall be calculated, as pounds of nitrogen dioxide, during every interval of emission concentration measurement using the emission concentration and exhaust flue gas flow rate measurements required in Subsections (f)(2)(ii) and (f)(2)(iii) above. The emissions of oxides of nitrogen during every clock hour of operation, or portion thereof, shall be calculated by summing the emissions calculated for each measurement interval, following the methods described in Subsection (g)(4), and shall be recorded.~~

~~(v) The megawatt-hours of electrical energy generated by the unit during every clock hour of operation, or portion thereof shall be measured and recorded.~~

~~(vi) The cumulative emissions of oxides of nitrogen, expressed as pounds of nitrogen dioxide; the total megawatt-hours of electrical energy generated; and, the average emission rate of oxides of nitrogen, expressed as pounds of nitrogen dioxide per megawatt-hour of energy generated, for every calendar day of operation, or portion thereof, shall be calculated and recorded.~~

<u>(2) For each electrical generating steam boiler, replacement unit or new unit, emissions of oxides of nitrogen, and megawatt-hours of electrical energy produced, if applicable, shall be measured, and the resultant data processed and reported, in accordance with a protocol prepared by the owner or operator of such boiler or unit and approved by the Air Pollution Control Officer. The protocol shall specify the maintenance, calibration and quality assurance procedures to be followed for each emission or energy measurement device and all data processing and associated equipment.</u>

The Air Pollution Control Officer may approve continuous emissions monitoring on a common stack that serves more than one electrical generating steam boiler, replacement unit, or new unit subject to this rule provided that the owner or operator of such boilers or units demonstrates, to the satisfaction of the Air Pollution Control Officer, that such monitoring will be sufficient to determine compliance with the applicable requirements of this rule.

The records required by this section shall be retained on site for at least three years and shall be made available to the District upon request. Records of aggregate daily emissions required by Subsection (f)(1)(ii) shall be available within two working days of a request. Records of cumulative emissions required by Subsections (f)(1)(iii) and (f)(1)(iv) shall be available within ~~20~~ 15 working days of a request.

(g) **TEST METHODS**

The following methods shall be used to determine compliance with the requirements of this rule:

(1) Oxides of nitrogen emissions shall be measured utilizing District ~~modified~~ Method ~~20~~ 100 as it exists on ~~January 18, 1994~~ *(date of adoption)*. This method shall not apply to continuous emission monitors required by Subsections (f)(1) ~~and (f)(2)~~.

~~(2) Total energy generation in megawatt hours shall be measured using watt transducers calibrated according to methods approved by the Air Pollution Control Officer. The methods shall be submitted by the owner or operator of a boiler or unit as part of the compliance plan required by Subsection (e)(2), and shall include a description of the principal of measurement, the frequency of measurement and basis therefore, and the calculations used to determine the megawatt hours (MW-hr) generated. The method shall also include the techniques and procedures used to calibrate each measurement device. Each measurement device shall be calibrated against standards which are based on the National Institute of Standards and Technology (NIST) standards or equivalent if no NIST standards exist. The calibration accuracy tolerance of each measurement device shall be (+/-) 0.5 percent of each measured value.~~

~~(3)~~ (2) The oxides of nitrogen (NOx) emission rate, in pounds, in pounds per megawatt-hour, if applicable, and in pounds per million Btu's of fuel heat input for each clock hour of operation, or portion thereof, for each boiler, replacement unit or new unit subject to the requirements of ~~Subsections~~ Section (d) ~~(1) or (d)(2)~~, shall be calculated ~~as follows:~~ in accordance with procedures approved by the Air Pollution Control Officer.

$$\cancel{NOx_{lb/MW\text{-}hr} = \frac{NOx_{lb}}{MW\text{-}hr_{Total}}}$$

~~where,~~

~~$NOx_{lb/MW\text{-}hr}$ = NOx emission rate in lb/MW-hr, for each clock hour of operation, or portion thereof.~~

~~NOx_{lb} = NOx emissions in pounds during each clock hour, as calculated in Subsection (g)(4) below.~~

~~$MW\text{-}hr_{Total}$ = Total megawatt-hours generated for each clock hour.~~

~~(4) The emissions of oxides of nitrogen (NOx) for each applicable unit during each clock hour, or portion thereof, shall be calculated as follows:~~

$$\cancel{NOx_{lb} = \sum_{i=1}^{n} NOx_i}$$

~~where,~~

~~NOx_{lb} = Emissions of oxides of nitrogen, in pounds, during each clock hour of operation.~~

~~NOx_i = Emission of oxides of nitrogen, in pounds, calculated for each five minute or approved alternative time interval within each clock hour, or portion thereof.~~

~~n = Number of valid data points during each clock hour of operation, or portion thereof. There shall not be fewer than four valid data points during each clock hour.~~

~~Emissions occurring during periods of no electrical generation shall not be included when calculating oxides of nitrogen emissions per megawatt-hour but shall be included when calculating aggregate oxides of nitrogen emissions for a calendar year.~~

AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

PROPOSED AMENDED RULE 69
ELECTRICAL GENERATING STEAM BOILERS, REPLACEMENT UNITS AND NEW UNITS

WORKSHOP REPORT

A workshop notice was mailed to each company that might be subject to the rule, to each participant at a previous workshop on Rule 69, to all interested parties, and to the U.S. Environmental Protection Agency (EPA), the California Air Resources Board (ARB), the California Energy Commission (CEC), and the California Public Utilities Commission (CPUC).

The workshop was held on September 7, 1995 and was attended by 11 people. Written comments were also received from one interested party. No written comments were received from the EPA nor the ARB. The following are the comments received and District responses.

1. **WORKSHOP COMMENT**

What is the status of the approval by EPA of the recent revisions to District Rule 68 into the SIP?

DISTRICT RESPONSE

Rule 68, which applies to large fuel burning equipment including electrical generating steam boilers, was revised on September 20, 1994 and submitted to EPA for approval into the SIP on October 19, 1994. As of this date, EPA has not acted on the submission.

2. **WORKSHOP/WRITTEN COMMENT**

Was the change to the offset ratio in Section (d)(4)(ii) of the rule related to the change in the San Diego Air Basin's non-attainment reclassification?

DISTRICT RESPONSE

Since the emission reductions required by Rule 69 are intended to meet the requirements of the California Clean Air Act, and are not related to the Air Basin's ozone classification relative to the national ambient air quality standard, the offset ratio for exceedances of the emissions cap in limited circumstances was changed from 1.3 : 1.0 to 1.0 : 1.0.

3. **WORKSHOP/WRITTEN COMMENT**

Does the rule allow interpollutant trading for offsets?

DISTRICT RESPONSE

Rule 69 allows offsetting emission reductions to be provided in certain circumstances when the annual oxides of nitrogen (NOx) emissions cap may be exceeded. It also specifies that the offsetting emission reductions must conform to the criteria for emission offsets specified in District Rule 20.1. Since Rule 20.1 allows interpollutant offsets, such offsets would be allowed under Rule 69.

4. **WORKSHOP/WRITTEN COMMENT**

In different locations, the rule refers to person/company and owner/operator. Are they the same?

DISTRICT RESPONSE

Yes. The rule language will be clarified to reflect consistent references.

5. **WORKSHOP COMMENT**

Are there opportunities for other companies to qualify for the emissions offset waiver?

DISTRICT RESPONSE

The emission offset waiver provided in Rule 69 is only available to owners/operators of existing boilers subject to the rule who implement sufficient emission reductions at those existing boilers in excess of U.S. EPA Reasonably Available Control Technology requirements, and who meet other criteria specified. Since San Diego Gas and Electric is the only owner/operator of existing boilers subject to the rule who would be able to implement sufficient emission reductions, it is unlikely that any other party could qualify for the emission offset waiver.

6. **WORKSHOP COMMENT**

How does the District forecast possible exceedances of the state ambient air quality standard for ozone?

DISTRICT RESPONSE

The District meteorological staff evaluate meteorological forecasts for the air basin, air quality in neighboring areas, air basin topography, and historic and seasonal trends associated with state ozone standard exceedances. Based on this information, the District prepares a forecast for anticipated air quality levels for the following day. This forecast is available to the public on a tape recorded message (565-6626).

7. **WORKSHOP COMMENT**

Did the District evaluate the fiscal impacts of the proposed Rule 69 amendments on electricity rates? Did that analysis include the "stranded costs" associated with inactive units?

DISTRICT RESPONSE

The proposed amendments to Rule 69 are not expected to result in any increased costs and impacts on electricity rates compared to current Rule 69. The proposed amendments could result in reduced costs and impacts. The electricity rate and socioeconomic impacts of current Rule 69 were evaluated by a District contractor prior to adoption of Rule 69 in 1994. That study is available from the District. All resource forecasts associated with the currently operating SDG&E boilers show those boilers continuing to operate after implementation of Rule 69.

8. **WORKSHOP COMMENT**

What is the purpose of the aggregate emissions forecast required in Section (e) of the proposed amended rule? How would the public know of an exceedance of the forecast?

DISTRICT RESPONSE

The annual forecast of monthly aggregate NOx emissions in the forthcoming calendar year is intended to provide a compliance tool to assure the District that SDG&E has in place an emissions control and operations plan adequate to meet its aggregate NOx emissions cap, to ensure that progress towards compliance with the final emissions cap is occurring, and to allow a comparison of actual emissions on a monthly basis to ensure that total NOx emissions will not exceed the applicable cap and to identify where any adjustments to emission controls or operations are needed to ensure that the cap will be met. All records submitted in regards to the emissions forecast, the compliance plan/report and the monthly emissions reports are public records, available to any member of the public for inspection upon request.

9. **WORKSHOP COMMENT**

Does the District have concerns with incorporating the monitoring requirements of 40 CFR Part 75 into Rule 69? What are the specific concerns with calibration?

DISTRICT RESPONSE

The District agrees with the concept of integrating the monitoring requirements of Rule 69 and 40 CFR Part 75. However, the District is concerned with specifying Part 75 in Rule 69 since there may be areas where Part 75 requirements are not adequate to ensure proper monitoring under Rule 69. For example, calibrations of instruments under Part 75 are based on anticipated NOx emission rate levels that may be significantly higher than those of boilers retrofitted with emission controls to comply with Rule 69. In addition, Part 75 may be changed by EPA without District concurrence, and existing Part 75 contains provisions for the EPA Administrator to grant waivers from Part 75 requirements on a case-by-case basis, again without District concurrence.

Accordingly, the proposed amendments to Rule 69 will require that monitoring be conducted to collect and record specified data, but that the methods for monitoring, recording and reporting will be pursuant to a protocol proposed by the owner/operator of affected boilers and units and approved by the District. In this way, the District can work with SDG&E or any other affected owner/operator to assure that monitoring necessary to ensure compliance with Rule 69 will be adequate and can also meet other requirements such as 40 CFR Part 75.

10. **WRITTEN COMMENT**

What will be the impact of the proposed amendments to Rule 69 to the overall attainment plan (or RFP)? Will additional sources of ozone precursors be controlled or further controlled? If so, what is anticipated? If not, has the APCD determined that other control strategies provide for RFP?

DISTRICT RESPONSE

The proposed amendments to Rule 69 are not expected to result in increased NOx emissions compared to the current Rule 69 or current power plant boiler emissions. The proposed amendments retain the same overall annual NOx mass emission limits and schedule that current Rule 69 imposes - 2100 tons per year by the year 1997, and 800 tons per year by the year 2001. The 800 ton annual emissions cap is significantly below the 1200 tons per year emissions level anticipated for this source category in San Diego's Regional Air Quality Strategy. No Rule 69 emission reductions were relied on in the District's demonstration of attainment of the national ambient air quality standard for ozone, nor has Rule 69 been submitted to EPA for inclusion in the State Implementation Plan.

Accordingly, the District does not anticipate any emission increases that will need to be compensated for by additional emission reductions from other source categories. If in the future there are significant changes in electrical energy demand, energy resource availability from outside the air basin, or emission control technologies, and/or additional emission reductions to meet federal or state ambient air quality standards are needed, Rule 69 will be re-evaluated for possible further amendments.

11. **WRITTEN COMMENT**

With the removal of the "increments of progress" which would have provided a tracking mechanism for NOx emission reductions toward attainment, how does the District anticipate tracking the reductions based on the proposed amendments? What additional cost burdens or cost reductions (e.g. APCD costs, SDG&E retrofit costs) result from the proposed amendments?

DISTRICT RESPONSE

The District will track progress towards compliance with Rule 69 emission limits through the requirement for an annual compliance plan/report, including a forecast of emissions each month in the following year, by review of the required monthly reporting of total aggregate emissions, and by permitting all NOx emissions controls required to meet the limits of Rule 69. Given that SDG&E has nine currently active boilers, most of which will require retrofitting with NOx emission controls to meet the limits of Rule 69, and five years in which to reduce aggregate annual NOx emissions to 800 tons per year, the District expects, and will be looking for, continual emissions reduction progress to be made.

SDG&E has projected possible capital cost savings up to $70 million as a result of the proposed amendments to Rule 69. Actual savings will be dependent on development of less costly NOx control technologies, availability of external electrical energy resources, and future SDG&E decisions regarding the development of more energy efficient capacity from repowering projects and new electrical generating units. The fiscal impacts to the District from the proposed amendments is expected to be minimal.

12. **WRITTEN COMMENT**

What is the current estimated tons per year of NOx emissions from SDG&E's affected units?

DISTRICT RESPONSE

The average of the annual NOx emissions from the nine currently operating SDG&E boilers affected by the rule for the last five emissions inventory years is approximately 3500 tons.

13. **WRITTEN COMMENT**

Is the forecast of cumulative monthly system NOx emissions the primary mechanism for demonstrating compliance with the aggregate NOx limit placed on the system? Please clarify the process for how exceedances of the bubble would be determined and the associated compliance procedures.

DISTRICT RESPONSE

The forecast of cumulative monthly emissions for the forthcoming calendar year will be used as a compliance tool to ensure that SDG&E has in place an operating and emissions control plan that will ensure compliance with the aggregate NOx emissions limit applicable to that forthcoming year. The primary mechanism for demonstrating compliance will be the continuous emissions monitoring system required by the rule for each affected boiler or unit. Monthly aggregate emissions will be determined from the emissions data collected by the monitoring system and reported to the District. In addition, aggregate NOx emissions data must be provided to the District upon request. The emissions monitoring system must be approved by the District, must have approvable calibration, audit and QA/QC features, and will be periodically validated by independent emissions testing required by the District.

The District will be regularly reviewing reported emissions data and forecasts to verify that emissions are expected to be in compliance with the applicable limits of Rule 69.

14. **WRITTEN COMMENT**

Please describe how the forecast of emissions will be calculated (e.g. per unit, per plant). Are these emissions based on traditional air quality emission calculations, source tests, emissions monitoring, etc. Or is there a more involved forecasting procedure or model?

DISTRICT RESPONSE

SDG&E will be required to forecast monthly electrical generation patterns and/or fuel usage for each affected boiler, new unit or replacement unit. The forecast would likely be based on historic generation levels as well as anticipated changes in resource availability, unit availability and costs. An emission factor would be applied that is specific to each unit and appropriate to that unit's load forecast. The emission factors will be derived from source testing and continuous emissions monitoring data. The factors will also reflect any in-place or anticipated NOx emissions controls for each affected unit. Forecast monthly emissions for each unit would then be aggregated for the entire system. This process would be repeated for each calendar month.

15. **WRITTEN COMMENT**

The rule essentially provides for offsetting of any NOx exceedances with creditable offsets. Was this the intent?

DISTRICT RESPONSE

This was not the District's intent. Current Rule 69 language will be retained to ensure that emission offsets can only be provided to mitigate anticipated exceedances of the NOx emissions limits in the case of an unforeseen event that is not due to an intentional or negligent act or omission.

16. **WRITTEN COMMENT**

Given the upcoming utility restructuring, it is conceivable that SDG&E and another entity could venture into a joint project, located at the existing SDG&E power plants (Encina, South Bay, Silvergate) or elsewhere in the County. The following questions pertain to the offset liability for such ventures:

- If another repower is proposed on SDG&E power plant sites, is it expected that no additional offsets would be needed?
- If SDG&E enters into a joint venture with another entity, does the built-in offset provision apply to such a venture?
- If SDG&E constructs a new facility, within the County, does that project benefit from the offset provision?
- If SDG&E and another entity enter into a venture for a new facility elsewhere in the County, does that project benefit from the offset provision?
- If an entity, separate from SDG&E, proposes an identical project, does that project benefit from the offset provision?

DISTRICT RESPONSE

The following responds to each specific scenario described in the written comment:

- If another repower is proposed on a SDG&E power plant site and that repower is owned or operated by SDG&E, additional NOx emission offsets would likely be needed only to the extent that the project causes total aggregate NOX emissions from the SDG&E system to exceed the annual aggregate NOX emissions limit prescribed by Rule 69. Emission offsets may be required for other pollutants such as VOC, PM10 and SOx.
- If SDG&E enters into a joint venture with another entity, the emission offset waiver provision would only apply if SDG&E owns or operates the existing, new or replacement unit, or has a controlling interest in the unit.
- If SDG&E constructs a new facility within the county, that project may qualify for the offset waiver of Rule 69 provided SDG&E meets all of the requirements for the waiver and only to the extent that the project does not cause total aggregate NOX emissions from the SDG&E system to exceed the annual aggregate NOX emissions limit prescribed by Rule 69. Emission offsets may be required for other pollutants such as VOC, PM10 and SOx.
- If SDG&E and another entity enter into a venture for a new facility elsewhere in the county, that project can likely only qualify for the emission offset waiver if SDG&E owns or operates the new or replacement unit or has a controlling interest in the unit.
- If an entity, separate from SDG&E, proposes an identical project, that project will likely not qualify for the emissions offset waiver of Rule 69 since the entity will likely not have generated emission reductions from existing units that exceed federal RACT requirements.

17. **WRITTEN COMMENT**

What is Reasonably Available Control Technology (RACT) for this source category? How do SDG&E sources currently compare to this RACT level?

DISTRICT RESPONSE

The NOx emission rates prescribed by District Rule 68 are consistent with EPA's presumptive RACT emission levels for fossil fuel fired electrical generating steam boilers. SDG&E boilers are currently meeting the emission limits of Rule 68, and thus are in compliance with EPA RACT requirements for major sources. Compliance with Rule 68 is verified by annual emissions source tests and continuous emissions monitors installed on SDG&E boilers. District Rule 69 goes beyond RACT controls required by EPA because it implements Best Available Retrofit Control Technology (BARCT) as required by the California Clean Air Act.

18. **WRITTEN COMMENT**

What are the envisioned logistics/procedures involved with the APCO's determination of an ozone exceedance and thus the lead time for SDG&E to burn fuel oil?

DISTRICT RESPONSE

The District will forecast whether an exceedance of the state ozone standard is expected the following day by 4:00 PM each day. SDG&E, or any other entity affected by Rule 69, must call the District daily to determine whether an exceedance is forecast. See also the response to Workshop Comment No. 6.

AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

DATE: November 14, 1995

TO: Air Pollution Control Board

SUBJECT: Amendments to Rule 69 (Electrical Generating Steam Boilers, Replacement Units and New Units)

SUMMARY:

The proposed amendments to Rule 69 respond to a request from the San Diego Gas and Electric Company (SDG&E) to amend Rule 69 to allow complete flexibility in complying with NOx emission control requirements. The amendments would remove current oxides of nitrogen emission rate limits (e.g. 0.15 pounds of NOx per megawatt-hour of electricity produced) applicable to each utility boiler subject to the rule and instead simply retain the requirement that total aggregate oxides of nitrogen emissions from all such boilers, as well as replacement units and new units under common ownership or control, be reduced to not more than 2100 tons per year starting in 1997, and not more than 800 tons per year starting in 2001.

SDG&E, the only company currently operating electrical generating steam boilers subject to Rule 69, has estimated possible compliance cost savings from these amendments of up to $60 million. However, these savings are very dependent upon future electrical generation levels and resources, and development and performance of less costly oxides of nitrogen emission controls. Rule 69 has not been submitted to the U.S. EPA for inclusion in the State Implementation Plan since it goes beyond federal requirements. Therefore, EPA is not involved with the proposed amendments.

Normally, rules are set for hearing only after all issues have been resolved or sufficiently narrowed and analyzed so that the Board can make a considered decision. That is not the case here. There is a substantial difference of opinion between the Air Resources Board (ARB) and SDG&E regarding whether the proposed rule amendments represent Best Available Retrofit Control Technology (BARCT).

The proposed amendments have been set for hearing in order to force timely consideration and resolution of issues between the parties. After a meeting between the District, ARB and SDG&E early in September, this issue was elevated at the state level to the Chair of the ARB. As a result, the normal communications between the ARB and the District was interrupted. The District will be meeting with ARB to define and further discuss the issues and review any ARB analysis.

The key issue to be resolved is how the Regional Clean Air Incentives Market (RECLAIM) program in the South Coast Air Quality Management District applies to the Southern California Edison Company. That program has been determined to be BARCT by the ARB. However, there are important differences between how the ARB, District and SDG&E understand RECLAIM works. If in fact the SDG&E proposal is sufficiently consistent with how RECLAIM applies to Edison, then SDG&E's proposal deserves approval. If it is not, then the SDG&E proposal needs to be revised.

Issue

Should the Board adopt the proposed amendments to Rule 69 (Electrical Generating Steam Boilers, Replacement Units and New Units) or make amendments to meet Best Available Retrofit Control Technology requirements if negotiations with the state Air Resources Board result in such amendments being necessary.

Recommendation

AIR POLLUTION CONTROL OFFICER:

1. Adopt the resolution amending Rule 69 and make the appropriate findings:

   (i) of necessity, authority, clarity, consistency, non-duplication and reference, as required by Section 40727 of the State Health and Safety Code;

   (ii) that the amendments will alleviate a problem and will promote attainment of ambient air quality standards (Section 40001 of the State Health and Safety Code);

   (iii) that an assessment of the socioeconomic impact of the proposed amendments was performed, and after actively considering the socioeconomic impact of the proposed amendments in accordance with Section 40728.5 of the Health and Safety Code, a finding be made that there will be no adverse socioeconomic impacts resulting from the adoption of the proposed amendments; and,

   (iv) that the proposed amendments to Rule 69 will not have a significant effect on the environment and that the proposed amendments are exempt from the requirements of the California Environmental Quality Act (CEQA).

2. Direct the Air Pollution Control Officer to execute the proposed Memorandum of Understanding with the San Diego Gas and Electric Company regarding indemnification of the District with regard to any litigation that may arise from adoption of the proposed amendments.

3. Direct the Air Pollution Control Officer to consider and recommend, if appropriate, future amendments to Rule 69 if the Air Pollution Control Officer finds that additional emission reductions from electrical generating steam boilers, replacement units and new units are achievable, are cost-effective and are necessary to further progress towards attainment of ambient air quality standards.

Advisory Statement

The Air Pollution Control District Advisory Committee recommended adopting the proposed amendments to Rule 69 at its October 25, 1995 meeting. The Committee also recommended that any additional changes which would be more inclusive or prescriptive be resisted.

Fiscal Impact

Adopting the proposed amendments will have no fiscal impact on the District.

Alternatives

The Air Pollution Control Officer will report on possible alternatives to the recommended amendments, and related analysis, prior to the public hearing scheduled for November 14, 1995.

BACKGROUND:

Current Rule 69 was adopted by the Board on January 18, 1994 to meet the requirement of the California Clean Air Act for Best Available Retrofit Control Technology (BARCT). It requires oxides of nitrogen (NOx) emissions from electrical generating steam boilers, and from new and replacement electrical generating units, be controlled to specified levels. It requires at least one existing boiler be controlled each year to specified levels beginning in 1997 and all existing boilers be in compliance by 2001, with the exception of replacement units, and associated boilers that may be scheduled for initial startup between January 1, 2001 and January 1, 2003. Such replacement units and associated boilers are required to be in compliance by January 1, 2003 or initial startup, whichever is sooner. The current rule also requires total calendar year NOx emissions from all such boilers, replacement units and new units under common ownership not exceed 2100 tons starting in 1997, and 800 tons starting in 2001. Electrical generating steam boilers operated by the San Diego Gas and Electric Company (SDG&E) are the only existing boilers in San Diego County affected by Rule 69. However, Rule 69 could also affect other future electrical energy generators who may assume ownership or operation of one or more boilers currently operated by SDG&E, or who may enter into joint ventures with SDG&E for operation of new or replacement electrical generating units.

Current Rule 69 was developed in collaboration with SDG&E, in coordination with the Air Resources Board (ARB) and with technical assistance from the California Energy Commission. At the time of adoption, Rule 69 was supported by SDG&E and ARB. It met the BARCT requirements of the California Clean Air Act by requiring that oxides of nitrogen emissions from existing electrical generating steam boilers be controlled by approximately 85 percent using combinations of emission control technologies, including selective catalytic reduction (SCR), for eight of the nine operating utility boilers subject to the rule. The rule prescribed emission rate limits (e.g. 0.15 pounds of NOx per megawatt-hour of electricity produced) for each affected boiler to ensure NOx emission reductions would be achieved from each boiler regardless of its level of use or total emissions.

By establishing an annual total oxides of nitrogen emissions limit in conjunction with a waiver from the New Source Review rule requirement to provide offsetting emission reductions for emission increases from modified, replacement and new units, Rule 69 provides for expected increases in electrical generation levels in the future and helps to preserve scarce emission offsets in San Diego County that would otherwise be needed for power plant projects. The emission limits apply to total NOx emissions from all existing SDG&E boilers, as well as any replacement or new units that might be built to meet projected increases in electrical energy demand to ensure that total NOx emissions from the SDG&E utility boilers will be reduced by approximately 42 percent by the year 1997, and 78 percent by the year 2001 and thereafter, as compared to recent average annual system emissions even if additional electrical generating capacity were to be added to the SDG&E system. Current average NOx emissions from SDG&E boilers subject to the rule are approximately 3500 tons per year.

With the exception of the annual emissions cap and related waiver for emission offset requirements, rules similar to current Rule 69 have been adopted over the past several years in the South Coast Air Quality Management District, Ventura County Air Pollution Control District, Bay Area Air Quality Management District, Monterey Bay Unified Air Pollution Control District and San

Luis Obispo County Air Pollution Control District. Rule amendments to delay full implementation of selective catalytic reduction NOx control technologies have been proposed and approved in San Luis Obispo and Monterey Bay. Rule amendments to provide greater operational and compliance flexibility for affected utility boilers have been proposed in the Bay Area. While these amended rules would eventually require the most stringent emission rate limits be applied to large utility boilers, they do not incorporate an annual NOx emission cap.

Recently, the adoption and implementation of the Regional Clean Air Incentives Market (RECLAIM) open-market emissions trading program in the South Coast Air Quality Management District has created an emissions reduction program for Southern California Edison Company in the South Coast. Under that program, Southern California Edison must meet annual NOx emission caps that are established based on historic peak annual emissions, reductions required by the South Coast BARCT rule, and further reductions needed to meet the South Coast attainment plan for the federal ozone standard. The annual NOx emission caps went into affect in 1994 and decline to the year 2003. Edison can comply with the annual emission caps by installing emission controls and varying levels of effectiveness, by importing more electrical power from outside their electrical generating facilities in the South Coast District, by replacing existing boilers with more efficient electrical generating units, and by purchasing emission reduction credits from other NOx sources in the air basin. Edison is not required to install any specific emission control technologies, such as SCR, nor is it required to limit emissions on a daily basis.

On July 24, 1995, SDG&E requested Rule 69 be amended to allow complete flexibility in implementing the NOx emission control requirements of the rule. SDG&E requested both the boiler specific NOx emission rate limits of the rule and the requirement to retrofit at least one existing boiler with NOx emission controls each year starting in 1997 be deleted and requested other clarifications to the rule. The NOx emission control requirement would then become the overall annual system NOx emission limits of 2100 tons per year starting in 1997, and 800 tons per year starting in 2001. SDG&E stated that such amendments would provide an opportunity to significantly reduce the costs of compliance and to evaluate and implement alternative, less costly NOx emission control technologies.

Under the proposed amendments, SDG&E would be allowed to choose levels of emission controls required for each boiler, select the performance levels at which to operate those emission controls (except on days expected to exceed the state ozone standard), import more electrical power to reduce local NOx emissions (and reduce the need for and cost of emission controls), and replace existing boilers with more energy efficient electrical generating units, so long as total system-wide annual NOx emissions from SDG&E's units do not exceed the prescribed annual emission caps. Basing the rule on NOx caps alone is a significant departure from current Rule 69 which mandates that each affected boiler be equipped with emission reduction technology that will meet the daily NOx emission rate limits (e.g. 0.15 pounds of NOx per megawatt-hour of electricity produced) specified for each boiler, and requires maximum emission control performance every day.

When current Rule 69 was first adopted, the estimated initial capital costs to comply were approximately $110 million (the $73 million included as back-up information when Rule 69 was adopted reflects 1987 dollars). Recently, SDG&E estimated capital costs of compliance to be approximately $90 to $100 million, the decrease being due primarily to lower costs of NOx emission control technologies. Under the requested amendments to Rule 69, SDG&E estimates compliance capital cost savings may be up to $65 million resulting from additional opportunities to implement less costly NOx emission control technologies, to import additional electrical energy, and to optimize more cost-effective electricity generation in NOx controlled boilers. Savings may also result from construction of replacement or new electrical generating units with significantly higher energy efficiencies.

SDG&E has stated it intends to meet the system-wide annual NOx emission caps of the amended rule and it is not their intent to request subsequent revisions to Rule 69 to increase the annual cap above 800 tons, even in light of recent changes in state law which require considering incremental cost effectiveness when establishing BARCT requirements.

Issues

Normally, rules are set for hearing only after all issues have been resolved or sufficiently narrowed and analyzed so that the Board can make a considered decision. That is not the case here. There is a substantial difference of opinion between the ARB and SDG&E regarding whether the proposed rule amendments represent BARCT.

The proposed amendments have been set for hearing in order to force timely consideration and resolution of issues between the parties. After a meeting between the District, ARB and SDG&E early in September, this issue was elevated at the state level to the Chair of the ARB. As a result, the normal communications between the ARB and the District was interrupted. The District will be meeting with ARB to define and further discuss the issues and review any ARB analysis.

The key issue to be resolved is how the RECLAIM program in the South Coast Air Quality Management District applies to the Southern California Edison Company. That program has been determined to be BARCT by the ARB. However, there are important differences between how the ARB, District and SDG&E understand RECLAIM works. If in fact the SDG&E proposal is sufficiently consistent with how RECLAIM applies to Edison, then SDG&E's proposal deserves approval. If it is not, then the SDG&E proposal needs to be revised.

Finally, the District has requested that the California Energy Commission provide data on probable future electrical generating scenarios for the SDG&E system. This information is expected shortly and will be considered in any final recommended amendments to Rule 69.

Prior to the public hearing on the proposed amendments, the Board and interested public will be provided with an update on these and any other remaining issues. If these issues have been resolved or sufficiently narrowed and analyzed, the Board and interested public will be provided updated information. A continuation of this matter may be requested if more time is necessary.

Rule Amendments

The proposed amendments to Rule 69 specify oxides of nitrogen emission limits for electrical generating steam boilers, replacement units and new units, and prohibit the burning of fuel oils and require maximum performance of emission controls on days when the state ambient air quality standard for ozone is expected to be exceeded. More specifically, the proposed amendments to Rule 69 would:

- Retain the requirement that total aggregate NOx emissions from all existing boilers, replacement units and new units under common ownership or control be not more than 2100 tons in each calendar year commencing with calendar year 1997, and not more than 800 tons in each calendar year commencing with calendar year 2001.
- Delete boiler-specific NOx emission rate limits. For most existing electrical generating steam boilers, these current limits are from 0.15 to 0.18 pounds of NOx per megawatt-hour of electricity produced when burning natural gas and 0.40 pounds per megawatt-hour when burning fuel oil. By deleting these emission rate limits, SDG&E would be able to choose

NOx emission controls for individual units that minimize costs and maximize flexibility, provided that total system NOx emissions are reduced to the same annual levels as specified in current Rule 69.

- Delete the requirement that at least one existing electrical generating steam boiler be retrofitted each year with NOx emission controls starting in January, 1997. This requirement is no longer needed since boiler specific NOx emission rates will no longer be specified. There are additional compliance planning and reporting requirements that are a part of the proposed amendments.

- Add a requirement that, on and after January 1, 1997, NOx emission controls installed on any units subject to the rule must be operated at their maximum emissions control performance level on days on which the District predicts an exceedance of the state ambient air quality standard for ozone. Without this provision, SDG&E would be able to operate NOx emission controls at less than maximum effectiveness at any given time provided total annual NOx emissions did not exceed the cap. This additional requirement would ensure that NOx emissions are minimized through the maximum use of the emission controls installed to meet the aggregate NOx emission limits of the rule on poor air quality days.

- Add unit-specific NOx emission rate limits of 0.15 pounds per megawatt-hour when burning natural gas and 0.40 pounds per megawatt-hour when burning oil that would apply to any existing boilers which may come under the ownership or operational control of another company apart from SDG&E in the future. These unit specific emission rate limits would become effective within two years after such a change in ownership, but not later than January 1, 2001. In addition, the amendments would add a formula by which the annual aggregate emissions cap applicable to SDG&E would be reduced by an appropriate amount should such a change in ownership or control occur.

  These changes are intended to address the possibility that, under electric utility deregulation being considered by the California Public Utilities Commission, a company independent of SDG&E, or in a joint venture with SDG&E, could assume ownership or control of an existing SDG&E boiler subject to the rule. These changes would ensure that BARCT would be applied and the aggregate emissions cap for the remaining SDG&E boilers would be appropriately reduced.

- Add a requirement to include in the required Compliance Plan a forecast of NOx emissions during each calendar month in the forthcoming calendar year from boilers, replacement units and new units under common ownership, and a demonstration of how compliance with the system-wide (aggregate) annual NOx emission limits will be achieved, including a forecast of system-wide NOx emissions for each calendar year and a comparison with the system-wide annual NOx emission limits of the rule.

- Add a requirement for monthly reporting of system-wide year-to-date NOx emissions, a comparison with the forecast system-wide NOx emissions for the year to date, and an explanation and revised forecast if the system-wide NOx emissions exceed those forecast.

- Allow evaluation and approval by the Air Pollution Control Officer of single stack monitoring of NOx emissions when more than one boiler and/or new or replacement unit is exhausted through a common stack. This will allow SDG&E and the District to explore the possibility of reducing or streamlining emissions monitoring, and associated costs, for units at the Encina power plant, which all exhaust through a single tall stack.

- Require SDG&E to submit a proposed plan for continuous emissions monitoring of all affected boilers, replacement units and new units; and data collection, processing, recording and reporting for review and approval by the Air Pollution Control Officer. This provides SDG&E with an opportunity to make emissions monitoring and reporting consistent with both current federal monitoring and reporting requirements and Rule 69.

- Reduce the ratio of emissions offsets required to mitigate any increase in the annual system-wide NOx emissions limit (e.g. 800 tons per year cap) under specified circumstances. The current rule allows the annual emissions cap to be exceeded if unforeseen events occur such as a forced boiler outage or a disruption in the supply of imported power. In this case, the current rule requires emission offsets be provided at a 1.3 to 1.0 ratio (i.e. 13 tons of offsets for every 10 tons the cap is exceeded) to mitigate the emissions that exceed the cap. Since the system-wide emissions limit (cap) is intended to satisfy California Clean Air Act requirements and not federal emissions offset requirements, the appropriate ratio for mitigating offsets in these circumstances is 1.0 to 1.0 rather than the current ratio of 1.3 to 1.0. The proposed changes reflect this 1.0 to 1.0 ratio.

- Clarify that the prohibition on fuel oil burning on days expected to exceed the state ozone standard takes effect on and after January 1, 1997, with specified exceptions. The current rule was unclear whether the limits on fuel oil burning became effective January 1, 1997 for all affected boilers or January 18, 1994 for at least one affected boiler and for at least one additional boiler each year as they were retrofitted with emission controls to comply with the rule.

In addition, the rule amendments include changes to definitions, monitoring and reporting requirements, and test methods as needed to implement the proposed revisions to Rule 69.

Socioeconomic Impact Assessment

Section 40728.5 of the State Health and Safety Code requires that, to the extent data are available, the socioeconomic impacts of rule amendments and new rules be evaluated and actively considered by the Air Pollution Control Board, and that good faith efforts be made to minimize adverse socioeconomic impacts. The proposed amendments to Rule 69 will have impacts as follows:

- The proposed amendments will affect only one company, San Diego Gas and Electric Company. No other businesses currently have equipment subject to the current rule or the proposed amendments, and no small businesses will be affected by the proposed amendments.

- Due to the uncertainty of how SDG&E would choose to comply with the overall system annual emissions limit under the proposed amendments, no data are available on the impact the proposed amendments will have on employment and the economy of the region. The socioeconomic impact assessment (which may be conservatively high) prepared for the adoption of the original version of Rule 69 predicted slight job growth and slight improvement in the overall economy in the first two years of purchase and installation of the control systems required by current Rule 69, but long-term negative effects on employment and the economy of the region thereafter as a result of higher electricity rates. Both positive and negative impacts are small compared to total employment growth between 1994 and 2010. SDG&E's proposed amendments to Rule 69 would likely moderate both the short-term positive impacts on employment and the economy and the long-term negative impacts on employment and the economy predicted to result from the current Rule 69.

- There are no probable additional costs to SDG&E and its customers if the proposed amendments are adopted. SDG&E estimates it could save up to $65 million in capital costs as a result of the amendments.

- There are alternatives to the proposed amendments to Rule 69. The first would retain the current rule, without amendment. The cost effectiveness of this alternative was determined and considered by the Board when the rule was adopted. The others are not well defined at this time. Accordingly, the exact cost effectiveness of alternatives is unknown. Presuming the current rule is not retained, alternatives to the proposed amendments may be more expensive compared to the proposal but less expensive than the current rule.

- The proposed amendments will not result in additional emission reductions.

- The proposed amendments to Rule 69 are not necessary to attain the state or federal ambient air quality standard for ozone.

Environmental Impacts

The California Environmental Quality Act (CEQA) requires an environmental review for certain actions, including rule adoptions which may result in environmental impacts. The proposed amendments to Rule 69 will not have a significant effect on the environment and are exempt from the requirements of CEQA because the proposed amendments will require significant reduction in daily and annual emissions of NOx to the environment compared to emissions currently occurring from boilers subject to the rule. Current emissions from affected boilers average approximately 3500 tons per year and represent approximately 60 percent of stationary source NOx emissions and 5 percent of total NOx emissions (stationary, mobile and area sources) in the county. Under the proposed amended Rule 69, emissions from these boilers, and any new or replacement electrical generating units, will be reduced to 2100 tons per year by 1997 and to 800 tons by 2001. The final emissions will then represent approximately one percent of current total NOx emissions in the County.

The potential environmental impacts associated with NOx emission controls for electrical generating steam boilers and current Rule 69 were considered in the Environmental Impact Report prepared for the 1991 San Diego Regional Air Quality Strategy, and in conjunction with adoption of Rule 69 in January, 1994. It was determined that, although Rule 69 does not specify which oxides of nitrogen emission control technologies must be used to comply, it was likely that at least some of the existing SDG&E boilers located at the Encina and South Bay power plants would be equipped with selective catalytic reduction technology. This technology uses ammonia injected in the flue gas ahead of a catalyst to reduce oxides of nitrogen emissions. The use of selective catalytic reduction creates the potential for adverse environmental impacts, specifically associated with the handling of ammonia, a toxic gas, and the handling of spent catalyst, a potential hazardous waste.

In adopting Rule 69, the Board found that the Final Environmental Impact Report (FEIR) for the 1991 San Diego Regional Air Quality Strategy, prepared in October, 1991 and approved by the Board on June 30, 1992, discussed potential environmental impacts that may result from the emission reduction measures upon which Rule 69 is based and concluded that the impacts would not be significant after mitigation. The amendments to Rule 69 may provide greater opportunities to implement NOx emission controls other than selective catalytic reduction technologies, and therefore may reduce the potential significant (although mitigated) environmental impacts that were identified with the use of such technologies to comply with current Rule 69. There are no known significant environmental impacts associated with alternative NOx emission controls that could be applied under the proposed amendments to Rule 69.

Since the proposed amendments to Rule 69 have been requested by SDG&E, SDG&E has agreed to indemnify the District from any costs associated with any litigation that might arise regarding adopting the proposed amendments. A proposed memorandum of understanding documenting this indemnification is attached. The District is recommending that the Air Pollution Control

Officer be directed to execute this memorandum of understanding if the proposed amendments to Rule 69 are adopted.

Section 40001 of the Health and Safety Code requires the District to determine, prior to adopting any rule to reduce criteria pollutants, that the rule will alleviate a problem and promote the attainment or maintenance of state or federal air quality standards. The proposed amendments may save SDG&E and its customers up to $65 million in capital costs. The proposed amendments will still promote attainment of the state and federal ambient air quality standards.

On February 2, 1993, the Air Pollution Control Board directed that, with the exception of a regulation requested by business or a regulation for which a socioeconomic impact assessment is not required, no new or revised regulation shall be implemented during the 1993 calendar year, unless specifically required by federal or state law. The proposed amendments to Rule 69 were requested by SDG&E, the only business currently impacted by the rule, to be adopted on an expeditious schedule. They meet the California Clean Air Act requirement for expeditious implementation of the 1991 San Diego Regional Air Quality Strategy. The amendments currently appear consistent with BARCT based on a comparison with the South Coast Air Quality Management District's RECLAIM program as it applies to Southern California Edison Company. ARB disagrees.

A public workshop on proposed amendments to Rule 69 was held on September 7, 1995. The workshop report is attached.

Concurrence:

DAVID E. JANSSEN
Chief Administrative Officer

Respectfully submitted,

R. J. SOMMERVILLE
Air Pollution Control Officer

AIR POLLUTION CONTROL BOARD
AGENDA ITEM
INFORMATION SHEET

SUBJECT: Amendments to Rule 69 (Electrical Generating Steam Boilers, Replacement Units and New Units)

11 10/31/95

SUPV DIST.: All

COUNTY COUNSEL APPROVAL: Form and Legality [X] Yes [ ] N/A
[ ] Standard Form [ ] Ordinance [X] Resolution

CHIEF FINANCIAL OFFICER/AUDITOR REVIEW: [X] N/A [ ] Yes
4 VOTES: [ ] Yes [ ] No

CONTRACT REVIEW PANEL: [ ] Approved ____________ [X] N/A

CONTRACT NUMBER(S): N/A

PREVIOUS RELEVANT BOARD ACTION: January 18, 1994 (APCB Item #1)

BOARD POLICIES APPLICABLE: N/A

CITIZEN COMMITTEE STATEMENT: The Air Pollution Control District Advisory Committee recommended adoption of the proposed amendments to Rule 69 at its October 25, 1995 meeting. The Committee also recommended that any additional changes which would be more inclusive or prescriptive be resisted.

CONCURRENCES: N/A

ORIGINATING DEPARTMENT:

CONTACT PERSON: Richard J. Smith, Deputy Director 750-3303 MS: 0-176

R.J. SOMMERVILLE
DEPARTMENT AUTHORIZED REPRESENTATIVE

NOVEMBER 14, 1995
MEETING DATE

AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

CHANGE COPY

PROPOSED AMENDMENTS TO RULE 69

Proposed amendments to Rule 69 are to read as follows:

RULE 69. ELECTRICAL GENERATING STEAM BOILERS, REPLACEMENT UNITS AND NEW UNITS

(a) APPLICABILITY

(1) Except as provided in Section (b) or otherwise specified in this rule, this rule is applicable to ~~all~~ the following existing electrical generating steam boilers, and to all replacement units and to all new units, including any auxiliary boiler used in conjunction with ~~an~~ such electrical generating steam boilers, ~~and to~~ replacement units ~~and~~ or new units:

(i) Encina Power Plant Units 1, 2, 3, 4 and 5

(ii) South Bay Power Plant Units 1, 2, 3 and 4

(iii) Silvergate Power Plant Units

(2) Equipment subject to this rule shall also comply with the emission limitations and exemptions set forth in Rule 68.

(b) EXEMPTIONS

(1) The provisions of Sections (d), (e), (f) and (g) shall not apply to:

(i) Any electrical generating steam boiler with a maximum heat input capacity of less than 100 million Btu's per hour.

(ii) Boilers which generate steam used exclusively for space heat or process heat and not used for electrical generation.

(c) DEFINITIONS

For the purposes of this rule, the following definitions shall apply:

(1) **"Boiler"** means any combustion equipment fired with solid, liquid and/or gaseous fuels and used to produce steam, excluding electrical generating gas turbines.

(2) **"Calendar Day"** means the 24-hour period starting on the 00:00 hour and ending on the 24:00 hour.

(3) **"Calendar Year"** means the consecutive 12-month period beginning January 1 and ending December 31.

~~(4) **"Capacity Factor"** means the fraction of an electrical generating steam boiler's, replacement unit's or new unit's maximum electrical generating capacity that is actually utilized during a calendar year. The maximum electrical generating capacity shall be determined by multiplying the maximum rated capacity of a boiler, replacement unit or new unit, in megawatts, by 8760 maximum operating hours per year (8784 hours for a leap year).~~

(4) **"Compliance Emissions Testing"** means any emissions or continuous emissions monitor (CEM) quality assurance/quality control (QA/QC) testing required by federal, state, or local regulations.

(5) **"Clock Hour"** means every 60-minute period starting on the hour.

(6) **"Electrical Generating Steam Boiler"** means any boiler used to produce steam to be expanded in a turbine generator used for the generation of electric power.

(7) **"Electrical Generating Gas Turbine"** means any combustion turbine fired with solid, liquid and/or gaseous fuels and used to provide direct shaft work for the generation of electric power.

(8) **"Force Majeure Natural Gas Curtailment"** means an interruption in natural gas service such that the daily fuel needs of a boiler or replacement unit subject to this rule cannot be met with the natural gas available due to:

(i) Unforeseeable natural disaster or other cause resulting in the failure or malfunction of natural gas supply, delivery or storage system facilities, not resulting from an intentional or negligent act or omission on the part of an owner or operator of a boiler, a new unit or a replacement unit, or

(ii) A supply restriction resulting from a California Public Utilities Commission priority allocation ruling, or

(iii) Delivery restrictions due to pipeline capacity limitations of the natural gas supplier or upstream transports or within a gas utility's delivery system.

(9) **"Heat Input"** means the heat derived from combustion of fuel in an electrical generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc. The maximum heat input rating means the lesser of the steady state heat input capacity of an electrical generating unit, as limited by its design and construction or as limited by an Authority to Construct or Permit to Operate.

(10) **"Megawatt-hour (MW-hr)"** means the total electrical energy generation of a boiler, new unit or replacement unit subject to this rule.

(11) **"New Unit"** means any electrical generating steam boiler or electrical generating gas turbine for which the first Authority to Construct is issued on or after January 18, 1994.

(12) **"Oxides of Nitrogen (NOx)"** means the sum of all compounds containing at least one atom of nitrogen and one atom of oxygen, measured as nitrogen dioxide.

(13) **"Reasonable Further Progress"** means annual incremental reductions in emissions of the applicable air pollutant which are sufficient, in the judgment of the Air Pollution Control Officer, to provide for attainment of the applicable National Ambient Air Quality Standard by the date required by law.

(14) **"Reasonably Available Control Technology"** means the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonably available, considering technological and economic feasibility and any technology findings made by the U. S. Environmental Protection Agency.

(15) **"Replacement Unit"** means any electrical generating steam boiler or electrical generating gas turbine which permanently replaces or augments, on or after January 18, 1994 , an existing electrical generating steam boiler subject to this rule. For purposes of this rule, a replacement unit need not be limited to the same electrical generating capacity as the existing boiler being replaced.

(16) **"SIP Control Measures"** means those emission control measures approved by the Air Pollution Control Board for inclusion in the State Implementation Plan (SIP) required by federal law or contained in the SIP approved by the U.S. Environmental Protection Agency.

~~(16) **"Startup"** means the period of time during which a boiler, replacement unit or new unit, and associated emissions control device(s), are being heated to the minimum functional operating temperatures of the emission control device(s), or when electrical generation equals or exceeds 25 percent of rated capacity, whichever is sooner.~~

~~(17) **"Shutdown"** means the period of time during which a boiler, replacement unit or new unit, and its associated emissions control device(s), are allowed to cool from the minimum functional operating temperatures of the emission control device(s) or when electrical generation drops below 25 percent of rated capacity, whichever is later.~~

(d) **STANDARDS**

A person shall not operate an existing electrical generating steam boiler, replacement unit or new unit subject to this rule unless only natural gas, alternative fuel and/or fuel oil is burned and the following requirements are met. If an alternative fuel is burned in an existing boiler subject to the provisions of Subsection (d)(7), the operator shall have previously demonstrated to the satisfaction of the Air Pollution Control Officer that the emissions of oxides of nitrogen

(NOx) per megawatt-hour of electricity generated is not greater than would be the emissions from the burning of natural gas in the same boiler, replacement unit or new unit.

~~(1) Except as provided in Subsections (d)(2) through (d)(6), a person shall not operate an electrical generating steam boiler unless:~~

~~(i) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the boiler do not exceed 0.15 pounds per megawatt-hour, and~~

~~(ii) The person has met the compliance schedule specified in Section (e).~~

~~(2) Except as provided in Subsections (d)(3), (d)(4) and (d)(5), no person shall operate one or more of the electrical generating steam boilers listed below unless the emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the boiler do not exceed 0.18 pounds per megawatt-hour and such person has met the compliance schedule specified in Section (e).~~

~~Encina Power Plant Units 1, 2, 3 and 4~~
~~South Bay Power Plant Units 1,2 and 4~~

~~(3) The provisions of Subsection (d)(2) shall not apply and the provisions of Subsection (d)(1) shall apply if the capacity factor of an electrical generating boiler with a maximum heat input rating of equal to or greater than 2100 million Btu's per hour is greater than 0.15 over any calendar year.~~

~~(4)~~ (1) Fuel Oil Firing ~~NOx Emission Rate Limits~~

A person shall not operate an electrical generating steam boiler, replacement unit or new unit when burning fuel oil on or after January 1, 1997 unless~~:~~

~~(i) The requirements of Subsection (d)(1), (d)(2) or (d)(3), as applicable, are met by the operator of an affected boiler when burning natural gas exclusively in that boiler, and~~

~~(ii) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from an affected boiler do not exceed 0.40 pounds per megawatt-hour when burning fuel oil exclusively in that boiler, and~~

~~(iii) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the boiler when fired on a mixture of fuel oil and natural gas do not exceed the limits prescribed in Subsections (d)(4)(i) and (d)(4)(ii), prorated for the relative heat input from fuel oil and natural gas, as follows:~~

$$\cancel{EL = \frac{[(Lo)(Qo)(HHVo)] + [(Lg)(Qg)(HHVg)]}{(Qo)(HHVo) + (Qg)(HHVg)}}$$

~~where,~~

~~EL = Emission limit, pounds per megawatt-hour~~

~~Lo = 0.40 pounds per megawatt-hour~~
~~Qo = Quantity of fuel oil burned, barrels per hour~~
~~HHVo = Higher heating value of fuel oil, Btu's per barrel~~
~~Lg = 0.15 or 0.18 pounds per megawatt-hour, as applicable~~
~~Qg = Quantity of natural gas burned, scf per hour~~
~~HHVg = Higher heating value of natural gas, Btu per scf,~~

~~and~~

~~(iv)~~ the Air Pollution Control Officer has determined that an exceedance of the state ambient air quality standard for ozone is not predicted at any location in the air basin at any time during the fuel oil burning. This paragraph shall not apply when burning of fuel oil is required due to a force majeure natural gas curtailment. Prior to January 1, 1998 ~~7~~, this paragraph shall not apply to fuel oil burning in the existing South Bay Power Plant Unit 4 boiler on days when fuel oil burning is needed to meet peak electrical generation demand.

~~(5) Low Capacity Factor Boiler NOx Emission Rate Limits~~

~~The provisions of Subsections (d)(1)(i), (d)(2) and (d)(4)(i), (ii) and (iii), shall not apply to the operation of the existing electrical generating steam boilers located at the Silvergate Power Plant nor to the existing Unit 4 boiler at the South Bay Power Plant provided:~~

~~(i) The capacity factor for each such boiler, over each calendar year, does not exceed 0.10, and~~

~~(ii) The emissions of oxides of nitrogen, expressed as nitrogen dioxide, do not exceed 0.60 pounds per megawatt-hour when burning natural gas, and~~

~~(iii) Fuel oil shall not be burned in the Silvergate Power Plant boilers, and may only be burned in the South Bay Unit 4 boiler during force majeure natural gas curtailments on and after January 1, 1997. Prior to January 1, 1997, this limitation shall not apply to fuel oil burning in the South Bay Power Plant Unit 4 boiler on days when fuel oil burning is needed to meet peak electrical generation demand. The emissions of oxides of nitrogen, expressed as nitrogen dioxide, from the South Bay Unit 4 boiler when burning fuel oil shall not exceed 1.20 pounds per megawatt- hour and when fired on a mixture of fuel oil and natural gas shall not exceed the limits prescribed in Subsections (d)(5)(ii) and (d)(5)(iii), prorated for the relative heat input from fuel oil and natural gas, as follows:~~

$$\cancel{EL = \frac{[(Lo)(Qo)(HHVo)] + [(Lg)(Qg)(HHVg)]}{(Qo)(HHVo) + (Qg)(HHVg)}}$$

~~where,~~

~~EL = Emission limit, pounds per megawatt-hour~~
~~Lo = 1.20 pounds per megawatt-hour~~

~~Qo~~	~~=~~	~~Quantity of fuel oil burned, barrels per hour~~
~~HHVo~~	~~=~~	~~Higher heating value of fuel oil, Btu's per barrel~~
~~Lg~~	~~=~~	~~0.60 pounds per megawatt-hour~~
~~Qg~~	~~=~~	~~Quantity of natural gas burned, scf per hour~~
~~HHVg~~	~~=~~	~~Higher heating value of natural gas, Btu per scf,~~

~~and~~

~~(iv) The Air Pollution Control Officer has determined that an exceedance of the state ambient air quality standard for ozone is not predicted at any location in the air basin at any time during the fuel oil burning. This paragraph shall not apply when burning of fuel oil is required due to a force majeure natural gas curtailment.~~

~~(6) Compliance with the standards of Subsections (d)(1) through (d)(5) shall be based on emissions of oxides of nitrogen from an affected boiler averaged over each calendar day of operation, or portion thereof, excluding periods of startups and shutdowns.~~

~~(7) Startups and Shutdowns~~

~~The provisions of Subsections (d)(1)(i), (d)(2)(i), (d)(3), (d)(4) and (d)(5) shall not apply to electrical generating steam boilers during periods of startup or shutdown provided the startup or shutdown does not exceed fifteen hours.~~

~~(8)~~ (2) Replacement Units and New Units NOx Emission Limits

~~Notwithstanding the requirements of Subsections (d)(1) through (d)(7), no~~ A person shall not operate a replacement unit or new unit subject to this rule unless such unit has been built with, and is operated in conjunction with, the Lowest Achievable Emission Rate or Best Available Control Technology as applicable and defined in Rule 20.1 for emissions of oxides of nitrogen. ~~Emissions of oxides of nitrogen from any replacement unit or new unit shall not be greater than the emission rate limit of Subsection (d)(1)(i). For a cogeneration unit which generates process steam as well as electricity, the emissions of oxides of nitrogen per megawatt-hour of electrical energy generated shall be determined by prorating the total unit emissions of oxides of nitrogen by the ratio of the gross electrical energy generated to the total energy produced by the unit.~~

(3) Maximum NOx Emissions Control Performance

On and after January 1, 1977, a person shall not operate an electrical generating steam boiler, replacement unit or new unit on any calendar day for which the Air Pollution Control Officer has predicted an exceedance of the state ambient air quality standard for ozone at any location in the air basin at any time during that day unless all NOx emissions controls associated with such boiler, replacement unit or new unit are operated in a manner that achieves the maximum NOx emission control performance for that boiler or unit. The Air Pollution Control Officer shall specify maximum allowable

NOx emission rates and/or key emission control device and boiler or unit operating parameters, to be applicable on days predicted to exceed the state ambient air quality standard for ozone, for NOx emission controls installed on each such boiler, replacement unit or new unit as necessary to ensure compliance with this requirement.

~~(9)~~ (4) Aggregate NOx Emission Limit

(i) Except as provided in Subsection (d)(5), ~~(10),~~ no person who owned or operated an electrical generating steam boiler subject to this rule on January 18, 1994 ~~or company which qualifies for the NOx offset waiver provisions of Subsection (d)(11)~~ shall operate any existing electrical generating steam boiler, replacement unit or new unit subject to this rule unless such person ~~or company~~ has demonstrated that the aggregate emissions of oxides of nitrogen, expressed as nitrogen dioxide, from all such boilers, replacement units and new units located in San Diego County and owned or operated by such person ~~or company~~ and any electrical generating steam boilers, replacement units and new units located in San Diego County that are owned or operated by ~~a company~~ another entity in which such person ~~or company~~ has a controlling interest, are not greater than:

~~(i)~~ (A) On and after January 1, 1997, 2100 tons during every calendar year.

(B) On and after January 1, 2001, 800 tons during every calendar year.

(ii) The aggregate NOx emission limits specified in Subsections (d)(4)(i)(A) and (d)(4)(i)(B) shall be adjusted if any existing boiler replacement unit or new unit subject to the aggregate limit is transferred to another entity in which the person who owned or operated an existing boiler on January 18, 1994 does not have a controlling interest. The transferred existing boiler, replacement unit or new unit shall not be subject to an aggregate NOx emission limit pursuant to this rule, but shall be subject to unit specific emission limits, as applicable, specified in Subsections (d)(2) and (d)(7) of this rule.

(iii) The aggregate NOx emission limits shall be adjusted when boilers or units are transferred by reducing the limits by an amount equal to the annual average megawatt-hours generated over the five years preceding transfer when burning natural gas, fuel oil, and any combination of natural gas and fuel oil, for each such boiler or unit, multiplied by a NOx emission rate of 0.15 pounds per megawatt-hour when burning natural gas, a NOx emission rate of 0.40 pounds per megawatt-hour when burning fuel oil and, when burning a combination of natural gas and fuel oil, a NOx emission rate prorated for the relative heat input from natural gas and fuel oil, as specified in Subsection (d)(7) of this rule. For boilers, replacement units or new units that have operated less than five years prior to transfer, the annual average megawatt-hours generated shall be based on the most representative years of operation preceding transfer, as determined by the Air Pollution Control Officer.

(iv) The annual oxides of nitrogen emission limits specified in this subsection shall be adjusted to account for fuel oil burning that results from a force majeure natural gas curtailment, or is due to compliance emissions testing, using methods approved by the Air Pollution Control Officer. The adjustment shall be made by adding to the applicable limit the difference between the total pounds of oxides of nitrogen emissions occurring during such fuel oil burning and the total pounds of oxides of nitrogen emissions which would have occurred during the same period had natural gas been fired in that boiler, replacement unit or new unit. ~~product of the megawatt-hours generated by each boiler, replacement unit, or new unit during such fuel oil burning and the difference between the applicable oxides of nitrogen emission rate limits for fuel oil burning and natural gas burning in that boiler, replacement unit or new unit.~~ The adjustment shall be prorated for the relative heat inputs of fuel oil and natural gas when co-firing both fuels.

~~(10)~~ (5) Exceedances of an Aggregate NOx Emission Limit

An ~~person or company~~ owner or operator subject to the requirements of Subsection (d)(4)~~(9)~~ may operate its electrical generating steam boilers, replacement units and new units when aggregate oxides of nitrogen emissions exceed the calendar year limits specified in Subsection (d)(4)~~(9)~~ provided:

(i) Such ~~person or company~~ owner or operator has demonstrated, to the satisfaction of the Air Pollution Control Officer, that the exceedance is due to an unforeseen event, such as a forced outage of one or more ~~generating units~~ boilers, replacement units or new units or a disruption in the supply of imported power, and is not due to an intentional or negligent act or omission on the part of such person or company, and

(ii) The Air Pollution Control Officer has approved the exceedance in advance and has issued modified permits to operate for the affected equipment adding conditions that establish a new, enforceable calendar year aggregate emission limit, and

(iii) Such person or company has provided offsetting emission reductions, on an annual basis and at a ~~1.3~~ 1.0 to 1.0 offset ratio, for all emissions of oxides of nitrogen in excess of the calendar year limits specified in Subsection (d)(4)~~(9)~~.

The new calendar year aggregate oxides of nitrogen emission limit established pursuant to ~~Subsection (d)(10)(ii)~~ the above shall be based on the sum of the aggregate emission limit specified in Subsection (d)(4) and the emission offsets provided pursuant to Subsection (d)(5). ~~maximum expected calendar year emissions in compliance with this rule. The quantity of offsetting emission reductions required shall be 1.3 times the difference between the new calendar year aggregate oxides of nitrogen emission limit and the applicable calendar year limit specified in Subsection (d)(9).~~ Offsetting emission reductions shall conform to the criteria for emission offsets specified in Rule 20.1.

~~(11)~~ (6) Waiver from New Source Review NOx Offset Requirements

On and after January 1, 1997, oxides of nitrogen emission increases from any new, modified or replacement unit subject to and in compliance with Subsections (d)(4)~~(9)~~ and (d)(5)~~(10)~~ of this rule, shall not be subject to the offset provisions of Regulation II, Rules 20.1 through ~~20.4~~ 20.3, and 20.9 (New Source Review) of these Rules and Regulations provided that:

(i) The owner or operator of the new, modified or replacement unit has demonstrated, using methods approved by the Air Pollution Control Officer and the U.S. Environmental Protection Agency, the extent to which the NOx emission reductions that have been achieved by the owner or operator from electrical generating steam boilers existing prior to January 18, 1994 by compliance with this rule are in excess of the NOx emission reductions required to demonstrate compliance with Reasonably Available Control Technology, any NOx emission reductions from electrical generating steam boilers contained in SIP Control Measures and any NOx emission reductions from electrical generating steam boilers necessary to demonstrate compliance with Reasonable Further Progress, and

(ii) The excess NOx emission reductions determined in Subsection (d)(6)(i) ~~(11)(i)~~ are greater than ~~1.3~~ 1.2 times the NOx emissions increases from the new, modified or replacement unit that would otherwise be subject to the offset provisions of Regulation II, Rules 20.1 through ~~20.4~~ 20.3, and 20.9 (New Source Review) of these Rules and Regulations, and

(iii) The excess NOx emission reductions determined in Subsection (d)(6)(i) ~~(11)(i)~~ are reduced by ~~1.3~~ 1.2 times the NOx emissions increases from the new, modified or replacement unit that would otherwise be subject to the offset provisions of Regulation II, Rules 20.1 through ~~20.4~~ 20.3, and 20.9 (New Source Review) of these Rules and Regulations.

Only oxides of nitrogen emission increases associated with generating capacity which the California Energy Commission or the California Public Utilities Commission or their successor, as applicable, has determined a need for shall be eligible for this waiver.

(7) NOx Emission Rate Limits for Existing Boilers Not Subject to an Aggregate NOx Emission Limit

The emissions of oxides of nitrogen from any existing electrical generating steam boiler that has been transferred to another entity in which the person who owned or operated the boiler on January 18, 1994 does not have a controlling interest, shall not exceed 0.15 pounds per megawatt-hour when burning exclusively natural gas, 0.40 pounds per megawatt-hour when burning exclusively fuel oil, and a prorated emissions limit, determined as follows, when burning a combination of natural gas and fuel oil:

$$\underline{EL} = \frac{[(Lo)(Qo)(HHVo)] + [(Lg)(Qg)(HHVg)]}{(Qo)(HHVo) + (Qg)(HHVg)}$$

where,

EL	=	Emission limit, pounds per megawatt-hour
Lo	=	0.40 pounds per megawatt-hour
Qo	=	Quantity of fuel oil burned, barrels per hour
HHVo	=	Higher heating value of fuel oil, Btu's per barrel
Lg	=	0.15 pounds per megawatt-hour
Qg	=	Quantity of natural gas burned, scf per hour
HHVg	=	Higher heating value of natural gas, Btu per scf,

Compliance with the standards of this subsection shall be based on emissions of oxides of nitrogen from an affected boiler averaged over each calendar day of operation, or portion thereof.

~~(12)~~ (8) Emission Standards for Ammonia

The emissions of ammonia from any electrical generating steam boiler, replacement unit or new unit subject to the requirements of this rule, or from any emissions control device used to achieve compliance with this rule, shall not be greater than the lowest emission rate achievable, consistent with the requirements of this rule, taking into consideration the costs of achieving that emission rate and the potential public health impacts associated with such emissions.

~~(13)~~ (9) Banking of Excess Emission Reductions

No person shall be eligible to obtain emission reduction credits for emissions of oxides of nitrogen below the limits specified in this Section (d).

(e) **COMPLIANCE SCHEDULE, PLAN AND REPORT**

(1) ~~Increments of Progress~~ Compliance Schedule

A person subject to the provisions of Section (d) shall comply with the following increments of progress:

(i) Any replacement unit or any new unit shall be in compliance with the applicable requirements of Section (d) on and after initial startup.

(ii) ~~Not later than January 18, 1997, be in compliance with the applicable requirements of Section (d) for not fewer than one electrical generating steam boiler, replacement unit or new unit and each calendar year thereafter bring into compliance a minimum of one additional boiler, replacement unit or new unit owned or operated by such person.~~ Any existing electrical generating steam boiler subject to the requirements of Subsection (d)(7) shall be in compliance with the requirements of this rule within two years after the first transfer of such boiler that occurs after (*date of adoption*), but not later than January 1, 2001.

(iii) ~~Except as provided in Subsection (e)(1)(iv) below, on and after January 1, 2001, be in compliance with the requirements of Section (d) for all operating electrical generating steam boilers, replacement units and new units owned or operated by such person.~~ The owner or operator of an existing electrical generating steam boiler, replacement unit or new unit subject to the provisions of Subsection (d)(4) shall be in compliance with the applicable aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5) beginning with calendar year 1997, and each calendar year thereafter.

~~(iv) Be in compliance with Section (d) by January 1, 2003, or upon initial startup, whichever is sooner, for all replacement units, and associated boiler(s), scheduled for initial startup between January 1, 2001 and January 1, 2003.~~

(2) Initial Compliance Plan~~/Report~~

~~(i)~~ The owner or operator of any equipment subject to the provisions of this rule shall submit to the Air Pollution Control Officer, for approval, by ~~July 18, 1994~~ (*date of adoption + 180 days*) a Compliance Plan describing the actions, and contingencies, which are proposed by the owner or operator to meet the requirements of Section (d) ~~and Subsection (e)(1)~~. The Compliance Plan shall contain, at a minimum, the following applicable information for each electrical generating steam boiler, replacement unit and new unit subject to this rule:

- District Permit to Operate number.
- Equipment location.
- Manufacturer.
- Model number.
- Maximum permitted heat input rating.
- Primary and backup fuels to be used.
- Proposed methods to measure, ~~and~~ record and report ~~megawatt-hours~~ emissions of oxides of nitrogen, measured as parts per million by volume (ppmv) as nitrogen dioxide at 3% O_2, as pounds per million Btu's of fuel heat input, as pounds per day, as tons per calendar month and as tons per calendar year ~~generated and watt transducer calibration method with supporting documentation~~.
- For existing boilers subject to the provisions of Subsection (d)(7), proposed methods to measure, ~~and~~ record and report megawatt-hours generated and watt transducer calibration method with supporting documentation.
- Maximum hourly, daily and annual pre-controlled NOx emission rates.
- Method and type of emission controls to be used.
- Expected performance of the emission controls.
- Proposed schedule for applications for Authorities to Construct, issuing purchase orders for emission controls, commencing con-

struction of emission controls, completing construction, conducting compliance tests and demonstrating compliance with the provisions of this rule.

- For boilers and replacement units and new units subject to the aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5), a forecast of aggregate emissions of oxides of nitrogen, in tons, for each calendar month of the next calendar year, a forecast of aggregate emissions of oxides of nitrogen, in tons, for each calendar year through the year 2001, and a demonstration of how compliance will be achieved with the aggregate NOx emission limits specified in Subsections (d)(4) and (d)(5).
- All analyses, operating data, emission factors, assumptions and calculations used to develop the forecast of aggregate calendar month and calendar year emissions of oxides of nitrogen.

The initial Compliance Plan submittal need not contain detailed information regarding emission control specifications, performance and schedules, but must contain at least preliminary information regarding the type of control equipment and the anticipated ~~final compliance~~ date for installation of any planned emission controls for each affected unit. A copy of the Compliance Plan shall be kept at each affected site and shall be made available for District inspection upon request. Adherence to a Compliance Plan does not relieve the owner or operator from complying with any other provisions of this rule. The owner or operator of any boiler, replacement unit or new unit subject to this rule shall update the Compliance Plan ~~shall be updated~~ annually.

(3) Compliance Reporting

(i) Annual Compliance Report

~~(ii)~~ The owner or operator of any equipment subject to the provisions of this rule shall submit by the submittal date in 1997 of the Emissions Statement Form(s) required by Rule 19.3, and each year thereafter, a Compliance Report which describes the measures taken in the preceding calendar year to achieve compliance with the requirements of Section (d) ~~and Subsection (e)(1)~~. The Compliance Report shall contain, at a minimum, the following information for the preceding calendar year for each electrical generating steam boiler, replacement unit and new unit subject to Section (d) of this rule:

- District Permit to Operate number.
- Number of hours of operation.
- Types and amounts of fuels consumed, and the number of hours on each fuel type.
- Dates and times of any force majeure natural gas curtailments that occurred.
- Mass emissions of oxides of nitrogen for each calendar ~~day~~ month and for the calendar year for each such boiler and unit and

for the aggregate emissions of such boilers and units under common ownership or control.

- Megawatt-hours generated and total mass emissions of NOx each calendar day and for the calendar year for each boiler subject to the NOx emission rate limits of Subsection (d)(7).
- Indication of whether the ~~unit~~ owner or operator is on schedule to meet the Compliance Plan(s) submitted pursuant to Subsection (e)(1).
- Emissions rate data and/or key emissions control device or boiler or unit operating parameter data, as required pursuant to Subsection (d)(3), for each day that the Air Pollution Control Officer predicted an exceedance of the state ambient air quality standard for ozone during the preceding calendar year.
- Identification of each exceedance of the applicable requirements of Section (d).

The Compliance Report submitted in 1998 for calendar year 1997, and each annual compliance report thereafter, shall contain a demonstration by the owner or operator, in the manner and form prescribed by the Air Pollution Control Officer, that the applicable requirements of Section (d) were met in the preceding calendar year. The Compliance Report shall be certified by the owner or operator as to its accuracy and completeness.

Where the Air Pollution Control Officer has approved emissions monitoring on a common stack that serves more than one electrical generating steam boiler, replacement unit, or new unit subject to this rule, the annual Compliance Report may contain aggregate emissions data from such boilers or units in lieu of emissions data for each such boiler or unit.

The Compliance Report shall also contain any proposed revisions to the Compliance Plan. These revisions shall include the justification for the changes and a demonstration that the changes will ensure compliance with the requirements of Section (d) and Subsection (e)(1).

Documentation and calculations used to prepare the material presented in the Compliance Report shall be maintained by the owner or operator for at least two years and shall be made available to the District upon request.

(ii) Monthly Compliance Reporting

The owner or operator of any boiler, replacement unit or new unit subject to the provisions of Subsections (d)(4)and (d)(5) shall submit monthly, by the 15th day of the calendar month, a report of the aggregate oxides of nitrogen emissions for the preceding calendar month and cumulatively for the current calendar year from each and all such boilers, replacement units and new units under the control of the owner or operator, and a comparison of oxides of nitrogen emissions during the preceding calendar months for the current calendar year to that forecast in the current Compliance Plan.

Where the Air Pollution Control Officer has approved emissions monitoring on a common stack that serves more than one electrical generating steam boiler, replacement unit or new unit subject to this rule, the monthly Compliance Report may contain aggregate emissions data from such boilers or units in lieu of emissions data for each such boiler or unit.

If the actual monthly or cumulative aggregate emissions exceed that forecast in the current Compliance Plan, the owner or operator shall submit an explanation of the exceedance, a description of all emission control and operational steps to be taken to ensure that the applicable calendar year aggregate emission limit of Section (d) will not be exceeded, and a revised forecast of the aggregate oxides of nitrogen emissions from each and all electrical generating steam boilers, replacement units and new units for each calendar month for the remainder of the calendar year.

(f) **RECORDKEEPING**

(1) On and after January 1, 1997, no person ~~or company subject to the requirements of Subsection (d)(9)~~ shall operate any electrical generating steam boiler, replacement unit or new unit subject to this rule unless such boiler or unit is equipped with continuous ~~emission~~ monitors, and associated data collection, processing and storage systems, which record and preserve, on a daily basis and in the manner and form prescribed by the Air Pollution Control Officer, all of the information needed to demonstrate compliance with Subsections (d)(1)~~,~~ (~~d)(4)(9) and~~ through (d)(5)~~(10)~~ and (d)(7) of this rule, as applicable, including but not limited to:

(i) The daily emissions, in pounds, of oxides of nitrogen from each boiler, replacement unit~~,~~ or new unit.

(ii) The aggregate daily emissions, in pounds, of oxides of nitrogen from all such boilers, replacement units or new units under common ownership or control.

(iii) The cumulative calendar month and annual emissions, in tons, of oxides of nitrogen, commencing with January 1 of the current calendar year, for each such boiler, replacement unit or new unit.

(iv) The cumulative calendar month and annual emissions, in tons, of oxides of nitrogen, commencing with January 1 of the current calendar year, for the aggregate of all such boilers, replacement units or new units under common ownership or control.

(v) The hours of operation for each such boiler, replacement unit or new unit.

(vi) For each such boiler, replacement unit or new unit, the following, averaged over each clock hour or portion thereof:

(A) NOx emission concentration, in parts per million by volume (ppmv) as nitrogen dioxide at three percent oxygen on a dry basis.

(B) Diluent concentration (CO_2 or O_2), in percent on a dry basis.

(C) NOx emission rate, in pounds per million Btu's of fuel heat input.

(D) Fuel heat input, in millions of Btu's.

(E) NOx mass emission, in pounds.

(F) For boilers subject to the provisions of Subsection (d)(7), NOx emissions per unit of electrical energy generated, in pounds per megawatt-hour, megawatt-hours of electrical energy generated, and the type and amount of fuel being burned.

Oxides of nitrogen emission concentrations shall be measured at equally spaced intervals, not to be less frequent than once every five minutes, or such other period determined by the Air Pollution Control Officer to be necessary to determine compliance with this rule and not inconsistent with monitoring requirements imposed under these rules or state or federal law, and averaged up to each clock hour, or portion thereof. Only the clock hour average data, or portion thereof, must be recorded and preserved.

~~(2) On and after the final compliance date specified in the Compliance Plan, a person shall not operate any electrical generating steam boiler, replacement unit or new unit subject to this rule unless such boiler or unit is equipped with continuous monitors, approved by the Air Pollution Control Officer, which record and preserve all of the information needed to determine compliance with Subsections (d)(1) through (d)(5) and (d)(7), including but not limited to:~~

~~(i) The hours of operation of the unit.~~

~~(ii) The emission concentration of oxides of nitrogen, calculated as parts per million by volume (ppmv) of nitrogen dioxide at three percent oxygen on a dry basis, averaged over every clock hour of operation, or portion thereof. The emission concentration shall be measured at equally spaced intervals, not to be less frequent than once every five minutes, or such other period determined by the Air Pollution Control Officer to be necessary to determine compliance with this rule and not inconsistent with monitoring requirements imposed under these rules or state or federal law, and averaged up to each clock hour, or portion thereof. Only the clock hour average data, or portion thereof, must be recorded and preserved.~~

~~(iii) The unit exhaust flue gas flow rate, calculated as cubic feet per hour at standard conditions and at three percent oxygen on a dry basis, averaged over every clock hour of operation, or portion thereof. The exhaust flue gas flow rate shall be measured at the same interval as emission concentration measurements. If unit exhaust flue gas flow rate is not measured directly but instead calculated from~~

~~fuel flow rate or other operating parameter, such parameter shall be measured at the specified concentration measurement interval, the parameter measurement shall be recorded, and the exhaust flue gas flow rate shall be calculated for each such interval. The exhaust flue gas flow rate measurements shall be averaged up to each clock hour, or portion thereof. Only the clock hour average data, or portion thereof, must be recorded and preserved.~~

~~(iv) The emissions of oxides of nitrogen shall be calculated, as pounds of nitrogen dioxide, during every interval of emission concentration measurement using the emission concentration and exhaust flue gas flow rate measurements required in Subsections (f)(2)(ii) and (f)(2)(iii) above. The emissions of oxides of nitrogen during every clock hour of operation, or portion thereof, shall be calculated by summing the emissions calculated for each measurement interval, following the methods described in Subsection (g)(4), and shall be recorded.~~

~~(v) The megawatt-hours of electrical energy generated by the unit during every clock hour of operation, or portion thereof shall be measured and recorded.~~

~~(vi) The cumulative emissions of oxides of nitrogen, expressed as pounds of nitrogen dioxide; the total megawatt-hours of electrical energy generated; and, the average emission rate of oxides of nitrogen, expressed as pounds of nitrogen dioxide per megawatt-hour of energy generated, for every calendar day of operation, or portion thereof, shall be calculated and recorded.~~

(2) For each electrical generating steam boiler, replacement unit or new unit, emissions of oxides of nitrogen, and megawatt-hours of electrical energy produced, if applicable, shall be measured, and the resultant data processed and reported, in accordance with a protocol prepared by the owner or operator of such boiler or unit and approved by the Air Pollution Control Officer. The protocol shall specify the maintenance, calibration and quality assurance procedures to be followed for each emission or energy measurement device and all data processing and associated equipment.

The Air Pollution Control Officer may approve continuous emissions monitoring on a common stack that serves more than one electrical generating steam boiler, replacement unit, or new unit subject to this rule provided that the owner or operator of such boilers or units demonstrates, to the satisfaction of the Air Pollution Control Officer, that such monitoring will be sufficient to determine compliance with the applicable requirements of this rule.

The records required by this section shall be retained on site for at least three years and shall be made available to the District upon request. Records of aggregate daily emissions required by Subsection (f)(1)(ii) shall be available within two working days of a request. Records of cumulative emissions required by Subsections (f)(1)(iii) and (f)(1)(iv) shall be available within ~~20~~ 15 working days of a request.

(g) **TEST METHODS**

The following methods shall be used to determine compliance with the requirements of this rule:

(1) Oxides of nitrogen emissions shall be measured utilizing District ~~modified~~ Method ~~20~~ 100 as it exists on ~~January 18, 1994~~ (*date of adoption)*. This method shall not apply to continuous emission monitors required by Subsection~~s~~ (f)(1)~~ and (f)(2)~~.

~~(2) Total energy generation in megawatt-hours shall be measured using watt transducers calibrated according to methods approved by the Air Pollution Control Officer. The methods shall be submitted by the owner or operator of a boiler or unit as part of the compliance plan required by Subsection (e)(2), and shall include a description of the principal of measurement, the frequency of measurement and basis therefore, and the calculations used to determine the megawatt hours (MW-hr) generated. The method shall also include the techniques and procedures used to calibrate each measurement device. Each measurement device shall be calibrated against standards which are based on the National Institute of Standards and Technology (NIST) standards or equivalent if no NIST standards exist. The calibration accuracy tolerance of each measurement device shall be (+/-) 0.5 percent of each measured value.~~

~~(3)~~ (2) The oxides of nitrogen (NOx) emission rate, in pounds, in pounds per megawatt-hour, if applicable, and in pounds per million Btu's of fuel heat input for each clock hour of operation, or portion thereof, for each boiler, replacement unit or new unit subject to the requirements of ~~Subsections~~ Section (d)~~(1) or (d)(2)~~, shall be calculated ~~as follows:~~ in accordance with procedures approved by the Air Pollution Control Officer.

$$\cancel{NOx_{lb/MW\text{-}hr} = \frac{NOx_{lb}}{MW\text{-}hr_{Total}}}$$

~~where,~~

~~$NOx_{lb/MW\text{-}hr}$ = NOx emission rate in lb/MW-hr, for each clock hour of operation, or portion thereof.~~

~~NOx_{lb} = NOx emissions in pounds during each clock hour, as calculated in Subsection (g)(4) below.~~

~~$MW\text{-}hr_{Total}$ = Total megawatt-hours generated for each clock hour.~~

~~(4) The emissions of oxides of nitrogen (NOx) for each applicable unit during each clock hour, or portion thereof, shall be calculated as follows:~~

$$\cancel{NOx_{lb} = \sum_{i=1}^{n} NOx_i}$$

~~where,~~

~~NOx_{lb} = Emissions of oxides of nitrogen, in pounds, during each clock hour of operation.~~

~~NOx_i = Emission of oxides of nitrogen, in pounds, calculated for each five minute or approved alternative time interval within each clock hour, or portion thereof.~~

~~n = Number of valid data points during each clock hour of operation, or portion thereof. There shall not be fewer than four valid data points during each clock hour.~~

~~Emissions occurring during periods of no electrical generation shall not be included when calculating oxides of nitrogen emissions per megawatt-hour but shall be included when calculating aggregate oxides of nitrogen emissions for a calendar year.~~