(Adopted October 15, 1993)(Amended March 10, 1995)(Amended December 7, 1995)
(Amended July 12, 1996)(Amended February 14, 1997)(Amended May 11, 2001)
(Amended January 7, 2005)(Amended November 5, 2010)(Amended December 4, 2015)
(PAR2002 072216)

PROPOSE AMENDED RULE 2002. ALLOCATIONS FOR OXIDES OF NITROGEN (NO_X) AND OXIDES OF SULFUR (SOx)

(a) Purpose

The purpose of this rule is to establish the methodology for calculating facility Allocations and adjustments to RTC holdings for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx).

(b) RECLAIM Allocations

(1) RECLAIM Allocations will begin in 1994.

(2) An annual Allocation will be assigned to each facility for each compliance year starting from 1994.

(3) Allocations and RTC holdings for each year after 2011 are equal to the 2011 Allocation and RTC holdings, as determined pursuant to subdivision (f) unless, as part of the AQMP process, and pursuant to Rule 2015 (b)(1), (b)(3), (b)(4), or (c), the District Governing Board determines that additional reductions are necessary to meet air quality standards, taking into consideration the current and projected state of technology available and cost-effectiveness to achieve further emission reductions.

(4) The Facility Permit or relevant sections thereof shall be re-issued at the beginning of each compliance year to include allocations determined pursuant to subdivisions (c), (d), (e), and (f) and any RECLAIM Trading Credits (RTC) obtained pursuant to Rule 2007 - Trading Requirements for the next fifteen years thereafter and any other modifications approved or required by the Executive Officer.

(5) Annual emission reports submitted pursuant to Rule 301 more than five years after the original due date shall not be considered by the Executive Officer in determining facility Allocations.

(c) Establishment of Starting Allocations

(1) The starting Allocation for RECLAIM NO_X and SO_X facilities initially permitted by the District prior to October 15, 1993, shall be determined by the Executive Officer utilizing the following methodology:

Starting Allocation=$\Sigma[A \text{ X } B_1]$+ERCs+External Offsets

Where

A = the throughput for each NO_X and SO_X source or process unit in the facility for the maximum throughput year from 1989 to 1992 inclusive; and

B_1 = the applicable starting emission factor for the subject source or process unit as specified in Table 1 or Table 2

(2) (A) Use of 1992 data is subject to verification and revision by the Executive Officer or designee to assure validity and accuracy.

(B) The maximum throughput year will be determined by the Executive Officer or designee from throughput data reported through annual emissions reports submitted pursuant to Rule 301 - Permit Fees, or may be designated by the permit holder prior to issuance of the Facility Permit.

(C) To determine the applicable starting emission factor in Table 1 or Table 2, the Executive Officer or designee will categorize the equipment at each facility based on information relative to hours of operation, equipment size, heating capacity, and permit information submitted pursuant to Rule 201 - Permit to Construct, and other relevant parameters as determined by the Executive Officer or designee. No information used for purposes of this subparagraph may be inconsistent with any information or statement previously submitted on behalf of the facility to the District, including but not limited to information and statements previously submitted pursuant to Rule 301 - Permit Fees, unless the facility can demonstrate, by clear and convincing documentation, that such information or statement was inaccurate.

(D) Throughput associated with each piece of equipment or NOx or SOx source will be multiplied by the starting emission factors specified in Table 1 or Table 2. If a lower emission factor was utilized for a given piece of equipment or NOx or SOx source pursuant to Rule 301 - Permit Fees, than the factor in Table 1 or

Table 2, the lower factor will be used for determining that portion of the Allocation.

(E) Fuel heating values may be used to convert throughput records into the appropriate units for determining Allocations based on the emission factors in Table 1 or Table 2. If a different unit basis than set forth in Tables 1 and 2 is needed for emissions calculations, the Executive Officer shall use a default heating value to determine source emissions, unless the Facility Permit holder can demonstrate with substantial evidence to the Executive Officer that a different value should be used to determine emissions from that source.

(3) All NO_X and SO_X ERCs generated at the facility and held by a RECLAIM Facility Permit holder shall be reissued as RTCs. RECLAIM facilities will have these RTCs added to their starting Allocations. RTCs generated from the conversion of ERCs shall have a zero rate of reduction for the year 1994 through the year 2000. Such RTCs shall have a cumulative rate of reduction for the years 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule and shall have a rate of reduction for compliance year 2004 and subsequent years determined pursuant to paragraph (f)(1) of this rule.

(4) Non-RECLAIM facilities may elect to have their ERCs converted to RTCs and listed on the RTC Listing maintained by the Executive Officer or designee pursuant to Rule 2007 - Trading Requirements, so long as the written request is filed before July 1, 1994. Such RTCs will be assigned to the trading zone in which the generating facility is located. RTCs generated from the conversion of ERCs shall have a zero rate of reduction for the year 1994 through the year 2000. Such RTCs shall have a cumulative rate of reduction for the years, 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule.

(5) External offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio, will be added to the starting Allocation pursuant to paragraph (c)(1) provided:

(A) The offsets were not received from either the Community Bank or the Priority Reserve.

(B) External offsets will only be added to the starting Allocation to the extent that the Facility Permit holder demonstrates that they have not already been included in the starting Allocation or as an ERC.

RTCs issued for external offsets shall not include any offsets in excess of a 1 to 1 ratio required under Regulation XIII - New Source Review.

(C) RTCs generated from the conversion of external offsets shall have a zero rate of reduction for the year 1994 through the year 2000. These RTCs shall have a cumulative rate of reduction for the years 2001, 2002, and 2003, equal to the percentage inventory adjustment factor applied to 2003 Allocations pursuant to paragraph (e)(1) of this rule, and for compliance year 2004 and subsequent years allocations shall be determined pursuant to paragraph (f)(1) of this rule. The rate of reduction for the year 2001 through year 2003 shall not be applied to new facilities initially totally permitted on or after January 7, 2005.

(D) Existing facilities with units that have Permits to Construct issued pursuant to Regulation II - Permits, dated on or after January 1, 1992, or existing facilities which have, between January 1, 1992 and October 15, 1993, installed air pollution control equipment that was exempt from offset requirements pursuant to Rule 1304 (a)(5), shall have their starting Allocations increased by the total external offsets provided, or the amount that would have been offset if the exemption had not applied.

(E) Existing facilities with units whose reported emissions are below capacity due to phased construction, and/or where the Permit to Operate issued pursuant to Regulation II - Permits, was issued after January 1, 1992, shall have their starting Allocations increased by the total external offsets provided.

(6) If a Facility Permit holder can demonstrate that its 1994 Allocation is less than the 1992 emissions reported pursuant to Rule 301 - Permit Fees, and that the facility was, in 1992, operating in compliance with all applicable District rules in effect as of December 31, 1993, the facility's starting Allocation will be equal to the 1992 reported emissions.

(7) For new facilities initially totally permitted on or after January 1, 1993 but prior to October 15, 1993, the starting Allocation shall be equal to the external offsets provided by the facility to offset emission increases at the facility pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio.

(8) The Allocation for new facilities initially totally permitted on and after October 15, 1993, shall be equal to the total RTCs provided by the facility to offset emission increases at the facility pursuant to Rule 2005- New Source Review for RECLAIM.

(9) The starting Allocation for existing facilities which enter the RECLAIM program pursuant to Rule 2001 - Applicability, shall be determined by the methodology in paragraph (c)(1) of this rule. The most recent two years reported emission fee data filed pursuant to Rule 301 - Permit Fees, may be used if 1989 through 1992 emission fee data is not available. For facilities lacking reported emission fee data, the Allocation shall be equal to the external offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio. The Allocation shall not include any emission offsets received from either the Community Bank or the Priority Reserve.

(10) A facility may not receive more than one set of Allocations.

(11) A facility that is no longer holding a valid District permit on January 1, 1994 will not receive an Allocation, but may, if authorized by Regulation XIII, apply for ERCs.

(12) Clean Fuel Adjustment to Starting Allocation

Any refiner who is required to make modifications to comply with CARB Phase II reformulated gasoline production (California Code of Regulations, Title 13, Sections 2250, 2251.5, 2252, 2260, 2261, 2262, 2262.2, 2262.3, 2262.4, 2262.5, 2262.6, 2262.7, 2263, 2264, 2266, 2267, 2268, 2269, 2270, and 2271) or federal requirements (Federal Clean Air Act, Title II, Part A, Section 211; 42 U.S.C. Section 7545) may receive (an) increase(s) in his Allocations except to the extent that there is an increase in maximum rating of the new or modified equipment. Each facility requesting an increase to Allocations shall submit an application for permit amendment specifying the necessary modifications and tentative schedule for completion. The Facility Permit holder shall establish the amount of emission increases resulting from the reformulated gasoline modifications for each year in which the increase in Allocations is requested. The increase to its Allocations will be issued contemporaneously with the modification according to a schedule approved by the Executive Officer or designee (i.e., 1994 through 1997 depending on the refinery). Each increase to the Allocations shall be equal to the increased emissions resulting from the modifications solely to comply with the state or federal reformulated gasoline requirements at the refinery or facility

producing hydrogen for reformulated gasoline production, and shall be established according to present and future compliance limits in current District rules or permits. Allocation increases for each refiner pursuant to this paragraph, shall not exceed 5 percent of the refiner's total starting Allocation, unless any refiner emits less than 0.0135 tons of NO_X per thousand barrels of crude processed, in which case the Allocation increases for such refiner shall not exceed 20 percent of that refiner's starting Allocation. The emissions per amount of crude processed will be determined on the basis of information reported to the District pursuant to Rule 301 - Permit Fees, for the same calendar year as the facility's peak activity year for their NO_X starting Allocation.

(d) Establishment of Year 2000 Allocations

(1) (A) The year 2000 Allocations for RECLAIM NO_X and SO_X facilities will be determined by the Executive Officer or designee utilizing the following methodology:

Year 2000 Allocation $= \Sigma [A \times B_2]$ + RTCs created from ERCs + External Offsets,

Where

A = the throughput for each NO_X or SO_X source or process unit in the facility for the maximum throughput year from 1987 to 1992, inclusive, as reported pursuant to Rule 301 - Permit Fees; and

B_2 = the applicable Tier I year Allocation emission factor for the subject source or process unit, as specified in Table 1 or Table 2.

(B) The maximum throughput year will be determined by the Executive Officer or designee from throughput data reported through annual emissions reports pursuant to Rule 301 - Permit Fees, or may be designated by the permit holder prior to issuance of the Facility Permit.

(C) To determine the applicable emission factor in Table 1 or Table 2, the Executive Officer or designee will categorize the equipment at each facility based on information on hours of operation, equipment size, heating capacity, and permit information submitted pursuant to Rule 201 - Permit to Construct, and other parameters as determined by the Executive Officer or designee. No information used for purposes of this subparagraph may be inconsistent with any information or statement previously submitted on behalf of the

facility to the District including but not limited to information and statements previously submitted pursuant to Rule 301 - Permit Fees, unless the facility can demonstrate, by clear and convincing documentation, that such information or statement was inaccurate.

(D) Throughput associated with each piece of equipment or NO_X or SO_X source will be multiplied by the Tier I emission factor specified in Table 1 or Table 2. If a factor lower than the factor in Table 1 or Table 2 was utilized for a given piece of equipment or NO_X or SO_X source pursuant to Rule 301, the lower factor will be used for determining that portion of the Allocation.

(E) The fuel heating value may be considered in determining Allocations and will be set to 1.0 unless the Facility Permit holder demonstrates that it should receive a different value.

(F) The year 2000 Allocation is the sum of the resulting products for each piece of equipment or NO_X or SO_X source multiplied by any inventory adjustment pursuant to paragraph (d)(4) of this rule.

(2) For facilities existing prior to October 15, 1993 which enter RECLAIM after October 15, 1993, the year 2000 Allocation will be determined according to paragraph (d)(1). The most recent two years reported emission fee data filed pursuant to Rule 301 - Permit Fees, may be used if 1989 through 1992 emission fee data is not available. For facilities lacking reported emission fee data, the Allocation shall be equal to their external offsets provided pursuant to Regulation XIII - New Source Review, not including any offsets in excess of a 1 to 1 ratio.

(3) No facility shall have a year 2000 Allocation [calculated pursuant to subdivision (d)] greater than the starting Allocation [calculated pursuant to subdivision (c)].

(4) If the sum of all RECLAIM facilities' year 2000 Allocations differs from the year 2000 projected inventory for these sources under the 1991 AQMP, the Executive Officer or designee will establish a percentage inventory adjustment factor that will be applied to adjust each facility's year 2000 Allocation. The inventory adjustment will not apply to RTCs generated from ERCs or external offsets.

(e) Allocations for the Year 2003

(1) The 2003 Allocations will be determined by the Executive Officer or designee applying a percentage inventory adjustment to reduce each facility's

unadjusted year 2000 Allocation so that the sum of all RECLAIM facilities' 2003 Allocations will equal the 1991 AQMP projected inventory for RECLAIM sources for the year 2003, corrected based on actual facility data reviewed for purposes of issuing Facility Permits and to reflect the highest year of actual Basin-wide economic activity for RECLAIM sources considered as a whole during the years 1987 through 1992.

(2) No facility shall have a 2003 Allocation (calculated pursuant this subdivision) greater than the year 2000 Allocation [calculated pursuant to subdivision (d)].

(f) Annual Allocations for NO_X and SOx and Adjustments to RTC Holdings

(1) Allocations for the years between 1994 and 2000, for RECLAIM NO_X and SO_X facilities shall be determined by a straight line rate of reduction between the starting Allocation and the year 2000 Allocation. For the years 2001 and 2002, the Allocations shall be determined by a straight line rate of reduction between the year 2000 and year 2003 Allocations. NOx Allocations for 2004, 2005, and 2006 and SOx Allocations for 2004 through 2012 are equal to the facility's 2003 Allocation, as determined pursuant to subdivision (e). NOx RTC Allocations and holdings subsequent to the year 2006 and SOx Allocations and holdings subsequent to the year 2012 shall be adjusted to the nearest pound as follows:

(A) The Executive Officer will adjust NOx RTC holdings, as of January 7, 2005 for compliance years 2007 and thereafter by multiplying the amount of RTC holdings by the following adjustment factors for the relevant compliance year, to obtain tradable/usable and non-tradable/non-usable holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor
2007	0.883
2008	0.856
2009	0.829
2010	0.802
2011 and after	0.775

(B) The Executive Officer shall adjust NOx RTCs held as of September 22, 2015 by the RTC holders identified in Table 7 and their successors using the following adjustment factors to obtain Tradable/Usable and Non-Tradable/Non-Usable RTC Holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2015	1.0	0
2016	0.906	0.094
2017	0.906	0
2018	0.859	0.047
2019	0.812	0.047
2020	0.719	0.093
2021	0.625	0.094
2022	0.437	0.188
2023 and after	0.437	0

RTC holdings traded from RTC holders in Table 7 on and after September 22, 2015 and held by other RTC holders not listed in Table 7 shall be subjected to the above adjustment factors. The adjustment factor(s) for any RTC sold by an RTC holder that both purchased and sold RTCs between September 22, 2015 and December 4, 2015 shall be based on a last in/first out basis.

(C) The Executive Officer shall adjust NOx RTCs held as of September 22, 2015 by the RTC holders identified in Table 8 and their successors using the following adjustment factors to obtain Tradable/Usable and Non-Tradable/Non-Usable RTC holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2015	1.0	0
2016	0.931	0.069
2017	0.931	0
2018	0.896	0.035
2019	0.861	0.035
2020	0.792	0.069
2021	0.722	0.070
2022	0.583	0.139
2023 and after	0.583	0

RTC holdings traded from RTC holders in Table 8 on and after September 22, 2015 and held by other RTC holders not listed in Table 8 shall be subjected to the above adjustment factors. The adjustment factor(s) for any RTC sold by an RTC holder that both purchased and sold RTCs between September 22, 2015 and December 4, 2015 shall be based on a last in/first out basis.

(D) RTCs designated as non-tradable/non-usable pursuant to subparagraphs (f)(1)(B) and (f)(1)(C) shall be held, but shall not be traded or used for reconciling emissions pursuant to Rule 2004.

(E) Commencing on January 1, 2008 with NOx RTC prices averaged from January 1, 2007 through December 31, 2007, the Executive Officer will calculate the 12-month rolling average RTC price for all trades for the current compliance year. Commencing on May 1, 2016 with NOx RTC prices averaged from January 1, 2016 through March 31, 2016, the Executive Officer will calculate the 3-month rolling average NOx RTC price for all trades for the current compliance year NOx RTCs and the 12-month rolling average NOx RTC price for all trades for infinite year block NOx RTC as defined in subparagraph (f)(1)(I). The Executive Officer will update the 3-month and 12-month rolling average once per month. The computation of the rolling average prices will not include RTC transactions reported at no price or RTC swap transactions.

(F) The Executive Officer shall transfer to a Regional NSR Holding account the amount of NOx RTCs holdings listed in Table 9 of this Rule from the corresponding facilities identified in the same table.

(G) For purposes of meeting the NSR holding requirement as specified in subdivision (f) of Rule 2005, the facilities identified in Table 9 may use a combination of their Tradable/Usable and Non-tradable/Non-usable RTCs specified in subparagraph (f)(1)(C) and the amount listed for each facility in Table 9, which represents the RTCs in the Regional NSR Holding account.

(H) In the event that the NOx RTC prices exceed $22,500 per ton (current compliance year credits) based on the 12-month rolling average, or exceed $35,000 per ton (current compliance year credits) based on the 3-month rolling average calculated pursuant to subparagraph (f)(1)(E), the Executive Officer will report the determination to the Governing Board. If the Governing Board finds that the 12-month rolling average RTC price exceeds $22,500 per ton or the 3-month rolling average RTC price exceeds $35,000 per ton, then the Non-tradable/Non-usable NOx RTCs, as specified in subparagraphs (f)(1)(B) and (f)(1)(C) valid for the period in which the RTC price is found to have exceeded the applicable

threshold, shall be converted to Tradable/Usable NOx RTCs upon Governing Board concurrence.

(I) In the event that the infinite year block NOx RTC prices fall below $200,000 per ton based on the 12-month rolling average, calculated pursuant to subparagraph (f)(1)(E) beginning in 2019 for the compliance year in which Cycle 1 facilities are operating, the Executive Officer will report the determination to the Governing Board.

For the purpose of this rule, infinite year block refers to trades involving blocks of RTCs with a specified start year and continuing into the future for ten or more years.

(J) Pursuant to subparagraphs (f)(1)(H) and (f)(1)(I) the Executive Officer's report to the Board will also include a commitment and schedule to conduct a more rigorous control technology implementation, emission reduction, cost-effectiveness, market analysis, and socioeconomic impact assessment of the RECLAIM program. The Executive Officer's report to the Board will be made at a public hearing at the earliest possible regularly scheduled Board Meeting, but no more than 90 days from Executive Officer determination.

(K) The NOx emission reductions associated with the RTC adjustment factors for compliance years 2016, and 2018 through 2022 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. However, the amount of NOx RTCs adjustments specified in sub-paragraph (f)(1)(F) shall not be submitted for inclusion in the State Implementation Plan.

(L) NOx Allocations for existing facilities that enter RECLAIM after December 4, 2015 for Compliance Year 2016 and all subsequent years shall be the amount determined pursuant to subparagraph (d)(1)(A) except the variable B2 shall be the lowest of:

(i) The applicable 2000 (Tier I) Ending Emission Factor for the subject source(s) or process unit(s), as specified in Table 1 multiplied by the percentage inventory adjustment pursuant to subdivision (e) (0.72);

(ii) The BARCT Emission factor for the subject source as specified in Table 3; and

(iii) The BARCT Emission factor for the subject source, as specified in Table 6.

(M) SOx RTC Holdings as of November 5, 2010, for compliance years 2013 and after shall be adjusted to achieve an overall reduction in the following amounts:

Compliance Year	Minimum emission reductions (lbs.)
2013	2,190,000
2014	2,920,000
2015	2,920,000
2016	2,920,000
2017	3,650,000
2018	3,650,000
2019 and after	4,161,000

(N) The Executive Officer shall determine Tradable/usable SOx RTC Adjustment Factor for each compliance year after 2012 as follows:

$$F_{\text{compliance year i}} = 1 - [Xi / (Ai + Bi + Ci)]$$

Where:

$F_{\text{compliance year i}}$ = Tradable/usable SOx RTC Adjustment Factor for compliance year i starting with 2013

Ai = Total SOx RTCs for compliance year i held as of November 5, 2010, by all RTC holders, except those listed in Table 5

Bi = Total SOx RTCs for compliance year i credited to any facilities listed in Table 5 between August 29, 2009 and November 5, 2010, and not included in Ci

Ci = Total SOx RTCs held as of November 5, 2010 by facilities listed in Table 5 for compliance year i in excess of allocations as determined pursuant to subdivision (e).

Xi = Amount to be reduced for compliance year i starting with 2013 as listed in subparagraph (f)(1)(M).

(O) The Executive Officer shall determine Non-tradable/Non-usable SOx RTC Adjustment Factors for compliance years 2017 through 2019 as follows:

$$N_{\text{compliance year j}} = F_{\text{compliance year 2016}} - F_{\text{compliance year j}}$$

Where:

$N_{\text{compliance year j}}$ = Non-tradable/Non-usable SOx RTC Adjustment Factor for compliance year j

$F_{compliance\ year\ j}$ = Tradable/Usable SOx RTC Adjustment Factor for compliance year j as determined pursuant to subparagraph (f)(1)(N)

j = 2017 through 2019

$F_{compliance\ year\ 2016}$ = Tradable/usable SOx RTC Adjustment Factor for compliance year 2016 as determined pursuant to subparagraph (f)(1)(N)

Non-tradable/Non-usable SOx RTC Adjustment Factors for compliance years 2013, 2014, 2020, and all years after 2020 shall be 0.0.

(P) The Executive Officer shall adjust the SOx RTC holdings as of November 5, 2010, for compliance years 2013 and after as follows:

(i) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/Non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(Q) to SOx RTC holdings held by any RTC holder except those listed in Table 5;

(ii) Apply no adjustment to SOx RTC holdings that are held as of August 29, 2009 by a facility listed in Table 5, and that are less than or equal to the facility's allocations as determined pursuant to subdivision (e), and that were not credited between August 29, 2009 and November 5, 2010;

(iii) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/Non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(Q) to any SOx RTC holding as of November 5, 2010, that is held by a facility that is listed in Table 5, and that is over the facility's allocations as determined pursuant to subdivision (e); and

(iv) Apply the Tradable/Usable SOx RTC Adjustment Factor ($F_{compliance\ year\ i}$) and Non-tradable/non-usable SOx RTC Adjustment Factor ($N_{compliance\ year\ j}$) for the corresponding compliance year as published under subparagraph (f)(1)(Q) to any SOx RTC holding that was acquired between August 29, 2009 and November 5, 2010, by a facility that is listed in Table 5.

No SOx RTC holding shall be subject to the SOx RTC adjustments as published under subparagraph (f)(1)(Q) more than once.

(Q) The Executive Officer shall publish the SOx RTC Adjustment Factors determined according to subparagraphs (f)(1)(N) and (f)(1)(O) within 30 days after November 5, 2010.

(R) Commencing on January 1, 2017 and ending on February 1, 2020, the Executive Officer will calculate the 12-month rolling average SOx RTC price for all trades during the preceding 12 months for the current compliance year. The Executive Officer will update the 12-month rolling average once per month. The computation of the rolling average prices will not include RTC transactions reported at no price or RTC swap transactions.

(S) In the event that the SOx RTC prices exceed $50,000 per ton based on the 12-month rolling average calculated pursuant to subparagraph (f)(1)(R), the Executive Officer will report to the Governing Board at a duly noticed public hearing to be held no more than 60 days from Executive Officer determination. The Executive Officer will announce that determination on the SCAQMD website. At the public hearing, the Governing Board will decide whether or not to convert any portion of the Non-tradable/Non-usable RTCs, as determined pursuant to subparagraphs (f)(1)(O) and (f)(1)(P), and how much to convert if any, to Tradable/Usable RTCs. The portion of Non-tradable/Non-usable RTCs available for conversion to Tradable/Usable RTCs shall not include any portion of Non-tradable/Non-usable RTCs that are designated for previous compliance years and has not already been converted by the Governing Board, or that has been otherwise included in the State Implementation Plan pursuant to subparagraph (f)(1)(T).

(T) The Executive Officer will not submit the emission reductions obtained through subparagraph (f)(1)(M) for compliance years 2017 through 2019 for inclusion into the State Implementation Plan until the adjustments for the RTC Holdings have been in effect for one full compliance year.

(U) SOx Allocations for compliance years 2013 and after, for facilities that enter RECLAIM after November 5, 2010, and for basic equipment listed in Table 4 shall be determined according to the BARCT level listed in Table 4 or the permitted emission limits, whichever is lower.

(V) By no later than July 1, 2012, SOx emissions at the exhaust of a Fluidized Catalytic Cracking Unit, as measured at the final stack venting gases originating from the facility's FCC Regenerator, including after the CO Boiler or any additional controls in the system following the regenerator (the final stack shall constitute the only exhaust gas compliance point within the FCCU facility), shall not exceed a concentration of 25 ppm dry @ 0% oxygen on a 365-day rolling average. The numeric concentration-based limit does not apply during time periods in which SOx data are determined to be incorrect due to analyzer calibration or malfunction. For the purpose of demonstrating compliance with this limit, the operator of a FCCU shall commence the use of SOx reducing additives in the FCCU no later than July 1, 2011, unless the operator has an existing wet gas scrubber in operation at BARCT levels prior to November 5, 2010 or can demonstrate to the Executive Officer that the FCCU will achieve this limit by using other control methods.

(2) New facilities initially totally permitted, on and after October 15, 1993, but prior to January 7, 2005, and entering the RECLAIM program after January 7, 2005 shall not have a rate of reduction until 2001. Reductions from 2001 to 2003, inclusive, shall be implemented pursuant to subdivision (e). New facilities initially totally permitted on or after January 7, 2005 using external offsets shall have a rate of reduction for such offsets pursuant to subparagraph (c)(5)(C). New facilities initially totally permitted on or after January 7, 2005 using RTCs shall have no rate of reduction for such RTCs, provided that RTCs obtained have been adjusted according to paragraph (f)(1), as applicable. The Facility Permit for such facilities will require the Facility Permit holder to, at the commencement of each compliance year,

hold RTCs equal to the amount of RTCs provided as offsets pursuant to Rule 2005.

(3) Increases to Allocations for permits issued for Clean Fuel adjustments pursuant to paragraph (c)(12), shall be added to each year's Allocation.

(4) During a State of Emergency declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries, the current compliance year Non-tradable/Non-usable NOx RTCs held by electricity generating facilities as defined in Rule 2001(g)(1) that generate and distribute electricity to the grid system(s) affected by the State of Emergency may be used to offset their emissions after completely exhausting their own Tradable/Usable NOx RTCs.

If such a facility has completely exhausted their Non-tradable/Non-usable NOx RTCs, the owner or operator of the facility may apply for the use of the NOx RTCs in the Regional NSR Holding Account. The use of such RTCs in this Account shall be based on availability at the end of each quarter. The owner or operator of each electricity generating facility requesting NOx RTCs from the Regional NSR Holding Account shall submit a written request to the Executive Officer specifying the amount of RTCs needed and the basis for requesting the required amount.

The Executive Officer will determine the amount and distribution of the NOx RTCs from the Regional NSR Holding Account based on the requesting facility meeting the following criteria:

(i) The State of Emergency related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries, as declared by the Governor, was the direct cause of the excess emissions;

(ii) The facility has been ordered to generate electricity in an increased amount and/or frequency due to the State of Emergency;

(iii) The facility has adequately demonstrated their need for the specific amount of RTCs from the Regional NSR Holding Account; and

(iv) The facility owner or operator has not sold any part of their RTC holdings for the subject compliance year.

If the total RTCs requested exceed the supply of RTCs in this Account, the RTCs will be distributed proportionately according to the offset needs of the

facilities on a quarterly basis. These RTCs will be non-tradable, but usable to offset emissions.

(5) The Executive Officer will report to the Governing Board within 60 days of the end of the quarter in which a State of Emergency was declared by the Governor related to electricity demand or power grid stability within the SCAQMD jurisdictional boundaries. Included in this report will be, as applicable:

(i) the quantity of RTCs from the Regional NSR Holding Account that were distributed for compliance with the requirement to reconcile quarterly and annual emissions;

(ii) any adverse impacts that the State of Emergency is having on the RECLAIM program; and

(iii) any potential changes to the RECLAIM program that will be needed to help correct these impacts.

(g) High Employment/Low Emissions (HILO) Facility

The Executive Officer or designee will establish a HILO bank funded with the following maximum total annual emission Allocations:

(1) 91 tons per year of NO_X

(2) 91 tons per year of ~~So~~SO_X

(3) After January 1, 1997, new facilities may apply to the HILO bank in order to obtain non-tradable RTCs. Requests will be processed on a first-come, first-served basis, pending qualification.

(4) When credits are available, annual Allocations will be granted for the year of application and all subsequent years.

(5) HILO facilities receiving such Allocations from the HILO bank must verify their HILO status on an annual basis through their APEP report.

(6) Failure to qualify will result in all subsequent years' credits being returned to the HILO bank.

(7) Facilities failing to qualify for the HILO bank Allocations may reapply at any time during the next or subsequent compliance year when credits are available.

(h) Non-Tradable Allocation Credits

(1) Any existing RECLAIM facility with reported emissions pursuant to Rule 301 - Permit Fees, in either 1987, 1988, or 1993, greater than its starting Allocation, shall be assigned non-tradable credits for the first three years of

the program which shall be determined according to the following methodology:

Non-tradable credit for NO_X and SO_X:

Year 1 = $(\Sigma [A \times B_1])$ - 1994 Allocation;

Where:

A	=	the throughput for each NO_X or SO_X source or process unit in the facility from the single maximum throughput year from 1987, 1988, or 1993; and
B_1	=	the applicable starting emission factor, as specified in Table 1 or Table 2.
Year 2	=	Year 1 non-tradable credits X 0.667
Year 3	=	Year 1 non-tradable credits X 0.333
Year 4 and subsequent years	=	Zero non-tradable credit.

(2) The use of non-tradable credits shall be subject to the following requirements:

(A) Non-tradable credits may only be used for an increase in throughput over that used to determine the facility's starting Allocation. Non-tradable credits may not be used for emissions increases associated with equipment modifications, change in feedstock or raw materials, or any other changes except increases in throughput. The Executive Officer or designee may impose Facility Permit conditions necessary to ensure compliance with this subparagraph.

(B) The use of activated non-tradable credits shall be subject to a non-tradable RTC mitigation fee, as specified in Rule 301 subdivision (n).

(C) In order to utilize non-tradable credits, the Facility Permit holder shall submit a request to the Executive Officer or designee in writing, including a demonstration that the use of the non-tradable credits complies with all requirements of this paragraph, pay any fees required pursuant to Rule 301 - Fees, and have received written approval from the Executive Officer or designee for their use. The Executive Officer or designee shall deny the request unless the Facility Permit holder demonstrates compliance with all requirements of this paragraph. The Executive Officer or designee shall, in writing, approve or deny the request within three business days of submittal of a complete request and notify the Facility Permit holder of the decision. If the request is denied, the Executive Officer or designee will refund the mitigation fee.

(D) In the event that a facility transfers any RTCs for the year in which non-tradable credits have been issued, the non-tradable credit Allocation shall be invalid, and is no longer available to the facility.

(i) Facility Shutdowns

(1) Any Facility Permit Holder that permanently shuts down or surrenders all operating permits for the entire facility shall have its adjusted initial NOx allocation reduced each compliance year by an amount equivalent to the difference between:

(A) The average of actual NOx emissions from the highest 2 of the past 5 compliance years for the facility; and

(B) The NOx emissions that would have occurred in those same 2 years as if it was operated at the most stringent applicable BARCT emission factors specified in Rule 2002(f)(1)(L).

(2) Any offsets provided by the SCAQMD pursuant to Rule 1304 that remain as part of the adjusted initial NOx allocation shall also be subtracted for each compliance year.

(3) The reduction of RTCs calculated pursuant to paragraph (i)(1) shall not exceed the adjusted initial allocation.

(4) The reduction of NOx RTCs pursuant to paragraph (i)(1) shall apply to all future compliance year RTCs.

(5) If any RTCs that would have been reduced from the adjusted initial allocation pursuant to paragraph (i)(1) have been sold prior to the reduction, the Facility Permit Holder shall purchase and retire sufficient RTCs to fulfill the entire reduction requirement.

(6) The requirements specified in this subdivision shall not apply to facility shutdowns where the RTCs are transferred to another facility under common ownership that conducts the same functions at another facility with the same 6-digit North American Industry Classification System (NAICS) designation.

(7) In addition to self-reported facility shutdowns, the Executive Officer will determine a NOx RECLAIM facility to have shut down if the facility has been non-operational for a period of two consecutive years or longer, based on APEP reports. A facility is deemed to be non-operational if NOx emissions in any compliance year are less than 10 percent of the maximum annual NOx emissions in the previous 2 compliance years, excluding:

(A) Cyclical operations in conjunction with facility equipment;

(B) Delay in the availability of parts used to repair the shutdown equipment;

(C) Equipment that must be placed in a reserve status until remaining operations at the facility are recommissioned requiring the reinstatement of this equipment; or

(D) Emission reductions due to implementation of add-on NOx emission controls.

(8) In accordance to paragraph (i)(7), the Executive Officer will notify the Facility Permit Holder with a preliminary determination that their facility has been deemed as shutdown. The Facility Permit Holder shall submit within 30 days of the preliminary determination a plan application and provide information to demonstrate the preliminary determination did not adequately consider any of the factors listed under Subparagraphs (i)(7)(A) through (D). The Executive Officer shall evaluate the plan application and provide a final determination within 60 days of plan submittal.

(9) The facility shall be deemed shut down if the Executive Officer fails to notify the Facility Permit Holder of changes to the preliminary determination within 60 days of the preliminary determination or of the plan submittal date, whichever is later. In such a case, the Facility Permit Holder may file an appeal to the Hearing Board.

(10) Within 30 days of the preliminary determination of the facility shutdown as specified in paragraph (i)(7), the Facility Permit Holder may submit a plan application to request planned non-operation (PNO) status for a non-operational time period of no longer than 5 years for equipment within the facility. The Executive Officer shall consider the criteria in paragraphs (i)(6) and (i)(7) for approving the plan. All of the referenced criteria shall require company records to support the claim that a PNO status of no longer than 5 years is necessary and meets the criteria of this paragraph. Executive Officer approval for this PNO shall be obtained within 6 months of receiving the plan application. Otherwise, the facility shall be deemed shutdown and subject to

the requirements specified in paragraphs (i)(1), (i)(2), (i)(3), (i)(4), and (i)(5). If granted, the facility's NOx RTCs shall become non-tradable for the duration of the PNO status. Executive Officer denial of a PNO plan application may be appealed to the Hearing Board.

(11) If a facility has been deemed shutdown, the adjusted initial allocation shall be reduced pursuant to paragraphs (i)(1), (i)(2), (i)(3), (i)(4), and (i)(5).

(12) These requirements in this subdivision shall not apply to facilities without an initial allocation.

Table 1

RECLAIM NO_X Emission Factors

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Afterburner (Direct Flame and Catalytic)	Natural Gas	mmcf	130.000	39.000
Afterburner (Direct Flame and Catalytic)	LPG, Propane, Butane	1000 Gal	RV	3.840
Afterburner (Direct Flame and Catalytic)	Diesel	1000 Gal	RV	5.700
Agr Chem-Nitric Acid	Process-Absrbr Tailgas/Nw	tons pure acid produced	RV	1.440
Agricultural Chem - Ammonia	Process	tons produced	RV	1.650
Air Ground Turbines	Air Ground Turbines	(unknown process units)	RV	1.860
Ammonia Plant	Neutralizer Fert, Ammon Nit	tons produced	RV	2.500
Asphalt Heater, Concrete	Natural Gas	mmcf	130.000	65.000
Asphalt Heater, Concrete	Fuel Oil	1000 gals	RV	9.500
Asphalt Heater, Concrete	LPG	1000 gals	RV	6.400
Boiler, Heater R1109 (Petr Refin)	Natural Gas	mmbtu	0.100	0.030
Boiler, Heater R1109 (Petr Refin)	Fuel Oil	mmbtu	0.100	0.030
Boiler, Heater R1146 (Petr Refin)	Natural Gas	mmbtu	0.045	0.045
Boiler, Heater R1146 (Petr Refin)	Fuel Oil	mmbtu	0.045	0.045
Boiler, Heater R1146 (Petr Refin)	Refinery Gas	mmbtu	0.045	0.045
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Natural Gas	mmcf	49.180	47.570
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	LPG, Propane, Butane	1000 gals	4.400	4.260
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Diesel Light Dist. (0.05% S)	1000 gals	6.420	6.210
Boilers, Heaters, Steam Gens Rule 1146 and 1146.1	Refinery Gas	mmcf	51.520	49.840
Boilers, Heaters, Steam Gens	Bituminous Coal	tons burned	RV	4.800
Boiler, Heater, Steam Gen (Rule 1146.1)	Natural Gas	mmcf	130.000	39.460
Boiler, Heater, Steam Gen (Rule 1146.1)	Refinery Gas	mmcf	RV	41.340

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Boiler, Heater, Steam Gen (Rule 1146.1)	LPG, Propane, Butane	1000 gallons	RV	3.530
Boiler, Heater, Steam Gen (Rule 1146.1)	Diesel Light Dist (0.05%)	1000 gallons	RV	5.150
Boiler, Heater, Steam Gen (Rule 1146)	Natural Gas	mmcf	47.750	47.750
Boiler, Heater, Steam Gen (Rule 1146)	Refinery Gas	mmcf	50.030	50.030
Boiler, Heater, Steam Gen (Rule 1146)	LPG, Propane, Butane	1000 gallons	4.280	4.280
Boiler, Heater, Steam Gen (Rule 1146)	Diesel Light Dist (0.05%)	1000 gallons	6.230	6.230
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Natural Gas	mmcf	RV	47.750
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Refinery Gas	mmcf	RV	50.030
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	LPG, Propane, Butane	1000 gallons	RV	4.280
Boiler, Heater, Steam Gen (R1146, <90,000 Therms)	Diesel Light Dist (0.05%)	1000 gallons	RV	6.230
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Natural Gas	mmcf	RV	39.460
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Refinery Gas	mmcf	RV	41.340
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	LPG, Propane, Butane	1000 gallons	RV	3.530
Boiler, Heater, Steam Gen (R1146.1, <18,000 Therms)	Diesel Light Dist (0.05%)	1000 gallons	RV	5.150
Boiler, Heater R1109 (Petr Refin)	Refinery Gas	mmbtu	0.100	0.030
Boilers, Heaters, Steam Gens, (Petr Refin)	Natural Gas	mmcf	105.000	31.500
Boilers, Heaters, Steam Gens, (Petr Refin)	Refinery Gas	mmcf	110.000	33.000
Boilers, Heaters, Steam Gens, Unpermitted	Natural Gas	mmcf	130.000	32.500
Boilers, Heaters, Steam Gens, Unpermitted	LPG, Propane, Butane	1000 gallons	RV	3.200
Boilers, Heaters, Steam Gens ****	Natural Gas	mmcf	38.460	38.460

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**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Boilers, Heaters, Steam Gens ****	Refinery Gas	mmbtu	0.035	0.035
Boilers, Heaters, Steam Gens ****	LPG, Propane, Butane	1000 gallons	3.55	3.55
Boilers, Heaters, Steam Gens ****	Diesel Light Dist (0.05%), Fuel Oil No. 2	mmbtu	0.03847	0.03847
Boilers, Heaters, Steam Gens, Unpermitted	Diesel Light Dist (0.05%)	1000 gallons	RV	4.750
Catalyst Manufacturing	Catalyst Mfg	tons of catalyst produced	RV	1.660
Catalyst Manufacturing	Catalyst Mfg	tons of catalyst produced	RV	2.090
Cement Kilns	Natural Gas	mmcf	130.000	19.500
Cement Kilns	Diesel Light Dist. (0.05% S)	1000 gals	RV	2.850
Cement Kilns	Kilns-Dry Process	tons cement produced	RV	0.750
Cement Kilns	Bituminous Coal	tons burned	RV	4.800
Cement Kilns	Tons Clinker	tons clinker	RV	2.73***
Ceramic and Brick Kilns (Preheated Combustion Air)	Natural Gas	mmcf	213.000	170.400
Ceramic and Brick Kilns (Preheated Combustion Air)	Diesel Light Distillate (.05%)	1000 gallons	RV	24.905
Ceramic and Brick Kilns (Preheated Combustion Air)	LPG	1000 gallons	RV	16.778
Ceramic Clay Mfg	Drying	tons input to process	RV	1.114
CO Boiler	Refinery Gas	mmbtu		0.030
Cogen, Industr	Coke	tons burned	RV	3.682
Electric Generation, Commercial Institutional Boiler	Distillate Oil	1000 gallons	6.420	6.210
Composite Internal Combustion	Waste Fuel Oil	1000 gals burned	RV	31.340
Curing and Drying Ovens	Natural Gas	mmcf	130.000	32.500

* RV = Reported Value

** Does not include ceramic, clay, cement or brick kilns or metal melting, heat treating or glass melting furnaces.

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor *	2000 (Tier I) Ending Ems Factor *
Curing and Drying Ovens	LPG, Propane, Butane	1000 gals	RV	3.200
Delacquering Furnace	Natural Gas	mmcf	182.2***	182.2***
Fiberglass	Textile-Type Fibr	tons of material processed	RV	1.860
Fluid Catalytic Cracking Unit	Fresh Feed	1000 BBLS fresh feed	RV	RV*0.3 ***
Fluid Catalytic Cracking Unit with Urea Injection	Fresh Feed	1000 BBLS fresh feed	RV	(RV*0.3) / (1-control efficiency) ***
Fugitive Emission	Not Classified	tons product	RV	0.087
Furnace Process	Carbon Black	tons produced	RV	38.850
Furnace Suppressor	Furnace Suppressor	unknown	RV	0.800
Glass Fiber Furnace	Mineral Products	tons product produced	RV	4.000
Glass Melting Furnace	Flat Glass	tons of glass pulled	RV	4.000
Glass Melting Furnace	Tableware Glass	tons of glass pulled	RV	5.680
Glass Melting Furnaces	Container Glass	tons of glass produced	4.000	1.2***
ICEs****	All Fuels		Equivalent to permitted BACT limit	Equivalent to permitted BACT limit
ICEs, Permitted (Rule 1110.1 and 1110.2)	Natural Gas	mmcf	2192.450	217.360
ICEs Permitted (Rule 1110.2)	Natural Gas	mmcf	RV	217.360
ICEs, Permitted (Rule 1110.1 and 1110.2)	LPG, Propane, Butane	1000 gals	RV	19.460
ICEs, Permitted (Rule 1110.1 and 1110.2)	Gasoline	1000 gals	RV	20.130
ICEs, Permitted (Rule 1110.1 and 1110.2)	Diesel Oil	1000 gals	RV	31.340
ICEs, Exempted per Rule 1110.2	All Fuels		RV	RV
ICEs, Exempted per Rule 1110.2 and subject to Rule 1110.1	All Fuels		RV	RV
ICEs, Unpermitted	All Fuels		RV	RV
In Process Fuel	Coke	tons burned	RV	24.593
Incinerators	Natural Gas	mmcf	130.000	104.000
Industrial	Propane	1000 gallons	RV	20.890
Industrial	Gasoline	1000 gallons	RV	21.620

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*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Ems Factor *
Industrial	Dist.Oil/Diesel	1000 gallons	RV	33.650
Inorganic Chemicals, H2SO4 Chamber	General	tons pure acid produced	RV	0.266
Inorganic Chemicals, H2SO4 Contact	Absrbr 98.0% Conv	tons 100% H2S04	RV	0.376
Iron/Steel Foundry	Steel Foundry, Elec Arc Furn	tons metal processed	RV	0.045
Metal Heat Treating Furnace	Natural Gas	mmcf	130.000	104.000
Metal Heat Treating Furnace	Diesel Light Distillate (.05%)	1000 gallons	RV	15.200
Metal Heat Treating Furnace	LPG	1000 gallons	RV	10.240
Metal Forging Furnace (Preheated Combustion Air)	Natural Gas	mmcf	213.000	170.400
Metal Forging Furnace (Preheated Combustion Air)	Diesel Light Distillate (.05%)	1000 gallons	RV	24.905
Metal Forging Furnace (Preheated Combustion Air)	LPG	1000 gallons	RV	16.778
Metal Melting Furnaces	Natural Gas	mmcf	130.000	65.000
Metal Melting Furnaces	LPG, Propane, Butane	1000 gals	RV	6.400
Miscellaneous		bbls-processed	RV	1.240
Natural Gas Production	Not Classified	mmcf gas	RV	6.320
Nonmetallic Mineral	Sand/Gravel	tons product	RV	0.030
NSPS	Refinery Gas	mmbtu	RV	0.030
Other BACT Heater (24F-1)	Natural Gas	mmcf	RV	RV
Other Heater (24F-1)	Pressure Swing Absorber Gas	mmcf	RV	RV
Ovens, Kilns, Calciners, Dryers, Furnaces**	Natural Gas	mmcf	130.000	65.000
Ovens, Kilns, Calciners, Dryers, Furnaces**	Diesel Light Dist. (0.05% S)	1000 gals	RV	9.500
Paint Mfg, Solvent Loss	Mixing/Blending	tons solvent	RV	45.600
Petroleum Refining	Asphalt Blowing	tons of asphalt produced	RV	45.600
Petroleum Refining, Calciner	Petroleum Coke	Calcined Coke	RV	0.971***
Plastics Prodn	Polyester Resins	tons product	RV	106.500
Pot Furnace	Lead Battery	lbs Niter	0.077***	0.062***
Process Specific	ID# 012183	(unknown process units)	RV	240.000
Process Specific	SCC 30500311	tons produced	RV	0.140

* RV = Reported Value

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*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Ems Factor *
Process Specific	ID 14944	(unknown process units)	RV	0.512
SCC 39090003			RV	170.400
Sec. Aluminum	Sweating Furnace	tons produced	RV	0.300
Sec. Aluminum	Smelting Furnace	tons metal produced	RV	0.323
Sec. Aluminum	Annealing Furnace	mmcf	130.000	65.000
Sec. Aluminum	Boring Dryer	tons produced	RV	0.057
Sec. Lead	Smelting Furnace	tons metal charged	RV	0.110
Sec. Lead	Smelting Furnace	tons metal charged	RV	0.060
Sodium Silicate Furnace	Water Glass	Tons Glass Pulled	RV	6.400
Steel Hot Plate Furnace	Natural Gas	mmcf	213.000	106.500
Steel Hot Plate Furnace	Diesel Light Distillate (.05%)	1000 gallons	31.131	10.486
Steel Hot Plate Furnace	LPG, Propane, Butane	1000 gallons	20.970	10.486
Surface Coal Mine	Haul Road	tons coal	RV	62.140
Tail Gas Unit		hours of operation	RV	RV
Turbines	Butane	1000 Gallons	RV	5.700
Turbines	Diesel Oil	1000 gals	RV	8.814
Turbines	Refinery Gas	mmcf	RV	62.275
Turbines	Natural Gas	mmcf	RV	61.450
Turbines (micro-)	Natural Gas	mmcf	54.4	54.4
Turbines - Peaking Unit	Natural Gas	mmcf	RV	RV
Turbines - Peaking Unit	Dist. Oil/Diesel	1000 gallons	RV	RV
Utility Boiler	Digester/Landfill Gas	mmcf	52.350	10.080
Turbine	Natural Gas	mmcf	RV	61.450
Turbine	Fuel Oil	1000 gallons	RV	8.810
Turbine	Dist.Oil/Diesel	1000 gallons	RV	3.000
Utility Boiler Burbank	Natural Gas	mmcf	148.670	17.200
Utility Boiler Burbank	Residual Oil	1000 gallons	20.170	2.330
Utility Boiler, Glendale	Natural Gas	mmcf	140.430	16.000
Utility Boiler, Glendale	Residual Oil	1000 gallons	20.160	2.290
Utility Boiler, LADWP	Natural Gas	mmcf	86.560	15.830
Utility Boiler, LADWP	Residual Oil	1000 gallons	12.370	2.260
Utility Boiler, LADWP	Digester Gas	mmcf	52.350	10.080
Utility Boiler, LADWP	Landfill Gas	mmcf	37.760	6.910
Utility Boiler, Pasadena	Natural Gas	mmcf	195.640	18.500
Utility Boiler, Pasadena	Residual Oil	1000 gallons	28.290	2.670
Utility Boiler, SCE	Natural Gas	mmcf	74.860	15.600
Utility Boiler, SCE	Residual Oil	1000 gallons	10.750	2.240

* RV = Reported Value

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*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Table 2

RECLAIM SO_x Emission Factors

Sulfur Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Emission Factor *	Ending Emission Factor *
Air Blown Asphalt		hours of operation	RV	RV
Asphalt Concrete	Cold Ag Handling	tons produced	RV	0.032
Calciner	Petroleum Coke	Calcined Coke	RV	0.000
Catalyst Regeneration		hours of operation	RV	RV
Cement Kiln	Distillate Oil	1000 gallons	RV	RV
Cement Mfg	Kilns, Dry Process	tons produced	RV	RV
Claus Unit		pounds	RV	RV
Cogen	Coke	pounds per ton	RV	RV
Non Fuel Use		hours of operation	RV	RV
External Combustion Equipment / Incinerator	Natural Gas	mmcf	RV	0.830
External Combustion Equip/Incinerator	LPG, Propane, Butane	1000 gallons	RV	4.600
External Combustion Equip/Incinerator	Diesel Light Dist. (0.05% S)	1000 gallons	7.00	5.600
External Combustion Equip/Incinerator	Residual Oil	1000 gallons	8.00	6.400
External Combustion Equip/Incinerator	Refinery Gas	mmcf	RV	6.760
Fiberglass	Recuperative Furn, Textile-Type Fiber	tons produced	RV	2.145
Fluid Catalytic Cracking Units		1000 bbls refinery feed	RV	13.700
Glass Mfg, Forming/Fin	Container Glass		RV	RV
Grain Milling	Flour Mill	tons Grain Processed	RV	RV
ICEs	Natural Gas	mmcf	RV	0.600
ICEs	LPG, Propane, Butane	1000 gallons	RV	0.350
ICEs	Gasoline	1000 gallons	RV	4.240
ICEs	Diesel Oil	1000 gallons	6.24	4.990
Industrial	Cogeneration, Bituminous Coal	tons produced	RV	RV
Industrial (scc 10200804)	Cogeneration, Coke	tons produced	RV	RV
Inorganic Chemcals	General, H2SO4 Chamber	tons produced	RV	RV
Inorganic Chemcals	Absrbr 98.0% Conv, H2SO4 Contact	tons produced	RV	RV

* RV = Reported Value

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

Sulfur Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Emission Factor *	Ending Emission Factor *
Inprocess Fuel	Cement Kiln/Dryer, Bituminous Coal	tons produced	RV	RV
Iron/Steel Foundry	Cupola, Gray Iron Foundry	tons produced	RV	0.720
Melting Furnace, Container Glass		tons produced	RV	RV
Mericher Alkyd Feed		hours of operation	RV	RV
Miscellaneous	Not Classified	tons produced	RV	0.080
Miscellaneous	Not Classified	tons produced	RV	0.399
Natural Gas Production	Not Classified	mmcf	RV	527.641
Organic Chemical (scc 30100601)		tons produced	RV	RV
Petroleum Refining (scc30600602)	Column Condenser		RV	1.557
Petroleum Refining (scc30600603)	Column Condenser		RV	1.176
Refinery Process Heaters	LPG fired	1000 gal	RV	2.259
Pot Furnace	Lead Battery	lbs Sulfur	0.133***	0.106***
Sec. Lead	Reverberatory, Smelting Furnace	tons produced	RV	RV
Sec. Lead	Smelting Furnace, Fugitiv	tons produced	RV	0.648
Sour Water Oxidizer		hours of operation	RV	RV
Sulfur Loading		1000 bbls	RV	RV
Sour Water Oxidizer		1000 bbls fresh feed	RV	RV
Sour Water Coker		1000 bbls fresh feed	RV	RV
Sodium Silicate Furnace		tons of glass pulled	RV	RV
Sulfur Plant		hours of operation	RV	RV
Tail gas unit		hours of operation	RV	RV
Turbines	Refinery Gas	mmcf	RV	6.760
Turbines	Natural Gas	mmcf	RV	0.600
Turbines	Diesel Oil	1000 gal	6.24	0.080
Turbines	Residual Oil	1000 gallons	8.00	0.090
Utility Boilers	Diesel Light Dist. (0.05% S)	1000 gallons	7.00	0.080
Utility Boilers	Residual Oil	1000 gallons	8.00	0.090
Other Heater (24F-1)	Pressure Swing Absorber Gas	mmcf	RV	RV

* RV = Reported Value

*** Applies retroactively to January 1, 1994 for Cycle 1 facilities and July 1, 1994 for Cycle 2 facilities.

Table 3

RECLAIM NO_X 2011 Ending Emission Factors

Nitrogen Oxides Basic Equipment	BARCT Emission Factor
Asphalt Heater, Concrete	0.036 lb/mmbtu (30 ppm)
Boiler, Heater R1109 (Petr Refin) >110 mmbtu/hr	0.006 lb/mmbtu (5 ppm)
Boilers, Heaters, Steam Gens, (Petr Refin) >110 mmbtu/hr	0.006 lb/mmbtu (5 ppm)
Boiler, Heater, Steam Gen (Rule 1146.1) 2-20 mmbtu/hr	0.015 lb/mmbtu (12 ppm)
Boiler, Heater, Steam Gen (Rule 1146) >20 mmbtu/hr	0.010 lb/mmbtu (9 ppm)
CO Boiler	85% Reduction
Delacquering Furnace	0.036 lb/mmbtu (30 ppm)
Fluid Catalytic Cracking Unit	85% Reduction
Iron/Steel Foundry	0.055 lb/mmbtu (45 ppm)
Metal Heat Treating Furnace	0.055 lb/mmbtu (45 ppm)
Metal Forging Furnace (Preheated Combustion Air)	0.055 lb/mmbtu (45 ppm)
Metal Melting Furnaces	0.055 lb/mmbtu (45 ppm)
Other Heater (24F-1)	0.036 lb/mmbtu (30 ppm)
Ovens, Kilns, Calciners, Dryers, Furnaces	0.036 lb/mmbtu (30 ppm)
Petroleum Refining, Calciner	0.036 lb/mmbtu (30 ppm)
Sec. Aluminum	0.055 lb/mmbtu (45 ppm)
Sec. Lead	0.055 lb/mmbtu (45 ppm)
Steel Hot Plate Furnace	0.055 lb/mmbtu (45 ppm)
Utility Boiler	0.008 lb/mmbtu (7 ppm)

Table 4
RECLAIM SOx Tier III Emission Standards

Basic Equipment	BARCT Emission Standard
Calciner, Petroleum Coke	10 ppmv (0.11 lbs/ton coke)
Cement Kiln	5 ppmv (0.04 lbs/ton clinker)
Coal-Fired Boiler	5 ppmv (95% reduction)
Container Glass Melting Furnace	5 ppmv (0.03 lbs/ton glass)
Diesel Combustion	15 ppm by weight as required under Rule 431.2
Fluid Catalytic Cracking Unit	5 ppmv (3.25 lbs/thousand barrels feed)
Refinery Boiler/Heater	40 ppmv (6.76 lbs/mmscf~~t~~)
Sulfur Recovery Units/Tail Gas	5 ppmv for combusted tail gas (5.28 lbs/hour)
Sulfuric Acid Manufacturing	10 ppmv (0.14 lbs/ton acid produced)

Table 5
List of SOx RECLAIM Facilities Referenced in Subparagraphs (f)(1)(M) and (f)(1)(O)

FACILITY PERMIT HOLDER	AQMD ID NO.
AES HUNTINGTON BEACH, LLC*	115389
AIR LIQUIDE LARGE INDUSTRIES U.S., LP	148236
ANHEUSER-BUSCH INC., (LA BREWERY)	16642
CALMAT CO	119104
CENCO REFINING CO	800373
EDGINGTON OIL COMPANY	800264
EQUILON ENTER. LLC, SHELL OIL PROD. US	800372
EXIDE TECHNOLOGIES	124838
INEOS POLYPROPYLENE LLC	124808
KIMBERLY-CLARK WORLDWIDE INC.-FULT. MILL	21887
LUNDAY-THAGARD COMPANY	800080
OWENS CORNING ROOFING AND ASPHALT, LLC	35302
PABCO BLDG PRODUCTS LLC,PABCO PAPER, DBA	45746
PARAMOUNT PETR CORP*	800183
QUEMETCO INC	8547
RIVERSIDE CEMENT CO	800182
TECHALLOY CO., INC.	14944
TESORO REFINING AND MARKETING CO*	151798
THE PQ CORP	11435
US GYPSUM CO	12185
WEST NEWPORT OIL CO	42775

* SOx RECLAIM facilities that have RTC Holdings larger than initial allocations as of August 29, 2009.

Table 6

RECLAIM NO_X 2022 Ending Emission Factors

Nitrogen Oxides Basic Equipment	BARCT Emission Factor
Boiler, Heater R1109 (Petr Refin) >40 mmbtu/hr	2 ppm
Cement Kilns	0.5 lbs per ton clinker
Fluid Catalytic Cracking Unit	2 ppm
Gas Turbines	2 ppm
Glass Melting Furnaces – Container Glass	80% reduction (0.24 lb/ton glass produced)
ICEs, Permitted (Rule 1110.2) (Non-OCS)	11 ppm @15%O_2 0.041 lb/MMBTU 43.05 lb/mmcf
Metal Heat Treating Furnace >150 mmbtu/hr	0.011 lb/mmbtu (9 ppm)
Petroleum Refining, Calciner	10 ppm
Sodium Silicate Furnace	80% reduction (1.28 lb/ton glass pulled)
SRU/Tail Gas Unit	95% reduction 2ppm

Table 7
List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(B)

FACILITY PERMIT HOLDER	AQMD ID NO.
CHEVRON PRODUCTS CO.	800030
EXXONMOBIL OIL CORPORATION	800089
PHILLIPS 66 CO/LA REFINERY WILMINGTON PL	171107
PHILLIPS 66 COMPANY/LOS ANGELES REFINERY	171109
TESORO REF & MKTG CO LLC,CALCINER	174591
TESORO REFINING & MARKETING CO, LLC	174655
TESORO REFINING AND MARKETING CO, LLC	151798
TESORO REFINING AND MARKETING CO, LLC	800436
ULTRAMAR INC	800026
NOx RTC holders not designated as Facility Permit Holders as of September 22, 2015, except any NOx RTC holders listed in Table 8	Multiple

Table 8
List of NOx RECLAIM Facilities Referenced in Subparagraph (f)(1)(C)

FACILITY PERMIT HOLDER	AQMD ID NO.
AES ALAMITOS, LLC	115394
AES HUNTINGTON BEACH, LLC	115389
AES REDONDO BEACH, LLC	115536
BERRY PETROLEUM COMPANY	119907
BETA OFFSHORE	166073
BICENT (CALIFORNIA) MALBURG LLC	155474
BORAL ROOFING LLC	1073
BURBANK CITY, BURBANK WATER & POWER	25638
BURBANK CITY,BURBANK WATER & POWER,SCPPA	128243
CALIFORNIA PORTLAND CEMENT CO	800181
CALIFORNIA STEEL INDUSTRIES INC	46268
CANYON POWER PLANT	153992
CPV SENTINEL LLC	152707
DISNEYLAND RESORT	800189
EDISON MISSION HUNTINGTON BEACH, LLC	167432
EL SEGUNDO POWER, LLC	115663
EXIDE TECHNOLOGIES	124838
GENERAL ELECTRIC COMPANY	700126
HARBOR COGENERATION CO, LLC	156741
INLAND EMPIRE ENERGY CENTER, LLC	129816
LA CITY, DWP HAYNES GENERATING STATION	800074
LA CITY, DWP SCATTERGOOD GENERATING STN	800075
LA CITY, DWP VALLEY GENERATING STATION	800193
LONG BEACH GENERATION, LLC	115314
NEW- INDY ONTARIO, LLC	172005
NRG CALIFORNIA SOUTH LP, ETIWANDA GEN ST	115315
OWENS-BROCKWAY GLASS CONTAINER INC	7427
OXY USA INC	169754
PACIFIC CLAY PRODUCTS INC	17953
PARAMOUNT PETR CORP	800183
PASADENA CITY, DWP	800168
PQ CORPORATION	11435
QUEMETCO INC	8547
SAN DIEGO GAS & ELECTRIC	4242
SNOW SUMMIT INC	43201
SO CAL EDISON CO	4477
SO CAL GAS CO	800128
SO CAL GAS CO	800127
SO CAL GAS CO	5973
SO CAL GAS CO/PLAYA DEL REY STORAGE FACI	8582
SOLVAY USA, INC.	114801

FACILITY PERMIT HOLDER	AQMD ID NO.
SOUTHERN CALIFORNIA EDISON	160437
TABC, INC	3968
TAMCO	18931
US GOVT, NAVY DEPT LB SHIPYARD	800153
WALNUT CREEK ENERGY, LLC	146536
WHEELABRATOR NORWALK ENERGY CO INC	51620
WILDFLOWER ENERGY LP/INDIGO GEN., LLC	127299

Table 9
List of NOx RECLAIM Facilities for the Regional NSR Holding Account with Balances (in lbs)

FACILITY PERMIT HOLDER	AQMD ID NO.	2016		2017		2018		2019		2020		2021		2022		2023+	
		Dec 2016	Jun 2017	Dec 2017	Jun 2018	Dec 2018	Jun 2019	Dec 2019	Jun 2020	Dec 2020	Jun 2021	Dec 2021	Jun 2022	Dec 2022	Jun 2023	Dec 2023+	Jun 2023+
BICENT (CALIFORNIA) MALBURG LLC	155474	0	0	1,854	1,854	1,854	1,854	2,794	2,794	3,735	3,734	5,588	5,588	7,469	7,469	11,204	11,203
BURBANK CITY, BURBANK WATER & POWER, SCPPA	128243	0	0	1,604	5,159	1,604	5,159	2,418	7,775	3,232	10,392	4,836	15,551	6,464	20,784	9,695	31,177
CANYON POWER PLANT	153992	0	0	3,248	2,548	3,248	2,548	4,896	3,840	6,543	5,133	9,792	7,680	13,087	10,265	19,630	15,398
CPV CENTINEL LLC	152707	0	0	9,645	6,981	9,645	6,981	14,538	10,522	19,430	14,063	29,075	21,044	38,860	28,127	58,290	42,190
GENERAL ELECTRIC COMPANY/INLAND EMPIRE ENERGY CENTER	700126/ 129816	0	0	9,065	6,573	9,065	6,573	13,664	9,907	18,262	13,241	27,327	19,815	36,524	26,484	54,785	39,725
LONG BEACH GENERATION, LLC	115314	0	0	0	5,962	0	5,962	0	8,986	0	12,010	0	17,971	0	24,019	0	36,029
SOUTHERN CALIFORNIA EDISON	160437	0	0	13,227	6,758	13,227	6,758	19,937	10,184	26,646	13,612	39,874	20,370	53,293	27,225	79,940	40,837
WALNUT CREEK ENERGY, LLC	146536	0	0	3,690	4,242	3,690	4,242	5,562	6,393	7,434	8,544	11,124	12,786	14,867	17,089	22,301	25,633
WILDFLOWER ENERGY LP/INDIGO GEN., LLC	127299	0	0	0	3,483	0	3,483	0	5,250	0	7,016	0	10,499	0	14,033	0	21,049