APPENDIX A

PROPOSED AMENDED RULE 2002 – ALLOCATIONS FOR OXIDES OF NITROGEN (NOX) AND OXIDES OF SULFUR (SOX)

(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)
(PAR2002 08072015)

PROPOSED 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) Emission data submitted pursuant to Rule 301 paragraph (l)(10) shall not be considered by the Executive Officer in determining facility Allocation if new or amended data is submitted more than five years after the original due date.

(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=Σ[A 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 = Σ [A X 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	~~Non-tradable/ Non-usable NOx RTC Adjustment Factor~~
2007	0.883	~~0~~
2008	0.856	~~0.027~~
2009	0.829	~~0.054~~

2010	0.802	0.081
2011 and after through 2015	0.775	0.108

RTCs designated as non-tradable/non-usable pursuant to this subparagraph shall be held, but shall not be used or traded. The adjustment factors in this subparagraph are subject to change pursuant to paragraph (i)(5).

(B) The Executive Officer will adjust NOx RTC holdings, as of (Date of Amendment) for compliance years 2016 and thereafter by multiplying the amount of RTC holdings as of March 20, 2015 by the following adjustment factors for the relevant compliance year to each of the Facility Permit Holders listed in Table 7 and all other NOx RTC holders not designated as Facility Permit Holders, to obtain tradable/usable and non-tradable/non-usable holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2016	0.810	0
2017	0.810	0
2018	0.715	0.0949
2019	0.620	0.190
2020	0.525	0.285
2021	0.430	0.380
2022 and after	0.335	0.474

(C) The Executive Officer will adjust NOx RTC holdings, as of (Date of Amendment) for compliance years 2016 and thereafter by multiplying the amount of RTC holdings as of March 20, 2015 by the following adjustment factors for the relevant compliance year to each of the Facility Permit Holder listed in Table 8 to obtain tradable/usable and non-tradable/non-usable holdings:

Compliance Year	Tradable/Usable NOx RTC Adjustment Factor	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2016	0.867	0
2017	0.867	0
2018	0.800	0.0670
2019	0.733	0.134
2020	0.666	0.201

2021	0.599	0.268
2022 and after	0.532	0.335

(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 used or traded. The adjustment factors in this subparagraph are subject to change pursuant to paragraph (i)(5).

(~~B~~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. 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.

(~~C~~F) ~~Notwithstanding the requirements of non-tradable/non-usable credits specified in subparagraphs (f)(1)(A), i~~In the event that the NOx RTC prices exceed $15,000 per ton based on the 12-month rolling average calculated pursuant to subparagraph (f)(1)(~~B~~F), the Executive Officer will report to the Governing Board. Notwithstanding the requirements of non-tradable/non-usable credits specified in subparagraphs (f)(1)(B) and (f)(1)(C) and ~~I~~if the Governing Board finds that the 12-month rolling average RTC price exceeds $15,000 per ton, then the incremental NOx reductions as specified in subparagraph (f)(1)(~~D~~F) shall be converted to Tradable/Usable NOx RTCs upon Governing Board concurrence. 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 60 days from Executive Officer determination.

(~~D~~G) The incremental NOx RTCs restored shall be the difference between the Non-tradable/Non-usable Adjustment Factors, as specified in subparagraphs ~~(f)(1)(A)~~ (f)(1)(B) and (f)(1)(C), of the current compliance year and the most recent prior year the adjustment factor was implemented.

(~~E~~H) RTC conversion pursuant to subparagraph (f)(1)(~~C~~F) shall only occur in the compliance year in which Cycle 1 facilities are operating.

(FI) Notwithstanding the adjustment factors required pursuant to subparagraphs (f)(1)(A) (f)(1)(B) and (f)(1)(C), beginning with the following December and each year thereafter that the Governing Board finds the $15,000 per ton NOx RTC price is exceeded pursuant to subparagraph (f)(1)(CF), the Executive Officer will publish the applicable adjustment factors for the next compliance year beginning January 1. The adjustment factors will be published at a public hearing during a regularly scheduled Board Meeting. The adjustment factors will be determined as follows:

(i) If the 12-month rolling average falls below $15,000 per ton for at least 6 consecutive months, then the emission adjustment factors for the following compliance year shall equal the next more stringent adjustment factors listed in subparagraphs (f)(1)(A) (f)(1)(B) and (f)(1)(C) than the factors currently in effect; otherwise;

(ii) The next compliance year adjustment factors shall equal the compliance year adjustment factors currently in place.

The Executive Officer need no longer comply with the annual public hearing requirement once the adjustment factors for the 202210 compliance year have been implemented for a 12-month period.

(GJ) The NOx RTC adjustment factors for compliance years 200819 through 201021 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. The 202211 NOx RTC adjustment factors shall not be submitted for inclusion into the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year.

(HK) NOx Allocations for facilities that enter RECLAIM after January 7, 2005 for compliance years 2007 and after shall be determined by applying the Tradable/Usable and Non-tradable/Non-usable NOx RTC Adjustment Factors under subparagraph (f)(1)(A) to the facility's Compliance Year 2006 Allocation and under subparagraphs (f)(1)(B) and (f)(1)(C) to the facility's Compliance Year 2015 Allocation.

(~~I~~L) 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

(~~J~~M) The Executive Officer shall determine Tradable/usable SOx RTC Adjustment Factors for each compliance year~~s~~ after 2012 as follows:

Fcompliance year i = 1 – [Xi / (Ai + Bi + Ci)]

Where:

Fcompliance 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 ~~11~~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 ~~(rule adoption date)~~November 5, 2010, and not included~~s~~ in Ci

Ci = Total SOx RTCs held as of ~~(rule adoption date)~~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)(~~I~~L).

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

Ncompliance year j = Fcompliance year 2016 - Fcompliance year j

Where:

Ncompliance year j = Non-tradable/Non-usable SOx RTC

Adjustment Factor for compliance year j

Fcompliance year j = Tradable/Usable SOx RTC Adjustment Factor for compliance year j as determined pursuant to subparagraph (f)(1)(JM)

j = 2017 through 2019

Fcompliance year 2016 = Tradable/usable SOx RTC Adjustment Factor for compliance year 2016 as determined pursuant to subparagraph (f)(1)(JM)

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

(LO) 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 (Fcompliance year i) and Non-tradable/Non-usable SOx RTC Adjustment Factor (Ncompliance year j) for the corresponding compliance year as published under subparagraph (f)(1)(MP) 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 (Fcompliance year i) and Non-tradable/Non-usable SOx RTC Adjustment Factor (Ncompliance year j) for the corresponding compliance year as published under subparagraph (f)(1)(MP) 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 (Fcompliance year i) and Non-tradable/non-usable SOx RTC Adjustment Factor (Ncompliance year j) for the corresponding compliance year as published under subparagraph (f)(1)(~~M~~P) 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)(~~M~~P) more than once.

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

(~~N~~Q) 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.

(~~O~~R) 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)(~~N~~Q), 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)(~~K~~N) and (f)(1)(~~L~~O), 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)(~~P~~S).

(~~P~~S) The Executive Officer will not submit the emission reductions obtained through subparagraph (f)(1)(~~I~~L) 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.

(~~Q~~T) 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.

(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) All Power Producing Facilities which have received all District Permits to Construct on or after October 15, 1993 shall have access to an Adjustment Account for the purpose of complying with the requirements specified in Rule 2005 subdivision (f). The Executive Officer will determine and distribute the RTCs from this Adjustment Account according to the needs of each Power Producing Facility as specified in their Facility Permit.

(5) During a State of Emergency as declared by the Governor, the Executive Officer will allow Power Producing Facilities access to Adjustment Account RTCs for the purpose of compliance with the annual emissions. These available RTCs will be limited to those that are in excess of those

specified for use in paragraph (f)(4). The amount and distribution of the RTCs will be determined by the Executive Officer based on the impact that the State of Emergency has on the RECLAIM program,

(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_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) RTC Reduction Exemption

(1) A facility may file an application for Executive Officer approval to be exempted from all or a portion of the requirements pursuant to subparagraphs (f)(1)(~~A~~B) or (f)(1)(C) with the exception of RTC

holdings as of January 7, 2005 for compliance year 2007 (Date of Amendment) for compliance year 2016 and thereafter in excess of the initial allocation. For the purposes of this rule, initial allocation refers to the RTCs issued by the District to a facility upon entering the RECLAIM program. The application shall contain sufficient data to demonstrate to the satisfaction of the Executive Officer that the facility meets the following criteria:

(A) the facility has been in the program since the start of RECLAIM, or existed prior to 1994, but subsequently entered RECLAIM pursuant to Rule 2001 because facility emissions exceeded 4 tons per year;

(B) at least 99 percent of the facility's emissions reported for the most recent completed cCompliance yYear 2013 prior to the date of filing an application is from equipment not listed in Table 3 or Table 6 and the achieved emission rates for each and every piece of equipment at the facility is less than or equal to the 2000 (Tier I) Ending Emission Factor listed in Table 1 or the emission factor listed in Table 3, whichever is lower, for the corresponding equipment type;

(C) RTCs that were part of the total initial allocation for the facility have never been transferred or sold by the facility for Compliance Yearyear 201607 or later compliance years; and

(D) the cumulative NOx compliance costs incurred by the facility up to the submittal date of the application as specified in paragraph (i)(3) to comply with the RECLAIM Allocation as required under Rule 2004(b) and (d)(1) exceed the compliance costs that otherwise would have occurred to meet and maintain emission limits specified in Table 1 or 3, whichever is lower, for each and every piece of equipment at the facility. The compliance costs shall be based on the following parameters:

(i) cost of controlling emissions using the parameters and procedures for determining total direct and indirect capital investment and total annual costs as specified in the most recent edition of the Control Cost Manual published by the U.S. EPA Office of Air Quality and Planning Standards, excluding control costs for any equipment listed in Table 3 or Table 6, if any;

(ii) realized and anticipated revenues and expenditures of the Facility Permit holder resulting from buying and selling any RTCs that are or were held by the facility where the contract of sale or purchase was executed prior to the date of application for exemption pursuant to paragraph (i)(1);

(iii) costs associated with compliance with the New Source Review provisions of Rule 2005, Rule 2012(c), or other applicable state or federal requirements shall not be included;

(iv) costs that result only in improving process efficiency or product quality, costs of projects that were initiated before the date the facility was subject to RECLAIM requirements, or legal costs or any other costs that do not directly reduce NOx emissions shall not be included; and

(v) any cost savings that resulted in implementing any NOx emissions strategy, such as fuel savings, increased production or sale; or

(2) A facility may file an application for Executive Officer approval to be exempted from all or a portion of the requirements pursuant to subparagraph (f)(1)(~~A~~B) or (f)(1)(C) for the initial allocations portion of a facility's RTC holdings provided that the facility meets all of the following:

(A) The facility's starting and year 2000 Allocations were calculated using the same emission factors that are equal to or lower than the 2000 (Tier 1) emission factors listed in Table 1;

(B) Emission rate achieved for each source at the facility is less than or equal to the emission factors listed in Table 3 for the corresponding equipment type; and

(C) RTCs for ~~2007~~ 2016 or later compliance years for the facility have never been transferred or sold.

(3) A facility shall submit the applications specified pursuant to paragraphs (i)(1) or (i)(2) no later than ~~July 7, 2005~~ (*six months after rule amendment date*) ~~or between January 1 and March 31, 2006~~, pay the appropriate evaluation fee pursuant to Rule 306, and accept enforceable permit conditions to ensure compliance with the provisions of this subdivision, in order for the Executive Officer to approve the exemption.

If approved, the facility's initial RTC allocation shall be designated as non-tradable and additional RTCs purchased above the initial allocation shall be subject to the RTC adjustments specified in subparagraph (f)(1)(~~A~~B) or (f)(1)(C), as appropriate. The Executive Officer shall deny an application that is not filed within the time periods specified in this paragraph, lacks any information specified under paragraph (i)(7), or fails to demonstrate that it meets the requirements in paragraphs (i)(1) or (i)(2).

(4) Upon approval the exemption shall:

(A) be limited to the adjustment factors specified in subparagraph (f)(1)(~~A~~B) or (f)(1)(C);

(B) begin the next compliance year following the exemption approval; and

(C) not apply to reductions resulting from future periodic BARCT review.

(5) RTC adjustments exempted pursuant to this subdivision shall be distributed proportionally among the remainder of the RTC holders and implemented two years from the compliance year of the applicable exemption and are subject to applicable paragraph (f)(1) provisions. Public notification of the distributed reductions shall occur at least one year prior to implementation.

(6) A Facility Permit holder has the right to appeal the denial of the exemption application to the Hearing Board in the same manner as a permit denial as specified in Health and Safety Code Section 42302.

(7) An application submitted to request an exemption from the RTCs reduction pursuant to paragraphs (i)(1) or (i)(2) shall include the following information.

(A) Detailed description of each project and itemized listing of how it relates to meeting the RECLAIM reduction requirements;

(B) Date of start and completion of each project listed in subparagraph (i)(7)(A);

(C) Detailed calculations or emissions data demonstrating NOx emission reductions resulting from each project or combination of projects directly resulting in reductions. The emission levels achieved shall be based on actual CEMS data or source tests results;

(D) Itemized revenue and expenditures for each RTC trading activity since participation in the RECLAIM program;

(E) Itemized costs for each project and corresponding receipts or other equivalent documentation as approved by the Executive Officer for such expenditures; and

(F) Cost savings resulting from each project(s) (e.g. fuel savings, improved productivity, increased sales, etc.) and documentation of the values of such savings.

(8) A facility qualifying for exemption shall report as part of its Annual Permit Emission Program (APEP) report, submitted pursuant to Rule 2004(b)(4), whether or not emissions from equipment listed in Tables 3 and 6, if any, remain less than or equal to 1 percent of the total facility emissions on an annual basis for the duration of the exemption. If the emissions exceed 1 percent, the facility shall be in violation of the rule for each and every day of the compliance year and the Executive Officer shall reduce the facility's initial allocation for the next compliance year to the emissions level specified for that year pursuant to subparagraph (f)(1)(~~A~~B) or (f)(1)(C).

(9) A facility applying for exemption shall have 1 percent of its initial allocations subject to the requirements pursuant to subparagraph (f)(1)(~~A~~B) or (f)(1)(C).

(10) Non-tradable RTC allocations designated pursuant to paragraph (i)(3) shall become tradable in the event the facility permanently ceases to operate.

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

* 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 *
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

** 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 *
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

** 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.

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 ppmv 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 SubPparagraphs (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

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
CITY OF ANAHEIM/COMB TURBINE GEN STATION	56940
CITY OF COLTON	172077
CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	139796
CITY OF RIVERSIDE PUBLIC UTILITIES DEPT	129810
CITY OF RIVERSIDE, PUBLIC UTILITIES DEPT	164204
CPV SENTINEL LLC	152707
DISNEYLAND RESORT	800189
EDISON MISSION HUNTINGTON BEACH, LLC	167432
EL SEGUNDO POWER, LLC	115663
EXIDE TECHNOLOGIES	124838
HARBOR COGENERATION CO, LLC	156741
INLAND EMPIRE ENERGY CENTER, LLC	129816
LA CITY, DWP HARBOR GENERATING STATION	800170
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
PURENERGY OPERATING SERVICES, LLC	132191
PURENERGY OPERATING SERVICES, LLC	132192
QUEMETCO INC	8547

FACILITY PERMIT HOLDER	AQMD ID NO.
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
SOUTHERN CALIFORNIA EDISON	160437
TABC, INC	3968
TAMCO	18931
US GOVT, NAVY DEPT LB SHIPYARD	800153
VERNON CITY, LIGHT & POWER DEPT	14502
WALNUT CREEK ENERGY, LLC	146536
WHEELABRATOR NORWALK ENERGY CO INC	51620
WILDFLOWER ENERGY LP/INDIGO GEN., LLC	127299

APPENDIX B

PROPOSED AMENDED RULE 2005 – NEW SOURCE REVIEW FOR RECLAIM

(Adopted October 15, 1993)(Amended December 7, 1995)(Amended May 10, 1996)
(Amended July 12, 1996)(Amended February 14, 1997)(Amended April 9, 1999)
(Amended April 20, 2001)(Amended May 6, 2005)(Amended June 3, 2011)
(July 2015)

RULE 2005. NEW SOURCE REVIEW FOR RECLAIM

(a) Purpose

This rule sets forth pre-construction review requirements for new facilities subject to the requirements of the RECLAIM program, for modifications to RECLAIM facilities, and for facilities which increase their allocation to a level greater than their starting Allocation plus non-tradable credits. The purpose of this rule is to ensure that the operation of such facilities does not interfere with progress in attainment of the National Ambient Air Quality Standards, and that future economic growth in the South Coast Air Basin is not unnecessarily restricted.

(b) Requirements for New or Relocated RECLAIM Facilities

(1) The Executive Officer shall not approve the application for a Facility Permit to authorize construction or installation of a new or relocated facility unless the applicant demonstrates that:

(A) Best Available Control Technology will be applied to every emission source located at the facility; and

(B) the operation of any emission source located at the new or relocated facility will not cause a violation nor make significantly worse an existing violation of the state or national ambient air quality standard at any receptor location in the District for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

(2) The Executive Officer shall not approve the application for a Facility Permit authorizing operation of a new or relocated facility, unless the applicant demonstrates that:

(A) the facility holds sufficient RTCs, including any RTCs from the Adjustment Acount referenced in Rule 2002 (f)(4), to offset the total facility emissions for the first year of operation, at a 1-to-1 ratio; and

(B) the RTCs procured to comply with the requirements of subparagraph (b)(2)(A) were obtained pursuant to the requirements of subdivision (e), and

(C) the total facility emissions determined to comply with the requirements of subparagraph (b)(2)(A) shall also include ship emissions directly associated with activities at stationary sources subject to this rule as follows:

(i) all emissions from ships during the loading and unloading of cargo and while at berth where the cargo is loaded or unloaded; and

(ii) non-propulsion ship emissions within coastal waters under District jurisdiction.

(c) Requirements for Existing RECLAIM Facilities, Modification to New RECLAIM Facilities, Facilities which Undergo a Change of Operator, or Facilities which Increase an Annual Allocation to a Level Greater Than the Facility's Starting Allocation Plus Non-tradable Credits.

(1) The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source or modification of an existing source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that:

(A) Best Available Control Technology will be applied to the source; and

(B) the operation of the source will not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

(2) The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize operation of the new or modified source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that the facility holds sufficient RTCs to offset the annual emission increase for the first year of operation at a 1-to-1 ratio.

(3) The Executive Officer shall not approve an application for Change of Operator for a Facility Permit unless the applicant demonstrates that the facility holds sufficient RTCs for the compliance year in which the change of operator permit is issued. Credits must be held in an amount equal to:

(A) The annual Allocation initially issued to the original Facility Permit holder for existing facility as defined in Rule 2000 for the same compliance year, in which the change of operator permit is issued, multiplied, where applicable, by the Tradable/Usable RTC Adjustment Factor for the same compliance year as listed in Rule 2002(f)(1)(A); or

(B) The sum of annual RECLAIM pollutants from all the sources located at the facility. The amount of annual RECLAIM pollutants for each source shall be calculated by the maximum hourly potential to emit, over an operating schedule of 24 hours per day and 365 days per year, or shall be based on a permit condition limiting the source's emission.

(4) The Executive Officer shall not approve an application to increase an annual Allocation to a level greater than the facility's starting Allocation plus non-tradable credits, unless the applicant demonstrates that:

(A) each source which creates an emission increase as defined in subdivision (d) will:

(i) apply Best Available Control Technology;

(ii) not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A; and

(B) the facility holds sufficient RTCs acquired pursuant to subdivision (e) to offset the annual increase in the facility's starting Allocation plus non-tradable credits at a 1-to-1 ratio for a minimum of one year.

(d) Emission Increase

An increase in emissions occurs if a source's maximum hourly potential to emit immediately prior to the proposed modification is less than the source's post-modification maximum hourly potential to emit. The amount of emission increase will be determined by comparing pre-modification and post-modification emissions on an annual basis by using: (1) an operating schedule of 24 hours per day, 365 days per year; or (2) a permit condition limiting mass emissions.

(e) Trading Zones Restrictions

Any increase in an annual Allocation to a level greater than the facility's starting plus non-tradable Allocations, and all emissions from a new or relocated facility must be fully offset by obtaining RTCs originated in one of the two trading zones as illustrated in the RECLAIM Trading Zones Map. A facility in Zone 1 may only obtain RTCs from Zone 1. A facility in Zone 2 may obtain RTCs from either Zone 1 or 2, or both.

(f) Offsets

The Facility Permit for a new or modified facility shall require compliance with this subdivision, if applicable.

(1) Any facility which was required to provide offsets pursuant to paragraphs (b)(2), or subparagraph (c)(4)(B) or any new facility required to provide offsets pursuant to paragraph (c)(2) shall, at the commencement of each compliance year, hold RTCs in an amount equal to the amount of such required offsets. The Facility Permit holder may reduce the amount of offsets required pursuant to this subdivision by accepting a permit condition limiting emissions which shall serve in lieu of the starting Allocation plus non-tradable credits for purposes of paragraph (c)(4).

(2) Except for the Adjustment Account RTCs referenced in Rule 2002(f)(4), ~~Unused~~ unused RTCs acquired to comply with this subdivision or with paragraphs (b)(2), (c)(2), or subparagraph (c)(4)(B) may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year.

(3) In lieu of compliance with paragraph (f)(2), the Facility Permit holder may accept a permit condition limiting quarterly emissions from the facility. A facility with quarterly emission limits may sell, at any time after the end of that quarter and prior to the end of the reconciliation period for that compliance year, unused RTCs acquired pursuant to this subdivision, excluding the Adjustment Account RTCs referenced in Rule 2002(f)(4), at the amount not to exceed the difference between the permitted emission limit for that quarter and the emissions during that quarter as reported to the District in the Quarterly Emission Certification. Any facility with quarterly certified emissions exceeding the quarterly emission limit for any quarter may sell RTCs, excluding the Adjustment Account RTCs referenced in Rule 2002(f)(4), only during the reconciliation period for the fourth quarter of the applicable compliance year. If there are a total of three exceedances in any five consecutive compliance years, the facility shall permanently comply with paragraph (f)(2) in lieu of (f)(3).

(g) Additional Federal Requirements for Major Stationary Sources

The Executive Officer shall not approve the application for a Facility Permit or an Amendment to a Facility Permit for a new, relocated or modified major stationary source, as defined in the Clean Air Act, 42 U.S.C. Section 7511a(e), unless the applicant:

(1) certifies that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards (42 U.S.C. Section 7503(a)(3)); and

(2) submits an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction, or modification (42 U.S.C. Section 7503(a)(5));

(3) Compliance Through California Environmental Quality Act

The requirements of paragraph (g)(2) may be met through compliance with the California Environmental Quality Act in the following manner.

(A) if the proposed project is exempt from California Environmental Quality Act analysis pursuant to a statutory or categorical exemption pursuant to Title 14, California Code of Regulations, Sections 15260 to 15329, paragraph (g)(2) shall not apply to that project;

(B) if the proposed project qualifies for a negative declaration pursuant to Title 14 California Code of Regulations, Section 15070, or a mitigated negative declaration as defined in Public Resources Code Section 21064.5, paragraph (g)(2) shall not apply to that project; or

(C) if the proposed project has been analyzed by an environmental impact report pursuant to Public Resources Code Section 21002.1 and Title 14 California Code of Regulations, Section 15080 et seq., paragraph (g)(2) shall be deemed satisfied.

(4) Protection of Visibility

(A) Conduct a modeling analysis for plume visibility in accordance with the procedures specified in Appendix B if the net emission increase from the new or modified source exceeds 40 tons/year of NO_X; and the location of the source, relative to the closest boundary of a specified Federal Class I area, is within the distance specified in Table 4-1.

Table 4-1

Federal Class I Area	*Distance (km)*
Agua Tibia	28
Cucamonga	28
Joshua Tree	29
San Gabriel	29
San Gorgonio	32
San Jacinto	28

(B) In relation to a permit application subject to the modeling analysis required by subparagraph (g)(4)(A), the Executive Officer shall:

(i) deem a permit application complete only when the applicant has complied with the requisite modeling analysis for plume visibility pursuant to subparagraph (g)(4)(A);

(ii) notify and provide a copy of the complete permit application file to the applicable Federal Land Manager(s) within 30 calendar days after the application has been deemed complete and at least 60 days prior to final action on the permit application;

(iii) consider written comments, relative to visibility impacts from the new or modified source, from the responsible Federal Land Manager(s), including any regional haze modeling performed by the Federal Land Manager(s), received within 30 days of the date of notification when determining the terms and conditions of the permit;

(iv) consider the Federal Land Manager(s) findings with respect to the geographic extent, intensity, duration, frequency and time of any identified visibility impairment of an affected Federal Class I area, including how these factors correlate with times of visitor use of the Federal Class I area, and the frequency and timing of natural conditions that reduce visibility; and,

(v) explain its decision or give notice as to where to obtain this explanation if the Executive Officer finds that the Federal Land Manager(s) analysis does not demonstrate that a new or modified source may have an adverse impact on visibility in an affected Federal Class I area.

(C) If a project has an adverse impact on visibility in an affected Federal Class I area, the Executive Officer may consider the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, the useful life of the source, and all other relevant factors in determining whether to issue or deny the Permit to Construct or Permit to Operate.

(h) Public Notice
The applicant shall provide public notice, if required, pursuant to Rule 212 - Standards for Approving Permits.

(i) Rule 1401
All new or modified sources shall comply with the requirements of Rule 1401 - New Source Review of Carcinogenic Air Contaminants, if applicable.

(j) Compliance with State and Federal New Source Review Requirements
The Executive Officer will report to the District Governing Board regarding the effectiveness of Rule 2005 in meeting the state and federal New Source Review requirements for the preceding year. The Executive Officer may impose permit

conditions to monitor and ensure compliance with such requirements. This report shall be incorporated in the Annual Program Audit Report prepared pursuant to Rule 2015(b)(1).

(k) Exemptions

(1) Functionally identical source replacements are exempt from the requirements of subparagraph (c)(1)(B) of this rule.

(2) Physical modifications that consist of the installation of equipment where the modification will not increase the emissions rate of any RECLAIM pollutant, and will not cause an increase in emissions above the facility's current year Allocation, shall be exempt from the requirements of paragraph (c)(2).

(3) Increases in hours of operation or throughput for equipment or processes permitted prior to October 15, 1993 that the applicant demonstrates would not violate any permit conditions in effect on October 15, 1993 which were imposed in order to limit emissions to implement New Source Review offset requirements, shall be exempt from the requirements of this rule.

(4) Increase to RECLAIM emission concentration limits or emission rates not associated with Best Available Control Technology permit conditions provided that the increase is not a result of any modification to equipment shall be exempt from the requirements of this rule.

(5) The requirements under subparagraphs (b)(1)(B) and (c)(1)(B), and clause (c)(4)(A)(ii) shall not apply to equipment used exclusively on a standby basis for non-utility electrical power generation or any other equipment used on a standby basis in case of emergency, provided the source does not operate more than 200 hours per year as evidenced by an engine-hour meter or equivalent method and is listed as emergency equipment in the Facility Permit.

APPENDIX A

The following sets forth the procedure for complying with the air quality modeling requirements. An applicant must either (1) provide an analysis approved by the Executive Officer or designee, or (2) show by using the Screening Analysis below, that a significant change (increase) in air quality concentration will not occur at any receptor location for which the state or national ambient air quality standard for NO_2 is exceeded.

Table A-1 of the screening analysis is subject to change by the Executive Officer, based on improved modeling data.

SCREENING ANALYSIS

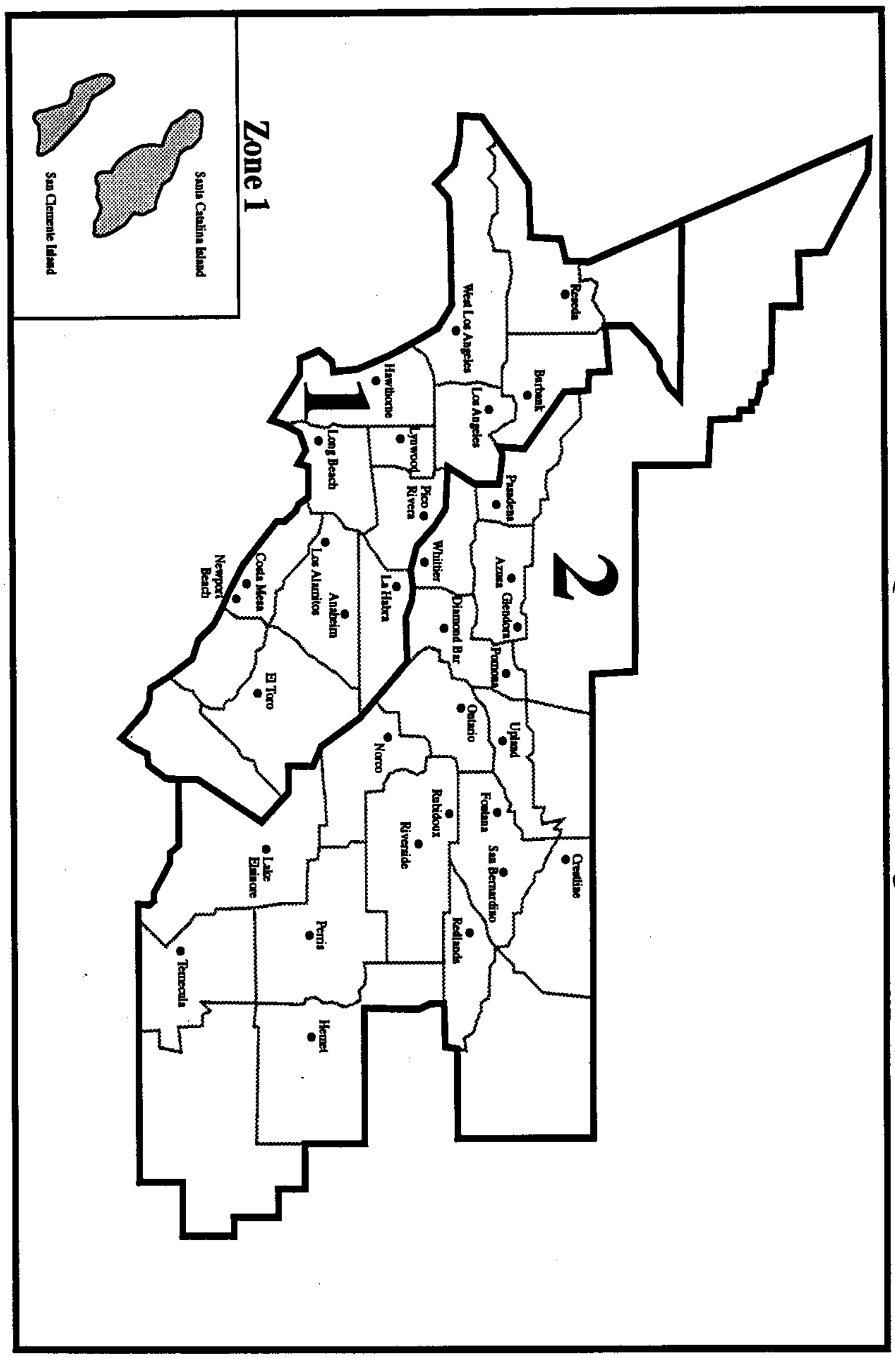
Compare the emissions from the equipment you are applying for to those in Table A-1. If the emissions are less than the allowable emissions, no further analysis is required. If the emissions are greater than the allowable emissions, a more detailed air quality modeling analysis is required.

Table A-1
Allowable Emissions
for Noncombustion Sources and for
Combustion Sources less than 40 Million BTUs per hour

Heat Input Capacity (million BTUs/hr)	NOx (lbs/hr)
Noncombustion Source	0.068
2	0.20
5	0.31
10	0.47
20	0.86
30	1.26
40	1.31

Table A-2
Most Stringent Ambient Air Quality Standard and
Allowable Change in Concentration
For Each Air Contaminant/Averaging Time Combination

Air Contaminant	Averaging Time	Most Stringent Air Quality Standard		Significant Change in Air Quality Concentration	
Nitrogen Dioxide	1-hour	25 pphm	500 ug/m^3	1 pphm	20 ug/m^3
	Annual	5.3 pphm	100 ug/m^3	0.05 pphm	1 ug/m^3


RECLAIM Trading Zones
South Coast AQMD Air Monitoring Stations
Zone 1
Santa Catalina Island
San Clemente Island
1
2
Reseda
West Los Angeles
Burbank
Los Angeles
Hawthorne
Lynwood
Long Beach
Pico Rivera
Pasadena
Azusa
Glendora
Whittier
La Habra
Los Alamitos
Anaheim
Costa Mesa
Newport Beach
Diamond Bar
Pomona
El Toro
Ontario
Upland
Norco
Fontana
Rubidoux
Riverside
San Bernardino
Crestline
Lake Elsinore
Perris
Redlands
Temecula
Hemet

APPENDIX B

MODELING ANALYSIS FOR VISIBILITY

(a) The modeling analysis performed by the applicant shall consider:

(1) the net emission increase from the new or modified source; and

(2) the location of the source and its distance to the closest boundary of specified Federal Class I area(s).

(b) Level 1 and 2 screening analysis for adverse plume impact pursuant to paragraph (g)(4) of this rule for modeling analysis of plume visibility shall consider the following applicable screening background visual ranges:

Federal Class I Area	Screening Background Visual Range (km)
Agua Tibia	171
Cucamonga	171
Joshua Tree	180
San Gabriel	175
San Gorgonio	192
San Jacinto	171

For level 1 and 2 screening analysis, no adverse plume impact on visibility results when the total color contrast value (Delta-E) is 2.0 or less and the plume contrast value (C) is 0.05 or less. If these values are exceeded, the Executive Officer shall require additional modeling. For level 3 analysis the appropriate background visual range, in consultation with the Executive Officer, shall be used. The Executive Officer may determine that there is no adverse visibility impact based on substantial evidence provided by the project applicant.

(c) When more detailed modeling is required to determine the project's visibility impact or when an air quality model specified in the Guidelines below is deemed inappropriate by the Executive Officer for a specific source-receptor application, the model may be modified or another model substituted with prior written approval by the Executive Officer, in consultation with the federal Environmental Protection Agency and the Federal Land Managers.

(d) The modeling analysis for plume visibility required pursuant to paragraph (g)(4) of this rule shall comply with the most recent version of:

(1) "Guideline on Air Quality Model (Revised)" (1986), supplement A (1987), supplement B (1993) and supplement C (1994), EPA-450/2-78-027R, US EPA, Office of Air Quality Planning and Standards Research Triangle Park, NC 27711; and

(2) "Workbook for Plume Visual Impact Screening and Analysis (Revised)," EPA-454-/R-92-023, US EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711;

(3) "User's Manual for the Plume Visibility Model (PLUVUE II) (Revised)," EPA-454/B-92-008, US EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711 (for Level-3 Visibility Analysis)

APPENDIX C

PROPOSED AMENDED RULE 2011 APPENDIX A – PROTOCOL FOR MONITORING, REPORTING, AND RECORDKEEPING OXIDES OF OXIDES OF SULFUR (SOX) EMISSIONS (ATTACHMENT C – QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES)

PROPOSED AMENDED RULE 2011 PROTOCOL- ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

TABLE OF CONTENTS

ATTACHMENT C - QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. QUALITY CONTROL PROGRAM

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

Explain how each component of the CEMS shall be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that shall be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However, facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the SOx protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be given is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments during each day in which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, during each day that emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Test, record, and compute the calibration error of each SO_2 pollutant concentration monitor, fuel gas sulfur content monitor, if applicable, and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Chapter 2, Subdivision B, Paragraph 1, Subparagraph a, Clause ii of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration or the fuel gas sulfur content has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration or the fuel gas sulfur content has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales.

i. Design Requirements for Calibration Error Testing of SO_x Concentration Monitors, the Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Design and equip each SO_x concentration monitor, fuel gas sulfur content monitor, and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor, fuel gas sulfur content and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for SO_x Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Measure the calibration error of each SO_2 concentration analyzer, fuel gas sulfur analyzer, and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials (CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking on all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the SO_x concentration monitors, the fuel gas sulfur content monitors, and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = Percentage calibration error based on the span range

R = Reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = Actual monitoring system response to the calibration gas.

S = Span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation :

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Chapter 2, Subdivision B, Paragraph 1, Subparagraph c of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the SOx monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an SO_2 concentration monitor or a fuel gas sulfur content monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, dscfh, and percent volume. Program monitors that automatically adjust data to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the SO_X pollutant concentration monitor, flow monitoring system, and SOx emission rate measurement system are~~is~~ 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are disconnected and either flanges or equivalent sealing devices are placed at both ends of the disconnected lines, and

ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

For any hour that fuel flow records are not available to verify no fuel flow, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that either only operates under a California Independent System Operator (Cal ISO) contract or is owned and operated by a municipality may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows:

i. The semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment was due;

ii. The assessment was not completed due to lack of adequate operational time; and

iii. A CGA was conducted and passed within the calendar quarter when the assessment was due.

ea. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each $S0_2$ pollutant concentration monitor, fuel gas sulfur content monitor, stack gas volumetric flow rate measurement systems, and the SO_2 mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, and 12, and 13 and Attachment B of the Protocol for Proposed Rule 2011. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, and 12, and 13 and Attachment B (bias test) of the Draft Protocol for Proposed Rule 2011.

fb. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an SO_2 pollutant concentration monitor, a fuel gas sulfur content monitor, or the SO_2 emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the -hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

gc. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

h~~d~~. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.e~~a~~.; and

III. conducted an alterative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.h~~d~~.iii.

If any of the requirements under Subclauses B.2.h~~d~~.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2011, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than 240 cumulative operating hours and no more than 72 consecutive hours ; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

APPENDIX D

PROPOSED AMENDED RULE 2012 APPENDIX A – PROTOCOL FOR MONITORING, REPORTING, AND RECORDKEEPING OXIDES OF OXIDES OF NITROGEN (NOX) EMISSIONS
(ATTACHMENT C – QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES)

PROPOSED AMENDED RULE 2012 PROTOCOL- ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

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ATTACHMENT C - QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. Quality Control Program

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

   Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

   Explain how each component of the CEMS will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

   Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

   Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that will be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the NO_x protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be performed is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments on each day during which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, on each day during which emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors and O_2 Monitors

Test, record, and compute the calibration error of each NO_x pollutant concentration monitor and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Paragraph B.1.a.ii. of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales

i. Design Requirements for Calibration Error Testing of NO_x Concentration Monitors and O_2 Monitors

Design and equip each NO_x concentration monitor and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for NO_x Concentration Monitors and O_2 Monitors

Measure the calibration error of each NO_x concentration analyzer and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the NO_x concentration monitors and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R-A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = The percentage calibration error based on the span range

R = The reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = The actual monitoring system response to the calibration gas.

S = The span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation :

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the. transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Paragraph B.1.c.i. of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

i. Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the NO_x monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an NO_x concentration monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, DSCFH, and percent volume. Program monitors that automatically adjust data to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the NO_X pollutant concentration monitor, flow monitoring system, and NOx emission rate measurement system ~~is~~ are 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are disconnected and either flanges or equivalent sealing devices are placed at both ends of the disconnected lines, and

ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

For any hour that fuel flow records are not available to verify no fuel flow, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that either only operates under a California Independent System Operator (Cal ISO) contract or is owned and operated by a municipality may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows:

i. The semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment was due;

ii. The assessment was not completed due to lack of adequate operational time; and

iii. A CGA was conducted and passed within the calendar quarter when the assessment was due.

e~~a~~. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each NO_X pollutant concentration monitor, stack gas volumetric flow rate measurement systems, and the NO_X mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraphs 10, ~~Chapter 2, Subdivision B, Paragraph~~ 11, ~~and Chapter 2, Subdivision B, Paragraph~~ 12, and 18. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Chapter 2, Subdivision B, Paragraphs ~~2.B.~~10, ~~2.B.~~11, ~~and 2.B.~~12, and 18.

f~~b~~. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an NO_X pollutant concentration monitor or the NO_X emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the ~~–~~hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

g~~c~~. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

hd. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.ea.; and

III. conducted an alterative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.hd.iii.

If any of the requirements under Subclauses B.2.hd.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2012, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than

240 cumulative operating hours and no more than 72 consecutive hours; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

APPENDIX E

CONSTRUCTION AND OPERATION CALCULATIONS

PROPOSED PROJECT: GRAND TOTALS - OPERATION

SRU/TGUs
4 refineries (Facilities 1, 5,6 & 8) - 5 LoTox with WGSs & 1 SCR

Usage Rates		
31,093	kWh/day	Electricity
468,767	gal/day	Water
175,890	gal/day	Wastewater
1,028	Mmbtu/day	Cooling Water
1,233	scf/day	Compressed Air
3.64	tons/day	Solid Waste Disposal
1.39	tons/day	Soda Ash
1397.00	lbs/day	NH3 (aqueous 19%)
25,696	sf	plot space needed
2,100	round trip miles/day	truck miles driven
11	trucks/day	no. of trucks
24,850	round trip miles/year	truck miles driven
97	trucks/year	no. of trucks

FCCU
5 refineries (Facilities 4, 5, 6, 7, & 9) - 3 LoTox w/WGSs & 2 SCRs

Usage Rates		
40,543	kWh/day	Electricity
93,151	gal/day	Water
43,836	gal/day	Wastewater
1	Mmbtu/day	Cooling Water
1,479	scf/day	Compressed Air
2.33	tons/day	Solid Waste Disposal
2.47	tons/day	NaOH (50%)
2,794	lbs/day	NH3 (aqueous 19%)
7,950	lbs/day	oxygen
10,959	sf	plot space needed
1,550	round trip miles/day	truck miles driven
11	trucks/day	no. of trucks
20776	round trip miles/year	truck miles driven
137	trucks/year	no. of trucks

Coke Calciner
1 refinery (Facility 2) - 1 Ultracat DGS or 1 LoTox w/WGS

Usage Rates		
11,621	kWh/day	Electricity
40896.00	gal/day	Water
16992.00	gal/day	Wastewater
36,576	scf/day	Compressed Air
0.44	tons/day	Solid Waste Disposal
3,068	lbs/day	NH3 (aqueous 19%)
1.81	tons/day	Hydrated Lime Ca(OH)2
3.37	tons/day	NaOH (50%)
1,200	sf	plot space needed
616	round trip miles/day	truck miles driven
4	trucks/day	no. of trucks
6,345	round trip miles/year	truck miles driven
86	trucks/year	no. of trucks

Boilers/Heaters
8 refineries (Facilities 1, 3, 4, 5, 6, 7, 8, & 9) - SCRs

Usage Rates		
78,389	kWh/day	Electricity
58,307	lbs/day	NH3 (aqueous 19%)
23,672	sf	plot space needed
2,400	round trip miles/day	truck miles driven
24	trucks/day	no. of trucks
47,900	round trip miles/year	truck miles driven
479	trucks/year	no. of trucks

Gas Turbines

5 refineries (Facilities 1, 4, 5, 6, & 7) - SCRs

Usage Rates

6,524	kWh/day	Electricity
3,576	lbs/day	NH3 (aqueous 19%)
0	sf	plot space needed
1,500	round trip miles/day	truck miles driven
15	trucks/day	no. of trucks
4,000	round trip miles/year	truck miles driven
40	trucks/year	no. of trucks

GRAND TOTALS (For Operation)

Usage Rates					Notes	Net Effect of Project		Percentage Change	Significant?	
168,170	kWh/day	168.17	MWh/day	Electricity	Significance Threshold: 1% of supply (8362 MW - instantaneous electricity)	7.01	MW (instantaneous)	0.08%	NO	Note 1: Instantaneous Electricity Equation: 166,389 kW-hr/day x 1 work day/24 hr x 1 MW/1000 kW = 6.9 MW. Note 2: This calculation takes into account the electricity needed to make 5.84 tons per day of NaOH to satisfy demand (13,235 kWh/day).
602,814	gal/day	0.60	MMgal/day	Water	Significance Threshold: 5,000,000 gal/day water	602,814	gal/day	12.06%	NO	*See Hydrology/Water Quality Analysis
236,718	gal/day	0.24	MMgal/day	Wastewater	Significance Threshold: 25% increase above permitted wastewater limits	236,718	gal/day	<25%*	NO	*See Hydrology/Water Quality Analysis

1,029	MMbtu/day	Cooling Water	This data already included in energy calculations.
39,288	scf/day	Compressed Air	This data already included in energy calculations.
6.41	tons/day	Solid Waste Disposal	Solid Waste Disposal, Air Quality off-site transportation emissions, & Energy (fuel usage)
1.39	tons/day	Soda Ash (Na2CO3)	Air Quality: off-site transportation emissions & Energy (fuel usage)
5.84	tons/day	NaOH (50% by weight)	Air Quality: off-site transportation emissions & Energy (fuel usage)
69,142	lbs/day	NH3 (aqueous 19%)	Air Quality: off-site transportation emissions & Energy (fuel usage)
7,950	lbs/day	Oxygen	Air Quality: off-site transportation emissions & Energy (fuel usage)
1.81	tons/day	Hydrated Lime Ca(OH)2	Air Quality: off-site transportation emissions & Energy (fuel usage)
95,127	sf	Plot Space Needed	Air Quality: grading/site-preparation construction emissions
8,166	round trip miles/day	Daily truck miles driven	Air Quality: off-site transportation emissions & Energy (fuel usage)
65	trucks/day	Daily no. of trucks	Air Quality: off-site transportation emissions & Energy (fuel usage)
103,871	round trip miles/year	Annual truck miles driven	Air Quality: off-site transportation emissions & Energy (fuel usage)
839	trucks/year	Annual no. of trucks	Air Quality: off-site transportation emissions & Energy (fuel usage)

Key:
Cooling water already accounted for in both water demand and energy demand.

NaOH is 50% by weight, usually delivered by tanker truck in an aqueous solution due to high concentration

1 MW = 1000 KW

1 tcf (trillion cubic feet) = 1000 bcf (billion cubic feet) = 1,000,000 MMcf (million cubic feet)

1 metric ton = 2205 lbs

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip Distance (miles/day)	Annual Round-trip Distance (miles/year)	Mileage Rate (miles/ gallon)	2016 Mobile Source Emission Factors							
On-Road Equipment Type				VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	8,166	103,871	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Heavy-Heavy Duty Trucks	11.86	53.12	138.04	0.33	6.93	5.69
TOTAL	12	53	138	0	7	6
Significance Threshold	55	550	55	150	150	150
Exceed Significance?	NO	NO	YES	NO	NO	NO

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	437,108	6.98	437,255	198
TOTAL	437,108	7	437,255	198
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	n/a	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	8,166	103,871	4.89	1,670	21,241
				TOTAL	1,670	21,241

Phase III: Operations - Criteria Pollutants From Electricity Generation

Phase III: Operation	Peak Daily Electricity Demand (MWh/day)	Simple Cycle Turbine Emission Factors					
Electricity Generation		VOC (lb/MWh)	CO (lb/MWh)	NOx (lb/MWh)	SOx (lb/MWh)	PM10 (lb/MWh)	PM2.5 (lb/MWh)
Electricity Needed by 9 Refineries	168	0.02	0.08	0.09	0.00	0.06	0.06

Incremental Increase in Criteria Pollutant Emissions from Electricty Generation	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Emissions from Electricity Needed by 9 Refineries	3.36	13.45	15.14	0.00	10.09	9.89
TOTAL	3	13	15	0	10	10

Example Calculation: NOx: 0.09 lbs/MWh x 45.3 MWh = 4.08 lbs

Operational Truck Trips and Miles Driven

Facility	Equipment Category	Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
1	Boilers/Heaters	14 SCRs	1	73	100	7,300	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Boilers/Heaters	2 SCRs	1	9	100	900	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Boilers/Heaters	6 SCRs	1	26	100	2,600	0	0	0	0	1	6	100	600	1	6	100	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Boilers/Heaters	12 SCRs	1	40	100	4,000	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Boilers/Heaters	15 SCRs	1	103	100	10,300	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Boilers/Heaters	9 SCRs	1	46	100	4,600	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Boilers/Heaters	9 SCRs	1	71	100	7,100	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Boilers/Heaters	7 SCRs	1	29	100	2,900	0	0	0	0	1	9	100	900	1	9	100	900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		BOILER/HEATER SUBTOTALS	**8**	**397**	**800**	**39,700**	**0**	**0**	**0**	**0**	**8**	**41**	**800**	**4,100**	**8**	**41**	**800**	**4,100**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

BOILER/HEATER TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	24	479	2,400	47,900

Operational Truck Trips and Miles Driven

Facility	Equipment Category	Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
2	Coke Calciner	1 Ultracat DGS or 1 LoTox WGS	1	21	100	200	1	7	400	2,800	0	0	0	0	0	0	0	0	0	0	0	0	1	26	66	1,745	1	32	50	1,600	0	0	0	0
		COKE CALCINER SUBTOTALS	**1**	**21**	**100**	**200**	**1**	**7**	**400**	**2,800**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**26**	**66**	**1,745**	**1**	**32**	**50**	**1,600**	**0**	**0**	**0**	**0**

COKE CALCINER TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	4	86	616	6,345

Operational Truck Trips and Miles Driven

Facility	Equipment Category	Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
4	FCCU	1 LoTox with WGS	0	0	0	0	1	7	400	2,800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	5	50	250				
5	FCCU	1 SCR	1	20	100	2,000	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	FCCU	1 SCR	1	10	100	1,000	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	FCCU	1 ozone generator for LoTox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	44	50	2,176
9	FCCU	1 LoTox with WGS	0	0	0	0	1	28	400	11,200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	19	50	950	0	0	0	0
		FCCU SUBTOTALS	**2**	**30**	**200**	**3,000**	**2**	**35**	**800**	**14,000**	**2**	**2**	**200**	**200**	**2**	**2**	**200**	**200**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**2**	**24**	**100**	**1,200**	**1**	**44**	**50**	**2,176**

FCCU TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	11	137	1,550	20,776

Operational Truck Trips and Miles Driven

Facility	Equipment Category	Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
1	Gas Turbine	1 SCR for Gas Turbine	1	8	100	800	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Gas Turbine	1 SCR for Gas Turbine	1	3	100	300	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gas Turbine	3 SCR for Gas Turbine	1	12	100	1,200	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Gas Turbine	1 SCR for Gas Turbine	1	2	100	200	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Gas Turbine	1 SCR for Gas Turbine	1	5	100	500	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		GAS TURBINE SUBTOTALS	**5**	**30**	**500**	**3,000**	**0**	**0**	**0**	**0**	**5**	**5**	**500**	**500**	**5**	**5**	**500**	**500**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

GAS TURBINE TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	15	40	1,500	4,000

Operational Truck Trips and Miles Driven

Facility	Equipment Category	Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
1	SRU/TGU	1 LoTox with WGS	0	0	0	0	1	10	400	4,000	0	0	0	0	0	0	0	0	1	4	50	200	0	0	0	0	0	0	0	0				
5	SRU/TGU	2 LoTox with WGSs	0	0	0	0	1	26	400	10,400	0	0	0	0	0	0	0	0	1	10	50	500	0	0	0	0	0	0	0	0				
5	SRU/TGU	1 SCR	1	20	100	2,000	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	SRU/TGU	1 LoTox with WGSs	0	0	0	0	1	13	400	5,200	0	0	0	0	0	0	0	0	1	5	50	250	0	0	0	0	0	0	0	0				
8	SRU/TGU	1 LoTox with WGS	0	0	0	0	1	5	400	2,000	0	0	0	0	0	0	0	0	1	2	50	100	0	0	0	0	0	0	0	0	0	0	0	0
		SRU/TGU SUBTOTALS	**1**	**20**	**100**	**2,000**	**4**	**54**	**1,600**	**21,600**	**1**	**1**	**100**	**100**	**1**	**1**	**100**	**100**	**4**	**21**	**200**	**1,050**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

SRU/TGU TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	11	97	2,100	24,850

	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
GRAND SUBTOTALS	**17**	**498**	**1,700**	**47,900**	**7**	**96**	**2,800**	**38,400**	**16**	**49**	**1,600**	**4,900**	**16**	**49**	**1,600**	**4,900**	**4**	**21**	**200**	**1,050**	**1**	**26**	**66**	**1,745**	**3**	**56**	**150**	**2,800**	**1**	**44**	**50**	**2,176**

GRAND TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS
	65	839	8,166	103,871

DAILY TRIPS TOTALS	65
ANNUAL TRIPS TOTALS	839
DAILY MILES TOTALS	8,166
ANNUAL MILES TOTALS	103,871

Facility	Equipment Category	Operational Truck Trips and Miles Driven – Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
1	SRU/TGU	1 LoTox with WGS	0	0	0	0	1	10	400	4,000	0	0	0	0	0	0	0	0	1	4	50	200	0	0	0	0	0	0	0	0				
1	Gas Turbine	1 SCR for Gas Turbine	1	8	100	800	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Boilers/Heaters	14 SCRs	1	73	100	7,300	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 1 SUBTOTALS	**2**	**81**	**200**	**8,100**	**1**	**10**	**400**	**4,000**	**2**	**6**	**200**	**600**	**2**	**6**	**200**	**600**	**1**	**4**	**50**	**200**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 1 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	8	107	1,050	13,500	5	215	2,761

Facility	Equipment Category	Operational Truck Trips and Miles Driven – Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
2	Coke Calciner	1 Ultracat DGS or 1 LoTox WGS	1	21	100	200	1	7	400	2,800	0	0	0	0	0	0	0	0	0	0	0	0	1	26	66	1,745	1	32	50	1,600	0	0	0	0
		FACILITY 2 SUBTOTALS	**1**	**21**	**100**	**200**	**1**	**7**	**400**	**2,800**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**26**	**66**	**1,745**	**1**	**32**	**50**	**1,600**	**0**	**0**	**0**	**0**

FACILITY 2 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	4	86	616	6,345	5	126	1,298

Facility	Equipment Category	Operational Truck Trips and Miles Driven – Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
3	Boilers/Heaters	2 SCRs	1	9	100	900	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 3 SUBTOTALS	**1**	**9**	**100**	**900**	**0**	**0**	**0**	**0**	**1**	**1**	**100**	**100**	**1**	**1**	**100**	**100**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 3 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	3	11	300	1,100	5	61	225

Facility	Equipment Category	Operational Truck Trips and Miles Driven – Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
4	FCCU	1 LoTox with WGS	0	0	0	0	1	7	400	2,800	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	5	50	250				
4	Gas Turbine	1 SCR for Gas Turbine	1	3	100	300	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Boilers/Heaters	6 SCRs	1	26	100	2,600	0	0	0	0	1	6	100	600	1	6	100	600	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 4 SUBTOTALS	**2**	**29**	**200**	**2,900**	**1**	**7**	**400**	**2,800**	**2**	**7**	**200**	**700**	**2**	**7**	**200**	**700**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**5**	**50**	**250**	**0**	**0**	**0**	**0**

FACILITY 4 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	8	55	1,050	7,350	5	215	1,503

Facility	Equipment Category	Operational Truck Trips and Miles Driven – Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
5	FCCU	1 SCR	1	20	100	2,000	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	SRU/TGU	2 LoTox with WGSs	0	0	0	0	1	26	400	10,400	0	0	0	0	0	0	0	0	1	10	50	500	0	0	0	0	0	0	0	0				
5	SRU/TGU	1 SCR	1	20	100	2,000	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Gas Turbine	3 SCR for Gas Turbine	1	12	100	1,200	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Boilers/Heaters	12 SCRs	1	40	100	4,000	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 5 SUBTOTALS	**4**	**92**	**400**	**9,200**	**1**	**26**	**400**	**10,400**	**4**	**8**	**400**	**800**	**4**	**8**	**400**	**800**	**1**	**10**	**50**	**500**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 5 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	14	144	1,650	21,700	5	337	4,438

Operational Truck Trips and Miles Driven

Facility	Equipment Category	Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
6	FCCU	1 SCR	1	10	100	1,000	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	SRU/TGU	1 LoTox with WGSs	0	0	0	0	1	13	400	5,200	0	0	0	0	0	0	0	0	1	5	50	250	0	0	0	0	0	0	0	0				
6	Gas Turbine	1 SCR for Gas Turbine	1	2	100	200	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Boilers/Heaters	15 SCRs	1	103	100	10,300	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 6 SUBTOTALS	**3**	**115**	**300**	**11,500**	**1**	**13**	**400**	**5,200**	**3**	**7**	**300**	**700**	**3**	**7**	**300**	**700**	**1**	**5**	**50**	**250**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 6 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	11	147	1,350	18,350	5	276	3,753

Operational Truck Trips and Miles Driven

Facility	Equipment Category	Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
7	FCCU	1 ozone generator for LoTox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	44	50	2,176
7	Gas Turbine	1 SCR for Gas Turbine	1	5	100	500	0	0	0	0	1	1	100	100	1	1	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Boilers/Heaters	9 SCRs	1	46	100	4,600	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 7 SUBTOTALS	**2**	**51**	**200**	**5,100**	**0**	**0**	**0**	**0**	**2**	**6**	**200**	**600**	**2**	**6**	**200**	**600**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**44**	**50**	**2,176**

FACILITY 7 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	7	107	650	8,476	5	133	1,733

Operational Truck Trips and Miles Driven

Facility	Equipment Category	Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
8	SRU/TGU	1 LoTox with WGS	0	0	0	0	1	5	400	2,000	0	0	0	0	0	0	0	0	1	2	50	100	0	0	0	0	0	0	0	0	0	0	0	0
8	Boilers/Heaters	9 SCRs	1	71	100	7,100	0	0	0	0	1	5	100	500	1	5	100	500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 8 SUBTOTALS	**1**	**71**	**100**	**7,100**	**1**	**5**	**400**	**2,000**	**1**	**5**	**100**	**500**	**1**	**5**	**100**	**500**	**1**	**2**	**50**	**100**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

FACILITY 8 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	5	88	750	10,200	5	153	2,086

Operational Truck Trips and Miles Driven

Facility	Equipment Category	Control Equipment Assumed to Be Installed	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
9	FCCU	1 LoTox with WGS	0	0	0	0	1	28	400	11,200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	19	50	950	0	0	0	0
9	Boilers/Heaters	7 SCRs	1	29	100	2,900	0	0	0	0	1	9	100	900	1	9	100	900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		FACILITY 9 SUBTOTALS	**1**	**29**	**100**	**2,900**	**1**	**28**	**400**	**11,200**	**1**	**9**	**100**	**900**	**1**	**9**	**100**	**900**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1**	**19**	**50**	**950**	**0**	**0**	**0**	**0**

FACILITY 9 TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	5	94	750	16,850	5	153	3,446

	Daily Trips NH3	Annual Trips NH3	Daily Miles NH3	Annual Miles NH3	Daily Trips Solid Waste	Annual Trips Solid Waste	Daily Miles Solid Waste	Annual Miles Solid Waste	Daily Trips Fresh Catalyst	Annual Trips Fresh Catalyst	Daily Miles Fresh Catalyst	Annual Miles Fresh Catalyst	Daily Trips Spent Catalyst	Annual Trips Spent Catalyst	Daily Miles Spent Catalyst	Annual Miles Spent Catalyst	Daily Trips Soda Ash	Annual Trips Soda Ash	Daily Miles Soda Ash	Annual Miles Soda Ash	Daily Trips Lime	Annual Trips Lime	Daily Miles Lime	Annual Miles Lime	Daily Trips NaOH	Annual Trips NaOH	Daily Miles NaOH	Annual Miles NaOH	Daily Trips Oxygen	Annual Trips Oxygen	Daily Miles Oxygen	Annual Miles Oxygen
GRAND SUBTOTALS	**17**	**498**	**1,700**	**47,900**	**7**	**96**	**2,800**	**38,400**	**16**	**49**	**1,600**	**4,900**	**16**	**49**	**1,600**	**4,900**	**4**	**21**	**200**	**1,050**	**1**	**26**	**66**	**1,745**	**3**	**56**	**150**	**2,800**	**1**	**44**	**50**	**2,176**

GRAND TOTALS	DAILY TRIPS TOTALS	ANNUAL TRIPS TOTALS	DAILY MILES TOTALS	ANNUAL MILES TOTALS	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Annual Diesel Fuel Usage (gal/year)
	65	839	8,166	103,871	5	1,670	21,241

PROPOSED PROJECT: GHG GRAND TOTALS

Phase III: Operations - GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use*	**169.25**	**MWh/day**	**Electricity GHGs**	**30,818**	**0**	**0**	**30,818**
Facility 1	41.31	MWh/day	Electricity GHGs	7521.50	0.00	0.00	7,522
Facility 2	11.62	MWh/day	Electricity GHGs	2115.96	0.00	0.00	2,116
Facility 3	1.63	MWh/day	Electricity GHGs	296.44	0.00	0.00	296
Facility 4	25.16	MWh/day	Electricity GHGs	4581.72	0.00	0.00	4,582
Facility 5	24.73	MWh/day	Electricity GHGs	4503.61	0.00	0.00	4,504
Facility 6	21.88	MWh/day	Electricity GHGs	3983.72	0.00	0.00	3,984
Facility 7	8.17	MWh/day	Electricity GHGs	1487.28	0.00	0.00	1,487
Facility 8	14.31	MWh/day	Electricity GHGs	2605.14	0.00	0.00	2,605
Facility 9	20.45	MWh/day	Electricity GHGs	3722.77	0.00	0.00	3,723
water - increased use[1]	**0.60**	**MMgal/day**	**Water Conveyance GHGs**	**811.06**	**0.0047**	**0.0085**	**813**
Facility 1	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.0005	0.0010	94
Facility 2	0.04	MMgal/day	Water Conveyance GHGs	55.02	0.00	0.00	55
Facility 4	0.05	MMgal/day	Water Conveyance GHGs	66.35	0.0004	0.0007	66
Facility 5	0.22	MMgal/day	Water Conveyance GHGs	294.89	0.0017	0.0031	295
Facility 6	0.11	MMgal/day	Water Conveyance GHGs	147.45	0.0009	0.0015	148
Facility 8	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.0005	0.0010	94
Facility 9	0.04	MMgal/day	Water Conveyance GHGs	58.98	0.0003	0.0006	59
wastewater - increased generation[1]	**0.24**	**MMgal/day**	**Wastewater Processing GHGs**	**318.49**	**0.0018**	**0.0033**	**319**
Facility 1	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.00	0.00	19
Facility 2	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.00	0.00	23
Facility 4	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	30
Facility 5	0.10	MMgal/day	Wastewater Processing GHGs	132.70	0.00	0.00	133
Facility 6	0.05	MMgal/day	Wastewater Processing GHGs	66.35	0.00	0.00	66
Facility 8	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.00	0.00	19
Facility 9	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	30
temporary construction activities[3]	**1372.90**	**MT/project**	**Construction GHGs in CO2e**				**1,373**
Facility 1	313						
Facility 2	82						
Facility 3	31						
Facility 4	97						
Facility 5	363						
Facility 6	181						
Facility 7	85						
Facility 8	85						
Facility 9	136						
operational truck trips	**194.10**	**MT/project**	**Operation GHGs in CO2e**				**194**
Facility 1	26						
Facility 2	12						
Facility 3	2						
Facility 4	14						
Facility 5	37						
Facility 6	35						
Facility 7	16						
Facility 8	19						
Facility 9	32						
						TOTAL CO2e	**33,517**
						Significance Threshold	**10,000**
						Exceed Significance?	**YES**

Phase III: Operations - GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use*	**169.25**	**MWh/day**	**Electricity GHGs**	**30,818**	**0**	**0**	**30,818**
Facility 1	41.31	MWh/day	Electricity GHGs	7521.50	0.00	0.00	7521.50
Facility 2	11.62	MWh/day	Electricity GHGs	2115.96	0.00	0.00	2115.96
Facility 3	1.63	MWh/day	Electricity GHGs	296.44	0.00	0.00	296.44
Facility 4	25.16	MWh/day	Electricity GHGs	4581.72	0.00	0.00	4581.72
Facility 5	24.73	MWh/day	Electricity GHGs	4503.61	0.00	0.00	4503.61
Facility 6	21.88	MWh/day	Electricity GHGs	3983.72	0.00	0.00	3983.72
Facility 7	8.17	MWh/day	Electricity GHGs	1487.28	0.00	0.00	1487.28
Facility 8	14.31	MWh/day	Electricity GHGs	2605.14	0.00	0.00	2605.14
Facility 9	20.45	MWh/day	Electricity GHGs	3722.77	0.00	0.00	3722.77
water - increased use[2]	**0.60**	**MMgal/day**	**Water Conveyance GHGs**	**325.23**	**0.0019**	**0.0034**	**326**
Facility 1	0.070	MMgal/day	Water Conveyance GHGs	8.90	0.0001	0.0001	9
Facility 2	0.041	MMgal/day	Water Conveyance GHGs	55.024	0.000	0.001	55
Facility 4	0.049	MMgal/day	Water Conveyance GHGs	66.35	0.00	0.00	66
Facility 5	0.219	MMgal/day	Water Conveyance GHGs	27.86	0.0002	0.0003	28
Facility 6	0.110	MMgal/day	Water Conveyance GHGs	13.93	0.00	0.00	14
Facility 8	0.070	MMgal/day	Water Conveyance GHGs	94.18	0.00	0.00	94
Facility 9	0.044	MMgal/day	Water Conveyance GHGs	58.98	0.0003	0.0006	59
wastewater - increased generation[2]	**0.24**	**MMgal/day**	**Wastewater Processing GHGs**	**121.22**	**0.0007**	**0.0013**	**121**
Facility 1	0.01	MMgal/day	Wastewater Processing GHGs	1.78	0.0000	0.0000	2
Facility 2	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.00	0.00	22.91
Facility 4	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	29.55
Facility 5	0.10	MMgal/day	Wastewater Processing GHGs	12.54	0.0001	0.0001	13
Facility 6	0.05	MMgal/day	Wastewater Processing GHGs	6.27	0.00	0.00	6.28
Facility 8	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.00	0.00	18.84
Facility 9	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.0002	0.0003	30
temporary construction activities[3]	**1372.90**	**MT/project**	**Construction GHGs in CO2e**				**1,373**
Facility 1	313.30						
Facility 2	81.67						
Facility 3	30.88						
Facility 4	97.11						
Facility 5	362.91						
Facility 6	181.46						
Facility 7	84.93						
Facility 8	84.93						
Facility 9	135.71						
operational truck trips	**194.10**	**MT/project**	**Operation GHGs in CO2e**				**194**
Facility 1	25.77						
Facility 2	12.11						
Facility 3	2.10						
Facility 4	14.03						
Facility 5	37.23						
Facility 6	35.03						
Facility 7	16.18						
Facility 8	19.47						
Facility 9	32.17						
						TOTAL CO2e	**32,832**
						Significance Threshold	**10,000**
						Exceed Significance?	**YES**

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO_2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH_4/MMscf fuel burned
1,110 lb CO_2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO_2/MWh for electricity use due to water conveyance
0.0067 lb CH_4/MWh for electricity use due to water conveyance
0.0037 lb N_2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

Facility 1	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
SRU/TGU	Subtotal for 1 LoTox with WGS	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Gas Turbine	Subtotal for 1 SCR for Gas Turbine	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Boilers/Heaters*	Subtotal for 4 SCRs	16	83	84	0	6	6	5	5	1,503	287	195,360	37,326
	Subtotal for 5 containment berms					236	118	118	59				
	TOTAL FOR FACILITY 1	**56**	**338**	**209**	**0**	**274**	**156**	**137**	**78**	**2,356**	**697**	**316,573**	**145,165**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**				

*For Facility 1, a total of 15 SCRs (14 for Boilers/Heaters and 1 for 1 Gas Turbine) could be installed, but peak construction is based on a 1/3rd overlap of 15 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 2	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
Coke Calciner	Subtotal for 1 Ultracat DGS or 1 LoTOx WGS	36	233	104	0	30	30	12	12	478	339	72,373	98,508
	TOTAL FOR FACILITY 2	**36**	**233**	**104**	**0**	**30**	**30**	**12**	**12**	**478**	**339**	**72,373**	**98,508**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**	**NO**	**NO**				

Facility 3	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
Boilers/Heaters*	Subtotal for 2 SCRs	8	42	42	0	3	3	3	3	751	144	97,680	18,663
	Subtotal for 2 containment berms					95	47	47	24				
	TOTAL FOR FACILITY 3	**8**	**42**	**42**	**0**	**98**	**50**	**50**	**26**	**751**	**144**	**97,680**	**18,663**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**				

*For Boilers/Heaters, Facility 3 could install 2 new SCRs so peak construction is based on construction of both units overlapping at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 4	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	**Construction Emissions Summary**	**VOC (lb/day)**	**CO (lb/day)**	**NOx (lb/day)**	**SOx (lb/day)**	**PM10 Unmitigated (lb/day)**	**PM10 Mitigated (lb/day)**	**PM2.5 Unmitigated (lb/day)**	**PM2.5 Mitigated (lb/day)**	**Total Diesel Fuel Usage (gal/day)**	**Total Gasoline Fuel Usage (gal/day)**	**Total Diesel Fuel Usage (gal/project)**	**Total Gasoline Fuel Usage (gal/project)**
FCCU	**Subtotal for 1 LoTox with WGS**	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Gas Turbine	**Subtotal for 1 SCR for Gas Turbine**	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Boilers/Heaters*	**Subtotal for 1 SCR**	4	21	21	0	1	1	1	1	376	72	48,840	9,332
	Subtotal for 2 containment berms					95	47	47	24				
	TOTAL FOR FACILITY 4	**44**	**275**	**146**	**0**	**128**	**81**	**62**	**38**	**1,229**	**482**	**170,053**	**117,171**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**	**YES**	**NO**				

*For Facility 4, a total of 7 SCRs (6 for Boilers/Heaters and 1 for 1 Gas Turbine) could be installed, but peak construction is based on a 1/3rd overlap of 7 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 5	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	**Construction Emissions Summary**	**VOC (lb/day)**	**CO (lb/day)**	**NOx (lb/day)**	**SOx (lb/day)**	**PM10 Unmitigated (lb/day)**	**PM10 Mitigated (lb/day)**	**PM2.5 Unmitigated (lb/day)**	**PM2.5 Mitigated (lb/day)**	**Total Diesel Fuel Usage (gal/day)**	**Total Gasoline Fuel Usage (gal/day)**	**Total Diesel Fuel Usage (gal/project)**	**Total Gasoline Fuel Usage (gal/project)**
FCCU	**Subtotal for 1 SCR**	10	66	41	0	3	3	2	2	789	371	205,237	96,568
SRU/TGU	**Subtotal for 1 LoTox with WGSs**	36	233	104	0	30	30	12	12	478	339	72,373	98,508
SRU/TGU	**Subtotal for 1 SCR**	10	66	41	0	3	2	2	2	789	371	205,237	96,568
Gas Turbine	**Subtotal for 2 SCR for Gas Turbine**	8	42	42	0	3	3	3	3	751	144	97,680	18,663
Boilers/Heaters	**Subtotal for 2 SCRs**	8	42	42	0	3	3	3	3	751	144	97,680	18,663
	Subtotal for 6 containment berms					284	142	142	71				
	TOTAL FOR FACILITY 5	**72**	**449**	**270**	**1**	**326**	**184**	**164**	**93**	**3,559**	**1,368**	**678,207**	**328,970**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**				

*For Facility 5, a total of 17 SCRs (12 for Boilers/Heaters, 3 for Gas Turbines, 1 for the FCCU, and 1 for a SRU) could be installed, but peak construction is based on a 1/3rd overlap of 6 SCRs and corresponding containment berms at one time. 1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 6	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
FCCU	Subtotal for 1 SCR	10	66	41	0	3	3	2	2	789	371	205,237	96,568
SRU/TGU	Subtotal for 1 LoTox with WGSs	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Gas Turbine	Subtotal for 1 SCR for Gas Turbine	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Boilers/Heaters*	Subtotal for 4 SCRs	16	83	84	0	6	6	5	5	1,503	287	195,360	37,326
	Subtotal for 6 containment berms					284	142	142	71				
	TOTAL FOR FACILITY 6	**66**	**404**	**250**	**1**	**324**	**183**	**163**	**92**	**3,145**	**1,069**	**521,810**	**241,733**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**				

*For Facility 6, a total of 17 SCRs (15 for Boilers/Heaters, 1 for Gas Turbines, and 1 for the FCCU) could be installed, but peak construction is based on a 1/3rd overlap of 6 SCRs and corresponding containment berms at one time. 1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 7	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
FCCU	Subtotal for 1 ozone generator for LoTox	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Gas Turbine	Subtotal for 1 SCR for Gas Turbine	4	21	21	0	1	1	1	1	376	72	48,840	9,332
Boilers/Heaters*	Subtotal for 2 SCRs	8	42	42	0	3	3	3	3	751	144	97,680	18,663
	Subtotal for 3 containment berms					142	71	71	35				
	TOTAL FOR FACILITY 7	**16**	**83**	**84**	**0**	**148**	**77**	**76**	**41**	**1,503**	**287**	**195,360**	**37,326**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**YES**	**NO**				

*For Facility 7, a total of 10 SCRs (9 for Boilers/Heaters and 1 for a Gas Turbine) could be installed, but peak construction is based on a 1/3rd overlap of 10 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 8	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
SRU/TGU	Subtotal for 1 LoTox with WGS	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Boilers/Heaters*	Subtotal for 3 SCRs	12	63	63	0	4	4	4	4	1,127	215	146,520	27,995
	Subtotal for 3 containment berms					142	71	71	35				
	TOTAL FOR FACILITY 8	**48**	**296**	**167**	**0**	**177**	**106**	**87**	**52**	**1,605**	**554**	**218,893**	**126,502**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**	**NO**				

*For Facility 8, a total of 9 SCRs forBoilers/Heaters could be installed, but peak construction is based on a 1/3rd overlap of 9 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

Facility 9	Emissions from Construction Activities									Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles			
Equipment/Source Category	Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
FCCU	**Subtotal for 1 LoTox with WGS**	36	233	104	0	30	30	12	12	478	339	72,373	98,508
Boilers/Heaters*	**Subtotal for 2 SCRs**	8	42	42	0	3	3	3	3	751	144	97,680	18,663
	Subtotal for 3 containment berms					142	71	71	35				
	TOTAL FOR FACILITY 9	**44**	**275**	**146**	**0**	**175**	**104**	**86**	**50**	**1,229**	**482**	**170,053**	**117,171**
	Significant Threshold	75	550	100	150	150	150	55	55				
	Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**	**NO**				

*For Facility 9, a total of 7 SCRs forBoilers/Heaters could be installed, but peak construction is based on a 1/3rd overlap of 7 SCRs and corresponding containment berms at one time.
1 new NH3 storage tank is assumed to be constructed for each SCR, which requires construction of containment one berm per storage tank.
Construction equipment emissions are already included, except fugitive dust/mitgation.

IF ALL CONSTRUCTION OCCURS DURING SAME YEAR	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
TOTAL FOR FACILITY 1	56	338	209	0.41	274	156	137	78	2,356	697	316,573	145,165
TOTAL FOR FACILITY 2	36	233	104	0.20	30	30	12	12	478	339	72,373	98,508
TOTAL FOR FACILITY 3	8	42	42	0.08	98	50	50	26	751	144	97,680	18,663
TOTAL FOR FACILITY 4	44	275	146	0.28	128	81	62	38	1,229	482	170,053	117,171
TOTAL FOR FACILITY 5	72	449	270	0.65	326	184	164	93	3,559	1,368	678,207	328,970
TOTAL FOR FACILITY 6	66	404	250	0.55	324	183	163	92	3,145	1,069	521,810	241,733
TOTAL FOR FACILITY 7	16	83	84	0.17	148	77	76	41	1,503	287	195,360	37,326
TOTAL FOR FACILITY 8	48	296	167	0.33	177	106	87	52	1,605	554	218,893	126,502
TOTAL FOR FACILITY 9	44	275	146	0.28	175	104	86	50	1,229	482	170,053	117,171
GRAND TOTAL	**389**	**2,396**	**1,417**	**2.97**	**1,680**	**970**	**838**	**483**	**15,855**	**5,422**	**2,441,003**	**1,231,208**
Significant Threshold	75	550	100	150	150	150	55	55				
Exceed Significance?	**YES**	**YES**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**				

IF ALL CONSTRUCTION OCCURS OVER A PERIOD OF 5 YEARS (e.g., 2016 to 2020)	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
TOTAL FOR FACILITY 1	56	338	209	0.41	274	156	137	78	2,356	697	316,573	145,165
TOTAL FOR FACILITY 2	36	233	104	0.20	30	30	12	12	478	339	72,373	98,508
TOTAL FOR FACILITY 3	8	42	42	0.08	98	50	50	26	751	144	97,680	18,663
TOTAL FOR FACILITY 4	44	275	146	0.28	128	81	62	38	1,229	482	170,053	117,171
TOTAL FOR FACILITY 5	72	449	270	0.65	326	184	164	93	3,559	1,368	678,207	328,970
TOTAL FOR FACILITY 6	66	404	250	0.55	324	183	163	92	3,145	1,069	521,810	241,733
TOTAL FOR FACILITY 7	16	83	84	0.17	148	77	76	41	1,503	287	195,360	37,326
TOTAL FOR FACILITY 8	48	296	167	0.33	177	106	87	52	1,605	554	218,893	126,502
TOTAL FOR FACILITY 9	44	275	146	0.28	175	104	86	50	1,229	482	170,053	117,171
GRAND TOTAL OVER 5 YEARS	**78**	**479**	**283**	**0.59**	**336**	**194**	**168**	**97**	**3,171**	**1,084**	**488,201**	**246,242**
Significant Threshold	75	550	100	150	150	150	55	55				
Exceed Significance?	**YES**	**NO**	**YES**	**NO**	**YES**	**YES**	**YES**	**YES**				

IF ALL CONSTRUCTION OCCURS OVER A PERIOD OF 7 YEARS (e.g., 2016 to 2022)	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 Unmitigated (lb/day)	PM10 Mitigated (lb/day)	PM2.5 Unmitigated (lb/day)	PM2.5 Mitigated (lb/day)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/project)
TOTAL FOR FACILITY 1	56	338	209	0.41	274	156	137	78	2,356	697	316,573	145,165
TOTAL FOR FACILITY 2	36	233	104	0.20	30	30	12	12	478	339	72,373	98,508
TOTAL FOR FACILITY 3	8	42	42	0.08	98	50	50	26	751	144	97,680	18,663
TOTAL FOR FACILITY 4	44	275	146	0.28	128	81	62	38	1,229	482	170,053	117,171
TOTAL FOR FACILITY 5	72	449	270	0.65	326	184	164	93	3,559	1,368	678,207	328,970
TOTAL FOR FACILITY 6	66	404	250	0.55	324	183	163	92	3,145	1,069	521,810	241,733
TOTAL FOR FACILITY 7	16	83	84	0.17	148	77	76	41	1,503	287	195,360	37,326
TOTAL FOR FACILITY 8	48	296	167	0.33	177	106	87	52	1,605	554	218,893	126,502
TOTAL FOR FACILITY 9	44	275	146	0.28	175	104	86	50	1,229	482	170,053	117,171
GRAND TOTAL OVER 7 YEARS	**56**	**342**	**202**	**0.42**	**240**	**139**	**120**	**69**	**2,265**	**775**	**348,715**	**175,887**
Significant Threshold	75	550	100	150	150	150	55	55				
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**YES**	**NO**	**YES**	**YES**				

Construction Water Use

Water Use from hydrotesting storage tank integrity (post-construction/pre-operation):

Refinery ID	plot space (sf) for all control equip	No. of NH3 storage tanks needed	Capacity of Storage Tank (gal)	Plot space (sf) needed per storage tank	Plot space (sf) needed for all storage tanks	Total plot space (sf) for all control equipment & chemical storage	Total acreage disturbed from Construction (acre)	Number of Tanks Overlapping Construction per day (assumes 1/3rd of total number of tanks)	Amount of Water Needed to Hydrotest during Overlap (gal/day)	Amount of Water Needed to Hydrotest for Entire Project (gal/project)
1	6,417	15	11,000	400	6,000	12,417	0.29	5	55,000	165,000
2	1,200	1	11,000	400	400	1,600	0.04	1	11,000	11,000
3	352	2	11,000	400	800	1,152	0.03	1	11,000	22,000
4	2,463	6	11,000	400	2,400	4,863	0.11	2	22,000	66,000
5	21,418	17	11,000	400	6,800	28,218	0.65	6	66,000	187,000
6	14,165	17	11,000	400	6,800	20,965	0.48	6	66,000	187,000
7	3,840	10	11,000	400	4,000	7,840	0.18	3	33,000	110,000
8	7,409	9	11,000	400	3,600	11,009	0.25	3	33,000	99,000
9	4,263	7	11,000	400	2,800	7,063	0.16	2	22,000	77,000
		84		**Total**	**33,600**	**95,127**	**2.18**	**29**	**319,000**	**924,000**

Water Use for Dust Suppresion (during construction):

Total Area Disturbed, acre	Area Disturbed, ft2	Depth of Water*, ft	Water Use Area, ft3	Water Use, gal	Number of Waterings per day	Total Daily Water Use, gal
2.18	95,127	0.005	476	3,558	3	**10,674**

*Assumes 1/16 inch depth of water applied per washing

SRU/TGU System

LoTox with Wet Gas Scrubber

Facility 1

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	2,197,800	kWh	6021.37	kWh
Water	25.55	MMgal	70000.00	gal
Wastewater	5.1	MMgal	13972.60	gal
Cooling Water	204,940	MMbtu	561.48	MMbtu
Compressed Air	50	1000 scf	136.99	scf
Solid Waste Disposal	250	tons	0.68	tons
Soda Ash	95	tons	0.26	tons
Plot Space needed	3953	sf		
1 Truck Hauling Away Solid Waste[1]	4000	round trip miles	400.00	round trip miles
1 Truck Delivering Soda Ash[2]	200	round trip miles	50.00	round trip miles
No. of Trucks Hauling Away Solid Waste	10	trucks	1	truck
No. of Trucks Delivering Soda Ash	4	trucks	1	truck

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank

Facility 1

	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	882,205	kWh	2417	kWh
Plot Space needed	176	sf		
19% Aqueous NH3 usage at 95% control	278,495	lb	763	lb
19% Aqueous NH3 usage at 95% control	36,262	gal	99	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck
1 Truck Delivering Aqueous NH3[3,4]	500	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

14 SCRs for 14 boilers/heaters

Facility 1

14 SCRs for 14 boilers/heaters	Annual Usage for 14 units		Daily Usage for 14 units	
Electricity	12,350,870	kWh	33,838	kWh
Plot Space needed	2464	sf		
19% Aqueous NH3 usage at 95% control	3,898,930	lb	10,682	lb
19% Aqueous NH3 usage at 95% control	507,673	gal	1,391	gal
No. of Trucks Delivering Aqueous NH3	73	trucks	1	truck
Trucks Delivering Aqueous NH3[3,4]	7,300	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	5	trucks	1	truck
Trucks hauling spent catalyst (once every five years per SCR)	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years per SCR)	500	round trip miles	100	round trip miles

*assume that not all 14 scr will be on same five year catalyst replacement schedule

GRAND TOTALS (during Operation)

Daily Usage		Daily Usage		
41,307.37	Kwh	41.31	MWh	Electricity
70,000.00	gal			Water
13,972.60	gal			Wastewater
561.48	MMbtu			Cooling Water
136.99	scf			Compressed Air
0.68	tons			Solid Waste Disposal
0.26	tons			Soda Ash (Na2CO3)
6,417	sf			Plot Space needed
11767.00	lb	1532.16	gal	19% Aqueous NH3
400	Daily round trip miles			1 Truck Hauling Away Solid Waste[1]
50	Daily round trip miles			1 Truck Delivering Soda Ash[2]
1	daily trucks			No. of Trucks Hauling Away Solid Waste
1	daily trucks			No. of Trucks Delivering Soda Ash
100	Daily round trip miles			1 Truck Delivering Aqueous Ammonia[3, 4]
1	daily trucks			No. of Trucks Delivering Aqueous Ammonia
100	Daily round trip miles			1 Truck Hauling Away Spent Catalyst
1	daily trucks			No. of Truck Hauling Away Spent Catalyst
100	Daily round trip miles			1 Truck Delivering Fresh Catalyst
1	daily trucks			No. of Trucks Delivering Fresh Catalyst
750.00	Daily round trip miles			Total Daily Truck Miles
5.00	Daily trucks			Total No. of Trucks
13,500	Annual round trip miles			Annual Truck Miles
107	Annual trucks			Annual Trucks

Modify existing Gas Turbine SCR with additional catalyst	Facility 1 Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	528,520	kWh	1448	kWh
Plot Space needed	0	sf		
19% Aqueous NH3 usage at 95% control	396,025	lb	1,085	lb
19% Aqueous NH3 usage at 95% control	51,566	gal	141	gal
No. of Trucks Delivering Aqueous NH3	8	trucks	1	truck
1 Truck Delivering Aqueous NH3	800	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

[1]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 10 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
250 tons/yr solid waste x 1 truck/25 tons = 10 trucks/year to haul extra solid waste away for recycling
This facility either sends its solid waste to a Class III landfill for disposal which is 80.64 miles (one-way) away or to a cement plant cement plant outside of the SCAQMD for recycling.
A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[2]Assumes delivery of soda ash arrives in a 25 ton capacity truck. It will take an extra 4 trucks to deliver one year's worth of soda ash.
95 tons/yr soda ash x 1 truck/25 tons = 3.8 trucks/year to deliver soda ash

[3, 4]Assumes delivery of aqueous ammonia to fill one 2,000 gallon tank. It will take an extra 4 trucks to deliver one year's worth of aqueous ammonia for 1 scr.
6,654 gal/yr NH3 x 1 tank/2,000 gal = 3.3 refills via truck/year to deliver aqueous ammonia

However, to fill 14 aqueous ammonia tanks, one delivery truck can hold up to 7,000 gallons. Thus, the annual number of deliveries to supply all 14 tanks would be 29 trucks.
201,206 gal/yr NH3 x 1 truck/7,000 gal = 28.7 trucks/year to deliver aqueous ammonia

Facility 1 can buy recycled water from California Water Service Company.

Facility 1 already accesses recycled water and will have increased future access to recycled water.

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Heavy-Heavy Duty Trucks	750	13,500	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.09	4.88	12.68	0.03	0.64	0.52	3156.15	0.05	3,157
TOTAL	**1**	**5**	**13**	**0**	**1**	**1**	**3,156**	**0**	**3,157**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	56810.72	0.91	56,830	26
TOTAL	**56,811**	**1**	**56,830**	**26**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	750	13,500	4.89	153	2,761
				TOTAL	153	2,761

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2017
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	41.31	MWh/day	Electricity GHGs	7521.50	0.0000	0.0000	7,522
water - increased use[1]	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.0005	0.0010	94
wastewater - increased generation[1]	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.0001	0.0002	19
temporary construction activities[3]	313	MT/year	Construction GHGs in CO2e				313
operational truck trips	25.77	MT/year	Operation GHGs in CO2e				26
						TOTAL CO2e	7,974

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	41.31	MWh/day	Electricity GHGs	7521.50	0.0000	0.00	7,522
water - increased use[2]	0.07	MMgal/day	Water Conveyance GHGs	8.90	0.0001	0.0001	9
wastewater - increased generation[2]	0.01	MMgal/day	Wastewater Processing GHGs	1.78	0.0000	0.0000	2
temporary construction activities[3]	313.30	MT/year	Construction GHGs in CO2e				313
operational truck trips	25.77	MT/year	Operation GHGs in CO2e				26
						TOTAL CO2e	7,871

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

Facility 2 - Coke Calciner
Coke Calciner
UltraCat DGS

Utility/Infrastructure	Annual Usage		Daily Usage		Daily Usage	
Electricity	4,241,535	kW	11620.64	kW	11.62	MW
Compressed Air	13,350	1000 scf	36,576	scf	25.40	scfm
Solid Waste Disposal	48.4	tons	0.13	tons		
Aqueous Ammonia (NH3 19%)	1,120,000	lbs	3068.49	lbs	128	lb/hr
Aqueous Ammonia (NH3 19%)	145,833	gal	400	gal		
Hydrated Lime Ca(OH)2	659	tons	1.81	tons		
Plot Space Needed	371.25	sf				
1 Truck Hauling Away Solid Waste[1]	800	round trip miles	400.00	round trip miles		
No. of Trucks Hauling Away Solid Waste	2	trucks	1	truck		
1 Truck Delivering NH3 aq[2]	200	round trip miles	100.00	round trip miles		
No. of Trucks Delivering NH3aq	21	trucks	1	truck		
1 Truck Delivering Hydrated Lime[2]	1,745	round trip miles	66.20	round trip miles		
No. of Trucks Delivering Hydrated Lime	26	trucks	1	truck		
Total Truck Miles	2745	round trip miles	501	round trip miles		
Total No. of Trucks	49	trucks	3	trucks		

[1]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 2 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
48.4 tons/yr solid waste x 1 truck/25 tons = 1.9 trucks/year to haul extra solid waste away for recycling
This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

Facility 2 - Coke Calciner
Belco wet gas scrubber

Utility/Infrastructure	Annual Usage		Daily Usage		Daily Usage			
Electricity	3,679,200	kWh	17710.86	kWh	17.71	MWh	Note: This calculation takes into account the electricity needed to make 3.37 tons per day of NaOH to satisfy demand (7,631 kWh/day).	
Water	14.93	MMgal	40896.00	gal	0.04	Mmgal		
Wastewater	6.2	MMgal	16992.00	gal	0.02	Mmgal		
Solid Waste Disposal	160	tons	0.44	tons				
NaOH (50%)	1,228	tons	3.37	tons	22	gal/hr	280.434	lb/hr
Plot Space Needed	1200	sf			density = 12.747 lb/gal for NaOH at 50%			
1 Truck Hauling Away Solid Waste[2]	2800	round trip miles	400.00	round trip miles				
1 Truck Delivering NaOH[3]	1,600	round trip miles	50.00	round trip miles				
No. of Trucks Hauling Away Solid Waste	7	trucks	1	truck				
No. of Trucks Delivering NaOH	32	trucks	1	truck				
Total Truck Miles	4400.00	round trip miles	450.00	round trip miles				
Total No. of Trucks	39.00	trucks	2.00	trucks				

[2]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 7 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
160 tons/yr solid waste x 1 truck/25 tons = 6.4 trucks/year to haul extra solid waste away for recycling
This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[3]Assumes that one 10,000 gallon capacity storage tank will be installed for NaOH storage. It will take 32 trucks to deliver one year's worth of NaOH 50% solution, but the peak would be one truck per
1,228 tons/yr NaOH x 2,000 lbs/ ton = 854,000 lbs/yr x 1 gal NaOH @ 50%/12.77 lbs = 192,326 gal/year x 1 truck/6,000 gallons = 32 trucks/year

GRAND TOTALS (during Operation)
Note: Since this facility has the option to choose between a WGS or DGS, the peak usage is chosen for the grand totals.

Daily Usage		Daily Usage		
11,620.64	Kwh	11.62	MWh	Electricity
40,896.00	gal			Water
16,992.00	gal			Wastewater
36,576.00	scf			Compressed Air
0.44	tons			Solid Waste Disposal
3068.49	lb	399.54	gal	19% Aqueous NH3
1.81	tons			Hydrated Lime Ca(OH)2
3.37	tons			NaOH
1,200	sf			Plot Space needed
400	Daily round trip miles			1 Truck Hauling Away Solid Waste
66	Daily round trip miles			1 Truck Delivering Hydrated Lime
50	Daily round trip miles			1 Truck Delivering NaOH
100	Daily round trip miles			1 Truck Delivering Aqueous Ammonia
1	daily trucks			No. of Trucks Hauling Away Solid Waste
1	daily trucks			No. of Trucks Delivering Hydrated Lime
1	daily trucks			No. of Trucks Delivering NaOH
1	daily trucks			No. of Trucks Delivering Aqueous Ammonia
2800	Annual round trip miles			Annual Distance of Trucks Hauling Away Solid Waste
1,745	Annual round trip miles			Annual Distance of Delivering Hydrated Lime
1,600	Annual round trip miles			Annual Distance of Delivering NaOH
200	Annual round trip miles			Annual Distance of Delivering Aqueous Ammonia
7	Annual trucks			No. of Trucks Hauling Away Solid Waste
26	Annual trucks			No. of Trucks Delivering Hydrated Lime
32	Annual trucks			No. of Trucks Delivering NaOH
21	Annual trucks			No. of Trucks Delivering Aqueous Ammonia
616	Daily round trip miles			Total Daily Truck Miles
4	Daily trucks			Total No. of Trucks
6,345	Annual round trip miles			Annual Truck Miles
86	Annual trucks			Annual Trucks

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	616.20	6,345	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.89	4.01	10.42	0.02	0.52	0.43	2593.09	0.04	2,594
TOTAL	**1**	**4**	**10**	**0**	**1**	**0**	**2,593**	**0**	**2,594**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	26701.17	0.43	26,710	12
TOTAL	**26,701**	**0**	**26,710**	**12**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds
Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day) *	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	616	6,345	4.89	126	1,298
				TOTAL	126	1,298

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2017
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	11.62	MWh/day	Electricity GHGs	2115.96	0.0000	0.0000	2,116
water - increased use[1]	0.04	MMgal/day	Water Conveyance GHGs	55.02	0.0003	0.0006	55
wastewater - increased generation[1]	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.0001	0.0002	23
temporary construction activities[3]	82	MT/year	Construction GHGs in CO2e				82
operational truck trips	12.11	MT/year	Operation GHGs in CO2e				12
						TOTAL CO2e	2,288

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	11.62	MWh/day	Electricity GHGs	2115.96	0.00	0.00	2,116
water - increased use[2]	0.04	MMgal/day	Water Conveyance GHGs	55.02	0.00	0.00	55.13
wastewater - increased generation[2]	0.02	MMgal/day	Wastewater Processing GHGs	22.86	0.00	0.00	22.91
temporary construction activities[3]	81.67	MT/year	Construction GHGs in CO2e				82
operational truck trips	12.11	MT/year	Operation GHGs in CO2e				12
						TOTAL CO2e	2,288

Note: This facility does not have current access or future access to recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[3] GHGs from temporary construction activities are amortized over 30 years.

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank — Facility 3

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	297,110	kWh	814.00	kWh
Plot Space needed	176	sf		
19% Aqueous NH3 usage at 95% control	234,695	lb	643.00	lb
19% Aqueous NH3 usage at 95% control	30,559	gal	83.72	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	500	round trip miles	100.00	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100.00	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles

2 SCR for 2 boilers/heaters — Facility 3

Utility/Infrastructure	Annual Usage for 2 units		Daily Usage for 2 units	
Electricity	594,220	kWh	1628.00	kWh
Plot Space needed	352	sf		
19% Aqueous NH3 usage at 95% control	469,390	lb	1286.00	lb
19% Aqueous NH3 usage at 95% control	61,118	gal	167.45	gal
No. of Trucks Delivering Aqueous NH3	9	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	900	round trip miles	100.00	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100.00	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles

GRAND TOTALS (during Operation)

Daily Usage		Daily Usage		
1628.00	Kwh	1.63	MWh	Electricity
176.00	sf			Plot Space needed
1286.00	lb	167.45	gal	19% Aqueous NH3 usage at 95% control
352.00	sf	Plot Space Needed		
1.00	truck			No. of Trucks Delivering Aqueous NH3
100.00	Daily round trip miles			1 Truck Delivering Aqueous NH3[1,2]
1.00	truck			No. of Trucks Hauling Spent Catalyst
100.00	Daily round trip miles			1 Truck hauling spent catalyst (once every five years)
1.00	truck			No. of Trucks Delivering Fresh Catalyst
100.00	Daily round trip miles			1 Truck delivering fresh catalyst (once every five years)
300.00	Daily round trip miles			Total Daily Truck Miles
3.00	Daily trucks			Total No. of Trucks
1,100	Annual round trip miles			Annual Truck Miles
11	Annual trucks			Annual Trucks

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Heavy-Heavy Duty Trucks	300	1,100	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.44	1.95	5.07	0.01	0.25	0.21	1262.46	0.02	1,263
TOTAL	**0**	**2**	**5**	**0**	**0**	**0**	**1,262**	**0**	**1,263**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	4629.02	0.07	4,631	2
TOTAL	**4,629**	**0**	**4,631**	**2**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	300	1,100	4.89	61	225
				TOTAL	**61**	**225**

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2017
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	1.63	MWh/day	Electricity GHGs	296.44	0.0000	0.0000	296
temporary construction activities[3]	31	MT/year	Construction GHGs in CO2e				31
operational truck trips	2.10	MT/year	Operation GHGs in CO2e				2
						TOTAL CO2e	**329**

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	1.63	MWh/day	Electricity GHGs	296.44	0.0000	0.00	296
temporary construction activities[3]	30.88	MT/year	Construction GHGs in CO2e				31
operational truck trips	2.10	MT/year	Operation GHGs in CO2e				2
						TOTAL CO2e	**329**

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank — **Facility 4**

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	297,110	kWh	814.00	kWh
Plot Space needed	148	sf		
19% Aqueous NH3 usage at 95% control	234,695	lb	643.00	lb
19% Aqueous NH3 usage at 95% control	30,559	gal	83.72	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	500	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles

6 SCR for 6 boilers/heaters — **Facility 4**

Utility/Infrastructure	Annual Usage for 6 units		Daily Usage for 6 units	
Electricity	1,782,660	kWh	4884.00	kWh
Plot Space needed	888	sf		
19% Aqueous NH3 usage at 95% control	1,408,170	lb	3858.00	lb
19% Aqueous NH3 usage at 95% control	183,355	gal	502.34	gal
No. of Trucks Delivering Aqueous NH3	26	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	2,600	round trip miles	100.00	round trip miles
No. of Trucks Hauling Spent Catalyst	6	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	600	round trip miles	100.00	round trip miles
No. of Trucks Delivering Fresh Catalyst	6	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	600	round trip miles	100.00	round trip miles

FCCU LoTox Wet Gas Scrubber — **Facility 4**

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	6,887,000	kWh	18868.49	kWh
Water	18	MMgal	49315.07	gal
Wastewater	8	MMgal	21917.81	gal
Cooling Water	240	MMbtu	0.66	MMbtu
Compressed Air	280	1000 scf	767.12	scf
Solid Waste Disposal	160	tons	0.44	tons
NaOH (50%)	164	tons	0.45	tons
Plot Space Needed	1575	sf		
1 Truck Hauling Away Solid Waste[3]	2800	round trip miles	400	round trip miles
1 Truck Delivering NaOH[4]	250	round trip miles	50	round trip miles
No. of Trucks Hauling Away Solid Waste	7	trucks	1	truck
No. of Trucks Delivering NaOH	5	trucks	1	truck

GRAND TOTALS (during Operation)

Daily Usage			Daily Usage	
25162.35	kWh	Electricity	25.16	MWh
49315.07	gal	Water	0.05	Mmgal
21917.81	gal	Wastewater	0.02	Mmgal
0.66	MMbtu	Cooling Water		
767.12	scf	Compressed Air		
0.44	tons	Solid Waste Disposal		
0.45	tons	NaOH (50%)		
4249.00	lb	19% Aqueous NH3 usage at 95% control	553.26	gal
2463.00	sf	Plot Space Needed		
400	Daily round trip miles	1 Truck Hauling Away Solid Waste		
50	Daily round trip miles	1 Truck Delivering NaOH		
1	daily trucks	No. of Trucks Hauling Away Solid Waste		
1	daily trucks	No. of Trucks Delivering NaOH		
1	daily trucks	No. of Trucks Delivering Aqueous NH3		
100	Daily round trip miles	1 Truck Delivering Aqueous NH3[1,2]		
1	daily trucks	No. of Trucks Hauling Spent Catalyst		
100	Daily round trip miles	1 Truck hauling spent catalyst (once every five years)		
1	daily trucks	No. of Trucks Delivering Fresh Catalyst		
100	Daily round trip miles	1 Truck delivering fresh catalyst (once every five years)		
750	Daily round trip miles	Total Daily Truck Miles		
5	Daily trucks	Total No. of Trucks		
7,350	Annual round trip miles	Annual Truck Miles		
55	Annual trucks	Annual Trucks		

Modify 1 existing Gas Turbine SCR with additional catalyst	Facility 4 Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	142,715	kWh	391	kWh
Plot Space needed	0	sf		
19% Aqueous NH3 usage at 95% control	142,715	lb	391	lb
19% Aqueous NH3 usage at 95% control	18,583	gal	51	gal
No. of Trucks Delivering Aqueous NH3	3	trucks	1	truck
1 Truck Delivering Aqueous NH3	300	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

[1,2] Assumes delivery of aqueous ammonia to fill one tank. It will take an extra 5 trucks to deliver one year's worth of aqueous ammonia for one tank
To fill 6 aqueous ammonia tanks, one delivery truck can hold up to 7,000 gallons. Thus, the annual number of deliveries to supply all 6 tanks would be 26 trucks.

183,355 gal/yr NH3 x 1 truck/7,000 gal = 26.2 trucks/year to deliver aqueous ammonia

[3]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 7 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
160 tons/yr solid waste x 1 truck/25 tons = 6.4 trucks/year to haul extra solid waste away for recycling
This facility either sends its solid waste to a cement plant cement plant outside of the SCAQMD for recycling.
A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[4]Assumes that one 10,000 gallon capacity storage tank will be installed for NaOH storage. It will take 5 trucks to deliver one year's worth of NaOH 50% solution, but the peak would be one truck per day.
164 tons/yr NaOH x 2,000 lbs/ ton = 328,000 lbs/yr x 1 gal NaOH @ 50%/12.77 lbs = 25,685 gal/year x 1 truck/6,000 gallons = 4.28 trucks/year

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	750	7,350	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.09	4.88	12.68	0.03	0.64	0.52	3156.15	0.05	3,157
TOTAL	**1**	**5**	**13**	**0**	**1**	**1**	**3,156**	**0**	**3,157**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	30930.28	0.49	30,941	14
TOTAL	**30,930**	**0**	**30,941**	**14**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	750	7,350	4.89	153	1,503
				TOTAL	**153**	**1,503**

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2017
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	25.16	MWh/day	Electricity GHGs	4581.72	0.0000	0.0000	4,582
water - increased use[1]	0.05	MMgal/day	Water Conveyance GHGs	66.35	0.0004	0.0007	66
wastewater - increased generation[1]	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.0002	0.0003	30
temporary construction activities[3]	97	MT/year	Construction GHGs in CO2e				97
operational truck trips	14.03	MT/year	Operation GHGs in CO2e				14
						TOTAL CO2e	4,789

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	25.16	MWh/day	Electricity GHGs	4581.72	0.0000	0.00	4,582
water - increased use[2]	0.05	MMgal/day	Water Conveyance GHGs	66.35	0.00	0.00	66.48
wastewater - increased generation[2]	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	29.55
temporary construction activities[3]	97.11	MT/year	Construction GHGs in CO2e				97
operational truck trips	14.03	MT/year	Operation GHGs in CO2e				14
						TOTAL CO2e	4,789

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[3] GHGs from temporary construction activities are amortized over 30 years.

Note: This calculation takes into account the electricity needed to make 0.45 ton per day of NaOH to satisfy demand (1,019 kWh/day).

FCCU + 1 SRU/TGU
1 SCR for 1 FCCU with one 11,000 aqueous NH3 storage tank + 1 SCR for

Facility 5

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	1,300,130	kWh	3562.00	kWh
Plot Space needed	4950	sf		
19% Aqueous NH3 usage at 95% control	1,019,810	lb	2794.00	lb
19% Aqueous NH3 usage at 95% control	132,788	gal	363.80	gal
No. of Trucks Delivering Aqueous NH3	20	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	2,000	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles

SRU/TGU

2 LoTox with Wet Gas Scrubber

Facility 5

Utility/Infrastructure	Annual Usage for 2 units		Daily Usage for 2 units	
Electricity	4,894,800	kWh	13410.41	kWh
Water	80	MMgal	219178.08	gal
Wastewater	36	MMgal	98630.14	gal
Cooling Water	1100	MMbtu	3.01	MMbtu
Compressed Air	200	1000 scf	547.95	scf
Solid Waste Disposal	640	tons	1.75	tons
Soda Ash	246	tons	0.67	tons
Plot Space Needed	11860	sf		
1 Truck Hauling Away Solid Waste[3]	10400	round trip miles	400.00	round trip miles
1 Truck Delivering Soda Ash[4]	500	round trip miles	50.00	round trip miles
No. of Trucks Hauling Away Solid Waste	26	trucks	1	truck
No. of Trucks Delivering Soda Ash	10	trucks	1	truck

1 SCR for 1 boiler/heater

with one 11,000 gal Aqueous NH3 tank

Facility 5 | **Facility 5**

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit		Annual Usage for 12 units		Daily Usage for 12 units	
Electricity	164,615	kWh	451	kWh	1,975,380	kWh	5,412	kWh
Plot Space needed	384	sf			4,608	sf		
19% Aqueous NH3 usage at 95% control	181,040	lb	496	lb	2,172,480	lb	5,952	lb
19% Aqueous NH3 usage at 95% control	23,573	gal	64.58	gal	282,875	gal	775	gal
No. of Trucks Delivering Aqueous NH3	3	trucks	1	truck	40	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	300	round trip miles	100	round trip miles	4,000	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles	500	round trip miles	100.00	round trip miles

Grand Totals

Daily Usage			Daily Usage	
24733.41	kWh	Electricity	24.73341096	MWh
219178.08	gal	Water	0.219178082	Mmgal
98630.14	gal	Wastewater	0.098630137	Mmgal
3.01	MMbtu	Cooling Water		
547.95	scf	Compressed Air		
1.75	tons	Solid Waste Disposal		
0.67	tons	Soda Ash		
21,418	sf	Plot Space Needed		
10,546	lb	19% Aqueous NH3 usage at 95% control	1373.18	gal
400	Daily round trip miles	1 Truck Hauling Away Solid Waste		
50	Daily round trip miles	1 Truck Delivering Soda Ash		
1	daily trucks	No. of Trucks Hauling Away Solid Waste		
1	daily trucks	No. of Trucks Delivering Soda Ash		
3	daily trucks	No. of Trucks Delivering Aqueous NH3		
300	Daily round trip miles	1 Truck Delivering Aqueous NH3[1,2]		
3	daily trucks	No. of Trucks Hauling Spent Catalyst		
300	Daily round trip miles	1 Truck hauling spent catalyst (once every five years)		
3	daily trucks	No. of Trucks Delivering Fresh Catalyst		
300	Daily round trip miles	1 Truck delivering fresh catalyst (once every five years)		
1350	Daily round trip miles	Total Daily Truck Miles		
11	Daily trucks	Total No. of Trucks		
19,500	Annual round trip miles	Annual Truck Miles		
122	Annual trucks	Annual Trucks		

Modify 1 existing Gas Turbine SCR	Facility 5				Facility 5			
with additional catalyst	**Annual Usage for 1 unit**		**Daily Usage for 1 unit**		**Annual Usage for 3 units**		**Daily Usage for 3 units**	
Electricity	285,795	kWh	783	kWh	857,385	kWh	2349	kWh
Plot Space needed	0	sf			0	sf		
19% Aqueous NH3 usage at 95% control	219,000	lb	600	lb	657000	lb	1,800	lb
19% Aqueous NH3 usage at 95% control	28,516	gal	78	gal	85,547	gal	234	gal
No. of Trucks Delivering Aqueous NH3	4	trucks	1	truck	12	trucks	1	truck
1 Truck Delivering Aqueous NH3	400	round trip miles	100	round trip miles	1,200	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles	100	round trip miles	100	round trip miles

[1,2] Assumes delivery of aqueous ammonia to fill one tank. It will take an extra 4 trucks to deliver one year's worth of aqueous ammonia for one tank
One delivery truck can hold up to 7,000 gallons.

28,516 gal/yr NH3 x 1 truck/7,000 gal = 4.1 trucks/year to deliver aqueous ammonia

[3]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 26 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
640 tons/yr solid waste x 1 truck/25 tons = 25.6 trucks/year to haul extra solid waste away for recycling

This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[4]Assumes delivery of soda ash arrives in a 25 ton capacity truck. It will take an extra 10 trucks to deliver one year's worth of soda ash.
246 tons/yr soda ash x 1 truck/25 tons = 9.84 trucks/year to deliver soda ash

Facility 5 already accesses recycled water.

Facility 5 has two distinct wastewater systems. System One is the un-segregated system, which handles water from cooling towers, boiler blowdowns, and stormwater.
This wastewater receives primary treatment, the maximum capacity for this system is 5000 gpm; the facility is currently running at about 3000 gpm.

System Two is the segregated system, which handles process water. This wastewater receives primary and secondary (biological) treatment.
The maximum capacity for this system is 2000 gpm; the facility is currently running at about 1800 gpm.
Facility 5 has some wastewater storage capacity to handle surges due to storms and upsets.

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	1350	19,500	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

*Assumes 260 days/year

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.96	8.78	22.82	0.05	1.15	0.94	5681.07	0.09	5,683
TOTAL	**2**	**9**	**23**	**0**	**1**	**1**	**5,681**	**0**	**5,683**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	82059.93	1.31	82,087	37
TOTAL	**82,060**	**1**	**82,087**	**37**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	1350	19,500	4.89	276	3,988
				TOTAL	**276**	**3,988**

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2017
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions S	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	24.73	MWh/day	Electricity GHGs	4503.61	0.0000	0.0000	4,504
water - increased use[1]	0.22	MMgal/day	Water Conveyance GHGs	294.89	0.0017	0.0031	295
wastewater - increased generation[1]	0.10	MMgal/day	Wastewater Processing GHGs	132.70	0.0008	0.0014	133
temporary construction activities[3]	363	MT/year	Construction GHGs in CO2e				363
operational truck trips	37.23	MT/year	Operation GHGs in CO2e				37
						TOTAL CO2e	**5,332**

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	24.73	MWh/day	Electricity GHGs	4503.61	0.0000	0.00	4,504
water - increased use[2]	0.22	MMgal/day	Water Conveyance GHGs	27.86	0.0002	0.0003	28
wastewater - increased generation[2]	0.10	MMgal/day	Wastewater Processing GHGs	12.54	0.0001	0.0001	13
temporary construction activities[3]	362.91	MT/year	Construction GHGs in CO2e				363
operational truck trips	37.23	MT/year	Operation GHGs in CO2e				37
						TOTAL CO2e	**4,944**

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO_2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH_4/MMscf fuel burned
1,110 lb CO_2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO_2/MWh for electricity use due to water conveyance
0.0067 lb CH_4/MWh for electricity use due to water conveyance
0.0037 lb N_2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

FCCU
1 SCR for 1 FCCU
with one 11,000

Facility 6

Utility/Infrastructure	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	456,980	kWh	1252.00	kWh
Plot Space needed	2475	sf		
19% Aqueous NH3 usage at 95% control	509,905	lb	1397.00	lb
19% Aqueous NH3 usage at 95% control	66,394	gal	181.90	gal
No. of Trucks Delivering Aqueous NH3	10	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	1,000	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles

SRU/TGU System
LoTox with Wet Gas
Scrubber

Facility 6

Utility/Infrastructure	Annual Usage		Daily Usage	
Electricity	2,447,400	kWh	6705.21	kWh
Water	40	MMgal	109589.04	gal
Wastewater	18	MMgal	49315.07	gal
Cooling Water	550	MMbtu	1.51	MMbtu
Compressed Air	100	1000 scf	273.97	scf
Solid Waste Disposal	320	tons	0.88	tons
Soda Ash	123	tons	0.34	tons
Plot Space Needed	5930	sf		
1 Truck Hauling Away Solid Waste[5]	5200	round trip miles	400.00	round trip miles
1 Truck Delivering Soda Ash[6]	250	round trip miles	50.00	round trip miles
No. of Trucks Hauling Away Solid Waste	13	trucks	1	truck
No. of Trucks Delivering Soda Ash	5	trucks	1	truck

1 SCR for 1 boiler/heater
with one 11,000 gal
Aqueous NH3 tank

Utility/Infrastructure	Facility 6 Annual Usage for 1 unit		Daily Usage for 1 unit		Facility 6 Annual Usage for 15 units		Daily Usage for 15 units	
Electricity	329,230	kWh	902	kWh	4,938,450	kWh	13,530	kWh
Plot Space needed	384	sf			5,760	sf		
19% Aqueous NH3 usage at 95% control	368,650	lb	1,010	lb	5,529,750	lb	15,150	lb
19% Aqueous NH3 usage at 95% control	48,001	gal	131.51	gal	720,020	gal	1,973	gal
No. of Trucks Delivering Aqueous NH3	7	trucks	1	truck	103	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	700	round trip miles	100	round trip miles	10,300	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles	500	round trip miles	100.00	round trip miles

Modify 1 existing
Gas Turbine SCR

Facility 6

with additional
catalyst

	Annual Usage for 1 unit		Daily Usage for 1 unit	
Electricity	142,715	kWh	391	kWh
Plot Space needed	0	sf		
19% Aqueous NH3 usage at 95% control	109,500	lb	300	lb

19% Aqueous NH3 usage at 95% control	14,258	gal	39	gal
No. of Trucks Delivering Aqueous NH3	2	trucks	1	truck
1 Truck Delivering Aqueous NH3	200	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

Facility 6 will have increased access to recycled water.

[5]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 13 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
320 tons/yr solid waste x 1 truck/25 tons = 12.8 trucks/year to haul extra solid waste away for recycling
This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[6]Assumes delivery of soda ash arrives in a 25 ton capacity truck. It will take an extra 5 trucks to deliver one year's worth of soda ash.
123 tons/yr soda ash x 1 truck/25 tons = 4.92 trucks/year to deliver soda ash

Facility 6 can buy recycled water from California Water Service Company.

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	1350	18,350	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

*Assumes 260 days/year

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.96	8.78	22.82	0.05	1.15	0.94	5681.07	0.09	5,683
TOTAL	**2**	**9**	**23**	**0**	**1**	**1**	**5,681**	**0**	**5,683**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	77220.49	1.23	77,246	35
TOTAL	**77,220**	**1**	**77,246**	**35**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	1350	18,350	4.89	276	3,753
				TOTAL	276	3,753

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2017
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	21.88	MWh/day	Electricity GHGs	3983.72	0.0000	0.0000	3,984
water - increased use[1]	0.11	MMgal/day	Water Conveyance GHGs	147.45	0.0009	0.0015	148
wastewater - increased generation[1]	0.05	MMgal/day	Wastewater Processing GHGs	66.35	0.0004	0.0007	66
temporary construction activities[3]	181	MT/year	Construction GHGs in CO2e				181
operational truck trips	35.03	MT/year	Operation GHGs in CO2e				35
						TOTAL CO2e	4,414

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	21.88	MWh/day	Electricity GHGs	3983.72	0.0000	0.00	3,984
water - increased use[2]	0.11	MMgal/day	Water Conveyance GHGs	13.93	0.0001	0.0001	14
wastewater - increased generation[2]	0.05	MMgal/day	Wastewater Processing GHGs	6.27	0.0000	0.0001	6
temporary construction activities[3]	181.46	MT/year	Construction GHGs in CO2e				181
operational truck trips	35.03	MT/year	Operation GHGs in CO2e				35
						TOTAL CO2e	4,220

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

GRAND TOTALS (during Operation)

Daily Usage		Daily Usage			
21878.21	Kwh	21.88	MWh	Electricity	
109589.04	gal	0.109589041	Mmgal	Water	
49315.07	gal	0.049315068	Mmgal	Wastewater	
1.51	MMbtu			Cooling Water	
273.97	scf			Compressed Air	
0.88	tons			Solid Waste Disposal	
0.34	tons			soda ash	
14,165	sf			Plot Space needed	
16,847	lb	19% Aqueous NH3 usage at 95% con			2193.62 gal

400	Daily round trip miles	1 Truck Hauling Away Solid Waste[5]
50	Daily round trip miles	1 Truck Delivering Soda Ash[6]
1	daily trucks	No. of Trucks Hauling Away Solid Waste
1	daily trucks	No. of Trucks Delivering Soda Ash
3	daily trucks	No. of Trucks Delivering Aqueous NH3
300	Daily round trip miles	1 Truck Delivering Aqueous NH3[1,2]
3	daily trucks	No. of Trucks Hauling Spent Catalyst
300	Daily round trip miles	1 Truck hauling spent catalyst (once every five years)
3	daily trucks	No. of Trucks Delivering Fresh Catalyst
300	Daily round trip miles	1 Truck delivering fresh catalyst (once every five years)
1,350	Daily round trip miles	Total Daily Truck Miles
11	Daily trucks	Total No. of Trucks
18,350	Annual round trip miles	Annual Truck Miles
147	Annual trucks	Annual Trucks

Modify 1 existing Gas Turbine SCR with additional catalyst — **Facility 7**

Modify 1 existing Gas Turbine SCR with additional catalyst	**Annual Usage for 1 unit**		**Daily Usage for 1 unit**	
Electricity	428,510	kWh	1174	kWh
Plot Space needed	0	sf		
19% Aqueous NH3 usage at 95% control	281,415	lb	771	lb
19% Aqueous NH3 usage at 95% control	36,643	gal	100	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck
1 Truck Delivering Aqueous NH3	500	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100	round trip miles

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank — **Facility 7** / **Facility 7**

Utility/Infrastructure	**Annual Usage for 1 unit**		**Daily Usage for 1 unit**		**Annual Usage for 9 units**		**Daily Usage for 9 units**	
Electricity	243,090	kWh	666	kWh	2,187,810	kWh	5,994	kWh
Plot Space needed	384	sf			3,456	sf		
19% Aqueous NH3 usage at 95% control	271,925	lb	745	lb	2,447,325	lb	6,705	lb
19% Aqueous NH3 usage at 95% control	35,407	gal	97.01	gal	318,662	gal	873	gal
No. of Trucks Delivering Aqueous NH3	5	trucks	1	truck	46	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	500	round trip miles	100	round trip miles	4,600	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles	500	round trip miles	100.00	round trip miles

FCCU: 1LoTox Ozone Generator for existing WGS — **Facility 7**

Utility/Infrastructure	**Annual Usage for 1 unit**		**Daily Usage for 1 unit**		
Electricity	365,000	kWh	1,000	kWh	
Plot Space needed	384	sf			
Oxygen (in pounds)	2,901,750	lb	7,950	lb	9.527 lbs O2 for 1 gallon
Oxygen (in gallons)	304,582	gal	834	gal	
No. of Trucks Delivering Oxygen	44	trucks	1	truck	
1 Truck Delivering Oxygen	2,176	round trip miles	50	round trip miles	

GRAND TOTALS (during Operation)

Daily Usage		**Daily Usage**		
8168.00	Kwh	8.17	MWh	Electricity
7950.00	lb	oxygen		

6,705	lb	19% Aqueous NH3 usage at 95' 873 gal
3840.00	sf	Plot Space needed
2	daily trucks	No. of Trucks Delivering Aqueous NH3
200	Daily round trip miles	1 Truck Delivering Aqueous NH3[1,2]
2	daily trucks	No. of Trucks Hauling Spent Catalyst
200	Daily round trip miles	1 Truck hauling spent catalyst (once every five years)
2	daily trucks	No. of Trucks Delivering Fresh Catalyst
200	Daily round trip miles	1 Truck delivering fresh catalyst (once every five years)
1	daily trucks	No. of Trucks Delivering Oxygen
50	Daily round trip miles	1 Truck delivering Oxygen
650.00	Daily round trip miles	Total Daily Truck Miles
5.00	Daily trucks	Total No. of Trucks
8,476	Annual round trip miles	Annual Truck Miles
107	Annual trucks	Annual Trucks

[2]Assumes Hauling Sulfur away in a 25 ton capacity truck. It will take 1 extra truck to haul away one year's worth of sulfur; the peak would be one truck per day.
6.58 long tons/yr Sulfur x 2,240 lbs/long ton = 14,739 lbs/y

Facility 7 will have future access to recycled water.

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	650	8,476	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

*Assumes 260 days/year

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	0.94	4.23	10.99	0.03	0.55	0.45	2735.33	0.04	2,736
TOTAL	**1**	**4**	**11**	**0**	**1**	**0**	**2,735**	**0**	**2,736**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	35666.96	0.57	35,679	16
TOTAL	35,667	1	35,679	16
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	n/a	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	650	8,476	4.89	133	1,733
				TOTAL	133	1,733

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2017
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	8.17	MWh/day	Electricity GHGs	1487.28	0.0000	0.0000	1,487
temporary construction activities[3]	85	MT/year	Construction GHGs in CO2e				85
operational truck trips	16.18	MT/year	Operation GHGs in CO2e				16
						TOTAL CO2e	1,588

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	8.17	MWh/day	Electricity GHGs	1487.28	0.0000	0.00	1,487
temporary construction activities[3]	84.93	MT/year	Construction GHGs in CO2e				85
operational truck trips	16.18	MT/year	Operation GHGs in CO2e				16
						TOTAL CO2e	1,588

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance

SRU/TGU System

LoTox with Wet Gas Scrubber

Utility/Infrastructure	Annual Usage		Facility 8 Daily Usage		Daily Usage	
Electricity	1,809,000	kWh	4956.16	kWh	4.96	MWh
Water	25.55	MMgal	70000.00	gal	0.07	Mmgal
Wastewater	5.1	MMgal	13972.60	gal	0.01	Mmgal
Cooling Water	168,700	MMbtu	462.19	MMbtu		
Compressed Air	100	1000 scf	273.97	scf		
Solid Waste Disposal	120	tons	0.33	tons		
Soda Ash	45	tons	0.12	tons		
plot space needed	3953	sf				
1 Truck Hauling Away Solid Waste[1]	2000	round trip miles	400.00	round trip miles		
1 Truck Delivering Soda Ash[3]	100	round trip miles	50.00	round trip miles		
No. of Trucks Hauling Away Solid Waste	5	trucks	1	truck		
No. of Trucks Delivering Soda Ash	2	trucks	1.00	truck		

GRAND TOTALS (during Operation)

Daily Usage		Daily Usage		
14307.16	Kwh	14.31	MWh	Electricity
70000.00	gal	0.07	MMgal	Water
13972.60	gal	0.01	MMgal	Wastewater
462.19	MMbtu			Cooling Water
273.97	scf			Compressed Air
0.33	tons			Solid Waste Disposal
0.12	tons			Soda Ash
10,467	lb	19% Aqueous NH3 usage at 95% control		1,363 gal
7409.00	sf			Plot Space needed
400.00	Daily round trip miles			1 Truck Hauling Away Solid Waste[1]
50.00	Daily round trip miles			1 Truck Delivering Soda Ash[3]
1.00	daily trucks			No. of Trucks Hauling Away Solid Waste
1.00	daily trucks			No. of Trucks Delivering Soda Ash
1	daily trucks			No. of Trucks Delivering Aqueous NH3
100	Daily round trip miles			1 Truck Delivering Aqueous NH3[1,2]
1	daily trucks			No. of Trucks Hauling Spent Catalyst
100	Daily round trip miles			1 Truck hauling spent catalyst (once every five years)
1	daily trucks			No. of Trucks Delivering Fresh Catalyst
100	Daily round trip miles			1 Truck delivering fresh catalyst (once every five years)
750.00	Daily round trip miles			Total Daily Truck Miles
5.00	Daily trucks			Total No. of Trucks
10,200	Annual round trip miles			Annual Truck Miles
88	Annual trucks			Annual Trucks

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank

Utility/Infrastructure	Facility 8 Annual Usage for 1 unit		Daily Usage for 1 unit		Facility 8 Annual Usage for 9 units		Daily Usage for 9 units	
Electricity	379,235	kWh	1,039	kWh	3,413,115	kWh	9,351	kWh
Plot Space needed	384	sf			3,456	sf		
19% Aqueous NH3 usage at 95% control	424,495	lb	1,163	lb	3,820,455	lb	10,467	lb
19% Aqueous NH3 usage at 95% control	55,273	gal	151.43	gal	497,455	gal	1,363	gal
No. of Trucks Delivering Aqueous NH3	8	trucks	1	truck	71	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	800	round trip miles	100	round trip miles	7,100	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	500	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	5	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles	500	round trip miles	100.00	round trip miles

[1]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 30 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
120 tons/yr solid waste x 1 truck/25 tons = 4.8 trucks/year to haul extra solid waste away for recycling

[3]Assumes delivery of soda ash arrives in a 25 ton capacity truck. It will take an extra 2 trucks to deliver one year's worth of soda ash.
45 tons/yr soda ash x 1 truck/25 tons = 1.8 trucks/year to deliver soda ash

Facility 8 will not have future access to recycled water, but currently uses non-potable well water to supply the facility.

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip	Annual Round-trip	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	Distance (miles/day)	Distance (miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	750	10,200	4.89	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

*Assumes 260 days/year

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Heavy-Heavy Duty Trucks	1.09	4.88	12.68	0.03	0.64	0.52	3156.15	0.05	3,157
TOTAL	**1**	**5**	**13**	**0**	**1**	**1**	**3,156**	**0**	**3,157**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	42923.65	0.69	42,938	19
TOTAL	**42,924**	**1**	**42,938**	**19**
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Workers' Vehicles - Offsite Delivery/Haul	Heavy Duty Truck	750	10,200	4.89	153	2,086
				TOTAL	**153**	**2,086**

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2017
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	14.31	MWh/day	Electricity GHGs	2605.14	0.0000	0.0000	2,605
water - increased use[1]	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.0005	0.0010	94
wastewater - increased generation[1]	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.0001	0.0002	19
temporary construction activities[3]	151	MT/year	Construction GHGs in CO2e				151
operational truck trips	19.47	MT/year	Operation GHGs in CO2e				19
						TOTAL CO2e	2,889

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	14.31	MWh/day	Electricity GHGs	2605.14	0.0000	0.00	2,605
water - increased use[2]	0.07	MMgal/day	Water Conveyance GHGs	94.18	0.00	0.00	94.37
wastewater - increased generation[2]	0.01	MMgal/day	Wastewater Processing GHGs	18.80	0.00	0.00	18.84
temporary construction activities[3]	151.16	MT/year	Construction GHGs in CO2e				151
operational truck trips	19.47	MT/year	Operation GHGs in CO2e				19
						TOTAL CO2e	2,889

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
[3] GHGs from temporary construction activities are amortized over 30 years.

FCCU
LoTox with Wet Gas Scrubber

Utility/Infrastructure	Annual Usage		Facility 9 Daily Usage	
Electricity	5,789,000	kWh	15860.27	kWh
Water	16	MMgal	43835.62	gal
Wastewater	8	MMgal	21917.81	gal
Cooling Water	200	MMbtu	0.55	MMbtu
Compressed Air	260	1000 scf	712.33	scf
Solid Waste Disposal	690	tons	1.89	tons
NaOH (50%)	738	tons	2.02	tons
Plot Space needed	1575	sf		
1 Truck Hauling Away Solid Waste[3]	11200	round trip miles	400.00	round trip miles
1 Truck Delivering NaOH[4]	950	round trip miles	50.00	round trip miles
No. of Trucks Hauling Away Solid Waste	28	trucks	1	truck
No. of Trucks Delivering NaOH	19	trucks	1	truck

GRAND TOTALS (during Operation)

Daily Usage		Daily Usage		
20445.12	Kwh	20.45	MWh	Electricity
43835.62	gal	0.043835616	Mmgal	Water
21917.81	gal	0.021917808	Mmgal	Wastewater
0.55	MMbtu			Cooling Water
712.33	scf			Compressed Air
1.89	tons			Solid Waste Disposal
2.02	tons			NaOH (50% by weight)
4263.00	sf			Plot Space needed
4,207	lb	19% Aqueous NH3 usag	547.79	gal
400	Daily round trip miles	1 Truck Hauling Away Solid Waste[5]		
1	daily trucks	No. of Trucks Hauling Away Solid Waste		
1	daily trucks	No. of Trucks Delivering Aqueous NH3		
100	Daily round trip miles	1 Truck Delivering Aqueous NH3[1,2]		
1	daily trucks	No. of Trucks Hauling Spent Catalyst		
100	Daily round trip miles	1 Truck hauling spent catalyst (once every five years)		
1	daily trucks	No. of Trucks Delivering Fresh Catalyst		
100	Daily round trip miles	1 Truck delivering fresh catalyst (once every five years)		
700	Daily round trip miles	Total Daily Truck Miles		
4	Daily trucks	Total No. of Trucks		
16,850	Annual round trip miles	Annual Truck Miles		
94	Annual trucks	Annual Trucks		

Note: This calculation takes into account the electricity needed to make 2.02 tons per day of NaOH to satisfy demand (4,585 kWh/day).

1 SCR for 1 boiler/heater with one 11,000 gal Aqueous NH3 tank

Utility/Infrastructure	Annual Usage for 1 unit		Facility 9 Daily Usage for 1 unit		Annual Usage for 7 units		Facility 9 Daily Usage for 7 units	
Electricity	195,640	kWh	536	kWh	1,369,480	kWh	3,752	kWh
Plot Space needed	384	sf			2,688	sf		
19% Aqueous NH3 usage at 95% control	219,365	lb	601	lb	1,535,555	lb	4,207	lb
19% Aqueous NH3 usage at 95% control	28,563	gal	78.26	gal	199,942	gal	548	gal
No. of Trucks Delivering Aqueous NH3	4	trucks	1	truck	29	trucks	1	truck
1 Truck Delivering Aqueous NH3[1,2]	400	round trip miles	100	round trip miles	2,900	round trip miles	100	round trip miles
No. of Trucks Hauling Spent Catalyst	1	trucks	1	truck	9	trucks	1	truck
1 Truck hauling spent catalyst (once every five years)	100	round trip miles	100	round trip miles	900	round trip miles	100	round trip miles
No. of Trucks Delivering Fresh Catalyst	1	trucks	1	truck	9	trucks	1	truck
1 Truck delivering fresh catalyst (once every five years)	100	round trip miles	100.00	round trip miles	900	round trip miles	100.00	round trip miles

Facility 9 will have future access to recycled water.

[3]Assumes Hauling Solid Waste away in a 25 ton capacity truck. It will take an extra 28 trucks to haul away one year's worth of solid waste, but the peak would be one truck per day.
690 tons/yr solid waste x 1 truck/25 tons = 27.6 trucks/year to haul extra solid waste away for recycling
This facility sends its solid waste to a cement plant outside of the SCAQMD for recycling. A maximum of 200 miles, one-way to the California/Arizona border is assumed.

[4]Assumes that one 10,000 gallon capacity storage tank will be installed for NaOH storage. It will take 19 trucks to deliver one year's worth of NaOH 50% solution, but the peak would be one truck per day.
738 tons/yr NaOH x 2,000 lbs/ ton = 1,476,000 lbs/yr x 1 gal NaOH @ 50%/12.77 lbs = 115,583 gal/year x 1 truck/6,000 gallons = 19.2 trucks/year

Phase III: Operations - On-Road Vehicles and Fuel Use

Phase III: Operation	Peak Daily Round-trip Distance	Annual Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors								
On-Road Equipment T	(miles/day)	(miles/year)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Heavy-Heavy Duty Truck)	700	16,850	4.89	0.00145203	0.00650533	0.01690387	0.00004033	#########	0.00069721	4.20820129	0.00006722

*Assumes 260 days/year

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)
Offsite (Heavy-Heavy Duty Truck)	1.02	4.55	11.83	0.03	0.59	0.49	2945.74	0.05	2,947
SUBTOTAL	1	5	12	0	1	0	2,946	0	2,947
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a
Exceed Significance?	NO	NO	NO	NO	NO	NO	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Offsite Combustion Emissions from Operation Vehicles	CO2 (lb/yr)	CH4 (lb/yr)	CO2e (lb/yr)	CO2e (MT*/year)
Heavy-Heavy Duty Trucks	70908.19	1.13	70,932	32
TOTAL	70,908	1	70,932	32
Significance Threshold	n/a	n/a	n/a	10,000
Exceed Significance?	n/a	n/a	n/a	n/a

*1 metric ton (MT) = 2,205 pounds

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day or year x Round-Trip length (mile/day or year) = Offsite Operation Emissions (lb/day or year)

Incremental Increase in Fuel Usage From Operation (Truck Trips)	Equipment Type	Total Miles Driven in a Peak Day (miles/day)	Total Annual Miles Driven (miles/year)	Mileage Rate (miles/gal)	Total Peak Daily Diesel Fuel Usage (gal/day)*	Total Annual Diesel Fuel Usage (gal/year)
Offsite Delivery/Haul	Heavy Duty Truck	700	16850	4.89	143	3,446
				TOTAL	143	3,446

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2017
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

GHG Emissions - Unmitigated

GHG Activity	Amount	Units	GHG Emissions	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	20.45	MWh/day	Electricity GHGs	3722.77	0.0000	0.0000	3,723
water - increased use[1]	0.04	MMgal/day	Water Conveyance GHGs	58.98	0.0003	0.0006	59
wastewater - increased generation[1]	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.0002	0.0003	30
temporary construction activities[3]	136	MT/year	Construction GHGs in CO2e				136
operational truck trips	32.17	MT/year	Operation GHGs in CO2e				32
						TOTAL CO2e	3,979

GHG Emissions - Mitigated by Using Recycled Water

GHG Activity	Amount	Units	GHG Emissions Source	CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2e (MT/yr)
electricity - increased use	20.45	MWh/day	Electricity GHGs	3722.77	0.0000	0.00	3,723
water - increased use[2]	0.04	MMgal/day	Water Conveyance GHGs	58.98	0.0003	0.00	59
wastewater - increased generation[2]	0.02	MMgal/day	Wastewater Processing GHGs	29.49	0.00	0.00	30
temporary construction activities[3]	135.71	MT/year	Construction GHGs in CO2e				136
operational truck trips	32.17	MT/year	Operation GHGs in CO2e				32
						TOTAL CO2e	3,979

Note: The mitigation calculations assume that 100% of the total water demand for this facility can potentially be supplied by recycled water.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
120,000 lb CO2/MMscf fuel burned
0.64 lb N20/MMscf fuel burned
2.3 lb CH4/MMscf fuel burned
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)
12,700 kWh/MMgallons for electricity use for water conveyance - potable water[1]
1,200 kWh/MMgallons for electricity use for water conveyance - recycled water as mitigation[2]
640 lb CO2/MWh for electricity use due to water conveyance
0.0067 lb CH4/MWh for electricity use due to water conveyance
0.0037 lb N2O/MWh for electricity use due to water conveyance

[1]California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[2]California's Water – Energy Relationship, Table 1-2, Page 9, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005.
http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

[3] GHGs from temporary construction activities are amortized over 30 years.

Refinery ID	Current Solid Waste Hauled away (tons/day)	Solid Waste is trucked to?	Distance to out of state cement plant for recycling (miles, one-way)	Proposed increase in Solid Waste (ton/day)	Increase in Solid Waste will be trucked to?
1	4.66	cement plant or Class III landfill	200	0.68	cement plant
2	175	cement plant	200	0.44	cement plant
4	0.99	n/a	n/a	0.00	n/a
5	1.12	cement plant	200	1.75	cement plant
6	0.41	cement plant	200	0.88	cement plant
7	2.16	n/a	n/a	0.00	n/a
8	not provided	cement plant	200	0.33	cement plant
9	2	cement plant	200	1.89	cement plant
				5.97	

PROPOSED PROJECT: NaOH LOSSES

Facility ID	NaOH Demand (tons/day)	Q = Fill Rate = NaOH Demand (MMgal/day)	S = Saturation Factor	P = Vapor Pressure of material Loaded (psia)	M = NaOH vapor molecular weight (lb/lbmole)	T= temperature of liquid loaded (°R)	Daily PM10 Filling Loss (lb/day)	$E_{loading}$ = Hourly PM10 Filling Loss (lb/hr)	$E_{working}$ = Hourly PM10 Working Loss (lb/hr)	Total Hourly PM10 Loss (lb/hr)	Acute Screening Level - 25 meters (lb/hr)	Does Hourly Filling Loss Exceed Acute Screening Level? (Yes/No)	Significant ?	Electricity Needed to Produce NaOH* (kWh/day)
2	3.37	0.53	1.45	0.0420	24.8	544.67	1.82E-02	7.60E-04	2.28E-03	3.04E-03	4.00E-03	NO	NO	7631
4	0.45	0.07	1.45	0.0420	24.8	544.67	2.44E-03	1.01E-04	3.04E-04	4.06E-04	4.00E-03	NO	NO	1019
9	2.02	0.32	1.45	0.0420	24.8	544.67	1.10E-02	4.57E-04	1.37E-03	1.83E-03	4.00E-03	NO	NO	4585
TOTAL	**5.84**	**0.92**					**0.03**							**13,235**

NaOH @ 50% solution density = 12.747 lb/gal
Mv for NaOH solution = 24.8 lb/lbmol
Vapor Pressure for NaOH = 2.18 mmHg at 29.4oC or 85oF = 0.042 psia
Loading Temperature = 85oF to 100oF (544.67oR to 559.67oR)
Breathing Loss = 3 * Filling Loss

Filling Loss:

$$E_{Loading}, lb/day = (12.46)\frac{(S)(P)(M)(Q)}{T}$$ where:

S = saturation factor (dimensionless; obtained from Table 5.2-1 in AP-42)
= 1.45 (Splash loading: dedicated normal service)
P = vapor pressure of the material loaded at temperature T (psia)
M = vapor molecular weight (lb/lb-mole)
Q = volume of material loaded (1,000 gal/day)
T = temperature of liquid loaded (°R).

*It takes approximately 2,500 kWh to produce one metric ton of NaOH.
Thus, approximately 22,444 kWh per day of additional electricity may be needed to produce additional NaOH to meet the needs of the proposed project, calculated as follows:

$$\frac{9.9 \text{ tons NaOH}}{\text{Day}} \times \frac{2{,}000 \text{ lbs}}{\text{ton}} \times \frac{1 \text{ metric ton}}{2{,}205 \text{ lbs}} \times \frac{2{,}500 \text{ kWh}}{1 \text{ metric ton of NaOH produced}} = 22{,}444 \text{ kWh/day}$$

Refinery Operation Activities for 1 SCR

Facility Type	No. of SCR	Operation Activity
Affected Facilities with SCR Retrofits	1	Operation/Maintenance of SCR + One Ammonia Tank

Operation Schedule 365 days/yr - 24 hours/day
Catalyst Replacement Schedule: Approximately once every 5 years
Ammonia Delivery Schedule: Two truck deliveries (at 7,000 gallons per truck) per week would be needed to fill one storage tank.

Activity	**No. of Facilities receiving deliveries on a peak day**	**Days of Deliveries**	**Crew Size per delivery**
Supply Deliveries	1	1.00	1

Operation		**Number**	**Round-trip Distance**	**Mileage Rate**	**2016 Mobile Source Emission Factors**							
On-Road Equipment Type	**Fuel**	**Needed**	**(miles/day)**	**(miles/ gallon)**	**VOC (lb/mile)**	**CO (lb/mile)**	**NOx (lb/mile)**	**SOx (lb/mile)**	**PM10 (lb/mile)**	**PM2.5 (lb/mile)**	**CO2 (lb/mile)**	**CH4 (lb/mile)**
Truck Delivery of Spent Catalyst Modules	diesel	1	100	8.9	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722
Truck Delivery of Fresh Catalyst	diesel	1	100	8.9	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722
Truck Delivery of Aqueous Ammonia	diesel	1	100	8.9	0.00145203	0.00650533	0.01690387	0.00004033	0.00084894	0.00069721	4.20820129	0.00006722

Incremental Increase in Combustion Emissions from On-Road Vehicles	**VOC (lb/day)**	**CO (lb/day)**	**NOx (lb/day)**	**SOx (lb/day)**	**PM10 (lb/day)**	**PM2.5 (lb/day)**	**CO2 (lb/day)**	**CH4 (lb/day)**	**CO2eq* (lb/day)**	**CO2eq* (MT/ project)**
Truck Delivery of Spent Catalyst Modules	0.15	0.65	1.69	0.00	0.08	0.07	420.82	0.01	420.96	0.1909
Truck Delivery of Fresh Catalyst	0.15	0.65	1.69	0.0040	0.0849	0.0697	420.82	0.01	420.96	0.1909
Truck Delivery of Aqueous Ammonia	0.15	0.65	1.69	0.0040	0.0849	0.0697	420.82	0.01	420.96	0.1909
SUBTOTAL	**0.44**	**1.95**	**5.07**	**0.01**	**0.25**	**0.21**	**1262.46**	**0.02**	**1262.88**	**0.57**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Emissions (lb/day)
*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21
*1 metric ton (MT) = 2,205 pounds

Emissions Summary	**VOC (lb/day)**	**CO (lb/day)**	**NOx (lb/day)**	**SOx (lb/day)**	**PM10 (lb/day)**	**PM2.5 (lb/day)**	**CO2 (lb/day)**	**CH4 (lb/day)**	**CO2eq (lb/day)**	**CO2eq* (MT/ project)**
Emissions from On-Road Vehicles	0.15	0.65	1.69	0.00	0.0849	0.0697	420.82	0.01	420.96	0.1909
TOTAL for 1 Facility	**0**	**1**	**2**	**0**	**0**	**0**	**421**	**0**	**421**	**0**
Significance Threshold	55	550	55	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Fuel Usage Delivery Activities	Equipment Type	Total Peak Daily Diesel Fuel Usage (gal/day)	Total Peak Annual Diesel Fuel Usage (gal/yr)	
Truck Delivery of Spent Catalyst Modules	Heavy Duty Truck	11.24	11.24	This activity would occur once every 5 Years
Truck Delivery of Fresh Catalyst	Heavy Duty Truck	11.24	11.24	This activity would occur once every 5 Years
Truck Delivery of Aqueous Ammonia	Heavy Duty Truck	11.24	1168.54	
TOTAL for 1 Facility		**33.71**	**1,191.01**	

Source:
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

Install 1 SCR for 1 refinery boiler/process heater or refinery gas turbine

Activity	Days/ wk	Hrs/day	Wks/ month	Days/ month	Months	Total Days	Crew Size
Construction	5	8	4.33	21.67	6	130.00	20
				Total	6	**130.00**	

Construction	Max Equipment Rating	Number	Operating Schedule	Usage Factor	2015 Mobile Source Emission Factors							
Off-Road Equipment Type	**hp**	**Needed**	**(hr/day)**		**VOC (lb/hr)**	**CO (lb/hr)**	**NOx (lb/hr)**	**SOx (lb/hr)**	**PM10 (lb/hr)**	**PM2.5 (lb/hr)**	**CO2 (lb/hr)**	**CH4 (lb/hr)**
Rough Terrain Crane (28 ton)	120	1	8	1	0.0800	0.3559	0.4822	0.0006	0.0415	0.0382	50.1	0.0072
Welding Machines	Composite	2	8	1	0.0534	0.1994	0.2301	0.0003	0.0187	0.0172	25.6	0.0048
Air Compressor	Composite	1	1	1	0.0773	0.3257	0.5175	0.0007	0.0357	0.0329	63.6	0.0070
Backhoe	Composite	1	4	1	0.0666	0.3716	0.4501	0.0008	0.0298	0.0274	66.8	0.0060
Plate Compactor	Composite	1	4	1	0.0050	0.0263	0.0314	0.0001	0.0012	0.0011	4.3	0.0005
Forklift	Composite	1	3	1	0.0459	0.2200	0.3163	0.0006	0.0156	0.0143	54.4	0.0041
Concrete Pump	Composite	1	2	1	0.0621	0.2825	0.4121	0.0006	0.0267	0.0245	49.6	0.0056
Concrete Saw	Composite	1	2	1	0.0835	0.3982	0.4921	0.0007	0.0374	0.0345	58.5	0.0075
Generator	Composite	1	8	1	0.0640	0.2913	0.4717	0.0007	0.0268	0.0246	61.0	0.0058
Aerial Lift (Man lift)	Composite	1	2	1	0.0439	0.1837	0.2670	0.0004	0.0167	0.0154	34.7	0.0040

Incremental Increase in Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Rough Terrain Crane (28 ton)	0.64	2.85	3.86	0.00	0.33	0.31	401.18	0.06	402.40	0.79
Welding Machines	0.85	3.19	3.68	0.01	0.30	0.27	409.64	0.08	411.26	0.81
Air Compressor	0.08	0.33	0.52	0.00	0.04	0.03	63.61	0.01	63.75	0.13
Backhoe	0.27	1.49	1.80	0.00	0.12	0.11	267.20	0.02	267.70	0.53
Plate Compactor	0.02	0.11	0.13	0.00	0.00	0.00	17.26	0.00	17.29	0.03
Forklift	0.14	0.66	0.95	0.00	0.05	0.04	163.19	0.01	163.45	0.32
Concrete Pump	0.12	0.56	0.82	0.00	0.05	0.05	99.21	0.01	99.45	0.20
Concrete Saw	0.17	0.80	0.98	0.00	0.07	0.07	116.93	0.02	117.24	0.23
Generator	0.51	2.33	3.77	0.01	0.21	0.20	487.94	0.05	488.91	0.96
Aerial Lift (Man lift)	0.09	0.37	0.53	0.00	0.03	0.03	69.44	0.01	69.61	0.14
SUBTOTAL	**3**	**13**	**17**	**0**	**1**	**1**	**2,096**	**0**	**2,101**	**4**

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21
*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

Construction		Number	Round- trip Distance	Mileage Rate	2015 Mobile Source Emission Factors							
On-Road Equipment Type	**Fuel**	**Needed**	**(miles/day)**	**(miles/ gallon)**	**VOC (lb/mile)**	**CO (lb/mile)**	**NOx (lb/mile)**	**SOx (lb/mile)**	**PM10 (lb/mile)**	**PM2.5 (lb/mile)**	**CO2 (lb/mile)**	**CH4 (lb/mile)**
Offsite (Construction Worker Vehicle)	gasoline	20	50	20	0.00066	0.00614	0.00060	0.00001	0.00009	0.00006	1.10193	0.00006
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	1	100	8.9	0.00179	0.00767	0.02123	0.00004	0.00105	0.00088	4.20902	0.00008
Offsite (Delivery Truck - Medium Duty)	diesel	1	100	12.2	0.00174	0.01169	0.01285	0.00003	0.00050	0.00041	2.81248	0.00008
Onsite (Pickup Truck)	gasoline	5	4	20	0.00066	0.00614	0.00060	0.00001	0.00009	0.00006	1.10193	0.00006
Onsite (Watering Truck)	diesel	3	4	8.9	0.00174	0.01169	0.01285	0.00003	0.00050	0.00041	2.81248	0.00008

Incremental Increase in Combustion Emissions from On-Road Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Offsite (Construction Worker Vehicle)	0.66	6.14	0.60	0.01	0.09	0.06	1101.93	0.06	1103.17	2.17
Offsite (Flatbed Truck - Heavy-Heavy Duty)	0.18	0.77	2.12	0.00	0.10	0.09	420.90	0.01	421.08	0.83
Offsite (Delivery Truck - Medium Duty)	0.17	1.17	1.29	0.00	0.05	0.04	281.25	0.01	281.42	0.55
Onsite (Pickup Truck)	0.01	0.12	0.01	0.00	0.00	0.00	22.04	0.00	22.06	0.04
Onsite (Watering Truck)	0.02	0.14	0.15	0.00	0.01	0.00	33.75	0.00	33.77	0.07
SUBTOTAL	**1**	**8**	**4**	**0**	**0**	**0**	**1,826**	**0**	**1,828**	**4**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Combustion Emissions from Construction Equipment	2.89	12.67	17.05	0.02	1.21	1.12	2095.60	0.26	2101.07	4.13
Combustion Emissions from On-Road Construction Vehicles	1.03	8.20	4.02	0.02	0.25	0.19	1826.12	0.08	1827.73	3.59
TOTAL for 1 SCR	**4**	**21**	**21**	**0**	**1**	**1**	**3,922**	**0**	**3,929**	**8**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

TOTAL for 2 SCRs Overlapping Construction	**8**	**42**	**42**	**0**	**3**	**3**	**7,843**	**1**	**7,858**	**15**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

TOTAL for 8 Facilities Overlapping Construction by Installing 2 SCRs each	**63**	**334**	**337**	**1**	**23**	**21**	**62,747**	**5**	**62,861**	**124**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds; construction GHGs are amortized over 30 years

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Construction Hours for Project	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/project)
Operation of Portable Equipment	1,040	Rough Terrain Crane (2	5.51	44.08	5,730.40	N/A	N/A
Operation of Portable Equipment	2,080	Welding Machines	10.02	160.32	20,841.60	N/A	N/A
Operation of Portable Equipment	130	Air Compressor	5.06	5.06	657.80	N/A	N/A
Operation of Portable Equipment	520	Backhoe	13.52	54.08	7,030.40	N/A	N/A
Operation of Portable Equipment	520	Plate Compactor	2.17	8.68	1128.40	N/A	N/A
Operation of Portable Equipment	390	Forklift	10.02	30.06	3907.80	N/A	N/A
Operation of Portable Equipment	260	Concrete Pump	3.25	6.50	845.00	N/A	N/A
Operation of Portable Equipment	260	Concrete Saw	1.75	3.50	455.00	N/A	N/A
Operation of Portable Equipment	1,040	Generator	5.06	40.48	5,262.40	N/A	N/A
Operation of Portable Equipment	260	Aerial Lift (Man lift)	1.75	3.50	455.00	N/A	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	N/A	50.00	6,500.00
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	11.24	1,460.67	11.24	1,460.67
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	8.20	1,065.57	8.20	1,065.57
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	N/A	1.00	130.00
Workers' Vehicles - Onsite	N/A	Watering Truck	N/A	N/A	N/A	1.35	175.28
TOTAL for 1 SCR				**376**	**48,840**	**72**	**9,332**
TOTAL for 2 SCRs Overlapping Construction				**751**	**97,680**	**144**	**18,663**
TOTAL for 8 Facilities Overlapping Construction by Installing @ SCRs each				**6,011**	**781,441**	**1,148**	**149,304**

Sources:

1. Off-Road Mobile Emission Factors, Scenario Year 2015
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/off-road-mobile-source-emission-factors
2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions
http://www.aqmd.gov/docs/default-source/ceqa/handbook/localized-significance-thresholds/particulate-matter-(pm)-2.5-significance-thresholds-and-calculation-methodology/final_pm2_5methodology.pdf?sfvrsn=2
3. On-Road Mobile Emission Factors (EMFAC 2007 v2.3), Scenario Year 2015
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

Install 1 SCR for 1 FCCU

Activity	Days/ wk	Hrs/day	Wks/ month	Days/ month	Months	Total Days	Crew Size
Construction	5	8	4.33	21.67	12	260.00	140
				Total	12	260.00	

Construction	Max Equipment Rating	Number	Operating Schedule	Usage Factor	2016 Mobile Source Emission Factors							
Off-Road Equipment Type	hp	Needed	(hr/day)		VOC (lb/hr)	CO (lb/hr)	NOx (lb/hr)	SOx (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	CO2 (lb/hr)	CH4 (lb/hr)
Crane	Composite	1	8	1	0.1073	0.4152	0.8625	0.0014	0.0352	0.0324	129	0.0097
Rough Terrain Crane (28 ton)	120	1	8	1	0.0690	0.3509	0.4155	0.0006	0.0341	0.0314	50.1	0.0062
Welding Machines	Composite	5	8	1	0.0434	0.1912	0.2054	0.0003	0.0150	0.0138	25.6	0.0039
Air Compressor	Composite	1	8	1	0.0641	0.3165	0.4318	0.0007	0.0282	0.0259	63.6	0.0058
Backhoe	Composite	1	8	1	0.0559	0.3666	0.3681	0.0008	0.0222	0.0204	66.8	0.0050
Plate Compactor	Composite	1	2	1	0.0050	0.0263	0.0314	0.0001	0.0012	0.0011	4.3	0.0005
Forklift	Composite	1	6	1	0.0399	0.2181	0.2493	0.0006	0.0119	0.0109	54.4	0.0036
Concrete Pump	Composite	1	2	1	0.0087	0.0417	0.0539	0.0001	0.0022	0.0021	7.2	0.0008
Concrete Saw	Composite	1	2	1	0.0679	0.3892	0.4267	0.0007	0.0298	0.0274	58.5	0.0061
Generator	Composite	2	8	1	0.0527	0.2821	0.4052	0.0007	0.0216	0.0198	61.0	0.0048
Aerial Lift (Man lift)	Composite	2	2	1	0.0358	0.1768	0.2310	0.0004	0.0134	0.0123	34.7	0.0032

Incremental Increase in Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Crane (140 ton)	0.86	3.32	6.90	0.01	0.28	0.26	1029.02	0.08	1030.65	4.05
Rough Terrain Crane (28 ton)	0.55	2.81	3.32	0.00	0.27	0.25	401.18	0.05	402.23	1.58
Welding Machines	1.73	7.65	8.22	0.01	0.60	0.55	1024.11	0.16	1027.39	4.04
Air Compressor	0.51	2.53	3.45	0.01	0.23	0.21	508.86	0.05	509.83	2.00
Backhoe	0.45	2.93	2.94	0.01	0.18	0.16	534.38	0.04	535.22	2.10
Plate Compactor	0.01	0.05	0.06	0.00	0.00	0.00	8.63	0.00	8.65	0.03
Forklift	0.24	1.31	1.50	0.00	0.07	0.07	326.37	0.02	326.83	1.28
Concrete Pump	0.02	0.08	0.11	0.00	0.00	0.00	14.50	0.00	14.53	0.06
Concrete Saw	0.14	0.78	0.85	0.00	0.06	0.05	116.93	0.01	117.18	0.46
Generator	0.84	4.51	6.48	0.01	0.34	0.32	975.88	0.08	977.48	3.84
Aerial Lift (Man lift)	0.14	0.71	0.92	0.00	0.05	0.05	138.89	0.01	139.16	0.55
SUBTOTAL	**5**	**27**	**35**	**0**	**2**	**2**	**5,079**	**0**	**5,089**	**20**

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21
1 metric ton (MT) = 2,205 pounds
Construction GHGs are amortized over 30 years

Construction		Number	Round- trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	Fuel	Needed	(miles/day)	(miles/ gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Construction Worker Vehicle)	gasoline	140	50	20	0.0006	0.0054	0.0005	0.0000	0.0001	0.0001	1.1063	0.0001
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	1	100	8.9	0.0015	0.0065	0.0169	0.0000	0.0008	0.0007	4.2082	0.0001

Offsite (Delivery Truck - Medium Duty)	diesel	1	100	12.2	0.0015	0.0100	0.0107	0.0000	0.0004	0.0003	2.8401	0.0001
Onsite (Pickup Truck)	gasoline	5	4	20	0.0006	0.0054	0.0005	0.0000	0.0001	0.0001	1.1063	0.0001
Onsite (Watering Truck)	diesel	3	4	12.2	0.0015	0.0100	0.0107	0.0000	0.0004	0.0003	2.8401	0.0001

Incremental Increase in Combustion Emissions from On-Road Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Offsite (Construction Worker Vehicle)	4.21	37.65	3.59	0.08	0.66	0.43	7743.92	0.37	7751.72	30.47
Offsite (Flatbed Truck - Heavy-Heavy Duty)	0.15	0.65	1.69	0.00	0.08	0.07	420.82	0.01	420.96	1.65
Offsite (Delivery Truck - Medium Duty)	0.15	1.00	1.07	0.00	0.04	0.03	284.01	0.01	284.14	1.12
Onsite (Pickup Truck)	0.01	0.11	0.01	0.00	0.00	0.00	22.13	0.00	22.15	0.09
Onsite (Watering Truck)	0.02	0.12	0.13	0.00	0.01	0.00	34.08	0.00	34.10	0.13
SUBTOTAL	**5**	**40**	**6**	**0**	**1**	**1**	**8,505**	**0**	**8,513**	**33**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

Construction GHGs are amortized over 30 years

Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Combustion Emissions from Construction Equipment	5.49	26.69	34.77	0.06	2.10	1.93	5078.75	0.50	5089.16	20.00
Combustion Emissions from On-Road Construction Vehicles	4.53	39.53	6.49	0.08	0.80	0.54	8504.96	0.39	8513.07	33.46
TOTAL for 1 SCR	**10**	**66**	**41**	**0**	**3**	**2**	**13,584**	**1**	**13,602**	**53**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Constructio n Hours for Project	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/project)
Operation of Portable Equipment	2,080	Crane	1.75	14.00	3,640.00	N/A	N/A
Operation of Portable Equipment	2,080	Rough Terrain Crane (28 to	5.51	44.08	11,460.80	N/A	N/A
Operation of Portable Equipment	10,400	Welding Machines	10.02	400.80	104,208.00	N/A	N/A
Operation of Portable Equipment	2,080	Air Compressor	5.06	40.48	10,524.80	N/A	N/A
Operation of Portable Equipment	2,080	Backhoe	13.52	108.16	28,121.60	N/A	N/A
Operation of Portable Equipment	520	Plate Compactor	2.17	4.34	1128.40	N/A	N/A
Operation of Portable Equipment	1,560	Forklift	10.02	60.12	15631.20	N/A	N/A
Operation of Portable Equipment	520	Concrete Pump	3.25	6.50	1690.00	N/A	N/A
Operation of Portable Equipment	520	Concrete Saw	1.75	3.50	910.00	N/A	N/A
Operation of Portable Equipment	4,160	Generator	5.06	80.96	21,049.60	N/A	N/A
Operation of Portable Equipment	1,040	Aerial Lift (Man lift)	1.75	7.00	1820.00	N/A	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	N/A	350.00	91,000.00
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	11.24	2,921.35	11.24	2,921.35
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	8.20	2,131.15	8.20	2,131.15
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	N/A	1.00	260.00

Workers' Vehicles - Onsite	N/A	Watering Truck	N/A	N/A	N/A	0.98	255.74
TOTAL for 1 SCR				**789**	**205,237**	**371**	**96,568**
TOTAL for 2 SCR Overlapping Construction				**1,579**	**410,474**	**743**	**193,136**
TOTAL for 5 SCR Overlapping Construction in 2017				**3,947**	**1,026,184**	**1,857**	**482,841**

Sources:

1. Off-Road Mobile Emission Factors, Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/off-road-mobile-source-emission-factors
2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions
http://www.aqmd.gov/docs/default-source/ceqa/handbook/localized-significance-thresholds/particulate-matter-(pm)-2.5-significance-thresholds-and-calculation-methodology/final_pm2_5methodology.pdf?sfvrsn=2
3. On-Road Mobile Emission Factors (EMFAC 2007 v2.3), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

Fugitive PM10 Emissions Associated with Installing One Ammonia Tank for One SCR Retrofit (due to building containment berm)

1. GRADING ACTIVITIES (Backhoe)			
G = Fugitive PM10 Emission Rate (lbs/day) = 0.75 x T x 1.0 x $(S)^{1.5}$ x $(M)^{-1.4}$			*Source: AP-42, 10/98, Table 11.9-1 (PM10 Equation for Overburden Bulldozing)*
S = Silt Content	7.5	%	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
M = Moisture Content	2	%	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
T = max hours of operation/day	8	hr/day	
G = Fugitive PM10 =	**46.70**	**lbs/day**	

2. TRENCHING/STOCKPILE LOADING (Backhoe)			
LPM10 = Emission Factor per particle size (lbs/ton) = kPM10 x (0.0032) x $(U/5)^{1.3}$ x $(M/2)^{-1.4}$			*Source: AP-42, 01/95, p. 13.2.4-3 (Equation 1 for English Units)*
U = Mean Wind Speed	12	mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (See Mine I)*
M = Material Moisture Content	2	%	*Source: AP-42, 10/98, Table 11.9-3 (Overburden Bulldozing)*
kPM10 = Particle Size Multiplier for PM10	0.35	dimensionless	*Source: AP-42, 01/95, p. 13.2.4-3*
G = Maximum Daily Weight of Material Moved	10	tons/day	Note: One backhoe can trench approximately 0.1 acre per day or 4,356 square feet per day, with a cut of 3 feet in depth, 13,068 cubic feet = 484 cubic yards and 1 cubic yard = 1 ton soil.
Tday, t = Truck Operating time, maximum	8	hr/day	
LPM10 = Emission Factor per particle size =	0.0035	lbs PM10/ton soil moved	
PPM10 = Emission Rate based on particle size = (LPMx G) =	**0.03**	**lbs PM10/day**	

3. STOCKPILE WIND EROSION			
Q = Wind Erosion Emission Rate based on particle size (lbs/day) = kPM10* 0.72 x U x Tc * (A x B /43,560 sq. ft/acre)			*Source: AP-42, 10/98, Table 11.9-1 (Emission Factor Equation for Active Storage Pile)*
A = Length of Stockpile	15	ft	
B = Width of Stockpile	15	ft	
U = Mean Wind Speed	12	mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (General Characteristics of Surface Coal Mines - Mine I)*
kPM10 = Particle Size Multiplier for PM10	0.5	dimensionless	*Source: AP-42, 01/95, p. 13.2.5-3 (PM10 Aerodynamic Particle Size Multiplier (k) for Equation 2)*
Tc = Time Piles Remain Uncovered	24	hr/day	Note: This calculation assumes that the piles remain uncovered for 24 hours/day.
QPM10 =	**0.54**	**lbs PM10/day**	

4. TRUCK FILLING/DUMPING		
TF = Fugitive PM10 Emissions From Truck Filling = G (ton/day) x TF, PM10 (lb/ton)		
TD = Fugitive PM10 Emissions From Truck Dumping = G (ton/day) x TD, PM10 (lb/ton)		
TFPM10 = Emission Factor for Truck Filling =	0.0221	lb/ton of material moved
TDPM10 = Emission Factor for Truck Dumping =	0.0091	lb/ton of material moved
G = Maximum Daily Weight of Material Trucked Away	1	ton/day
TF =	**0.02**	**lbs PM10/day**
TD =	**0.01**	**lbs PM10/day**

FUGITIVE PM10 EMISSIONS SUMMARY		
Activity	**Unmitigated PM10 (lbs/day)**	**Mitigated PM10 [1] (lbs/day)**
1. Grading	46.70	23.35
2. Trenching/Stockpile Loading	0.03	0.02
3. Storage Piles - Wind Erosion	0.54	0.27
4. Truck Filling/Dumping	0.03	0.02
TOTAL FOR 1 NH3 TANK BERM + 1 SCR	**47.30**	**23.65**
TOTAL FOR 2 NH3 TANK BERMS + 2 SCRS	**94.60**	**47.30**
TOTAL FOR 5 NH3 TANK BERMS + 5 SCRS	**236.50**	**118.25**

[1] Water two times per day per SCAQMD Rule 403 (50% control efficiency)

Refinery

Peak Operational Truck Trips per year at one facility (Refinery 6) = 147

EF, g/hr	Annual No of Trips	Idling, h/y	Emisions, lb/yr	Emisions, ton/yr
1.67	147	36.75	0.14	6.78E-05

Heavy-duty idling rates from emfac2011_idling_emission_rates.xlsx (http://www.arb.ca.gov/msei/emfac2011_idling_emission_rates.xlsx).

Emisions, ton/yr	Cancer Potency Factor, (mg/kg-d)-1	X/Q at 25 m, (ug/m3)/(ton/yr)	CEF	MP	MWHF	Carcinogenic Health Risk	Screening Level	Significant?
6.78E-05	1.1	29.64	676.63	1	1	1.50E-06	1.00E-05	NO

Carcinogenic health risk = emissions, ton/yr x cancer potency, (mg/kg-day)-1 x X/Q, (ug/m3)/(ton/yr) x CEF x MP x MWHF

Offsite Consequence Input Data for NH3 spill of one 11,000 gallon storage tank at a refinery facility

Refinery

Ammonia Storage, gal	Berm Capacity, gal	Ammonia Berm, ft3	Height of Berm, ft	Area, ft2
11,000	12,100	1,618	3.0	539

Berms must be able to contain 110% the volume of the tank
Typical berm heights are three feet tall.

RMP*Comp

RMP*Comp

Back

Estimated Distance Calculation

Estimated distance to toxic endpoint: 0.1 miles (0.2 kilometers)

This is the downwind distance to the toxic endpoint specified for this regulated substance under the RMP Rule. Report all distances shorter than 0.1 mile as 0.1 mile, and all distances longer than 25 miles as 25 miles.

Scenario Summary

Chemical: Ammonia (water solution)

Initial concentration: 20 %

CAS number: 7664-41-7

Threat type: Toxic Liquid

Scenario type: Worst-case

Liquid temperature: 25 C

Quantity released: 12100 gallons

Mitigation measures:

Diked area: 539 square feet

Dike height: 3 feet

Release rate to outside air: 11.7 pounds per minute

Surrounding terrain type: Urban surroundings (many obstacles in the immediate area)

Toxic endpoint: 0.14 mg/L; basis: ERPG-2

Assumptions about this scenario

Wind speed: 1.5 meters/second (3.4 miles/hour)

Stability class: F

Air temperature: 77 degrees F (25 degrees C)

Ammonia Slip Conc at the Exit of the Stack, ppm	Dispersion Factor	Molecular Weight, g/mol	Peak Conc at a Receptor 25 m from the Stack, ug/m3	Acute REL, ug/m3	Chronic REL, ug/m3	Acute Hazard Index	Chronic Hazard Index
5	0.01	17.03	35	3,200	200	0.01	0.17

Ammonia slip is limited to five ppm by permitting.
Conc., ug/m3 = (conc., ppm x 1,000 x molecular weight, g/mol)/24.5 m3/kmol

Based on the Staff Report for Toxic Air Contaminants 1401.1 – Requirements for New and Relocated Facilities Near Schools, and 1402 – Control of Toxic Air Contaminants from Existing Source, June 2015 the concentration at a receptor 25 m from a stack would be much less than one percent of the concentration at the release from the exist of the stack.

Hazard index = conc. at receptor 25 m from stack, ug/m3/REL, ug/m3

Activity **No. of Scrubbers**

Phase I: Demolition **1** **Preparation to Install WGS or DGS**

Activity	Days/ wk	Wks/ month	Days/ month	Months	Total Days	Crew Size
Demolition	5	4.33	21.67	1	21.67	50
Construction	5	4.33	21.67	17	368.33	175
			Total	**18**	**390**	

Phase I: Demolition		Rating	Number	Operation Schedule	2016 Off-Road Emission Factors							
Off-Road Equipment Type	**Fuel**	**(hp)**	**Needed**	**(hr/day)**	**VOC (lb/hr)**	**CO (lb/hr)**	**NOx (lb/hr)**	**SOx (lb/hr)**	**PM10 (lb/hr)**	**PM2.5 (lb/hr)**	**CO2 (lb/hr)**	**CH4 (lb/hr)**
crane	diesel	comp	1	8	0.097200	0.331700	0.278900	0.000240	0.027900	0.025600	25.348000	0.007650
front end loader	diesel	comp.	1	8	0.042600	0.301600	0.406900	0.000390	0.031300	0.028800	40.459700	0.012200
forklift	diesel	comp.	1	8	0.057200	0.318300	0.492300	0.000380	0.041200	0.037900	40.003700	0.012100
concrete saw	diesel	comp.	1	8	0.080800	0.471900	0.577800	0.000780	0.043400	0.043400	74.083200	0.007170
jack hammer	diesel	comp.	1	8	0.061400	0.314000	0.395400	0.000500	0.032800	0.032800	46.908000	0.005530

Phase I: Demolition		Number	Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	**Fuel**	**Needed**	**miles/day**	**(miles/ gallon)**	**VOC (lb/mile)**	**CO (lb/mile)**	**NOx (lb/mile)**	**SOx (lb/mile)**	**PM10 (lb/mile)**	**PM2.5 (lb/mile)**	**CO2 (lb/mile)**	**CH4 (lb/mile)**
Offsite (Construction Worker Vehicle)	gasoline	50	30	20	0.002910	0.01100	0.000880	0.000010	0.000780	0.000220	1.030600	0.000070
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	3	50	4.89	0.007800	0.14800	0.033200	0.000060	0.001170	0.000500	5.440400	0.000080
Offsite (Delivery Truck - Medium Duty)	diesel	5	50	6	0.006570	0.10040	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060
Onsite (Pickup Truck)	gasoline	1	10	20	0.006570	0.10040	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060
Onsite (Watering Truck - Medium Duty)	diesel	1	10	6	0.006570	0.10040	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060

Incremental Increase in Onsite Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)
crane	0.78	2.65	2.23	0.00	0.22	0.20	202.78	0.06
front end loader	0.34	2.41	3.26	0.00	0.25	0.23	323.68	0.10
forklift	0.46	2.55	3.94	0.00	0.33	0.30	320.03	0.10
concrete saw	0.65	3.78	4.62	0.01	0.35	0.35	592.67	0.06
jack hammer	0.49	2.51	3.16	0.00	0.26	0.26	375.26	0.04
SUBTOTAL	**2.71**	**13.90**	**17.21**	**0.02**	**1.41**	**1.35**	**1814.42**	**0.36**

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lbs/day)

Worksheet B-1
Phase I: Demolition

Incremental Increase in Offsite Combustion Emissions from Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)
Offsite (Construction Worker Vehicle)	4.37	16.50	1.32	0.02	1.17	0.33	1545.90	0.11
Offsite (Flatbed Truck - Heavy-Heavy Duty)	1.17	22.20	4.98	0.01	0.18	0.08	816.06	0.01
Offsite (Delivery Truck - Heavy Duty)	1.64	25.10	7.38	0.01	0.30	0.13	1172.00	0.02
Onsite (Pickup Truck)	0.07	1.00	0.30	0.00	0.01	0.01	46.88	0.00
Onsite (Watering Truck - Medium Duty)	0.07	1.00	0.30	0.00	0.01	0.01	46.88	0.00
SUBTOTAL	**7.31**	**65.81**	**14.27**	**0.04**	**1.67**	**0.55**	**3627.72**	**0.13**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

Total Incremental Combustion Emissions from Construction Activities	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)	CO2e (MT*)
Phase I: Demolition TOTAL	**10**	**80**	**31**	**0.06**	**3**	**2**	**5442**	**0**	**5452**	**2**
Significant Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds; GHGs from temporary construction activities are amortized over 30 years.

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Demolition Hours	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/phase I)	Total Gasoline Fuel Usage (gal/phase I)
Operation of Portable Equipment	173	crane	3.9	31.20	N/A	676.00	N/A
Operation of Portable Equipment	173	front end loader	2.1	16.80	N/A	364.00	N/A
Operation of Portable Equipment	173	Forklift	1.1	8.80	N/A	190.67	N/A
Operation of Portable Equipment	173	Concrete Saw	1.5	12.00	N/A	260.00	N/A
Operation of Portable Equipment	173	jack hammer	1.5	12.00	N/A	260.00	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	75.00	N/A	1625.00
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	30.67	N/A	664.62	N/A
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	41.67	N/A	902.78	N/A
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	0.50	N/A	10.83
Workers' Vehicles - Onsite Hauling	N/A	Watering Truck	N/A	1.67	N/A	36.11	N/A
			TOTAL	**155**	**76**	**3,354**	**1,636**

Sources:
1. Off-Road Mobile Emission Factors, Scenario Year 2016
EF from Burden in EMFAC2011
2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html/finalAppA.doc
On-Road Mobile Emission Factors (EMFAC 2011), Scenario Year 2016
http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook/emfac-2007-(v2-3)-emission-factors-(on-road)

Worksheet B-3

Phase II: Fugitive Dust

Fugitive PM10 Emissions Associated with foundation work for WGS or DGS Installation

1. GRADING ACTIVITIES (Backhoe)		
G = Fugitive PM10 Emission Rate (lbs/day) = 0.75 x T x 1.0 x $(S)^{1.5}$ x $(M)^{-1.4}$		*Source: AP-42, 10/98, Table 11.9-1 (PM10 Equation for Overburden Bulldozing)*
S = Silt Content	7.5 %	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
M = Moisture Content	2 %	*Source: AP-42, 10/98, Table 11.9-3 (Correction Factors for Overburden Bulldozing)*
T = max hours of operation/day	8 hr/day	
G = Fugitive PM10 =	**46.70 lbs/day**	

2. TRENCHING/STOCKPILE LOADING (Backhoe)		
LPM10 = Emission Factor per particle size (lbs/ton) = kPM10 x (0.0032) x $(U/5)^{1.3}$ x $(M/2)^{-1.4}$		*Source: AP-42, 01/95, p. 13.2.4-3 (Equation 1 for English Units)*
U = Mean Wind Speed	12 mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (See Mine I)*
M = Material Moisture Content	2 %	*Source: AP-42, 10/98, Table 11.9-3 (Overburden Bulldozing)*
kPM10 = Particle Size Multiplier for PM10	0.35 dimensionless	*Source: AP-42, 01/95, p. 13.2.4-3*
G = Maximum Daily Weight of Material Moved	1 tons/day	Note: One backhoe can trench approximately 0.1 acre per day or 4,356 square feet per day, with a cut of 3 feet in depth, 13,068 cubic feet = 484 cubic yards and 1 cubic yard = 1 ton soil.
Tday, t = Truck Operating time, maximum	5 hr/day	
LPM10 = Emission Factor per particle size =	0.0035 lbs PM10/ton soil moved	
PPM10 = Emission Rate based on particle size = (LPMx G) =	**0.0035 lbs PM10/day**	

3. STOCKPILE WIND EROSION		
Q = Wind Erosion Emission Rate based on particle size (lbs/day) = kPM10* 0.72 x U x Tc * (A x B /43,560 sq. ft/acre)		*Source: AP-42, 10/98, Table 11.9-1 (Emission Factor Equation for Active Storage Pile)*
A = Length of Stockpile	21 ft	
B = Width of Stockpile	21 ft	
U = Mean Wind Speed	12 mile/hr	*Source: AP-42, 10/98, Table 11.9-5 (General Characteristics of Surface Coal Mines - Mine I)*
kPM10 = Particle Size Multiplier for PM10	0.5 dimensionless	*Source: AP-42, 01/95, p. 13.2.5-3 (PM10 Aerodynamic Particle Size Multiplier (k) for Equation 2)*
Tc = Time Piles Remain Uncovered	24 hr/day	Note: This calculation assumes that the piles remain uncovered for 24 hours/day.
QPM10 =	**1.05 lbs PM10/day**	

4. TRUCK FILLING/DUMPING	
TF = Fugitive PM10 Emissions From Truck Filling = G (ton/day) x TF, PM10 (lb/ton)	
TD = Fugitive PM10 Emissions From Truck Dumping = G (ton/day) x TD, PM10 (lb/ton)	
TFPM10 = Emission Factor for Truck Filling =	0.0221 lb/ton of material moved
TDPM10 = Emission Factor for Truck Dumping =	0.0091 lb/ton of material moved
G = Maximum Daily Weight of Material Trucked Away	1 ton/day
TF =	**0.02 lbs PM10/day**
TD =	**0.01 lbs PM10/day**

FUGITIVE PM10 EMISSIONS SUMMARY

Activity	**Unmitigated PM10 (lbs/day)**	**Mitigated PM10 [1] (lbs/day)**
1. Grading	46.70	18.21
2. Trenching/Stockpile Loading	0.00	0.00
3. Storage Piles - Wind Erosion	1.05	0.41
4. Truck Filling/Dumping	0.03	0.01
TOTAL	**47.78**	**18.64**

[1] Water three times per day per SCAQMD Rule 403 (61% control efficiency)

Activity	No. of Scrubbers	
Phase II: Construction	1	**Install WGS or DGS**

Activity	Days/wk	Wks/month	Days/month	Months	Total Days	Crew Size
Demolition	5	4.33	21.67	1	21.67	50
Construction	5	4.33	21.67	17	368.33	175
			Total	**18**	**390**	

Phase II: Construction		Rating	Number	Operation Schedule	2016 Off-Road Emission Factors							
Off-Road Equipment Type	**Fuel**	**(hp)**	**Needed**	**(hr/day)**	**VOC (lb/hr)**	**CO (lb/hr)**	**NOx (lb/hr)**	**SOx (lb/hr)**	**PM10 (lb/hr)**	**PM2.5 (lb/hr)**	**CO2 (lb/hr)**	**CH4 (lb/hr)**
backhoe	diesel	comp.	1	8	0.0426	0.3016	0.4069	0.0004	0.0313	0.0288	40.5	0.0122
crane	diesel	comp.	2	8	0.0972	0.3317	0.2789	0.0002	0.0279	0.0256	25	0.0077
aerial lift	diesel	comp.	3	8	0.0216	0.4173	0.3549	0.0006	0.0146	0.0134	66.0	0.0199
forklift	diesel	comp.	1	8	0.0572	0.3183	0.4923	0.0004	0.0412	0.0379	40.0	0.0121
generator	diesel	comp.	1	8	0.0799	0.4754	0.6043	0.0008	0.0424	0.0424	77.9	0.0071
welder	diesel	comp.	10	8	0.0553	0.2932	0.3713	0.0005	0.0297	0.0297	45.0	0.0050
cement mixer	diesel	comp.	1	2	0.0074	0.0386	0.0462	0.0001	0.0019	0.0019	6.3	0.0007

Phase II: Construction		Number	Round-trip Distance	Mileage Rate	2016 Mobile Source Emission Factors							
On-Road Equipment Type	**Fuel**	**Needed**	**(miles/day)**	**(miles/ gallon)**	**VOC (lb/mile)**	**CO (lb/mile)**	**NOx (lb/mile)**	**SOx (lb/mile)**	**PM10 (lb/mile)**	**PM2.5 (lb/mile)**	**CO2 (lb/mile)**	**CH4 (lb/mile)**
Offsite (Construction Worker Vehicle)	gasoline	175	30	20	0.002910	0.011000	0.000880	0.000010	0.000780	0.000220	1.030600	0.000070
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	3	50	4.89	0.007800	0.148000	0.033200	0.000060	0.001170	0.000500	5.440400	0.000080
Offsite (Delivery Truck - Medium Duty)	diesel	5	50	6	0.006570	0.100400	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060
Onsite (Pickup Truck)	gasoline	1	10	20	0.006570	0.100400	0.029500	0.000050	0.001200	0.000520	4.688000	0.000060

Incremental Increase in Onsite Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)
backhoe	0.34	2.41	3.26	0.00	0.25	0.23	323.68	0.10
crane	1.56	5.31	4.46	0.00	0.45	0.41	405.57	0.12
aerial lift	0.52	10.02	8.52	0.02	0.35	0.32	1583.75	0.48
forklift	0.46	2.55	3.94	0.00	0.33	0.30	320.03	0.10
generator	0.64	3.80	4.83	0.01	0.34	0.34	623.03	0.06
welder	4.42	23.46	29.70	0.04	2.38	2.38	3597.29	0.40
cement mixer	0.01	0.08	0.09	0.00	0.00	0.00	12.63	0.00
SUBTOTAL	**7.95**	**47.62**	**54.80**	**0.07**	**4.10**	**3.98**	**6865.97**	**1.25**

Equation: Emission Factor (lb/hr) x No. of Equipment x Work Day (hr/day) = Onsite Construction Emissions (lbs/day)

Incremental Increase in Offsite Combustion Emissions from Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)
Offsite (Construction Worker Vehicle)	15.28	57.75	4.62	0.05	4.10	1.16	5410.65	0.37
Offsite (Flatbed Truck - Heavy-Heavy Duty)	1.17	22.20	4.98	0.01	0.18	0.08	816.06	0.01
Offsite (Delivery Truck - Medium Duty)	1.64	25.10	7.38	0.01	0.30	0.13	1172.00	0.02
Onsite (Pickup Truck)	0.07	1.00	0.30	0.00	0.01	0.01	46.88	0.00
SUBTOTAL	**18.16**	**106.05**	**17.27**	**0.07**	**4.58**	**1.37**	**7445.59**	**0.40**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

FUGITIVE PM10 EMISSIONS SUMMARY				
Activity	Unmitigated PM10 (lbs/day)	Mitigated PM10 [1] (lbs/day)	Unmitigated PM2.5 (lbs/day)	Mitigated PM2.5 [1] (lbs/day)
1. Grading	46.70	18.21	9.71	4.86
2. Trenching/Stockpile Loading	0.00	0.00	0.00	0.00
3. Storage Piles - Wind Erosion	1.05	0.41	0.22	0.11
4. Truck Filling/Dumping	0.03	0.01	0.01	0.00
SUBTOTAL	**47.78**	**18.64**	**9.94**	**4.97**

[1] Water two times per day per SCAQMD Rule 403 (50% control efficiency)

Total Incremental Combustion Emissions from Construction Activities	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)	CO2e (MT)*
Phase II: Construction TOTAL	**26**	**154**	**72**	**0.14**	**27**	**10**	**14312**	**2**	**14346**	**80**
Significant Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	n/a

*1 metric ton (MT) = 2,205 pounds; GHGs from temporary construction activities are amortized over 30 years.

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Construction Hours	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/phase II)	Total Gasoline Fuel Usage (gal/phase II)
Operation of Portable Equipment	2947	backhoe	2.1	16.80	N/A	6,188.00	N/A
Operation of Portable Equipment	2947	crane	3.9	62.40	N/A	11,492.00	N/A
Operation of Portable Equipment	2947	aerial lift	1.2	28.80	N/A	3,536.00	N/A
Operation of Portable Equipment	2947	forklift	1.1	8.80	N/A	3,241.33	N/A
Operation of Portable Equipment	2947	generator	4.2	33.60	N/A	12,376.00	N/A
Operation of Portable Equipment	2947	welder	1.18	94.40	N/A	3,477.07	N/A
Operation of Portable Equipment	737	cement mixer	2.8	5.60	N/A	2,062.67	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	262.50	N/A	96,687.50
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	30.67	N/A	11,298.57	N/A
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	41.67	N/A	15,347.22	N/A
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	0.50	N/A	184.17
			TOTAL	**323**	**263**	**69,019**	**96,872**

Sources:
1. Off-Road Mobile Emission Factors, Scenario Year 2012
http://www.aqmd.gov/ceqa/handbook/offroad/offroad.html/offroadEF07_25.xls
2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions
http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html/finalAppA.doc
3. On-Road Mobile Emission Factors (EMFAC 2007 v2.3), Scenario Year 2012
http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEF07_26.xls
http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEFHHDT07_26.xls

One Facility Undergoing Demolition Overlapping with One Facility Under Construction

Total Incremental Combustion Emissions from Construction Activities	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)	CO2e (MT*)
Phase I: Demolition TOTAL	**10**	**80**	**31**	**0**	**3**	**2**	**5,442**	**0**	**5,452**	**2**
Phase II: Construction TOTAL	**26**	**154**	**72**	**0**	**27**	**10**	**14,312**	**2**	**14,346**	**80**
Overlapping Phase I + Phase II TOTAL	**36**	**233**	**104**	**0**	**30**	**12**	**19,754**	**2**	**19,799**	**82**
Significant Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**YES**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Diesel Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/both phases)	Total Gasoline Fuel Usage (gal/both phases)
Phase I: Demolition TOTAL	155	76	3,354	1,636
Phase II: Construction TOTAL	323	263	69,019	96,872
Overlapping Phase I + Phase II TOTAL	478	339	72,373	98,508

Facility	plot space (sf) for WGS or DGS	Acreage
1	3,953	0.09075
2	371	0.00852
3	0	0
4	1,575	0.03616
5	11,860	0.27227
6	5,930	0.13613
7	0	0
8	3,953	0.09075
9	1,575	0.03616
Total	**29,217**	**1**

Area Disturbed, ft2	Depth of Water, ft	Water Use, ft3	Water Use, gal	Number of Waterings per day	Total Daily Water Use, gal
29,217	0.005	146	1,093	3	3,278

Assumed 1/16 inch depth of water applied per washing

Non-Refinery Facility Number	Affected Device	Proposed NOx Control	NH3Tank Size, gallon	NH3 Use, ton/yr	NH3 Use, gal/yr
1	Turbines	3 SCRs	5,000	742.5	193,857
1	ICEs	5 SCRs	1,000		
2	Turbines	4 SCRs	2,000	81.8	21,355
2	ICEs	6 SCRs	1,000		
3	ICEs	5 SCRs	1,000		
4	Turbine	1 SCR	2,000	178.1	46,510
5	Turbines	2 SCRs	2,000	52.2	13,622
6	Turbine	1 SCR	2,000	195.1	50,933
7	Turbines	2 SCRs	2,000	158.9	41,479
8	Glass Furnace	2 SCRs	1,000	20.5	5,352
8	Glass Furnace	1 DGS	1,062	0.9	113,126
9	SiO2:Na2O Furnace	1 SCR	600	2.7	42,048
10	Metal Heat Treating	SCR mfr 1	2,000	182.6	47,688
10	Metal Heat Treating	SCR mfr 2	2,000	182.6	47,688
11	Turbines	SCR (Replacement)	10,000	407	106,078
				1,798	**623,657**

Facility 8 has two options, SCR or DGS.
Faciliy 11 has an existing NH3 tank and the annual usage is existing, not an increase.
The type of ammonia to be used is aqueous, 19% by weight.
Assumed that haul and delivery trucks can hold 20 yd3 of material.

Non-Refinery Facility Number	Electricity, kwh/yr	Electricity, kwh/day	Electricity, Mwh/day	Instantaneous Electricity, MW
1	5,183,169	14,200	14.20	0.59
1	61,269	168	0.17	0.01
2	1,052,422	2,883	2.88	0.12
2	74,656	205	0.20	0.01
3	168,490	462	0.46	0.02
4	222,099	608	0.61	0.03
5	444,198	1,217	1.22	0.05
6	222,099	608	0.61	0.03
7	3,419,977	9,370	9.37	0.39
8	258,007	707	0.71	0.03
8	806,270	2,209	2.21	0.09
9	455,520	1,248	1.25	0.05
10	2,091,180	5,729	5.73	0.24
10	2,091,180	5,729	5.73	0.24
11	0	0	0	0.00
	16,550,537	**45,344**	**45**	**1.89**

Note: Instantaneous Electricity Equation: 45,344 kW-hr/day x 1 work day/24 hr x 1 MW/1000 kW = 1.9 MW

Urea Use, gal/yr	Electricity, kwh/yr	Hydrated Lime Tank Capacity, lb	Hydrated Lime, lb/yr	Catalyst Delivered, ton/yr	Catalyst Delivered, ft3/yr	Solid Waste, lb/yr	Filter Waste, lb/yr
	5,183,169	N/A	N/A			N/A	N/A
16,134	61,269	N/A	N/A	0.9		N/A	N/A
	1,052,422	N/A	N/A			N/A	N/A
19,659	74,656	N/A	N/A	3.28		N/A	N/A
44,368	168,490	N/A	N/A	2.46		N/A	N/A
	222,099	N/A	N/A			N/A	N/A
	444,198	N/A	N/A			N/A	N/A
	222,099	N/A	N/A			N/A	N/A
	3,419,977	N/A	N/A			N/A	N/A
	258,007	N/A	N/A			N/A	N/A
	806,270	150,000	682,229		1315	837,281	5,664
	455,520	N/A	N/A		328	N/A	N/A
	2,091,180	N/A	N/A		743		
	2,091,180	N/A	N/A		743		
	Same	N/A	N/A		Same	N/A	N/A
80,161	**16,550,537**	**150,000**	**682,229**	**7**	**3,130**	**837,281**	**5,664**

NH3/Urea Number of Delivery Trips	Hydrated Lime Number of Delivery Trips	Solid Waste Number of Haul Trips	Filter Waste Minimum Number of Haul Trips	Catalyst Delivery	TOTAL per year
39					
17					
11					
20					
45					
23					
7					
25					
21					
5					
107	5	11	1	0	123
70					
24					
24					
Existing					
437	**5**	**11**	**1**	**0**	**454**

Non-Refinery Facility Number	Equipment/Source Category	Nox Control Technology Assumed to Be Installed	County	Equipment	Electricity Provider	Natural Gas Provider	Solid Waste
1	Utility	5 SCR - ICE, 3 SCR - turbine	Los Angeles	ICE, turbine	Self	So Cal Gas	Sunshine Canyon Landfill
2	Utility	6 SCR - ICE, 4 SCR - turbine	Riverside	ICE, turbine	Self	So Cal Gas	Badlands Sanitary Landfill
3	Utility	5 SCR	Los Angeles	ICE	Self/SCE	So Cal Gas	Chiquita Canyon Landfill
4	State Hospital Utility	1 SCR	Los Angeles	Turbine	Self/SCE	So Cal Gas	
5	Airport	2 SCR	Los Angeles	Turbine	Self/DWP	So Cal Gas	Sunshine Canyon Landfill
6	Paper mfg	1 SCR	San Bernardino	Turbine	Self/SCE	So Cal Gas	Milliken Sanitary Landfill
7	Oil Field	2 SCR	Los Angeles	Turbine	Self/SCE	So Cal Gas	Chiquita Canyon Landfill
8	Container Glass Mfg	2 SCRs or 1 DGS	Los Angeles	Glass furnace	City of Vernon	City of Vernon	
9	Glass mfg	1 DGS or 1 SCR	Los Angeles	SiO2:Na2O furnace	SCE	So Cal Gas	South Gate Transfer Station
10	Metal forging	1 SCR	San Bernardino	Heat treating furnace	SCE	So Cal Gas	Mid-Valley Landfill

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days
1	Demolition	Demolition	1/1/2016	1/14/2016	5	10
2	Site Preparation	Site Preparation	1/15/2016	1/18/2016	5	2
3	Building Construction	Building Construction	1/20/2016	1/3/2017	5	250
4	Paving	Paving	6/8/2016	6/14/2016	5	5

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Building Construction	Cranes	1	6	226	0.29
Building Construction	Forklifts	1	6	89	0.2
Building Construction	Generator Sets	1	8	84	0.74
Building Construction	Tractors/Loaders/Backhoes	1	6	97	0.37
Building Construction	Welders	2	8	46	0.45
Building Construction	Aerial Lifts	1	8	62	0.31
Demolition	Concrete/Industrial Saws	1	8	81	0.73
Demolition	Rubber Tired Dozers	1	8	255	0.4
Demolition	Tractors/Loaders/Backhoes	1	8	97	0.37
Demolition	Cranes	1	8	226	0.29
Paving	Cement and Mortar Mixers	1	6	9	0.56
Paving	Paving Equipment	1	8	130	0.36
Paving	Plate Compactors	1	6	125	0.42
Paving	Tractors/Loaders/Backhoes	1	8	97	0.37
Site Preparation	Rubber Tired Dozers	1	7	255	0.4
Site Preparation	Tractors/Loaders/Backhoes	1	8	97	0.37
Site Preparation	Trenchers	1	8	80	0.5

Peak Daily Criteria Construction Emissions per Control Equipment at Non-Refinery Facility

Description	ROG, lb/day	NOx, lb/day	CO, lb/day	SO2, lb/day	PM10 Total, lb/day	PM2.5 Total, lb/day
Daily Unmitigated	3.7	31.7	21.7	0.03	7.1	4.1
Daily Mitigated	3.7	31.7	21.7	0.03	3.5	2.3

Emissions estimated with CalEEMod for 2016.

Project Peak Daily Criteria Construction Emissions for Non-Refinery Facilities

Description	ROG, lb/day	NOx, lb/day	CO, lb/day	SO2, lb/day	PM10 Total, lb/day	PM2.5 Total, lb/day
Daily Unmitigated	40	349	239	0.38	78	45
Daily Mitigated	40	349	239	0.38	39	25

Emissions estimated with CalEEMod for 2016.

Construction Fuel Use

Diesel Fuel Use for Off-Road Construction Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor	Fuel Use by Piece of Equipment, gal/hr	Total Diesel Fuel Use, gal/day	Number of Days for Entire Project	Total Diesel Fuel Use, gal/project
Building Construction	Cranes	1	6.00	226	0.29	3.9	23.4	250	5,850
Building Construction	Aerial Lifts	1	8	62	0.31	1.2	9.6	250	2,400
Building Construction	Forklifts	1	6.00	89	0.20	1.1	6.6	250	1,650
Building Construction	Generator Sets	1	8.00	84	0.74	4.2	33.6	250	8,400
Building Construction	Tractors/Loaders/Backhoes	1	6.00	97	0.37	2.1	12.6	250	3,150
Building Construction	Welders	2	8.00	46	0.45	NA		250	0
							85.8		**21,450**
Demolition	Cranes	1	8	226	0.29	3.9	31.2	10	312
Demolition	Concrete/Industrial Saws	1	8.00	81	0.73	NA		10	0
Demolition	Tractors/Loaders/Backhoes	1	8.00	97	0.37	2.1	16.8	10	168
Demolition	Rubber Tired Dozers	1	8.00	255	0.40	5.9	47.2	10	472
							95.2		**952**
Paving	Cement and Mortar Mixers	1	6.00	9	0.56	2.8	16.8	5	84
Paving	Paving Equipment	1	8.00	130	0.36	2.8	22.4	5	112
Paving	Plate Compactors	1	6.00	125	0.42	2.8	16.8	5	84
Paving	Tractors/Loaders/Backhoes	1	8.00	97	0.37	2.1	16.8	5	84
							72.8		**364**
Site Preparation	Rubber Tired Dozers	1	7.00	255	0.40	5.9	41.3	2	83
Site Preparation	Tractors/Loaders/Backhoes	1	8.00	97	0.37	2.1	16.8	2	34
Site Preparation	Trenchers	1	8	80	0.5	2.1	16.8	2	34
							74.9		149.8
						Max Daily Usage, gal/day	**95.2**		**21,450**

Fuel use by equipment from Offroad for 2015

Fuel Use for On-Road Vehicles During Construction

Phase Name	Offroad Equipment Count	Worker Trip Number (gasoline)	Vendor Trip Number (diesel)	Hauling Trip Number (diesel)	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker, mpg	Vendor, mpg	Hauling, mpg	Worker Trip Fuel Use (gasoline), gal/day	Vendor Trip Fuel Use (diesel), gal/day	Hauling Trip Fuel Use (diesel), gal/day	Number of Days for Entire Project	Worker Trip Fuel Use (gasoline), gal/project	Vendor Trip Fuel Use (diesel), gal/project	Hauling Trip Fuel Use (diesel), gal/project
Demolition (Diesel)	3	15	0	5	14.7	6.9	20	19	12.2	8.9	23	0	22	10	232	0	225
Site Preparation (Diesel)	2	8	0	0	14.7	6.9	20	19	12.2	8.9	12	0	0	2	25	0	0
Building Construction (Gasoline)	6	18	7	0	14.7	6.9	20	19	12.2	8.9	28	8	0	250	6,963	1,980	0
Paving (Diesel)	4	13	0	0	14.7	6.9	20	19	12.2	8.9	20	0	0	5	101	0	0
											28	7.9	22		6,963	1,980	225

Fuel use by equipment from EMFAC2011 for 2015

Maximum Daily Fuel Use

Source	Gasoline, gal/day	Diesel Fuel, gal/day	Gasoline, gal/project	Diesel Fuel, gal/project
Construction Equipment	0	95	0	21,450
On-Road Vehicles	28	30	6,963	2,204
Total	28	126	6,963	23,654
Total for 11 facilities	306	1,381	76,595	260,197

Construction Water Use Estimate for Dust Suppression and Hydrotesting

Construction Water Use for Dust Suppression (during construction - demolition/site prep)

Area Disturbed, acre	Area Disturbed, ft2	Depth of Water, ft	Water Use Area, ft3	Water Use, gal	Number of Washings	Total Daily Water Use, gal
0.28	12,272	0.005	61	459	3	1,377

Assumed 1/16 inch depth of water applied per washing

Construction Water Use for Hydrotesting (after construction is completed)

Facility Number	Nox Control Technology Assumed to Be Installed	Total Number of Units	Plot Space Needed Per Unit (sf)	plot space (sf) for all control equip	No. of NH3 storage tanks needed	Capacity of Storage Tank (gal)	Plot space (sf) needed per storage tank	Plot space (sf) needed for all storage tanks	Total plot space (sf) for all control equipment & chemical storage	Total acreage disturbed from Construction	Number of Tanks Overlapping Construction per day	Amount of Water Needed to Hydrotest during Overlap (gal/day)	Amount of Water Needed to Hydrotest for Entire Project (gal/project)
1	5 SCR - ICE, 3 SCR - turbine	8	176	1,408	2	3,000	400	800	2,208	0.05	2	6,000	6,000
2	6 SCR - ICE, 4 SCR - turbine	10	176	1,760	2	1,500	400	800	2,560	0.06	2	3,000	3,000
3	5 SCR	5	176	880	1	1,000	400	400	1,280	0.03	1	1,000	1,000
4	1 SCR	1	176	176	1	2,000	400	400	576	0.01	1	2,000	2,000
5	2 SCR	2	176	352	1	2,000	400	400	752	0.02	1	2,000	2,000
6	1 SCR	1	176	176	1	2,000	400	400	576	0.01	1	2,000	2,000
7	2 SCR	2	176	352	1	2,000	400	400	752	0.02	1	2,000	2,000
8	2 SCR	2	176	352	2	1,062	400	800	1,152	0.03	2	2,124	2,124
9	1 Tri-Mer	1	640	640	1	600	400	400	1,040	0.02	1	600	600
10	1 SCR	1	176	176	2	2,000	400	800	976	0.02	2	4,000	4,000
11	1 Replacement SCR	1	0	0	1	10,000	400	400	400	0.01	1	10,000	10,000
			Total	**6,272**	**15**	**27,162**	**4,400**	**6,000**	**12,272**	**0.28**	**15**	**34,724**	**34,724**

* replacement means that no additional plot space would be needed

Non-Refinery Facility Operational Emissions

EMFAC2011 Emission Factors

Category	ROG	CO	NOx	SOx	PM10	PM2.5	CO2
Pass (lb/mile)	0.0005613	0.005211	0.000498	9.85E-06	0.000105	4.47E-05	0.863285
Deliv (lbmile)	0.0003299	0.001586	0.009749	1.73E-05	0.000421	0.000256	1.766573
HHDT-DSL (lb/mile)	0.0003516	0.001493	0.009812	2.38E-05	0.000572	0.000367	2.435248

EMFAC2011 Emission Factors for 2015 fleet

Heavy-duty Truck Trips

Description	NH3/Urea Number of Delivery Trips	Adsorbent Number of Delivery Trips	Solid Waste Number of Haul Trips	Filter Waste Number of Haul Trips	Catalyst Number of Delivery Trips	Total Heavy Duty Truck Trips
Annual	437	5	11	1	11	465
Peak Day	11	1	1	1	11	25

Adsorbent, solid waste and filter waste based on vendor calcs for SOx portion of Ultracat system

One catalyst delivery trips per facilty was assumed.

Peak day assumed one ammonia/urea delivery occurs at each non-refinery facility and adsorbent, solid waste and haul trip occurs on same day.

Peak Day

Vehicle Type	No of Trips	Distance, mile/trip	ROG, lb/day	CO, lb/day	NOx, lb/day	SOx, lb/day	PM10, lb/day	PM2.5, lb/day	Total Miles Per Day	Total Gallons Per Day
Heavy Duty Truck	25	100	0.88	3.73	24.5	0.06	1.43	0.92	2,500	511
Medium Duty Truck	11	80	0.29	1.40	8.58	0.02	0.37	0.23	880	99
			1.17	**5.13**	**33.1**	**0.07**	**1.80**	**1.14**	**3,380**	**610**

Assumed one tech trip for control system mantainance occurs at each of the ten non-refinery facilities

Default truck trips were assumed to 80 miles round trip. Ammonia deliveries were assumed to be 100 miles round trip.

Annual

Vehicle Type	No of Trips	Distance, mile/trip	CO2, metric ton/yr	Total Miles Per Year	Total Gallons Per Year
Heavy Duty Truck	465	100	51	46,536	9,517

Medium Duty Truck	286	80	25	22,880	2,574
			77	**69,416**	**12,090**

Assumed one tech trip every other week for control system mantainance occurs at each of the 11 non-refinery facilities
Default truck trips were assumed to 80 miles round trip. Ammonia deliveries were assumed to be 100 miles round trip.

Phase III: Operations - Criteria Pollutants From Electricity Generation

Phase III: Operation	Peak Daily Electricity Demand	Simple Cycle Turbine Emission Factors					
Electricity Generation		VOC (lb/MWh)	CO (lb/MWh)	NOx (lb/MWh)	SOx (lb/MWh)	PM10 (lb/MWh)	PM2.5 (lb/MWh)
Electricity Needed by 11 Non-Refineries	45	0.02	0.08	0.09	0.00	0.06	0.06

Incremental Increase in Criteria Pollutant Emissions from Electricty Generation	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)
Emissions from Electricity Needed by 11 Non-Refineries	0.91	3.63	4.08	0.00	2.72	2.67
TOTAL	1	4	4	0	3	3

Example Calculation: NOx: 0.09 lbs/MWh x 45.3 MWh = 4.08 lbs

Offsite Consequence Input Data for NH3 spill of one 5,000 gallon storage tank at a non-refinery facility

Non-Refinery

Ammonia Storage, gal	Berm Capacity, gal	Ammonia Berm, ft3	Height of Berm, ft	Area, ft2
5,000	5,500	735	3.0	245

Berms must be able to contain 110% the volume of the tank
Typical berm heights are three feet tall.

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Estimated Distance Calculation

Estimated distance to toxic endpoint: <0.1 miles (<0.16 kilometers); report as 0.1 mile

This is the downwind distance to the toxic endpoint specified for this regulated substance under the RMP Rule. Report all distances shorter than 0.1 mile as 0.1 mile, and all distances longer than 25 miles as 25 miles.

Scenario Summary

Chemical:	Ammonia (water solution)
Initial concentration:	20 %
CAS number:	7664-41-7
Threat type:	Toxic Liquid
Scenario type:	Worst-case
Liquid temperature:	25 C
Quantity released:	5500 gallons
Mitigation measures:	
Diked area:	245 square feet
Dike height:	3 feet
Release rate to outside air:	5.3 pounds per minute
Surrounding terrain type:	Urban surroundings (many obstacles in the immediate area)
Toxic endpoint:	0.14 mg/L; basis: ERPG-2

Assumptions about this scenario

Wind speed:	1.5 meters/second (3.4 miles/hour)
Stability class:	F
Air temperature:	77 degrees F (25 degrees C)

Ammonia Slip Estimate

Ammonia Slip Conc at the Exit of the Stack, ppm	Dispersion Factor	Molecular Weight, g/mol	Peak Conc at a Receptor 25 m from the Stack, ug/m3	Acute REL, ug/m3	Chronic REL, ug/m3	Acute Hazard Index	Chronic Hazard Index
5	0.01	17.03	35	3,200	200	0.01	0.17

Ammonia slip is subject to a permit limit of 5 ppm.

Conc., ug/m3 = (conc., ppm x 1,000 x molecular weight, g/mol)/24.5 m3/kmol

Based on the Staff Report for Toxic Air Contaminants 1401.1 – Requirements for New and Relocated Facilities Near Schools, and 1402 – Control of Toxic Air Contaminants from Existing Source, June 2015 the concentration at a receptor 25 m from a stack would be much less than one percent of the concentration at the release from the exist of the stack.

Hazard index = conc. at receptor 25 m from stack, ug/m3/REL, ug/m3

Non-Refinery - Diesel Idling Emissions

Facility 8 has the peak annual trips per year = 123 +26 tech trips (bi-weekly)=149 total trips

EF, g/hr	Annual No of Trips	Idling, h/y	Emisions, lb/yr	Emisions, ton/yr
1.67	149	37.26745	0.14	6.88E-05

Heavy-duty idling rates from emfac2011_idling_emission_rates.xlsx (http://www.arb.ca.gov/msei/emfac2011_idling_emission_rates.xlsx).

Emisions, ton/yr	Cancer Potency Factor, (mg/kg-d)-1	X/Q at 25 m, (ug/m3)/(ton/yr)	CEF	MP	MWHF	Carcinogenic Health Risk	Screening Level	Significant?
6.88E-05	1.1	29.64	676.63	1	1	1.52E-06	1.00E-05	NO

Carcinogenic health risk = emissions, ton/yr x cancer potency, (mg/kg-day)-1 x X/Q, (ug/m3)/(ton/yr) x CEF x MP x MWHF

ProjectNar	LocationS	EMFAC_II	WindSpee	Precipitatio	ClimateZo	Urbanizatio	Operationa	UtilityCom	CO2Intens	CH4Intens	N2OIntens	TotalPopu	TotalLotAc	UsingHistoricalEnergyUseData
RECLAIM	AD	SCAQMD	2.2	31	8	Urban	2015	Los Angel	1227.89	0.029	0.006	0	1	0

PollutantSelection	PollutantFullName	PollutantName
1	Reactive Organic Gases (ROG)	ROG
1	Nitrogen Oxides (NOx)	NOX
1	Carbon Monoxide (CO)	CO
1	Sulfur Dioxide (SO2)	SO2
1	Particulate Matter 10um (PM10)	PM10
1	Particulate Matter 2.5um (PM2.5)	PM2_5
1	Fugitive PM10um (PM10)	PM10_FUG
1	Fugitive PM2.5um (PM2.5)	PM25_FUG
1	Biogenic Carbon Dioxide (CO2)	CO2_BIO
1	Non-Biogenic Carbon Dioxide (CO2)	CO2_NBIO
1	Carbon Dioxide (CO2)	CO2
1	Methane (CH4)	CH4
1	Nitrous Oxide (N2O)	N2O
1	CO2 Equivalent GHGs (CO2e)	CO2E

LandUseType	LandUseSubType	LandUseUnitAmount	LandUseSizeMetric	LotAcreage	LandUseSquareFeet	Population
Industrial	General Heavy Industry	43.56	1000sqft	1	43560	0

PhaseNumber	PhaseName	PhaseType	PhaseStartDate	PhaseEndDate	NumDaysWeek	NumDays	PhaseDescription
1	Demolition	Demolition	2016/01/01	2016/01/14	5	10	
2	Site Preparation	Site Preparation	2016/01/15	2016/01/18	5	2	
3	Building Construction	Building Construction	2016/01/20	2017/01/03	5	250	
4	Paving	Paving	2016/06/08	2016/06/14	5	5	

PhaseName	OffRoadEquipmentType	OffRoadEquipmentUnitAmount	UsageHours	HorsePower	LoadFactor
Demolition	Concrete/Industrial Saws	1	8	81	0.73
Demolition	Cranes	1	8	226	0.29
Demolition	Rubber Tired Dozers	1	8	255	0.4
Demolition	Tractors/Loaders/Backhoes	1	8	97	0.37
Site Preparation	Rubber Tired Dozers	1	7	255	0.4
Site Preparation	Tractors/Loaders/Backhoes	1	8	97	0.37
Site Preparation	Trenchers	1	8	80	0.5
Building Construction	Aerial Lifts	1	8	62	0.31
Building Construction	Cranes	1	6	226	0.29
Building Construction	Forklifts	1	6	89	0.2
Building Construction	Generator Sets	1	8	84	0.74
Building Construction	Tractors/Loaders/Backhoes	1	6	97	0.37
Building Construction	Welders	2	8	46	0.45
Paving	Cement and Mortar Mixers	1	6	9	0.56
Paving	Paving Equipment	1	8	130	0.36
Paving	Plate Compactors	1	6	125	0.42
Paving	Tractors/Loaders/Backhoes	1	8	97	0.37

PhaseName	WorkerTripNumber	VendorTripNumber	HaulingTripNumber	WorkerTripLength	VendorTripLength	HaulingTripLength	WorkerVehicleClass	VendorVehicleClass	HaulingVehicleClass
Demolition	15	0	49	14.7	6.9	20	LD_Mix	HDT_Mix	HHDT
Site Preparation	8	0	0	14.7	6.9	20	LD_Mix	HDT_Mix	HHDT
Building Construction	18	7	0	14.7	6.9	20	LD_Mix	HDT_Mix	HHDT
Paving	13	0	0	14.7	6.9	20	LD_Mix	HDT_Mix	HHDT

PhaseName	WorkerPercentPave	VendorPercentPave	HaulingPercentPave	RoadSiltLoading	MaterialSiltContent	MaterialMoistureContent	AverageVehicleWeight	MeanVehicleSpeed
Demolition	100	100	100	0.1	8.5	0.5	2.4	40
Site Preparation	100	100	100	0.1	8.5	0.5	2.4	40
Building Construction	100	100	100	0.1	8.5	0.5	2.4	40
Paving	100	100	100	0.1	8.5	0.5	2.4	40

PhaseName	DemolitionSizeMetric	DemolitionUnitAmount
Demolition	Ton of Debris	500

PhaseName	MaterialImported	MaterialExported	GradingSizeMetric	ImportExportPhased	MeanVehicleSpeed	AcresOfGrading	MaterialMoistureContentBulldozing	MaterialMoistureContentTruckLoading	MaterialSiltContent
Site Preparation	0	0		0	7.1	1	7.9	12	6.9

PhaseName	ArchitecturalCoatingStartDate	ArchitecturalCoatingEndDate	EF_Residential_Interior	ConstArea_Residential_Interior	EF_Residential_Exterior	ConstArea_Residential_Exterior	EF_Nonresidential_Interior	ConstArea_Nonresidential_Interior	EF_Nonresidential_Exterior	ConstArea_Nonresidential_Exterior

ParkingLotAcreage

VehicleTripsLandUseSubType	VehicleTripsLandUseSizeMetric	WD_TR	ST_TR	SU_TR	HW_TL	HS_TL	HO_TL	CC_TL	CW_TL	CNW_TL	PR_TP	DV_TP	PB_TP	HW_TTP	HS_TTP	HO_TTP	CC_TTP	CW_TTP	CNW_TTP
General Heavy Industry	1000sqft	1.5	1.5	1.5	0	0	0	8.4	16.6	6.9	92	5	3	0	0	0	28	59	13

Season	EmissionType	LDA	LDT1	LDT2	MDV	LHD1	LHD2
A	FleetMix	0.514499	0.060499	0.179997	0.139763	0.042095	0.006675
A	CH4_IDLEX	0	0	0	0	0.001309	0.001023
A	CH4_RUNEX	0.013984	0.029514	0.019657	0.030056	0.016394	0.011954
A	CH4_STREX	0.010839	0.025416	0.014671	0.025703	0.02727	0.017952
A	CO_IDLEX	0	0	0	0	0.190064	0.152757
A	CO_RUNEX	1.233474	3.189989	1.739629	2.486494	1.63021	1.189601
A	CO_STREX	2.353874	5.693141	3.413938	5.206356	5.255995	3.391635
A	CO2_NBIO_IDLEX	0	0	0	0	8.332614	9.178367
A	CO2_NBIO_RUNEX	308.212585	363.470979	438.806245	569.400369	576.196465	555.270558
A	CO2_NBIO_STREX	64.829833	75.690488	91.133106	117.952064	44.555746	30.726279
A	NOX_IDLEX	0	0	0	0	0.045728	0.09691
A	NOX_RUNEX	0.110055	0.312796	0.203818	0.320636	1.416374	2.274808
A	NOX_STREX	0.159103	0.327401	0.327752	0.506279	1.457145	0.977107
A	PM10_IDLEX	0	0	0	0	0.000488	0.001068
A	PM10_PMBW	0.03675	0.03675	0.03675	0.03675	0.046153	0.062741
A	PM10_PMTW	0.008	0.008	0.008	0.008	0.008948	0.009983
A	PM10_RUNEX	0.002056	0.004908	0.002107	0.002358	0.008642	0.016542
A	PM10_STREX	0.002808	0.005384	0.002799	0.003289	0.00141	0.000939
A	PM25_IDLEX	0	0	0	0	0.000449	0.000982
A	PM25_PMBW	0.01575	0.01575	0.01575	0.01575	0.01978	0.026889
A	PM25_PMTW	0.002	0.002	0.002	0.002	0.002237	0.002496
A	PM25_RUNEX	0.001881	0.004504	0.001933	0.002168	0.007953	0.015216
A	PM25_STREX	0.002568	0.004943	0.002573	0.003029	0.001291	0.000844
A	ROG_DIURN	0.066402	0.189701	0.077836	0.089694	0.003055	0.001955
A	ROG_HTSK	0.14692	0.32917	0.168393	0.195309	0.076216	0.052279
A	ROG_IDLEX	0	0	0	0	0.030443	0.023575
A	ROG_RESTL	0.054554	0.136894	0.066595	0.080483	0.001725	0.001108
A	ROG_RUNEX	0.035351	0.097338	0.044946	0.071591	0.116884	0.109968
A	ROG_RUNLS	0.329804	1.166493	0.541766	0.61118	0.445414	0.299477
A	ROG_STREX	0.18834	0.445148	0.257689	0.452871	0.480847	0.313738
A	SO2_IDLEX	0	0	0	0	0.000088	0.000094
A	SO2_RUNEX	0.003609	0.00417	0.004911	0.006213	0.005871	0.005586
A	SO2_STREX	0.000776	0.000943	0.00106	0.001357	0.000554	0.000378
A	TOG_DIURN	0.066402	0.189701	0.077836	0.089694	0.003055	0.001955
A	TOG_HTSK	0.14692	0.32917	0.168393	0.195309	0.076216	0.052279
A	TOG_IDLEX	0	0	0	0	0.03235	0.025262
A	TOG_RESTL	0.054554	0.136894	0.066595	0.080483	0.001725	0.001108
A	TOG_RUNEX	0.049912	0.128354	0.065324	0.102752	0.13759	0.128711
A	TOG_RUNLS	0.329804	1.166493	0.541766	0.61118	0.445414	0.299477
A	TOG_STREX	0.201307	0.475598	0.275275	0.483697	0.513556	0.335238
S	FleetMix	0.514499	0.060499	0.179997	0.139763	0.042095	0.006675
S	CH4_IDLEX	0	0	0	0	0.001309	0.001023
S	CH4_RUNEX	0.013984	0.029514	0.019657	0.030056	0.016394	0.011954
S	CH4_STREX	0.010839	0.025416	0.014671	0.025703	0.02727	0.017952
S	CO_IDLEX	0	0	0	0	0.190064	0.152756
S	CO_RUNEX	1.350882	3.453577	1.905978	2.728272	1.656744	1.198792
S	CO_STREX	1.868119	4.517537	2.699157	4.111903	4.259587	2.777588
S	CO2_NBIO_IDLEX	0	0	0	0	8.332614	9.178367

S	CO2_NBIO_RUNEX	324.06492	381.257222	460.796131	598.471554	576.196459	555.270551
S	CO2_NBIO_STREX	64.829834	75.690489	91.133105	117.952065	44.555747	30.726279
S	NOX_IDLEX	0	0	0	0	0.045728	0.09691
S	NOX_RUNEX	0.09727	0.274387	0.179725	0.283025	1.31395	2.138796
S	NOX_STREX	0.147973	0.30427	0.304804	0.470634	1.401942	0.940016
S	PM10_IDLEX	0	0	0	0	0.000488	0.001068
S	PM10_PMBW	0.03675	0.03675	0.03675	0.03675	0.046153	0.062741
S	PM10_PMTW	0.008	0.008	0.008	0.008	0.008948	0.009983
S	PM10_RUNEX	0.002056	0.004908	0.002107	0.002358	0.008642	0.016542
S	PM10_STREX	0.002808	0.005384	0.002799	0.003289	0.00141	0.000939
S	PM25_IDLEX	0	0	0	0	0.000449	0.000982
S	PM25_PMBW	0.01575	0.01575	0.01575	0.01575	0.01978	0.026889
S	PM25_PMTW	0.002	0.002	0.002	0.002	0.002237	0.002496
S	PM25_RUNEX	0.001881	0.004504	0.001933	0.002168	0.007953	0.015216
S	PM25_STREX	0.002568	0.004943	0.002573	0.003029	0.001291	0.000844
S	ROG_DIURN	0.106937	0.310496	0.126009	0.146254	0.004832	0.00306
S	ROG_HTSK	0.155669	0.358306	0.179941	0.208545	0.082417	0.056164
S	ROG_IDLEX	0	0	0	0	0.030443	0.023575
S	ROG_RESTL	0.084087	0.217884	0.102674	0.124565	0.002767	0.001756
S	ROG_RUNEX	0.036348	0.100738	0.046745	0.075462	0.119071	0.110744
S	ROG_RUNLS	0.31515	1.093856	0.508247	0.577209	0.436118	0.291869
S	ROG_STREX	0.160037	0.378639	0.2195	0.385076	0.425075	0.277672
S	SO2_IDLEX	0	0	0	0	0.000088	0.000094
S	SO2_RUNEX	0.003797	0.004379	0.00516	0.006534	0.005871	0.005587
S	SO2_STREX	0.000767	0.000922	0.001048	0.001338	0.000536	0.000367
S	TOG_DIURN	0.106937	0.310496	0.126009	0.146254	0.004832	0.00306
S	TOG_HTSK	0.155669	0.358306	0.179941	0.208545	0.082417	0.056164
S	TOG_IDLEX	0	0	0	0	0.03235	0.025262
S	TOG_RESTL	0.084087	0.217884	0.102674	0.124565	0.002767	0.001756
S	TOG_RUNEX	0.051697	0.132929	0.068158	0.107954	0.14002	0.129611
S	TOG_RUNLS	0.31515	1.093856	0.508247	0.577209	0.436118	0.291869
S	TOG_STREX	0.17106	0.404544	0.234481	0.41129	0.453984	0.29669
W	FleetMix	0.514499	0.060499	0.179997	0.139763	0.042095	0.006675
W	CH4_IDLEX	0	0	0	0	0.001309	0.001023
W	CH4_RUNEX	0.013984	0.029514	0.019657	0.030056	0.016394	0.011954
W	CH4_STREX	0.010839	0.025416	0.014671	0.025703	0.02727	0.017952
W	CO_IDLEX	0	0	0	0	0.190064	0.152756
W	CO_RUNEX	1.193516	3.100688	1.684197	2.407556	1.624424	1.186618
W	CO_STREX	2.433359	5.864449	3.527735	5.365933	5.306769	3.437683
W	CO2_NBIO_IDLEX	0	0	0	0	8.332614	9.178367
W	CO2_NBIO_RUNEX	303.274273	358.142873	432.029902	560.763704	576.196459	555.270551
W	CO2_NBIO_STREX	64.829834	75.690489	91.133105	117.952065	44.555747	30.726279
W	NOX_IDLEX	0	0	0	0	0.045728	0.09691
W	NOX_RUNEX	0.106433	0.302816	0.197086	0.309883	1.388776	2.234735
W	NOX_STREX	0.161047	0.33106	0.331685	0.511887	1.462705	0.981562
W	PM10_IDLEX	0	0	0	0	0.000488	0.001068
W	PM10_PMBW	0.03675	0.03675	0.03675	0.03675	0.046153	0.062741
W	PM10_PMTW	0.008	0.008	0.008	0.008	0.008948	0.009983
W	PM10_RUNEX	0.002056	0.004908	0.002107	0.002358	0.008642	0.016542

W	PM10_STREX	0.002808	0.005384	0.002799	0.003289	0.00141	0.000939
W	PM25_IDLEX	0	0	0	0	0.000449	0.000982
W	PM25_PMBW	0.01575	0.01575	0.01575	0.01575	0.01978	0.026889
W	PM25_PMTW	0.002	0.002	0.002	0.002	0.002237	0.002496
W	PM25_RUNEX	0.001881	0.004504	0.001933	0.002168	0.007953	0.015216
W	PM25_STREX	0.002568	0.004943	0.002573	0.003029	0.001291	0.000844
W	ROG_DIURN	0.067842	0.198859	0.078401	0.089081	0.003369	0.002144
W	ROG_HTSK	0.166957	0.383619	0.189492	0.216372	0.089406	0.061396
W	ROG_IDLEX	0	0	0	0	0.030443	0.023575
W	ROG_RESTL	0.053212	0.133717	0.064685	0.078352	0.001771	0.001126
W	ROG_RUNEX	0.0349	0.095978	0.044277	0.07031	0.116392	0.109768
W	ROG_RUNLS	0.370102	1.380262	0.6353	0.711159	0.483048	0.326354
W	ROG_STREX	0.192428	0.453488	0.263055	0.461497	0.485385	0.317378
W	SO2_IDLEX	0	0	0	0	0.000088	0.000094
W	SO2_RUNEX	0.00355	0.004108	0.004834	0.006118	0.005871	0.005586
W	SO2_STREX	0.000777	0.000946	0.001062	0.00136	0.000555	0.000379
W	TOG_DIURN	0.067842	0.198859	0.078401	0.089081	0.003369	0.002144
W	TOG_HTSK	0.166957	0.383619	0.189492	0.216372	0.089406	0.061396
W	TOG_IDLEX	0	0	0	0	0.03235	0.025262
W	TOG_RESTL	0.053212	0.133717	0.064685	0.078352	0.001771	0.001126
W	TOG_RUNEX	0.049222	0.126641	0.064347	0.101088	0.137046	0.128482
W	TOG_RUNLS	0.370102	1.380262	0.6353	0.711159	0.483048	0.326354
W	TOG_STREX	0.205676	0.484505	0.281005	0.492909	0.518404	0.339126

MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098
0.007624	0.024528	0.018472	0	0	0.005424	0
0.005872	0.01213	0.003081	0	0	0.007712	0
0	0	0	0	0	0	0
1.836153	2.871608	2.240681	0	0	1.05372	0
1.373582	1.934274	1.632938	5.524531	23.495508	5.135838	5.101083
21.332757	64.369068	11.409411	10.884497	9.784148	34.385192	9.556879
608.920432	571.324293	576.199581	0	0	576.185345	0
998.23524	1662.819965	1089.859137	2143.365925	146.800774	1136.115926	657.208031
59.236621	62.554688	37.01571	29.696387	44.886823	130.61329	32.339246
6.682209	5.33745	6.457943	0	0	8.137056	0
3.731903	6.93817	4.826998	13.194861	1.191712	8.334269	1.761286
2.187072	3.901161	1.538267	1.232285	0.306462	2.274502	0.900295
0.02811	0.022337	0.022314	0	0	0.02741	0
0.11256	0.060052	0.094097	0.679664	0.036749	0.574428	0.050551
0.01124	0.03473	0.010451	0.008	0.008	0.011038	0.00859
0.093253	0.121195	0.063139	0.209684	0.000578	0.088393	0.029094
0.003758	0.003922	0.001248	0.000836	0.001854	0.00737	0.00179
0.025861	0.02055	0.020529	0	0	0.025217	0
0.04824	0.025737	0.040327	0.291285	0.01575	0.246184	0.021665
0.00281	0.008682	0.002613	0.002	0.002	0.002759	0.002147
0.085789	0.111499	0.058087	0.192889	0.000467	0.081246	0.026727
0.003176	0.003151	0.001076	0.000743	0.001467	0.006316	0.001546
0.003664	0.002617	0.001084	0.005873	0.999598	0.040185	1.405902
0.148396	0.146196	0.030425	0.104047	0.47086	0.287265	0.090027
0.16415	0.528083	0.397688	0	0	0.116768	0
0.002103	0.001662	0.000524	0.00321	0.572527	0.016957	0.543208
0.168477	0.274802	0.16882	0.826002	2.51152	0.436072	0.164067
0.617851	0.571991	0.308148	0.717582	1.628305	2.250725	2.067505
1.440778	2.38542	0.73497	0.796077	2.134906	2.363626	0.588984
0.005958	0.00559	0.005638	0	0	0.005638	0
0.009834	0.016287	0.010788	0.021114	0.001953	0.011277	0.00674
0.000987	0.001726	0.000581	0.0005	0.000681	0.001952	0.0005
0.003664	0.002617	0.001084	0.005873	0.999598	0.040185	1.405902
0.148396	0.146196	0.030425	0.104047	0.47086	0.287265	0.090027
0.186873	0.601183	0.452737	0	0	0.132932	0
0.002103	0.001662	0.000524	0.00321	0.572527	0.016957	0.543208
0.193707	0.313538	0.197872	0.920387	2.755048	0.485774	0.196115
0.617851	0.571991	0.308148	0.717582	1.628305	2.250725	2.067505
1.542818	2.556696	0.785914	0.850607	2.295552	2.530875	0.630464
0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098
0.007185	0.023116	0.017408	0	0	0.005111	0
0.005872	0.01213	0.003081	0	0	0.007712	0
0	0	0	0	0	0	0
1.334224	2.086629	1.628171	0	0	0.765677	0
1.380654	1.944328	1.656457	5.55465	22.684238	5.105164	5.148108
17.587788	53.891387	9.346911	9.183033	8.738903	29.5561	7.621596
645.097383	605.267596	610.432532	0	0	610.417451	0

998.235235	1662.819964	1089.859128	2143.365925	146.800774	1136.115939	657.208019
59.236621	62.554688	37.01571	29.696388	44.886823	130.613294	32.339247
6.897161	5.509144	6.665681	0	0	8.398808	0
3.508187	6.557672	4.535044	12.429094	1.036711	7.838125	1.607728
2.099169	3.74208	1.476893	1.177907	0.290277	2.150793	0.864345
0.023696	0.01883	0.018811	0	0	0.023107	0
0.11256	0.060052	0.094097	0.679664	0.036749	0.574428	0.050551
0.01124	0.03473	0.010451	0.008	0.008	0.011038	0.00859
0.093253	0.121195	0.063139	0.209684	0.000578	0.088393	0.029094
0.003758	0.003922	0.001248	0.000836	0.001854	0.00737	0.00179
0.021801	0.017324	0.017306	0	0	0.021258	0
0.04824	0.025737	0.040327	0.291285	0.01575	0.246184	0.021665
0.00281	0.008682	0.002613	0.002	0.002	0.002759	0.002147
0.085789	0.111499	0.058087	0.192889	0.000467	0.081246	0.026727
0.003176	0.003151	0.001076	0.000743	0.001467	0.006316	0.001546
0.005753	0.004301	0.001692	0.008697	1.700317	0.061434	2.183595
0.155025	0.151308	0.031846	0.107985	0.561483	0.292874	0.094741
0.154696	0.497669	0.374783	0	0	0.110043	0
0.003374	0.002841	0.000815	0.00494	1.085294	0.026954	0.872502
0.169056	0.275038	0.169948	0.834999	2.434698	0.437395	0.164617
0.603843	0.566792	0.301618	0.672654	1.535435	2.074873	2.031341
1.250518	2.040298	0.647208	0.713405	1.867254	2.084582	0.497069
0.006312	0.005923	0.005973	0	0	0.005973	0
0.009834	0.016287	0.010788	0.021114	0.001938	0.011277	0.006741
0.000922	0.001551	0.000546	0.000471	0.000656	0.001867	0.000466
0.005753	0.004301	0.001692	0.008697	1.700317	0.061434	2.183595
0.155025	0.151308	0.031846	0.107985	0.561483	0.292874	0.094741
0.17611	0.566558	0.426662	0	0	0.125276	0
0.003374	0.002841	0.000815	0.00494	1.085294	0.026954	0.872502
0.194354	0.313797	0.19914	0.929912	2.674178	0.487223	0.196917
0.603843	0.566792	0.301618	0.672654	1.535435	2.074873	2.031341
1.338953	2.186635	0.692039	0.762252	2.007642	2.231743	0.53206
0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098
0.008231	0.026479	0.019941	0	0	0.005855	0
0.005872	0.01213	0.003081	0	0	0.007712	0
0	0	0	0	0	0	0
2.529293	3.955628	3.086528	0	0	1.451495	0
1.370893	1.931917	1.623723	5.51775	23.371998	5.120318	5.084938
21.772496	65.087304	11.624986	11.025507	9.827199	35.310007	9.600634
558.961786	524.450208	528.925504	0	0	528.912437	0
998.235235	1662.819964	1089.859128	2143.365925	146.800774	1136.115939	657.208019
59.236621	62.554688	37.01571	29.696388	44.886823	130.613294	32.339247
6.38537	5.100348	6.171066	0	0	7.77559	0
3.662149	6.824618	4.73854	12.941701	1.159392	8.195525	1.722599
2.201793	3.919972	1.547748	1.239148	0.308334	2.301931	0.903018
0.034204	0.027179	0.027152	0	0	0.033352	0
0.11256	0.060052	0.094097	0.679664	0.036749	0.574428	0.050551
0.01124	0.03473	0.010451	0.008	0.008	0.011038	0.00859
0.093253	0.121195	0.063139	0.209684	0.000578	0.088393	0.029094

0.003758	0.003922	0.001248	0.000836	0.001854	0.00737	0.00179
0.031467	0.025005	0.02498	0	0	0.030684	0
0.04824	0.025737	0.040327	0.291285	0.01575	0.246184	0.021665
0.00281	0.008682	0.002613	0.002	0.002	0.002759	0.002147
0.085789	0.111499	0.058087	0.192889	0.000467	0.081246	0.026727
0.003176	0.003151	0.001076	0.000743	0.001467	0.006316	0.001546
0.00411	0.002907	0.001186	0.006858	1.127888	0.047474	1.666334
0.182742	0.187402	0.035009	0.132355	0.623192	0.361068	0.118237
0.177206	0.570084	0.429318	0	0	0.126055	0
0.002194	0.001738	0.00054	0.003517	0.567437	0.01842	0.588696
0.168308	0.274748	0.168506	0.824141	2.514867	0.43494	0.163868
0.668492	0.609357	0.329156	0.83574	1.898047	2.652978	2.181787
1.465078	2.415535	0.742361	0.805192	2.153808	2.416549	0.593399
0.005469	0.005132	0.005176	0	0	0.005175	0
0.009833	0.016287	0.010788	0.021113	0.001952	0.011277	0.00674
0.000995	0.001738	0.000585	0.000503	0.000683	0.001968	0.000501
0.00411	0.002907	0.001186	0.006858	1.127888	0.047474	1.666334
0.182742	0.187402	0.035009	0.132355	0.623192	0.361068	0.118237
0.201735	0.648997	0.488745	0	0	0.143505	0
0.002194	0.001738	0.00054	0.003517	0.567437	0.01842	0.588696
0.193521	0.313479	0.197524	0.918421	2.75856	0.484571	0.195866
0.668492	0.609357	0.329156	0.83574	1.898047	2.652978	2.181787
1.568829	2.588987	0.793772	0.860354	2.315874	2.587544	0.635197

RoadPercentPave	RoadSiltLoading	MaterialSiltContent	MaterialMoistureContent	MobileAverageVehicleWeight	MeanVehicleSpeed
100	0.1	4.3	0.5	2.4	40

WoodstovesLandUseSubType	NumberConventional	NumberCatalytic	NumberNoncatalytic	NumberPellet	WoodstoveDayYear	WoodstoveWoodMass

FireplacesLandUseSubType	NumberWood	NumberGas	NumberPropane	NumberNoFireplace	FireplaceHourDay	FireplaceDayYear	FireplaceWoodMass

ROG_EF
0.0000198

Area_EF_Residential_Interior	Area_Residential_Interior	Area_EF_Residential_Exterior	Area_Residential_Exterior	Area_EF_Nonresidential_Interior	Area_Nonresidential_Interior	Area_EF_Nonresidential_Exterior	Area_Nonresidential_Exterior	ReapplicationRatePercent
50	0	100	0	250	65340	250	21780	10

NumberSnowDays	NumberSummerDays
0	250

EnergyUseLandUseSubType	T24E	NT24E	LightingElect	T24NG	NT24NG
General Heavy Industry	1.99	3.83	3.42	14.78	6.86

WaterLandUseSubType	WaterLandUseSizeMetric	IndoorWaterUseRate	OutdoorWaterUseRate	ElectricityIntensityFactorToSupply	ElectricityIntensityFactorToTreat	ElectricityIntensityFactorToDistribute	ElectricityIntensityFactorForWastewaterTreatment	SepticTankPercent	AerobicPercent	AnaerobicandFacultativeLagoonsPercent	AnaDigestCombDigestGasPercent	AnaDigestCogenCombDigestGasPercent
General Heavy Industry	1000sqft	10073250	0	9727	111	1272	1911	10.33	87.46	2.21	100	0

SolidWasteLandUseSubType	SolidWasteLandUseSizeMetric	SolidWasteGenerationRate	LandfillNoGasCapture	LandfillCaptureGasFlare	LandfillCaptureGasEnergyRecovery
General Heavy Industry	1000sqft	54.01	6	94	0

VegetationLandUseType	VegetationLandUseSubType	AcresBegin	AcresEnd	CO2peracre

BroadSpeciesClass	NumberOfNewTrees	CO2perTree

ConstMitigationEquipmentType	FuelType	Tier	NumberOfEquipmentMitigated	TotalNumberOfEquipmentMitigated	DPF	OxidationCatalyst
Cement and Mortar Mixers	Diesel	No Change	0	1	No Change	0
Concrete/Industrial Saws	Diesel	No Change	0	1	No Change	0
Cranes	Diesel	No Change	0	1	No Change	0
Forklifts	Diesel	No Change	0	1	No Change	0
Generator Sets	Diesel	No Change	0	1	No Change	0
Paving Equipment	Diesel	No Change	0	1	No Change	0
Plate Compactors	Diesel	No Change	0	1	No Change	0
Rubber Tired Dozers	Diesel	No Change	0	2	No Change	0
Tractors/Loaders/Backhoes	Diesel	No Change	0	4	No Change	0
Welders	Diesel	No Change	0	2	No Change	0

SoilStabilizerCheck	SoilStabilizerPM10PercentReduction	SoilStabilizerPM25PercentReduction	ReplaceGroundCoverCheck	ReplaceGroundCoverPM10PercentReduction	ReplaceGroundCoverPM25PercentReduction	WaterExposedAreaCheck	WaterExposedAreaFrequency
0	0	0	0	0	0	1	3

WaterExposedAreaPM10PercentReduction	WaterExposedAreaPM25PercentReduction	WaterUnpavedRoadMoistureContentCheck	WaterUnpavedRoadVehicleSpeedCheck	WaterUnpavedRoadMoistureContent	WaterUnpavedRoadVehicleSpeed	CleanPavedRoadPercentReduction
61	61	0	0	0	0	0

ProjectSetting	IncreaseDensityCheck	IncreaseDensityDUPerAcre	IncreaseDensityJobPerAcre	IncreaseDiversityCheck	ImproveWalkabilityDesignCheck	ImproveWalkabilityDesignIntersections	ImproveDestinationAccessibilityCheck	ImproveDestinationAccessibilityDistance

IncreaseTransitAccessibilityCheck	IncreaseTransitAccessibilityDistance	IntegrateBelowMarketRateHousingCheck	IntegrateBelowMarketRateHousingDU	ImprovePedestrianNetworkCheck	ImprovePedestrianNetworkSelection	ProvideTrafficCalmingMeasuresCheck

ProvideTrafficCalmingMeasuresPercentStreet	ProvideTrafficCalmingMeasuresPercentIntersection	ImplementNEVNetworkCheck	ImplementNEVNetworkNumber	LimitParkingSupplyCheck	LimitParkingSupplySpacePercentReduction	UnbundleParkingCostCheck	UnbundleParkingCostCost

OnStreetMarketPricingCheck	OnStreetMarketPricingPricePercentIncrease	ProvideBRTSystemCheck	ProvideBRTSystemPercentBRT	ExpandTransitNetworkCheck	ExpandTransitNetworkTransitCoveragePercentIncrease	IncreaseTransitFrequencyCheck

IncreaseTransitFrequencyImplementationLevel	IncreaseTransitFrequencyHeadwaysPercentReduction

ImplementTripReductionProgramCheck	ImplementTripReductionProgramPercentEmployee	ImplementTripReductionProgramType	TransitSubsidyCheck	TransitSubsidyPercentEmployee	TransitSubsidyDailySubsidyAmount	ImplementEmployeeParkingCashOutCheck
0			0			0

ImplementEmployeeParkingCashOutPercentEmployee	WorkplaceParkingChargeCheck	WorkplaceParkingChargePercentEmployee	WorkplaceParkingChargeCost	EncourageTelecommutingCheck	EncourageTelecommutingPercentEmployee9_80
	0			0	

EncourageTelecommutingPercentEmployee4_40	EncourageTelecommutingPercentEmployee1_5days	MarketCommuteTripReductionOptionCheck	MarketCommuteTripReductionOptionPercentEmployee	EmployeeVanpoolCheck	EmployeeVanpoolPercentEmployee
		0		0	

EmployeeVanpoolPercentModeShare	ProvideRideSharingProgramCheck	ProvideRideSharingProgramPercentEmployee	ImplementSchoolBusProgramCheck	ImplementSchoolBusProgramPercentFamilyUsing
2	0		0	

LandscapeLawnmowerCheck	LandscapeLawnmowerPercentElectric	LandscapeLeafblowerCheck	LandscapeLeafblowerPercentElectric	LandscapeChainsawCheck	LandscapeChainsawPercentElectric	UseLowVOCPaintResidentialInteriorCheck	UseLowVOCPaintResidentialInteriorValue
0		0		0		0	50

UseLowVOCPaintResidentialExteriorCheck	UseLowVOCPaintResidentialExteriorValue	UseLowVOCPaintNonresidentialInteriorCheck	UseLowVOCPaintNonresidentialInteriorValue	UseLowVOCPaintNonresidentialExteriorCheck	UseLowVOCPaintNonresidentialExteriorValue
0	100	0	250	0	250

HearthOnlyNaturalGasHearthCheck	NoHearthCheck	UseLowVOCCleaningSuppliesCheck
0	0	0

ExceedTitle24Check	ExceedTitle24CheckPercentImprovement	InstallHighEfficiencyLightingCheck	InstallHighEfficiencyLightingPercentEnergyReduction	OnSiteRenewableEnergyCheck	KwhGeneratedCheck	KwhGenerated	PercentOfElectricityUseGeneratedCheck	PercentOfElectricityUseGenerated

ApplianceType	ApplianceLandUseSubType	PercentImprovement
ClothWasher		30
DishWasher		15
Fan		50
Refrigerator		15

ApplyWaterConservationStrategyCheck	ApplyWaterConservationStrategyPercentReductionIndoor	ApplyWaterConservationStrategyPercentReductionOutdoor	UseReclaimedWaterCheck	PercentOutdoorReclaimedWaterUse	PercentIndoorReclaimedWaterUse	UseGreyWaterCheck
0			0			0

PercentOutdoorGreyWaterUse	PercentIndoorGreyWaterUse	InstallLowFlowBathroomFaucetCheck	PercentReductionInFlowBathroomFaucet	InstallLowFlowKitchenFaucetCheck	PercentReductionInFlowKitchenFaucet	InstallLowFlowToiletCheck	PercentReductionInFlowToilet
		0	32	0	18	0	20

InstallLowFlowShowerCheck	PercentReductionInFlowShower	TurfReductionCheck	TurfReductionTurfArea	TurfReductionPercentReduction	UseWaterEfficientIrrigationSystemCheck	UseWaterEfficientIrrigationSystemPercentReduction	WaterEfficientLandscapeCheck	MAWA	ETWU
0	20	0			0	6.1	0		

InstituteRecyclingAndComposting ServicesCheck	InstituteRecyclingAndCompostingServices WastePercentReduction

OperOffRoadEquipmentType	OperOffRoadEquipmentNumber	OperHoursPerDay	OperDaysPerYear	OperHorsePower	OperLoadFactor	OperFuelType

SubModuleID	PhaseName	Season	Remarks
1			
3			
4			Average of construction estimates
5	Architectural Coating		
5	Building Construction		Engineering estimate
5	Demolition		Engineering estimate
5	Grading		Engineering estimate
5	Paving		Engineering estimate
5	Site Preparation		Engineering estimate
6			
8			
9			Engineering estimate
10			
25			

RECLAIM

South Coast AQMD Air District, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
General Heavy Industry	43.56	1000sqft	1.00	43,560.00	0

1.2 Other Project Characteristics

Urbanization Urban **Wind Speed (m/s)** 2.2 **Precipitation Freq (Days)** 31

Climate Zone 8 **Operational Year** 2015

Utility Company Los Angeles Department of Water & Power

CO2 Intensity (lb/MWhr) 1227.89 **CH4 Intensity (lb/MWhr)** 0.029 **N2O Intensity (lb/MWhr)** 0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use -

Construction Phase - Average of construction estimates

Off-road Equipment -

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Trips and VMT -

Demolition -

Grading - Engineering estimate

Architectural Coating -

Construction Off-road Equipment Mitigation -

Table Name	Column Name	Default Value	New Value
tblConstructionPhase	NumDays	100.00	250.00
tblConstructionPhase	NumDays	1.00	2.00
tblConstructionPhase	PhaseEndDate	1/2/2017	1/3/2017
tblConstructionPhase	PhaseEndDate	1/10/2017	6/14/2016
tblConstructionPhase	PhaseStartDate	1/19/2016	1/20/2016
tblConstructionPhase	PhaseStartDate	1/4/2017	6/8/2016
tblGrading	AcresOfGrading	0.00	1.00
tblOffRoadEquipment	HorsePower	8.00	125.00
tblOffRoadEquipment	LoadFactor	0.43	0.42
tblOffRoadEquipment	OffRoadEquipmentType		Cranes
tblOffRoadEquipment	OffRoadEquipmentType		Trenchers
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	2.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	PhaseName		Paving
tblOffRoadEquipment	PhaseName		Demolition
tblOffRoadEquipment	PhaseName		Site Preparation
tblOffRoadEquipment	PhaseName		Building Construction
tblProjectCharacteristics	OperationalYear	2014	2015
tblTripsAndVMT	WorkerTripNumber	8.00	15.00
tblTripsAndVMT	WorkerTripNumber	5.00	8.00
tblTripsAndVMT	WorkerTripNumber	10.00	13.00

2.0 Emissions Summary

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2016	0.3813	2.7264	2.0892	3.2800e-003	0.0427	0.1684	0.2111	0.0122	0.1613	0.1735	0.0000	283.1063	283.1063	0.0559	0.0000	284.2792
2017	2.6200e-003	0.0188	0.0152	2.0000e-005	2.4000e-004	1.1400e-003	1.3800e-003	6.0000e-005	1.0900e-003	1.1500e-003	0.0000	2.1233	2.1233	4.0000e-004	0.0000	2.1317
Total	**0.3840**	**2.7453**	**2.1045**	**3.3000e-003**	**0.0429**	**0.1695**	**0.2125**	**0.0123**	**0.1623**	**0.1746**	**0.0000**	**285.2296**	**285.2296**	**0.0563**	**0.0000**	**286.4110**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2016	0.3813	2.6078	2.0892	3.2800e-003	0.0359	0.1684	0.2043	9.9500e-003	0.1613	0.1712	0.0000	283.1060	283.1060	0.0559	0.0000	284.2790
2017	2.6200e-003	0.0180	0.0152	2.0000e-005	2.4000e-004	1.1400e-003	1.3800e-003	6.0000e-005	1.0900e-003	1.1500e-003	0.0000	2.1233	2.1233	4.0000e-004	0.0000	2.1317
Total	**0.3840**	**2.6258**	**2.1045**	**3.3000e-003**	**0.0361**	**0.1695**	**0.2057**	**0.0100**	**0.1623**	**0.1724**	**0.0000**	**285.2293**	**285.2293**	**0.0563**	**0.0000**	**286.4107**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**4.35**	**0.00**	**0.00**	**15.87**	**0.00**	**3.20**	**18.62**	**0.00**	**1.31**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.2079	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Energy	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	274.4767	274.4767	6.2600e-003	2.0200e-003	275.2336
Mobile	0.0540	0.1949	0.7133	1.5900e-003	0.1096	2.7600e-003	0.1124	0.0293	2.5400e-003	0.0319	0.0000	130.1681	130.1681	5.5600e-003	0.0000	130.2848
Waste						0.0000	0.0000		0.0000	0.0000	10.9635	0.0000	10.9635	0.6479	0.0000	24.5700
Water						0.0000	0.0000		0.0000	0.0000	3.1958	73.0532	76.2490	0.3300	8.1100e-003	85.6915
Total	**0.2670**	**0.2411**	**0.7527**	**1.8700e-003**	**0.1096**	**6.2700e-003**	**0.1159**	**0.0293**	**6.0500e-003**	**0.0354**	**14.1593**	**477.6990**	**491.8584**	**0.9897**	**0.0101**	**515.7810**

2.2 Overall Operational

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.2079	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Energy	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	274.4767	274.4767	6.2600e-003	2.0200e-003	275.2336
Mobile	0.0540	0.1949	0.7133	1.5900e-003	0.1096	2.7600e-003	0.1124	0.0293	2.5400e-003	0.0319	0.0000	130.1681	130.1681	5.5600e-003	0.0000	130.2848
Waste						0.0000	0.0000		0.0000	0.0000	10.9635	0.0000	10.9635	0.6479	0.0000	24.5700
Water						0.0000	0.0000		0.0000	0.0000	3.1958	73.0532	76.2490	0.3299	8.0900e-003	85.6864
Total	**0.2670**	**0.2411**	**0.7527**	**1.8700e-003**	**0.1096**	**6.2700e-003**	**0.1159**	**0.0293**	**6.0500e-003**	**0.0354**	**14.1593**	**477.6990**	**491.8584**	**0.9897**	**0.0101**	**515.7759**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.01**	**0.20**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Demolition	Demolition	1/1/2016	1/14/2016	5	10	
2	Site Preparation	Site Preparation	1/15/2016	1/18/2016	5	2	
3	Building Construction	Building Construction	1/20/2016	1/3/2017	5	250	
4	Paving	Paving	6/8/2016	6/14/2016	5	5	

Acres of Grading (Site Preparation Phase): 1

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Demolition	Concrete/Industrial Saws	1	8.00	81	0.73
Demolition	Rubber Tired Dozers	1	8.00	255	0.40
Demolition	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Site Preparation	Rubber Tired Dozers	1	7.00	255	0.40
Site Preparation	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Building Construction	Cranes	1	6.00	226	0.29
Building Construction	Forklifts	1	6.00	89	0.20
Building Construction	Generator Sets	1	8.00	84	0.74
Building Construction	Tractors/Loaders/Backhoes	1	6.00	97	0.37
Building Construction	Welders	2	8.00	46	0.45
Paving	Cement and Mortar Mixers	1	6.00	9	0.56
Paving	Paving Equipment	1	8.00	130	0.36
Paving	Plate Compactors	1	6.00	125	0.42
Paving	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Demolition	Cranes	1	8.00	226	0.29
Site Preparation	Trenchers	1	8.00	80	0.50
Building Construction	Aerial Lifts	1	8.00	62	0.31

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Demolition	3	15.00	0.00	49.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Site Preparation	2	8.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Building Construction	6	18.00	7.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Paving	4	13.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Water Exposed Area

3.2 Demolition - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					5.3500e-003	0.0000	5.3500e-003	8.1000e-004	0.0000	8.1000e-004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.0147	0.1511	0.0982	1.2000e-004		8.1400e-003	8.1400e-003		7.6300e-003	7.6300e-003	0.0000	10.9868	10.9868	2.7600e-003	0.0000	11.0448
Total	**0.0147**	**0.1511**	**0.0982**	**1.2000e-004**	**5.3500e-003**	**8.1400e-003**	**0.0135**	**8.1000e-004**	**7.6300e-003**	**8.4400e-003**	**0.0000**	**10.9868**	**10.9868**	**2.7600e-003**	**0.0000**	**11.0448**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	4.4000e-004	7.0800e-003	5.3500e-003	2.0000e-005	4.2000e-004	1.1000e-004	5.3000e-004	1.2000e-004	1.0000e-004	2.1000e-004	0.0000	1.6501	1.6501	1.0000e-005	0.0000	1.6503
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	3.0000e-004	4.4000e-004	4.6000e-003	1.0000e-005	8.2000e-004	1.0000e-005	8.3000e-004	2.2000e-004	1.0000e-005	2.2000e-004	0.0000	0.7709	0.7709	4.0000e-005	0.0000	0.7718
Total	**7.4000e-004**	**7.5200e-003**	**9.9500e-003**	**3.0000e-005**	**1.2400e-003**	**1.2000e-004**	**1.3600e-003**	**3.4000e-004**	**1.1000e-004**	**4.3000e-004**	**0.0000**	**2.4210**	**2.4210**	**5.0000e-005**	**0.0000**	**2.4221**

3.2 Demolition - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					2.0900e-003	0.0000	2.0900e-003	3.2000e-004	0.0000	3.2000e-004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	0.0147	0.1511	0.0982	1.2000e-004		8.1400e-003	8.1400e-003		7.6300e-003	7.6300e-003	0.0000	10.9868	10.9868	2.7600e-003	0.0000	11.0448
Total	**0.0147**	**0.1511**	**0.0982**	**1.2000e-004**	**2.0900e-003**	**8.1400e-003**	**0.0102**	**3.2000e-004**	**7.6300e-003**	**7.9500e-003**	**0.0000**	**10.9868**	**10.9868**	**2.7600e-003**	**0.0000**	**11.0448**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	4.4000e-004	7.0800e-003	5.3500e-003	2.0000e-005	4.2000e-004	1.1000e-004	5.3000e-004	1.2000e-004	1.0000e-004	2.1000e-004	0.0000	1.6501	1.6501	1.0000e-005	0.0000	1.6503
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	3.0000e-004	4.4000e-004	4.6000e-003	1.0000e-005	8.2000e-004	1.0000e-005	8.3000e-004	2.2000e-004	1.0000e-005	2.2000e-004	0.0000	0.7709	0.7709	4.0000e-005	0.0000	0.7718
Total	**7.4000e-004**	**7.5200e-003**	**9.9500e-003**	**3.0000e-005**	**1.2400e-003**	**1.2000e-004**	**1.3600e-003**	**3.4000e-004**	**1.1000e-004**	**4.3000e-004**	**0.0000**	**2.4210**	**2.4210**	**5.0000e-005**	**0.0000**	**2.4221**

3.3 Site Preparation - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					5.8000e-003	0.0000	5.8000e-003	2.9500e-003	0.0000	2.9500e-003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	1.9800e-003	0.0203	0.0144	1.0000e-005		1.2000e-003	1.2000e-003		1.1000e-003	1.1000e-003	0.0000	1.3530	1.3530	4.1000e-004	0.0000	1.3616
Total	**1.9800e-003**	**0.0203**	**0.0144**	**1.0000e-005**	**5.8000e-003**	**1.2000e-003**	**7.0000e-003**	**2.9500e-003**	**1.1000e-003**	**4.0500e-003**	**0.0000**	**1.3530**	**1.3530**	**4.1000e-004**	**0.0000**	**1.3616**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	3.0000e-005	5.0000e-005	4.9000e-004	0.0000	9.0000e-005	0.0000	9.0000e-005	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0822	0.0822	0.0000	0.0000	0.0823
Total	**3.0000e-005**	**5.0000e-005**	**4.9000e-004**	**0.0000**	**9.0000e-005**	**0.0000**	**9.0000e-005**	**2.0000e-005**	**0.0000**	**2.0000e-005**	**0.0000**	**0.0822**	**0.0822**	**0.0000**	**0.0000**	**0.0823**

3.3 Site Preparation - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Fugitive Dust					2.2600e-003	0.0000	2.2600e-003	1.1500e-003	0.0000	1.1500e-003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Off-Road	1.9800e-003	0.0154	0.0144	1.0000e-005		1.2000e-003	1.2000e-003		1.1000e-003	1.1000e-003	0.0000	1.3530	1.3530	4.1000e-004	0.0000	1.3616
Total	**1.9800e-003**	**0.0154**	**0.0144**	**1.0000e-005**	**2.2600e-003**	**1.2000e-003**	**3.4600e-003**	**1.1500e-003**	**1.1000e-003**	**2.2500e-003**	**0.0000**	**1.3530**	**1.3530**	**4.1000e-004**	**0.0000**	**1.3616**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	3.0000e-005	5.0000e-005	4.9000e-004	0.0000	9.0000e-005	0.0000	9.0000e-005	2.0000e-005	0.0000	2.0000e-005	0.0000	0.0822	0.0822	0.0000	0.0000	0.0823
Total	**3.0000e-005**	**5.0000e-005**	**4.9000e-004**	**0.0000**	**9.0000e-005**	**0.0000**	**9.0000e-005**	**2.0000e-005**	**0.0000**	**2.0000e-005**	**0.0000**	**0.0822**	**0.0822**	**0.0000**	**0.0000**	**0.0823**

3.4 Building Construction - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.3454	2.4380	1.7133	2.6100e-003		0.1564	0.1564		0.1501	0.1501	0.0000	226.1142	226.1142	0.0507	0.0000	227.1795
Total	**0.3454**	**2.4380**	**1.7133**	**2.6100e-003**		**0.1564**	**0.1564**		**0.1501**	**0.1501**	**0.0000**	**226.1142**	**226.1142**	**0.0507**	**0.0000**	**227.1795**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	7.7000e-003	0.0784	0.1010	1.9000e-004	5.3400e-003	1.2400e-003	6.5800e-003	1.5200e-003	1.1400e-003	2.6600e-003	0.0000	17.1079	17.1079	1.2000e-004	0.0000	17.1105
Worker	8.9700e-003	0.0132	0.1370	3.0000e-004	0.0245	2.1000e-004	0.0247	6.5000e-003	1.9000e-004	6.7000e-003	0.0000	22.9422	22.9422	1.2400e-003	0.0000	22.9681
Total	**0.0167**	**0.0916**	**0.2380**	**4.9000e-004**	**0.0298**	**1.4500e-003**	**0.0313**	**8.0200e-003**	**1.3300e-003**	**9.3600e-003**	**0.0000**	**40.0501**	**40.0501**	**1.3600e-003**	**0.0000**	**40.0786**

3.4 Building Construction - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.3454	2.3242	1.7133	2.6100e-003		0.1564	0.1564		0.1501	0.1501	0.0000	226.1139	226.1139	0.0507	0.0000	227.1793
Total	**0.3454**	**2.3242**	**1.7133**	**2.6100e-003**		**0.1564**	**0.1564**		**0.1501**	**0.1501**	**0.0000**	**226.1139**	**226.1139**	**0.0507**	**0.0000**	**227.1793**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	7.7000e-003	0.0784	0.1010	1.9000e-004	5.3400e-003	1.2400e-003	6.5800e-003	1.5200e-003	1.1400e-003	2.6600e-003	0.0000	17.1079	17.1079	1.2000e-004	0.0000	17.1105
Worker	8.9700e-003	0.0132	0.1370	3.0000e-004	0.0245	2.1000e-004	0.0247	6.5000e-003	1.9000e-004	6.7000e-003	0.0000	22.9422	22.9422	1.2400e-003	0.0000	22.9681
Total	**0.0167**	**0.0916**	**0.2380**	**4.9000e-004**	**0.0298**	**1.4500e-003**	**0.0313**	**8.0200e-003**	**1.3300e-003**	**9.3600e-003**	**0.0000**	**40.0501**	**40.0501**	**1.3600e-003**	**0.0000**	**40.0786**

3.4 Building Construction - 2017

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	2.5000e-003	0.0182	0.0135	2.0000e-005		1.1300e-003	1.1300e-003		1.0800e-003	1.0800e-003	0.0000	1.8096	1.8096	3.9000e-004	0.0000	1.8179
Total	**2.5000e-003**	**0.0182**	**0.0135**	**2.0000e-005**		**1.1300e-003**	**1.1300e-003**		**1.0800e-003**	**1.0800e-003**	**0.0000**	**1.8096**	**1.8096**	**3.9000e-004**	**0.0000**	**1.8179**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	6.0000e-005	5.7000e-004	7.7000e-004	0.0000	4.0000e-005	1.0000e-005	5.0000e-005	1.0000e-005	1.0000e-005	2.0000e-005	0.0000	0.1357	0.1357	0.0000	0.0000	0.1358
Worker	6.0000e-005	1.0000e-004	1.0000e-003	0.0000	2.0000e-004	0.0000	2.0000e-004	5.0000e-005	0.0000	5.0000e-005	0.0000	0.1779	0.1779	1.0000e-005	0.0000	0.1781
Total	**1.2000e-004**	**6.7000e-004**	**1.7700e-003**	**0.0000**	**2.4000e-004**	**1.0000e-005**	**2.5000e-004**	**6.0000e-005**	**1.0000e-005**	**7.0000e-005**	**0.0000**	**0.3136**	**0.3136**	**1.0000e-005**	**0.0000**	**0.3139**

3.4 Building Construction - 2017

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	2.5000e-003	0.0174	0.0135	2.0000e-005		1.1300e-003	1.1300e-003		1.0800e-003	1.0800e-003	0.0000	1.8096	1.8096	3.9000e-004	0.0000	1.8179
Total	**2.5000e-003**	**0.0174**	**0.0135**	**2.0000e-005**		**1.1300e-003**	**1.1300e-003**		**1.0800e-003**	**1.0800e-003**	**0.0000**	**1.8096**	**1.8096**	**3.9000e-004**	**0.0000**	**1.8179**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	6.0000e-005	5.7000e-004	7.7000e-004	0.0000	4.0000e-005	1.0000e-005	5.0000e-005	1.0000e-005	1.0000e-005	2.0000e-005	0.0000	0.1357	0.1357	0.0000	0.0000	0.1358
Worker	6.0000e-005	1.0000e-004	1.0000e-003	0.0000	2.0000e-004	0.0000	2.0000e-004	5.0000e-005	0.0000	5.0000e-005	0.0000	0.1779	0.1779	1.0000e-005	0.0000	0.1781
Total	**1.2000e-004**	**6.7000e-004**	**1.7700e-003**	**0.0000**	**2.4000e-004**	**1.0000e-005**	**2.5000e-004**	**6.0000e-005**	**1.0000e-005**	**7.0000e-005**	**0.0000**	**0.3136**	**0.3136**	**1.0000e-005**	**0.0000**	**0.3139**

3.5 Paving - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	1.7300e-003	0.0178	0.0130	2.0000e-005		1.1000e-003	1.1000e-003		1.0100e-003	1.0100e-003	0.0000	1.7650	1.7650	5.2000e-004	0.0000	1.7759
Paving	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**1.7300e-003**	**0.0178**	**0.0130**	**2.0000e-005**		**1.1000e-003**	**1.1000e-003**		**1.0100e-003**	**1.0100e-003**	**0.0000**	**1.7650**	**1.7650**	**5.2000e-004**	**0.0000**	**1.7759**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	1.3000e-004	1.9000e-004	1.9900e-003	0.0000	3.6000e-004	0.0000	3.6000e-004	9.0000e-005	0.0000	1.0000e-004	0.0000	0.3341	0.3341	2.0000e-005	0.0000	0.3344
Total	**1.3000e-004**	**1.9000e-004**	**1.9900e-003**	**0.0000**	**3.6000e-004**	**0.0000**	**3.6000e-004**	**9.0000e-005**	**0.0000**	**1.0000e-004**	**0.0000**	**0.3341**	**0.3341**	**2.0000e-005**	**0.0000**	**0.3344**

3.5 Paving - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	1.7300e-003	0.0178	0.0130	2.0000e-005		1.1000e-003	1.1000e-003		1.0100e-003	1.0100e-003	0.0000	1.7650	1.7650	5.2000e-004	0.0000	1.7759
Paving	0.0000					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**1.7300e-003**	**0.0178**	**0.0130**	**2.0000e-005**		**1.1000e-003**	**1.1000e-003**		**1.0100e-003**	**1.0100e-003**	**0.0000**	**1.7650**	**1.7650**	**5.2000e-004**	**0.0000**	**1.7759**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	1.3000e-004	1.9000e-004	1.9900e-003	0.0000	3.6000e-004	0.0000	3.6000e-004	9.0000e-005	0.0000	1.0000e-004	0.0000	0.3341	0.3341	2.0000e-005	0.0000	0.3344
Total	**1.3000e-004**	**1.9000e-004**	**1.9900e-003**	**0.0000**	**3.6000e-004**	**0.0000**	**3.6000e-004**	**9.0000e-005**	**0.0000**	**1.0000e-004**	**0.0000**	**0.3341**	**0.3341**	**2.0000e-005**	**0.0000**	**0.3344**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.0540	0.1949	0.7133	1.5900e-003	0.1096	2.7600e-003	0.1124	0.0293	2.5400e-003	0.0319	0.0000	130.1681	130.1681	5.5600e-003	0.0000	130.2848
Unmitigated	0.0540	0.1949	0.7133	1.5900e-003	0.1096	2.7600e-003	0.1124	0.0293	2.5400e-003	0.0319	0.0000	130.1681	130.1681	5.5600e-003	0.0000	130.2848

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
General Heavy Industry	65.34	65.34	65.34	289,344	289,344
Total	65.34	65.34	65.34	289,344	289,344

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
General Heavy Industry	16.60	8.40	6.90	59.00	28.00	13.00	92	5	3

4.4 Fleet Mix

LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.514499	0.060499	0.179997	0.139763	0.042095	0.006675	0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Electricity Mitigated						0.0000	0.0000		0.0000	0.0000	0.0000	224.1739	224.1739	5.2900e-003	1.1000e-003	224.6247
Electricity Unmitigated						0.0000	0.0000		0.0000	0.0000	0.0000	224.1739	224.1739	5.2900e-003	1.1000e-003	224.6247
NaturalGas Mitigated	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	50.3028	50.3028	9.6000e-004	9.2000e-004	50.6089
NaturalGas Unmitigated	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	50.3028	50.3028	9.6000e-004	9.2000e-004	50.6089

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
General Heavy Industry	942638	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	50.3028	50.3028	9.6000e-004	9.2000e-004	50.6089
Total		**5.0800e-003**	**0.0462**	**0.0388**	**2.8000e-004**		**3.5100e-003**	**3.5100e-003**		**3.5100e-003**	**3.5100e-003**	**0.0000**	**50.3028**	**50.3028**	**9.6000e-004**	**9.2000e-004**	**50.6089**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	tons/yr										MT/yr					
General Heavy Industry	942638	5.0800e-003	0.0462	0.0388	2.8000e-004		3.5100e-003	3.5100e-003		3.5100e-003	3.5100e-003	0.0000	50.3028	50.3028	9.6000e-004	9.2000e-004	50.6089
Total		**5.0800e-003**	**0.0462**	**0.0388**	**2.8000e-004**		**3.5100e-003**	**3.5100e-003**		**3.5100e-003**	**3.5100e-003**	**0.0000**	**50.3028**	**50.3028**	**9.6000e-004**	**9.2000e-004**	**50.6089**

5.3 Energy by Land Use - Electricity

Unmitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
General Heavy Industry	402494	224.1739	5.2900e-003	1.1000e-003	224.6247
Total		**224.1739**	**5.2900e-003**	**1.1000e-003**	**224.6247**

5.3 Energy by Land Use - Electricity

Mitigated

	Electricity Use	Total CO2	CH4	N2O	CO2e
Land Use	kWh/yr	MT/yr			
General Heavy Industry	402494	224.1739	5.2900e-003	1.1000e-003	224.6247
Total		**224.1739**	**5.2900e-003**	**1.1000e-003**	**224.6247**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Mitigated	0.2079	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Unmitigated	0.2079	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0505					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.1574					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	6.0000e-005	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Total	**0.2079**	**1.0000e-005**	**5.8000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**1.0800e-003**	**1.0800e-003**	**0.0000**	**0.0000**	**1.1500e-003**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	tons/yr										MT/yr					
Architectural Coating	0.0505					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Consumer Products	0.1574					0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Landscaping	6.0000e-005	1.0000e-005	5.8000e-004	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	1.0800e-003	1.0800e-003	0.0000	0.0000	1.1500e-003
Total	**0.2079**	**1.0000e-005**	**5.8000e-004**	**0.0000**		**0.0000**	**0.0000**		**0.0000**	**0.0000**	**0.0000**	**1.0800e-003**	**1.0800e-003**	**0.0000**	**0.0000**	**1.1500e-003**

7.0 Water Detail

7.1 Mitigation Measures Water

	Total CO2	CH4	N2O	CO2e
Category	MT/yr			
Mitigated	76.2490	0.3299	8.0900e-003	85.6864
Unmitigated	76.2490	0.3300	8.1100e-003	85.6915

7.2 Water by Land Use

Unmitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
General Heavy Industry	10.0733 / 0	76.2490	0.3300	8.1100e-003	85.6915
Total		**76.2490**	**0.3300**	**8.1100e-003**	**85.6915**

7.2 Water by Land Use

Mitigated

	Indoor/Outdoor Use	Total CO2	CH4	N2O	CO2e
Land Use	Mgal	MT/yr			
General Heavy Industry	10.0733 / 0	76.2490	0.3299	8.0900e-003	85.6864
Total		**76.2490**	**0.3299**	**8.0900e-003**	**85.6864**

8.0 Waste Detail

8.1 Mitigation Measures Waste

Category/Year

	Total CO2	CH4	N2O	CO2e
	MT/yr			
Mitigated	10.9635	0.6479	0.0000	24.5700
Unmitigated	10.9635	0.6479	0.0000	24.5700

8.2 Waste by Land Use

Unmitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
General Heavy Industry	54.01	10.9635	0.6479	0.0000	24.5700
Total		**10.9635**	**0.6479**	**0.0000**	**24.5700**

Mitigated

	Waste Disposed	Total CO2	CH4	N2O	CO2e
Land Use	tons	MT/yr			
General Heavy Industry	54.01	10.9635	0.6479	0.0000	24.5700
Total		**10.9635**	**0.6479**	**0.0000**	**24.5700**

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Vegetation

RECLAIM

South Coast AQMD Air District, Summer

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
General Heavy Industry	43.56	1000sqft	1.00	43,560.00	0

1.2 Other Project Characteristics

Urbanization	Urban	**Wind Speed (m/s)**	2.2	**Precipitation Freq (Days)**	31
Climate Zone	8			**Operational Year**	2015
Utility Company	Los Angeles Department of Water & Power				
CO2 Intensity (lb/MWhr)	1227.89	**CH4 Intensity (lb/MWhr)**	0.029	**N2O Intensity (lb/MWhr)**	0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use -

Construction Phase - Average of construction estimates

Off-road Equipment -

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Trips and VMT -

Demolition -

Grading - Engineering estimate

Architectural Coating -

Construction Off-road Equipment Mitigation -

Table Name	Column Name	Default Value	New Value
tblConstructionPhase	NumDays	100.00	250.00
tblConstructionPhase	NumDays	1.00	2.00
tblConstructionPhase	PhaseEndDate	1/2/2017	1/3/2017
tblConstructionPhase	PhaseEndDate	1/10/2017	6/14/2016
tblConstructionPhase	PhaseStartDate	1/19/2016	1/20/2016
tblConstructionPhase	PhaseStartDate	1/4/2017	6/8/2016
tblGrading	AcresOfGrading	0.00	1.00
tblOffRoadEquipment	HorsePower	8.00	125.00
tblOffRoadEquipment	LoadFactor	0.43	0.42
tblOffRoadEquipment	OffRoadEquipmentType		Cranes
tblOffRoadEquipment	OffRoadEquipmentType		Trenchers
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	2.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	PhaseName		Paving
tblOffRoadEquipment	PhaseName		Demolition
tblOffRoadEquipment	PhaseName		Site Preparation
tblOffRoadEquipment	PhaseName		Building Construction
tblProjectCharacteristics	OperationalYear	2014	2015
tblTripsAndVMT	WorkerTripNumber	8.00	15.00
tblTripsAndVMT	WorkerTripNumber	5.00	8.00
tblTripsAndVMT	WorkerTripNumber	10.00	13.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2016	3.6645	31.6449	21.7158	0.0346	5.8890	1.7129	7.0870	2.9774	1.6266	4.0796	0.0000	3,309.6669	3,309.6669	0.6983	0.0000	3,324.3300
2017	2.6227	18.7997	15.1854	0.0251	0.2450	1.1365	1.3815	0.0658	1.0901	1.1559	0.0000	2,350.8133	2,350.8133	0.4446	0.0000	2,360.1495
Total	**6.2872**	**50.4446**	**36.9013**	**0.0597**	**6.1340**	**2.8494**	**8.4685**	**3.0432**	**2.7167**	**5.2355**	**0.0000**	**5,660.4802**	**5,660.4802**	**1.1428**	**0.0000**	**5,684.4796**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2016	3.6645	31.6449	21.7158	0.0346	2.3513	1.7129	3.5493	1.1757	1.6266	2.2778	0.0000	3,309.6669	3,309.6669	0.6983	0.0000	3,324.3300
2017	2.6227	18.0031	15.1854	0.0251	0.2450	1.1365	1.3815	0.0658	1.0901	1.1559	0.0000	2,350.8133	2,350.8133	0.4446	0.0000	2,360.1495
Total	**6.2872**	**49.6480**	**36.9013**	**0.0597**	**2.5962**	**2.8494**	**4.9307**	**1.2415**	**2.7167**	**3.4337**	**0.0000**	**5,660.4802**	**5,660.4802**	**1.1428**	**0.0000**	**5,684.4796**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**1.58**	**0.00**	**0.00**	**57.67**	**0.00**	**41.78**	**59.21**	**0.00**	**34.41**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Energy	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Mobile	0.3017	0.9956	4.0124	9.0800e-003	0.6134	0.0152	0.6285	0.1639	0.0139	0.1778		819.7953	819.7953	0.0337		820.5028
Total	**1.4690**	**1.2488**	**4.2297**	**0.0106**	**0.6134**	**0.0344**	**0.6478**	**0.1639**	**0.0332**	**0.1971**		**1,123.6367**	**1,123.6367**	**0.0395**	**5.5700e-003**	**1,126.1938**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Energy	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Mobile	0.3017	0.9956	4.0124	9.0800e-003	0.6134	0.0152	0.6285	0.1639	0.0139	0.1778		819.7953	819.7953	0.0337		820.5028
Total	**1.4690**	**1.2488**	**4.2297**	**0.0106**	**0.6134**	**0.0344**	**0.6478**	**0.1639**	**0.0332**	**0.1971**		**1,123.6367**	**1,123.6367**	**0.0395**	**5.5700e-003**	**1,126.1938**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Demolition	Demolition	1/1/2016	1/14/2016	5	10	
2	Site Preparation	Site Preparation	1/15/2016	1/18/2016	5	2	
3	Building Construction	Building Construction	1/20/2016	1/3/2017	5	250	
4	Paving	Paving	6/8/2016	6/14/2016	5	5	

Acres of Grading (Site Preparation Phase): 1

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Demolition	Concrete/Industrial Saws	1	8.00	81	0.73
Demolition	Rubber Tired Dozers	1	8.00	255	0.40
Demolition	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Site Preparation	Rubber Tired Dozers	1	7.00	255	0.40
Site Preparation	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Building Construction	Cranes	1	6.00	226	0.29
Building Construction	Forklifts	1	6.00	89	0.20
Building Construction	Generator Sets	1	8.00	84	0.74
Building Construction	Tractors/Loaders/Backhoes	1	6.00	97	0.37
Building Construction	Welders	2	8.00	46	0.45
Paving	Cement and Mortar Mixers	1	6.00	9	0.56
Paving	Paving Equipment	1	8.00	130	0.36
Paving	Plate Compactors	1	6.00	125	0.42
Paving	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Demolition	Cranes	1	8.00	226	0.29
Site Preparation	Trenchers	1	8.00	80	0.50
Building Construction	Aerial Lifts	1	8.00	62	0.31

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Demolition	3	15.00	0.00	49.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Site Preparation	2	8.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Building Construction	6	18.00	7.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Paving	4	13.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Water Exposed Area

3.2 Demolition - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.0700	0.0000	1.0700	0.1620	0.0000	0.1620			0.0000			0.0000
Off-Road	2.9407	30.2234	19.6380	0.0239		1.6279	1.6279		1.5254	1.5254		2,422.1689	2,422.1689	0.6092		2,434.9621
Total	**2.9407**	**30.2234**	**19.6380**	**0.0239**	**1.0700**	**1.6279**	**2.6978**	**0.1620**	**1.5254**	**1.6874**		**2,422.1689**	**2,422.1689**	**0.6092**		**2,434.9621**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0838	1.3432	0.9500	3.6100e-003	0.0854	0.0213	0.1067	0.0234	0.0196	0.0430		364.1444	364.1444	2.5900e-003		364.1987
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0627	0.0783	0.9750	2.1200e-003	0.1677	1.4000e-003	0.1691	0.0445	1.2900e-003	0.0458		178.4188	178.4188	9.1500e-003		178.6110
Total	**0.1465**	**1.4215**	**1.9251**	**5.7300e-003**	**0.2530**	**0.0227**	**0.2758**	**0.0679**	**0.0209**	**0.0887**		**542.5631**	**542.5631**	**0.0117**		**542.8097**

3.2 Demolition - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					0.4173	0.0000	0.4173	0.0632	0.0000	0.0632			0.0000			0.0000
Off-Road	2.9407	30.2234	19.6380	0.0239		1.6279	1.6279		1.5254	1.5254	0.0000	2,422.168 9	2,422.168 9	0.6092		2,434.962 1
Total	**2.9407**	**30.2234**	**19.6380**	**0.0239**	**0.4173**	**1.6279**	**2.0452**	**0.0632**	**1.5254**	**1.5886**	**0.0000**	**2,422.168 9**	**2,422.168 9**	**0.6092**		**2,434.962 1**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0838	1.3432	0.9500	3.6100e-003	0.0854	0.0213	0.1067	0.0234	0.0196	0.0430		364.1444	364.1444	2.5900e-003		364.1987
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0627	0.0783	0.9750	2.1200e-003	0.1677	1.4000e-003	0.1691	0.0445	1.2900e-003	0.0458		178.4188	178.4188	9.1500e-003		178.6110
Total	**0.1465**	**1.4215**	**1.9251**	**5.7300e-003**	**0.2530**	**0.0227**	**0.2758**	**0.0679**	**0.0209**	**0.0887**		**542.5631**	**542.5631**	**0.0117**		**542.8097**

3.3 Site Preparation - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					5.7996	0.0000	5.7996	2.9537	0.0000	2.9537			0.0000			0.0000
Off-Road	1.9799	20.2613	14.4005	0.0143		1.1973	1.1973		1.1015	1.1015		1,491.4061	1,491.4061	0.4499		1,500.8532
Total	**1.9799**	**20.2613**	**14.4005**	**0.0143**	**5.7996**	**1.1973**	**6.9968**	**2.9537**	**1.1015**	**4.0552**		**1,491.4061**	**1,491.4061**	**0.4499**		**1,500.8532**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0334	0.0418	0.5200	1.1300e-003	0.0894	7.5000e-004	0.0902	0.0237	6.9000e-004	0.0244		95.1567	95.1567	4.8800e-003		95.2592
Total	**0.0334**	**0.0418**	**0.5200**	**1.1300e-003**	**0.0894**	**7.5000e-004**	**0.0902**	**0.0237**	**6.9000e-004**	**0.0244**		**95.1567**	**95.1567**	**4.8800e-003**		**95.2592**

3.3 Site Preparation - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					2.2618	0.0000	2.2618	1.1519	0.0000	1.1519			0.0000			0.0000
Off-Road	1.9799	15.3919	14.4005	0.0143		1.1973	1.1973		1.1015	1.1015	0.0000	1,491.406 1	1,491.406 1	0.4499		1,500.853 2
Total	**1.9799**	**15.3919**	**14.4005**	**0.0143**	**2.2618**	**1.1973**	**3.4591**	**1.1519**	**1.1015**	**2.2534**	**0.0000**	**1,491.406 1**	**1,491.406 1**	**0.4499**		**1,500.853 2**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0334	0.0418	0.5200	1.1300e-003	0.0894	7.5000e-004	0.0902	0.0237	6.9000e-004	0.0244		95.1567	95.1567	4.8800e-003		95.2592
Total	**0.0334**	**0.0418**	**0.5200**	**1.1300e-003**	**0.0894**	**7.5000e-004**	**0.0902**	**0.0237**	**6.9000e-004**	**0.0244**		**95.1567**	**95.1567**	**4.8800e-003**		**95.2592**

3.4 Building Construction - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.7851	19.6612	13.8165	0.0210		1.2613	1.2613		1.2102	1.2102		2,010.0661	2,010.0661	0.4510		2,019.5367
Total	**2.7851**	**19.6612**	**13.8165**	**0.0210**		**1.2613**	**1.2613**		**1.2102**	**1.2102**		**2,010.0661**	**2,010.0661**	**0.4510**		**2,019.5367**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0583	0.6046	0.6971	1.5200e-003	0.0438	9.9500e-003	0.0537	0.0125	9.1500e-003	0.0216		152.6202	152.6202	1.0900e-003		152.6431
Worker	0.0752	0.0940	1.1700	2.5500e-003	0.2012	1.6800e-003	0.2029	0.0534	1.5500e-003	0.0549		214.1025	214.1025	0.0110		214.3332
Total	**0.1335**	**0.6986**	**1.8672**	**4.0700e-003**	**0.2450**	**0.0116**	**0.2566**	**0.0658**	**0.0107**	**0.0765**		**366.7228**	**366.7228**	**0.0121**		**366.9763**

3.4 Building Construction - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.7851	18.7438	13.8165	0.0210		1.2613	1.2613		1.2102	1.2102	0.0000	2,010.0661	2,010.0661	0.4510		2,019.5367
Total	**2.7851**	**18.7438**	**13.8165**	**0.0210**		**1.2613**	**1.2613**		**1.2102**	**1.2102**	**0.0000**	**2,010.0661**	**2,010.0661**	**0.4510**		**2,019.5367**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0583	0.6046	0.6971	1.5200e-003	0.0438	9.9500e-003	0.0537	0.0125	9.1500e-003	0.0216		152.6202	152.6202	1.0900e-003		152.6431
Worker	0.0752	0.0940	1.1700	2.5500e-003	0.2012	1.6800e-003	0.2029	0.0534	1.5500e-003	0.0549		214.1025	214.1025	0.0110		214.3332
Total	**0.1335**	**0.6986**	**1.8672**	**4.0700e-003**	**0.2450**	**0.0116**	**0.2566**	**0.0658**	**0.0107**	**0.0765**		**366.7228**	**366.7228**	**0.0121**		**366.9763**

3.4 Building Construction - 2017

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.5018	18.1647	13.4715	0.0210		1.1260	1.1260		1.0804	1.0804		1,994.7570	1,994.7570	0.4334		2,003.8583
Total	**2.5018**	**18.1647**	**13.4715**	**0.0210**		**1.1260**	**1.1260**		**1.0804**	**1.0804**		**1,994.7570**	**1,994.7570**	**0.4334**		**2,003.8583**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0534	0.5501	0.6556	1.5200e-003	0.0438	8.8800e-003	0.0526	0.0125	8.1700e-003	0.0206		150.1482	150.1482	1.0500e-003		150.1703
Worker	0.0676	0.0849	1.0583	2.5500e-003	0.2012	1.6200e-003	0.2028	0.0534	1.4900e-003	0.0549		205.9080	205.9080	0.0101		206.1209
Total	**0.1210**	**0.6350**	**1.7139**	**4.0700e-003**	**0.2450**	**0.0105**	**0.2555**	**0.0658**	**9.6600e-003**	**0.0755**		**356.0563**	**356.0563**	**0.0112**		**356.2912**

3.4 Building Construction - 2017

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.5018	17.3681	13.4715	0.0210		1.1260	1.1260		1.0804	1.0804	0.0000	1,994.7570	1,994.7570	0.4334		2,003.8583
Total	**2.5018**	**17.3681**	**13.4715**	**0.0210**		**1.1260**	**1.1260**		**1.0804**	**1.0804**	**0.0000**	**1,994.7570**	**1,994.7570**	**0.4334**		**2,003.8583**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0534	0.5501	0.6556	1.5200e-003	0.0438	8.8800e-003	0.0526	0.0125	8.1700e-003	0.0206		150.1482	150.1482	1.0500e-003		150.1703
Worker	0.0676	0.0849	1.0583	2.5500e-003	0.2012	1.6200e-003	0.2028	0.0534	1.4900e-003	0.0549		205.9080	205.9080	0.0101		206.1209
Total	**0.1210**	**0.6350**	**1.7139**	**4.0700e-003**	**0.2450**	**0.0105**	**0.2555**	**0.0658**	**9.6600e-003**	**0.0755**		**356.0563**	**356.0563**	**0.0112**		**356.2912**

3.5 Paving - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.6916	7.0991	5.1871	7.6600e-003		0.4388	0.4388		0.4046	0.4046		778.2485	778.2485	0.2273		783.0208
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.6916**	**7.0991**	**5.1871**	**7.6600e-003**		**0.4388**	**0.4388**		**0.4046**	**0.4046**		**778.2485**	**778.2485**	**0.2273**		**783.0208**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0543	0.0679	0.8450	1.8400e-003	0.1453	1.2100e-003	0.1465	0.0385	1.1200e-003	0.0397		154.6296	154.6296	7.9300e-003		154.7962
Total	**0.0543**	**0.0679**	**0.8450**	**1.8400e-003**	**0.1453**	**1.2100e-003**	**0.1465**	**0.0385**	**1.1200e-003**	**0.0397**		**154.6296**	**154.6296**	**7.9300e-003**		**154.7962**

3.5 Paving - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.6916	7.0991	5.1871	7.6600e-003		0.4388	0.4388		0.4046	0.4046	0.0000	778.2485	778.2485	0.2273		783.0208
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.6916**	**7.0991**	**5.1871**	**7.6600e-003**		**0.4388**	**0.4388**		**0.4046**	**0.4046**	**0.0000**	**778.2485**	**778.2485**	**0.2273**		**783.0208**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0543	0.0679	0.8450	1.8400e-003	0.1453	1.2100e-003	0.1465	0.0385	1.1200e-003	0.0397		154.6296	154.6296	7.9300e-003		154.7962
Total	**0.0543**	**0.0679**	**0.8450**	**1.8400e-003**	**0.1453**	**1.2100e-003**	**0.1465**	**0.0385**	**1.1200e-003**	**0.0397**		**154.6296**	**154.6296**	**7.9300e-003**		**154.7962**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	0.3017	0.9956	4.0124	9.0800e-003	0.6134	0.0152	0.6285	0.1639	0.0139	0.1778		819.7953	819.7953	0.0337		820.5028
Unmitigated	0.3017	0.9956	4.0124	9.0800e-003	0.6134	0.0152	0.6285	0.1639	0.0139	0.1778		819.7953	819.7953	0.0337		820.5028

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
General Heavy Industry	65.34	65.34	65.34	289,344	289,344
Total	65.34	65.34	65.34	289,344	289,344

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
General Heavy Industry	16.60	8.40	6.90	59.00	28.00	13.00	92	5	3

4.4 Fleet Mix

LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.514499	0.060499	0.179997	0.139763	0.042095	0.006675	0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
NaturalGas Unmitigated	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	2582.57	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Total		**0.0279**	**0.2532**	**0.2127**	**1.5200e-003**		**0.0192**	**0.0192**		**0.0192**	**0.0192**		**303.8319**	**303.8319**	**5.8200e-003**	**5.5700e-003**	**305.6810**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	2.58257	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Total		**0.0279**	**0.2532**	**0.2127**	**1.5200e-003**		**0.0192**	**0.0192**		**0.0192**	**0.0192**		**303.8319**	**303.8319**	**5.8200e-003**	**5.5700e-003**	**305.6810**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Unmitigated	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.2766					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.8625					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	4.5000e-004	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Total	**1.1395**	**4.0000e-005**	**4.6000e-003**	**0.0000**		**2.0000e-005**	**2.0000e-005**		**2.0000e-005**	**2.0000e-005**		**9.5300e-003**	**9.5300e-003**	**3.0000e-005**		**0.0101**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.2766					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.8625					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	4.5000e-004	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Total	**1.1395**	**4.0000e-005**	**4.6000e-003**	**0.0000**		**2.0000e-005**	**2.0000e-005**		**2.0000e-005**	**2.0000e-005**		**9.5300e-003**	**9.5300e-003**	**3.0000e-005**		**0.0101**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Vegetation

RECLAIM

South Coast AQMD Air District, Winter

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
General Heavy Industry	43.56	1000sqft	1.00	43,560.00	0

1.2 Other Project Characteristics

Urbanization Urban

Wind Speed (m/s) 2.2

Precipitation Freq (Days) 31

Climate Zone 8

Operational Year 2015

Utility Company Los Angeles Department of Water & Power

CO2 Intensity (lb/MWhr) 1227.89

CH4 Intensity (lb/MWhr) 0.029

N2O Intensity (lb/MWhr) 0.006

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use -

Construction Phase - Average of construction estimates

Off-road Equipment -

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Off-road Equipment - Engineering estimate

Trips and VMT -

Demolition -

Grading - Engineering estimate

Architectural Coating -

Construction Off-road Equipment Mitigation -

Table Name	Column Name	Default Value	New Value
tblConstructionPhase	NumDays	100.00	250.00
tblConstructionPhase	NumDays	1.00	2.00
tblConstructionPhase	PhaseEndDate	1/2/2017	1/3/2017
tblConstructionPhase	PhaseEndDate	1/10/2017	6/14/2016
tblConstructionPhase	PhaseStartDate	1/19/2016	1/20/2016
tblConstructionPhase	PhaseStartDate	1/4/2017	6/8/2016
tblGrading	AcresOfGrading	0.00	1.00
tblOffRoadEquipment	HorsePower	8.00	125.00
tblOffRoadEquipment	LoadFactor	0.43	0.42
tblOffRoadEquipment	OffRoadEquipmentType		Cranes
tblOffRoadEquipment	OffRoadEquipmentType		Trenchers
tblOffRoadEquipment	OffRoadEquipmentType		Aerial Lifts
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	3.00	2.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	PhaseName		Paving
tblOffRoadEquipment	PhaseName		Demolition
tblOffRoadEquipment	PhaseName		Site Preparation
tblOffRoadEquipment	PhaseName		Building Construction
tblProjectCharacteristics	OperationalYear	2014	2015
tblTripsAndVMT	WorkerTripNumber	8.00	15.00
tblTripsAndVMT	WorkerTripNumber	5.00	8.00
tblTripsAndVMT	WorkerTripNumber	10.00	13.00

2.0 Emissions Summary

2.1 Overall Construction (Maximum Daily Emission)

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2016	3.6728	31.7013	21.6972	0.0343	5.8890	1.7130	7.0870	2.9774	1.6267	4.0796	0.0000	3,285.5266	3,285.5266	0.6983	0.0000	3,300.1904
2017	2.6289	18.8215	15.2376	0.0249	0.2450	1.1366	1.3815	0.0658	1.0901	1.1560	0.0000	2,336.7579	2,336.7579	0.4446	0.0000	2,346.0948
Total	**6.3017**	**50.5228**	**36.9348**	**0.0593**	**6.1340**	**2.8496**	**8.4685**	**3.0432**	**2.7168**	**5.2355**	**0.0000**	**5,622.2845**	**5,622.2845**	**1.1429**	**0.0000**	**5,646.2852**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	lb/day										lb/day					
2016	3.6728	31.7013	21.6972	0.0343	2.3513	1.7130	3.5493	1.1757	1.6267	2.2778	0.0000	3,285.5266	3,285.5266	0.6983	0.0000	3,300.1904
2017	2.6289	18.0249	15.2376	0.0249	0.2450	1.1366	1.3815	0.0658	1.0901	1.1560	0.0000	2,336.7579	2,336.7579	0.4446	0.0000	2,346.0948
Total	**6.3017**	**49.7262**	**36.9348**	**0.0593**	**2.5962**	**2.8496**	**4.9308**	**1.2415**	**2.7168**	**3.4338**	**0.0000**	**5,622.2845**	**5,622.2845**	**1.1429**	**0.0000**	**5,646.2852**

	ROG	**NOx**	**CO**	**SO2**	**Fugitive PM10**	**Exhaust PM10**	**PM10 Total**	**Fugitive PM2.5**	**Exhaust PM2.5**	**PM2.5 Total**	**Bio- CO2**	**NBio-CO2**	**Total CO2**	**CH4**	**N20**	**CO2e**
Percent Reduction	**0.00**	**1.58**	**0.00**	**0.00**	**57.67**	**0.00**	**41.78**	**59.21**	**0.00**	**34.41**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Energy	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Mobile	0.3102	1.0493	3.8644	8.6200e-003	0.6134	0.0152	0.6286	0.1639	0.0140	0.1779		779.7241	779.7241	0.0337		780.4319
Total	**1.4776**	**1.3026**	**4.0817**	**0.0101**	**0.6134**	**0.0345**	**0.6479**	**0.1639**	**0.0333**	**0.1971**		**1,083.5655**	**1,083.5655**	**0.0396**	**5.5700e-003**	**1,086.1230**

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Area	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Energy	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Mobile	0.3102	1.0493	3.8644	8.6200e-003	0.6134	0.0152	0.6286	0.1639	0.0140	0.1779		779.7241	779.7241	0.0337		780.4319
Total	**1.4776**	**1.3026**	**4.0817**	**0.0101**	**0.6134**	**0.0345**	**0.6479**	**0.1639**	**0.0333**	**0.1971**		**1,083.5655**	**1,083.5655**	**0.0396**	**5.5700e-003**	**1,086.1230**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Demolition	Demolition	1/1/2016	1/14/2016	5	10	
2	Site Preparation	Site Preparation	1/15/2016	1/18/2016	5	2	
3	Building Construction	Building Construction	1/20/2016	1/3/2017	5	250	
4	Paving	Paving	6/8/2016	6/14/2016	5	5	

Acres of Grading (Site Preparation Phase): 1

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Demolition	Concrete/Industrial Saws	1	8.00	81	0.73
Demolition	Rubber Tired Dozers	1	8.00	255	0.40
Demolition	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Site Preparation	Rubber Tired Dozers	1	7.00	255	0.40
Site Preparation	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Building Construction	Cranes	1	6.00	226	0.29
Building Construction	Forklifts	1	6.00	89	0.20
Building Construction	Generator Sets	1	8.00	84	0.74
Building Construction	Tractors/Loaders/Backhoes	1	6.00	97	0.37
Building Construction	Welders	2	8.00	46	0.45
Paving	Cement and Mortar Mixers	1	6.00	9	0.56
Paving	Paving Equipment	1	8.00	130	0.36
Paving	Plate Compactors	1	6.00	125	0.42
Paving	Tractors/Loaders/Backhoes	1	8.00	97	0.37
Demolition	Cranes	1	8.00	226	0.29
Site Preparation	Trenchers	1	8.00	80	0.50
Building Construction	Aerial Lifts	1	8.00	62	0.31

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Demolition	3	15.00	0.00	49.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Site Preparation	2	8.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Building Construction	6	18.00	7.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT
Paving	4	13.00	0.00	0.00	14.70	6.90	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Water Exposed Area

3.2 Demolition - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					1.0700	0.0000	1.0700	0.1620	0.0000	0.1620			0.0000			0.0000
Off-Road	2.9407	30.2234	19.6380	0.0239		1.6279	1.6279		1.5254	1.5254		2,422.1689	2,422.1689	0.6092		2,434.9621
Total	**2.9407**	**30.2234**	**19.6380**	**0.0239**	**1.0700**	**1.6279**	**2.6978**	**0.1620**	**1.5254**	**1.6874**		**2,422.1689**	**2,422.1689**	**0.6092**		**2,434.9621**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0886	1.3919	1.0891	3.6100e-003	0.0854	0.0214	0.1068	0.0234	0.0197	0.0430		363.2785	363.2785	2.6200e-003		363.3336
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0640	0.0860	0.8984	1.9900e-003	0.1677	1.4000e-003	0.1691	0.0445	1.2900e-003	0.0458		167.3573	167.3573	9.1500e-003		167.5495
Total	**0.1525**	**1.4779**	**1.9875**	**5.6000e-003**	**0.2530**	**0.0228**	**0.2758**	**0.0679**	**0.0210**	**0.0888**		**530.6358**	**530.6358**	**0.0118**		**530.8831**

3.2 Demolition - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					0.4173	0.0000	0.4173	0.0632	0.0000	0.0632			0.0000			0.0000
Off-Road	2.9407	30.2234	19.6380	0.0239		1.6279	1.6279		1.5254	1.5254	0.0000	2,422.1689	2,422.1689	0.6092		2,434.9621
Total	**2.9407**	**30.2234**	**19.6380**	**0.0239**	**0.4173**	**1.6279**	**2.0452**	**0.0632**	**1.5254**	**1.5886**	**0.0000**	**2,422.1689**	**2,422.1689**	**0.6092**		**2,434.9621**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0886	1.3919	1.0891	3.6100e-003	0.0854	0.0214	0.1068	0.0234	0.0197	0.0430		363.2785	363.2785	2.6200e-003		363.3336
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0640	0.0860	0.8984	1.9900e-003	0.1677	1.4000e-003	0.1691	0.0445	1.2900e-003	0.0458		167.3573	167.3573	9.1500e-003		167.5495
Total	**0.1525**	**1.4779**	**1.9875**	**5.6000e-003**	**0.2530**	**0.0228**	**0.2758**	**0.0679**	**0.0210**	**0.0888**		**530.6358**	**530.6358**	**0.0118**		**530.8831**

3.3 Site Preparation - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					5.7996	0.0000	5.7996	2.9537	0.0000	2.9537			0.0000			0.0000
Off-Road	1.9799	20.2613	14.4005	0.0143		1.1973	1.1973		1.1015	1.1015		1,491.406 1	1,491.406 1	0.4499		1,500.853 2
Total	**1.9799**	**20.2613**	**14.4005**	**0.0143**	**5.7996**	**1.1973**	**6.9968**	**2.9537**	**1.1015**	**4.0552**		**1,491.406 1**	**1,491.406 1**	**0.4499**		**1,500.853 2**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0341	0.0459	0.4791	1.0600e-003	0.0894	7.5000e-004	0.0902	0.0237	6.9000e-004	0.0244		89.2572	89.2572	4.8800e-003		89.3598
Total	**0.0341**	**0.0459**	**0.4791**	**1.0600e-003**	**0.0894**	**7.5000e-004**	**0.0902**	**0.0237**	**6.9000e-004**	**0.0244**		**89.2572**	**89.2572**	**4.8800e-003**		**89.3598**

3.3 Site Preparation - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Fugitive Dust					2.2618	0.0000	2.2618	1.1519	0.0000	1.1519			0.0000			0.0000
Off-Road	1.9799	15.3919	14.4005	0.0143		1.1973	1.1973		1.1015	1.1015	0.0000	1,491.4061	1,491.4061	0.4499		1,500.8532
Total	**1.9799**	**15.3919**	**14.4005**	**0.0143**	**2.2618**	**1.1973**	**3.4591**	**1.1519**	**1.1015**	**2.2534**	**0.0000**	**1,491.4061**	**1,491.4061**	**0.4499**		**1,500.8532**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0341	0.0459	0.4791	1.0600e-003	0.0894	7.5000e-004	0.0902	0.0237	6.9000e-004	0.0244		89.2572	89.2572	4.8800e-003		89.3598
Total	**0.0341**	**0.0459**	**0.4791**	**1.0600e-003**	**0.0894**	**7.5000e-004**	**0.0902**	**0.0237**	**6.9000e-004**	**0.0244**		**89.2572**	**89.2572**	**4.8800e-003**		**89.3598**

3.4 Building Construction - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.7851	19.6612	13.8165	0.0210		1.2613	1.2613		1.2102	1.2102		2,010.0661	2,010.0661	0.4510		2,019.5367
Total	**2.7851**	**19.6612**	**13.8165**	**0.0210**		**1.2613**	**1.2613**		**1.2102**	**1.2102**		**2,010.0661**	**2,010.0661**	**0.4510**		**2,019.5367**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0639	0.6198	0.8369	1.5100e-003	0.0438	0.0101	0.0538	0.0125	9.2500e-003	0.0217		151.3403	151.3403	1.1200e-003		151.3639
Worker	0.0768	0.1032	1.0780	2.3900e-003	0.2012	1.6800e-003	0.2029	0.0534	1.5500e-003	0.0549		200.8288	200.8288	0.0110		201.0594
Total	**0.1407**	**0.7230**	**1.9150**	**3.9000e-003**	**0.2450**	**0.0117**	**0.2567**	**0.0658**	**0.0108**	**0.0766**		**352.1690**	**352.1690**	**0.0121**		**352.4233**

3.4 Building Construction - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.7851	18.7438	13.8165	0.0210		1.2613	1.2613		1.2102	1.2102	0.0000	2,010.0661	2,010.0661	0.4510		2,019.5367
Total	**2.7851**	**18.7438**	**13.8165**	**0.0210**		**1.2613**	**1.2613**		**1.2102**	**1.2102**	**0.0000**	**2,010.0661**	**2,010.0661**	**0.4510**		**2,019.5367**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0639	0.6198	0.8369	1.5100e-003	0.0438	0.0101	0.0538	0.0125	9.2500e-003	0.0217		151.3403	151.3403	1.1200e-003		151.3639
Worker	0.0768	0.1032	1.0780	2.3900e-003	0.2012	1.6800e-003	0.2029	0.0534	1.5500e-003	0.0549		200.8288	200.8288	0.0110		201.0594
Total	**0.1407**	**0.7230**	**1.9150**	**3.9000e-003**	**0.2450**	**0.0117**	**0.2567**	**0.0658**	**0.0108**	**0.0766**		**352.1690**	**352.1690**	**0.0121**		**352.4233**

3.4 Building Construction - 2017

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.5018	18.1647	13.4715	0.0210		1.1260	1.1260		1.0804	1.0804		1,994.7570	1,994.7570	0.4334		2,003.8583
Total	**2.5018**	**18.1647**	**13.4715**	**0.0210**		**1.1260**	**1.1260**		**1.0804**	**1.0804**		**1,994.7570**	**1,994.7570**	**0.4334**		**2,003.8583**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0584	0.5637	0.7945	1.5100e-003	0.0438	8.9600e-003	0.0527	0.0125	8.2500e-003	0.0207		148.8859	148.8859	1.0900e-003		148.9087
Worker	0.0688	0.0931	0.9716	2.3900e-003	0.2012	1.6200e-003	0.2028	0.0534	1.4900e-003	0.0549		193.1150	193.1150	0.0101		193.3278
Total	**0.1272**	**0.6568**	**1.7661**	**3.9000e-003**	**0.2450**	**0.0106**	**0.2556**	**0.0658**	**9.7400e-003**	**0.0756**		**342.0009**	**342.0009**	**0.0112**		**342.2365**

3.4 Building Construction - 2017

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	2.5018	17.3681	13.4715	0.0210		1.1260	1.1260		1.0804	1.0804	0.0000	1,994.7570	1,994.7570	0.4334		2,003.8583
Total	**2.5018**	**17.3681**	**13.4715**	**0.0210**		**1.1260**	**1.1260**		**1.0804**	**1.0804**	**0.0000**	**1,994.7570**	**1,994.7570**	**0.4334**		**2,003.8583**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0584	0.5637	0.7945	1.5100e-003	0.0438	8.9600e-003	0.0527	0.0125	8.2500e-003	0.0207		148.8859	148.8859	1.0900e-003		148.9087
Worker	0.0688	0.0931	0.9716	2.3900e-003	0.2012	1.6200e-003	0.2028	0.0534	1.4900e-003	0.0549		193.1150	193.1150	0.0101		193.3278
Total	**0.1272**	**0.6568**	**1.7661**	**3.9000e-003**	**0.2450**	**0.0106**	**0.2556**	**0.0658**	**9.7400e-003**	**0.0756**		**342.0009**	**342.0009**	**0.0112**		**342.2365**

3.5 Paving - 2016

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.6916	7.0991	5.1871	7.6600e-003		0.4388	0.4388		0.4046	0.4046		778.2485	778.2485	0.2273		783.0208
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.6916**	**7.0991**	**5.1871**	**7.6600e-003**		**0.4388**	**0.4388**		**0.4046**	**0.4046**		**778.2485**	**778.2485**	**0.2273**		**783.0208**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0555	0.0745	0.7786	1.7300e-003	0.1453	1.2100e-003	0.1465	0.0385	1.1200e-003	0.0397		145.0430	145.0430	7.9300e-003		145.2096
Total	**0.0555**	**0.0745**	**0.7786**	**1.7300e-003**	**0.1453**	**1.2100e-003**	**0.1465**	**0.0385**	**1.1200e-003**	**0.0397**		**145.0430**	**145.0430**	**7.9300e-003**		**145.2096**

3.5 Paving - 2016

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Off-Road	0.6916	7.0991	5.1871	7.6600e-003		0.4388	0.4388		0.4046	0.4046	0.0000	778.2485	778.2485	0.2273		783.0208
Paving	0.0000					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Total	**0.6916**	**7.0991**	**5.1871**	**7.6600e-003**		**0.4388**	**0.4388**		**0.4046**	**0.4046**	**0.0000**	**778.2485**	**778.2485**	**0.2273**		**783.0208**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000		0.0000
Worker	0.0555	0.0745	0.7786	1.7300e-003	0.1453	1.2100e-003	0.1465	0.0385	1.1200e-003	0.0397		145.0430	145.0430	7.9300e-003		145.2096
Total	**0.0555**	**0.0745**	**0.7786**	**1.7300e-003**	**0.1453**	**1.2100e-003**	**0.1465**	**0.0385**	**1.1200e-003**	**0.0397**		**145.0430**	**145.0430**	**7.9300e-003**		**145.2096**

4.0 Operational Detail - Mobile

4.1 Mitigation Measures Mobile

Category	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
	lb/day										lb/day					
Mitigated	0.3102	1.0493	3.8644	8.6200e-003	0.6134	0.0152	0.6286	0.1639	0.0140	0.1779		779.7241	779.7241	0.0337		780.4319
Unmitigated	0.3102	1.0493	3.8644	8.6200e-003	0.6134	0.0152	0.6286	0.1639	0.0140	0.1779		779.7241	779.7241	0.0337		780.4319

4.2 Trip Summary Information

	Average Daily Trip Rate			Unmitigated	Mitigated
Land Use	Weekday	Saturday	Sunday	Annual VMT	Annual VMT
General Heavy Industry	65.34	65.34	65.34	289,344	289,344
Total	65.34	65.34	65.34	289,344	289,344

4.3 Trip Type Information

	Miles			Trip %			Trip Purpose %		
Land Use	H-W or C-W	H-S or C-C	H-O or C-NW	H-W or C-W	H-S or C-C	H-O or C-NW	Primary	Diverted	Pass-by
General Heavy Industry	16.60	8.40	6.90	59.00	28.00	13.00	92	5	3

LDA	LDT1	LDT2	MDV	LHD1	LHD2	MHD	HHD	OBUS	UBUS	MCY	SBUS	MH
0.514499	0.060499	0.179997	0.139763	0.042095	0.006675	0.015446	0.029572	0.001914	0.002508	0.004341	0.000594	0.002098

4.4 Fleet Mix

5.0 Energy Detail

Historical Energy Use: N

5.1 Mitigation Measures Energy

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
NaturalGas Mitigated	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
NaturalGas Unmitigated	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810

5.2 Energy by Land Use - NaturalGas

Unmitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	2582.57	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Total		**0.0279**	**0.2532**	**0.2127**	**1.5200e-003**		**0.0192**	**0.0192**		**0.0192**	**0.0192**		**303.8319**	**303.8319**	**5.8200e-003**	**5.5700e-003**	**305.6810**

5.2 Energy by Land Use - NaturalGas

Mitigated

	NaturalGas Use	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Land Use	kBTU/yr	lb/day										lb/day					
General Heavy Industry	2.58257	0.0279	0.2532	0.2127	1.5200e-003		0.0192	0.0192		0.0192	0.0192		303.8319	303.8319	5.8200e-003	5.5700e-003	305.6810
Total		**0.0279**	**0.2532**	**0.2127**	**1.5200e-003**		**0.0192**	**0.0192**		**0.0192**	**0.0192**		**303.8319**	**303.8319**	**5.8200e-003**	**5.5700e-003**	**305.6810**

6.0 Area Detail

6.1 Mitigation Measures Area

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	lb/day										lb/day					
Mitigated	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Unmitigated	1.1395	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101

6.2 Area by SubCategory

Unmitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.2766					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.8625					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	4.5000e-004	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Total	**1.1395**	**4.0000e-005**	**4.6000e-003**	**0.0000**		**2.0000e-005**	**2.0000e-005**		**2.0000e-005**	**2.0000e-005**		**9.5300e-003**	**9.5300e-003**	**3.0000e-005**		**0.0101**

Mitigated

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
SubCategory	lb/day										lb/day					
Architectural Coating	0.2766					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Consumer Products	0.8625					0.0000	0.0000		0.0000	0.0000			0.0000			0.0000
Landscaping	4.5000e-004	4.0000e-005	4.6000e-003	0.0000		2.0000e-005	2.0000e-005		2.0000e-005	2.0000e-005		9.5300e-003	9.5300e-003	3.0000e-005		0.0101
Total	**1.1395**	**4.0000e-005**	**4.6000e-003**	**0.0000**		**2.0000e-005**	**2.0000e-005**		**2.0000e-005**	**2.0000e-005**		**9.5300e-003**	**9.5300e-003**	**3.0000e-005**		**0.0101**

7.0 Water Detail

7.1 Mitigation Measures Water

8.0 Waste Detail

8.1 Mitigation Measures Waste

9.0 Operational Offroad

Equipment Type	Number	Hours/Day	Days/Year	Horse Power	Load Factor	Fuel Type

10.0 Vegetation

APPENDIX F

NOTICE OF PREPARATION/INITIAL STUDY (NOP/IS) (ENVIRONMENTAL CHECKLIST)

South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 • www.aqmd.gov

SUBJECT: **NOTICE OF PREPARATION OF A DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT**

PROJECT TITLE: **PROPOSED AMENDED REGULATION XX - REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)**

In accordance with the California Environmental Quality Act (CEQA), the South Coast Air Quality Management District (SCAQMD), as the Lead Agency, has prepared this Notice of Preparation (NOP) and Initial Study (IS). This NOP serves two purposes: 1) to solicit information on the scope of the environmental analysis for the proposed project; and, 2) to notify the public that the SCAQMD will prepare a Draft Program Environmental Assessment (PEA) to further assess potential environmental impacts that may result from implementing the proposed project.

This letter, NOP and the attached IS are not SCAQMD applications or forms requiring a response from you. Their purpose is simply to provide information to you on the above project. If the proposed project has no bearing on you or your organization, no action on your part is necessary.

Comments focusing on your area of expertise, your agency's area of jurisdiction, if applicable, or issues relative to the environmental analysis should be addressed to Ms. Barbara Radlein (c/o CEQA) at the address shown above, or sent by fax to (909) 396-3324 or by email to bradlein@aqmd.gov . Comments must be received no later than 5:00 p.m. on Friday, January 16, 2015. Please include the name and phone number of the contact person. Questions relative to the proposed amended regulation for the refinery sector should be directed to Ms. Minh Pham at (909) 396-2613 or by email to mpham@aqmd.gov. Questions relative to the proposed amended regulation for the non-refinery sector should be directed to Mr. Kevin Orellana at (909) 396-3492 or by email to korellana@aqmd.gov.

The Public Hearing for the proposed amended regulation is scheduled for March 6, 2015. (Note: Public meeting dates are subject to change).

Date: December 4, 2014 **Signature:** Michael Krause

Michael Krause
Program Supervisor, CEQA Section
Planning, Rules, and Area Sources

Reference: California Code of Regulations, Title 14, §§ 15082 (a), 15103, 15365, and 15375

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
21865 Copley Drive, Diamond Bar, CA 91765-4178

NOTICE OF PREPARATION OF A DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT

Project Title:
Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

Project Location:
South Coast Air Quality Management District (SCAQMD) area of jurisdiction consisting of the four-county South Coast Air Basin (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties), and the Riverside County portions of the Salton Sea Air Basin and the Mojave Desert Air Basin

Description of Nature, Purpose, and Beneficiaries of Project:
SCAQMD staff is proposing amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM), Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), to reduce the allowable NOx emission limits based on current Best Available Retrofit Control Technology (BARCT) to achieve additional NOx emission reductions for the following industrial equipment and processes: 1) fluid catalytic cracking units (FCCUs); 2) refinery boilers and heaters; 3) refinery gas turbines; 4) sulfur recovery units – tail gas treatment units (SRU/TGUs); 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines (ICEs); 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. Additional amendments are proposed to establish procedures and criteria for reducing NOx RECLAIM Trading Credits (RTCs) and NOx RTC adjustment factors for year 2016 and later. For clarity and consistency throughout the regulation, other minor changes are proposed to: 1) Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions; and, 2) Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions. The Initial Study identifies the following environmental topics as areas that may be adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. Impacts to these environmental areas will be further analyzed in the Draft Program Environmental Assessment (PEA).

Lead Agency:	**Division:**
South Coast Air Quality Management District	Planning, Rule Development and Area Sources

NOP/IS and all supporting documentation are available at:	**or by calling:**	**or by accessing the SCAQMD's website at:**
SCAQMD Headquarters 21865 Copley Drive Diamond Bar, CA 91765	(909) 396-2039	http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2014

The NOP/IS is provided to the public through the following:

☑ Los Angeles Times (December 5, 2014)
☑ SCAQMD Public Information Center
☑ SCAQMD Mailing List & Interested Parties
☑ SCAQMD Website

NOP/IS Review Period (43 days):
December 5, 2014 – January16, 2015

The proposed project may have statewide, regional or areawide significance; therefore, a CEQA scoping meeting is required (pursuant to Public Resources Code §21083.9 (a)(2)) and will be held on January 8, 2015. See Scheduled Public Meeting Dates below for details.

Scheduled Public Meeting Dates (subject to change):
Working Group Meeting: January 7, 2015, 1:30 p.m.; SCAQMD Headquarters
CEQA and Socioeconomic Scoping Meeting: January 8, 2015, 10:00 a.m.; SCAQMD Headquarters
SCAQMD Governing Board Hearing: March 6, 2015, 9:00 a.m.; SCAQMD Headquarters

	Phone:	**Email:**	**Fax:**
Send CEQA Comments to: Ms. Barbara Radlein	(909) 396-2716	bradlein@aqmd.gov	(909) 396-3324
Direct Questions on Proposed Amended Regulation for Refinery Sector: Ms. Minh Pham	(909) 396-2613	mpham@aqmd.gov	(909) 396-3324
Direct Questions on Proposed Amended Regulation for Non-Refinery Sector: Mr. Kevin Orellana	(909) 396-3492	korellana@aqmd.gov	(909) 396-3324

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

INITIAL STUDY FOR:

DRAFT PROGRAM ENVIRONMENTAL ASSESSEMENT FOR PROPOSED AMENDED REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

December 2014

SCAQMD No. 12052014BAR
State Clearinghouse No: To Be Determined

Executive Officer
Barry R. Wallerstein, D. Env.

Deputy Executive Officer
Planning, Rule Development and Area Sources
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	Joe Cassmassi	Planning and Rules Manager, Planning, Rule Development, and Area Sources
	Gary Quinn, P.E.	Program Supervisor, Planning, Rule Development, and Area Sources
	Barbara Baird	Chief Deputy Counsel
	William Wong	Principal Deputy District Counsel
	Karin Manwaring	Senior Deputy District Counsel

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CHAPTER 1

PROJECT DESCRIPTION

INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin referred to herein as the District. By statute, the SCAQMD is required to adopt an air quality management plan (AQMP) demonstrating compliance with all federal and state ambient air quality standards for the District[2]. Furthermore, the SCAQMD must adopt rules and regulations that carry out the AQMP[3]. The Final 2012 AQMP concluded that reductions in emissions of particulate matter (PM), oxides of sulfur (SOx), oxides of nitrogen (NOx), and volatile organic compounds (VOC) are necessary to attain the state and national ambient air quality standards for ozone, and particulate matter with an aerodynamic diameter of 2.5 microns or less (PM2.5). Ozone, a criteria pollutant which has been shown to adversely affect human health, is formed when VOCs react with NOx in the atmosphere. VOCs, NOx, SOx (especially sulfur dioxide) and ammonia also contribute to the formation of PM10 and PM2.5.

The Basin is designated by the United States Environmental Protection Agency (EPA) as a non-attainment area for PM2.5 emissions because the federal PM2.5 standards have been exceeded. For this reason, the SCAQMD is required to evaluate all feasible control measures in order to reduce direct PM2.5 emissions, as well as PM2.5 precursors, such as NOx and SOx. The Final 2012 AQMP sets forth a comprehensive program for the Basin to comply with the federal 24-hour PM2.5 air quality standard, satisfy the planning requirements of the federal Clean Air Act, and provide an update to the Basin's commitments towards meeting the federal 8-hour ozone standard. In particular, the Final 2012 AQMP contains a multi-pollutant control strategy to achieve attainment with the federal 24-hour PM2.5 air quality standard with direct PM2.5 and NOx reductions identified as the two most effective tools in reaching attainment with the PM2.5 standard. The 2012 AQMP also serves to satisfy the recent requirements promulgated by the EPA for a new attainment demonstration of the revoked 1-hour ozone standard, as well as to provide additional measures to partially fulfill long-term reduction obligations under the 2007 8-hour Ozone State Implementation Plan (SIP).

As part of this ongoing PM2.5 reduction effort, SCAQMD staff is proposing amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM) to achieve additional NOx emission reductions to address best available retrofit control technology (BARCT) requirements. The primary focus of the proposed project is to bring the NOx RECLAIM program up-to-date with the latest BARCT requirements while achieving the proposed NOx emission reductions in the 2012 AQMP Control Measure #CMB-01: Further NOx Reductions from RECLAIM (e.g., at least three to five tons per day by 2023). The proposed project may achieve additional NOx emission reductions depending on the actual BARCT NOx emission control efficiencies. In addition, the proposed project is designed to implement both the Phase I and Phase II reduction commitments described in #CMB-01.

The proposed project may require installation of new or modification of existing NOx emission control equipment for the following industrial equipment and processes at NOx RECLAIM facilities: 1) fluid catalytic cracking units (FCCUs); 2) refinery boilers and heaters; 3) refinery

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1 The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health and Safety Code, §§40400-40540).
2 Health and Safety Code, §40460 (a).
3 Health and Safety Code, §40440 (a).

gas turbines; 4) sulfur recovery units – tail gas treatment units (SRU/TGUs); 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant internal combustion engines (ICEs); 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns, and, 11) metal heat treating furnaces. Additional amendments are proposed to establish procedures and criteria for reducing NOx RECLAIM RTCs and NOx RTC adjustment factors for year 2016 and later. Other minor changes are proposed for clarity and consistency throughout the proposed amended regulation.

The proposed project is estimated to reduce at least three tons per day of NOx emissions or more starting in 2016. Despite this projected direct environmental benefit to air quality, this Initial Study, prepared pursuant to the California Environmental Quality Act (CEQA), identifies the following environmental topics as areas that may be adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. A Draft Program Environmental Assessment (PEA) will be prepared to analyze further whether the potential impacts to these environmental topics are significant. Any other potentially significant environmental impacts identified through this Notice of Preparation/Initial Study (NOP/IS) process will also be analyzed in the Draft PEA.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

The California Environmental Quality Act (CEQA), California Public Resources Code §21000 *et seq.*, requires environmental impacts of proposed projects to be evaluated and feasible methods to reduce, avoid or eliminate significant adverse impacts of these projects to be identified and implemented. The lead agency is the "public agency that has the principal responsibility for carrying out or approving a project that may have a significant effect upon the environment" (Public Resources Code §21067). Since the SCAQMD has the primary responsibility for supervising or approving the entire project as a whole, it is the most appropriate public agency to act as lead agency (CEQA Guidelines[4] §15051 (b)).

CEQA requires that all potential adverse environmental impacts of proposed projects be evaluated and that methods to reduce or avoid identified significant adverse environmental impacts of these projects be implemented if feasible. The purpose of the CEQA process is to inform the SCAQMD Governing Board, public agencies, and interested parties of potential adverse environmental impacts that could result from implementing the proposed project and to identify feasible mitigation measures or alternatives, when an impact is significant.

Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD's regulatory program was certified by the Secretary of Resources Agency on March 1, 1989, and has been adopted as SCAQMD Rule 110 – Rule Adoption Procedures to Assure Protection and Enhancement of the Environment.

CEQA includes provisions for the preparation of program CEQA documents in connection with issuance of rules, regulations, plans, or other general criteria to govern the conduct of a continuing program, including adoptions of broad policy programs as distinguished from those prepared for specific types of projects such as land use projects (CEQA Guidelines §15168). A

[4] The CEQA Guidelines are codified at Title 14 California Code of Regulations, §15000 et seq.

program CEQA document also allows consideration of broad policy alternatives and program-wide mitigation measures at a time when an agency has greater flexibility to deal with basic problems of cumulative impacts. Lastly, a program CEQA document also plays an important role in establishing a structure within which CEQA review of future related actions can effectively be conducted. This concept of covering broad policies in a program CEQA document and incorporating the information contained therein by reference into subsequent CEQA documents for specific projects is known as "tiering" (CEQA Guidelines §15152).

A program CEQA document will provide the basis for future environmental analyses and will allow future project-specific CEQA documents, if necessary, to focus solely on the new effects or detailed environmental issues not previously considered. If an agency finds that no new effects could occur, or no new mitigation measures would be required, the agency can approve the activity as being within the scope of the project covered by the program CEQA document and no new environmental document would be required (CEQA Guidelines §15168 (c)(2)).

The proposed amendments to Regulation XX (PAReg XX) are considered a "project" as defined by CEQA. Specifically, PARegXX includes amendments to Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures), and Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures), to be discussed in further detail under "Project Description." PAReg XX will assure that the BARCT commitments for NOx emission reductions in the Final 2012 AQMP are achieved and maintained as well as provide an overall environmental benefit to air quality. However, SCAQMD's review of the proposed project also shows that implementation of PAReg XX may also have a significant adverse effect on the environment. Since PAReg XX may have statewide, regional or areawide significance, a CEQA scoping meeting is also required to be held for the proposed project pursuant to Public Resources Code §21083.9 (a)(2). Information regarding the CEQA scoping meeting can be found on the NOP.

In addition, since the proposed project: 1) is connected to the issuance of rules, regulations, plans, or other general criteria to govern the conduct of a continuing program (CEQA Guidelines §15168 (a)(3)); and, 2) contains a series of actions that can be characterized as one large project and the series of actions are related as individual activities that would be carried out under the same authorizing regulatory authority and having similar environmental effects which can be mitigated in similar ways (CEQA Guidelines §15168 (a)(4)), the appropriate type of CEQA document to be prepared for the proposed project will be a Program Environmental Assessment (PEA). The PEA is a substitute CEQA document, prepared in lieu of a program environmental impact report (EIR) (CEQA Guidelines §15252), pursuant to the SCAQMD's Certified Regulatory Program (CEQA Guidelines §15251 (l); codified in SCAQMD Rule 110). The PEA is also a public disclosure document intended to: 1) provide the lead agency, responsible agencies, decision makers and the general public with information on the environmental impacts of the proposed project; and, 2) be used as a tool by decision makers to facilitate decision making on the proposed project.

The first step of preparing a Draft PEA is to prepare a Notice of Preparation (NOP) with an Initial Study (IS) that includes an Environmental Checklist and project description. The Environmental Checklist provides a standard evaluation tool to identify a project's adverse environmental impacts. The NOP/IS is also intended to provide information about the proposed project to other public agencies and interested parties prior to the release of the Draft PEA.

Thus, the SCAQMD as Lead Agency has prepared this NOP/IS for the proposed project. The initial evaluation in the NOP/IS identified the following topics as potentially being adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. Written comments received on the scope of the environmental analysis will be considered when preparing the Draft PEA.

PROJECT LOCATION

The proposed amendments to Regulation XX would apply to equipment and processes operated at NOx RECLAIM facilities located throughout the entire SCAQMD jurisdiction. The SCAQMD has jurisdiction over an area of approximately 10,743 square miles, consisting of the four-county South Coast Air Basin (Basin) (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties), and the Riverside County portions of the Salton Sea Air Basin (SSAB) and Mojave Desert Air Basin (MDAB). The Basin, which is a subarea of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto mountains to the north and east. It includes all of Orange County and the nondesert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a subregion of Riverside County and the SSAB that is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (Figure 1-1).

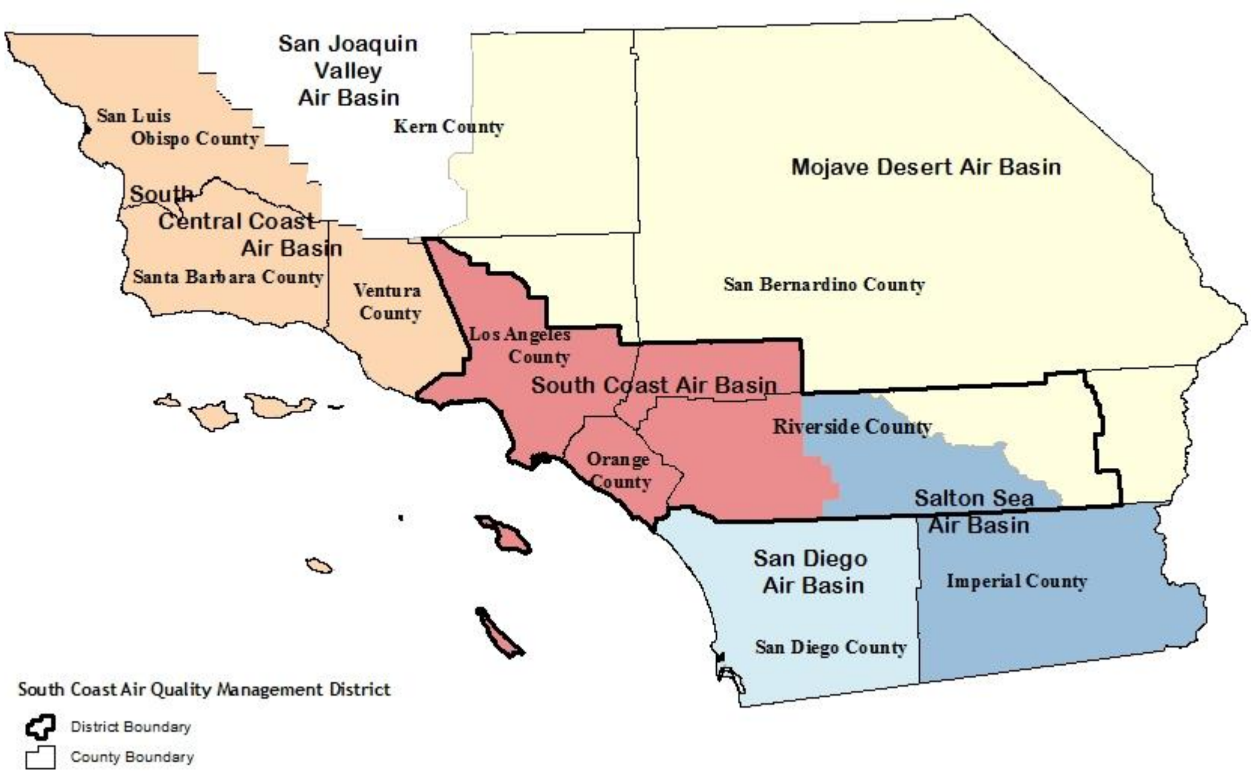

Figure 1-1: Southern California Air Basins

PROJECT BACKGROUND

On October 15, 1993, the SCAQMD Governing Board adopted Regulation XX, referred to herein as the RECLAIM program. Regulation XX is comprised of 15 rules which contain a declining market-based cap and trade mechanism to reduce NOx and SOx emissions from the largest stationary sources in the Basin and subsequently help meet air quality standards while providing facilities with the flexibility to seek the most cost-effective solution for achieving the required reductions. Instead of setting specific limits on each piece of equipment and each process that contributes to air pollution as is stipulated by traditional 'command-and-control' regulations, under the RECLAIM program each facility has a NOx and/or SOx annual emissions limit (allocation) and facility operators can decide what equipment, processes and materials they will use to reduce emissions to meet or go further below their annual emission limits. In lieu of reducing emissions, facility owners or operators may elect to use the trading market to purchase RTCs from other facilities that have reduced emissions below their annual target.

The portion of Regulation XX that focuses on reducing NOx emissions is referred to as "NOx RECLAIM" while the portion that focuses on reducing SOx emissions is referred to as "SOx RECLAIM." Regulation XX contains applicability requirements, NOx and SOx facility allocations, general requirements, as well as monitoring, reporting, and recordkeeping requirements for NOx and SOx sources located at RECLAIM facilities. The RECLAIM program started with 41 SOx facilities and 392 NOx facilities, but by the end of the 2005 compliance year, the program was populated with 33 SOx facilities and 304 NOx facilities. The population at the end of compliance year 2011 consists of 33 SOx facilities and 276 NOx facilities. The reduction in the number of facilities participating in the RECLAIM program since inception has been primarily due to facility shutdowns and/or consolidations.

Under the NOx RECLAIM program, the RECLAIM facilities were issued annual allocations of NOx emissions (also known as facility caps), which declined annually from 1993 until 2003 and remained constant after 2003, until SCAQMD staff conducted a BARCT reassessment for NOx in 2005. In 1993, annual allocations were issued to the RECLAIM facilities and the facility cap reflected BARCT in effect at that time. A BARCT reassessment is now necessary for NOx RECLAIM to assure that the participating facilities will continue to achieve emission reductions as expeditiously as possible to carry out the commitments in the 2012 AQMP. Under the RECLAIM program, the facilities have the flexibility to install air pollution control equipment, change method of operations, or purchase RTCs to meet BARCT levels.

To assure a more liquid market, as well as protect RECLAIM participants from price fluctuations that may be caused if all the RTCs expire at the same time, two trading cycles were established. Further, to balance emissions among the participating facilities in the RECLAIM program, the affected facilities were randomly divided into two cycles which vary by compliance year. That is, the Cycle 1 compliance year spans from January 1 to December 31 while the Cycle 2 compliance year spans from July 1 to June 30. A backstop level of $15,000 per ton was established to trigger program reevaluation.

Between compliance year 1994 and compliance year 1999, NOx emissions at RECLAIM facilities, in aggregate, were below the annual allocations, and the price of NOx RTCs remained relatively stable, ranging from $1,500 to $3,000 per ton. However, beginning June 2000, RECLAIM program participants experienced a sharp and sudden increase in NOx RTC prices for both 1999 and 2000 compliance years. This was mainly due to an increased demand for power generation due to the California energy situation and the delay of installing NOx control equipment by many power plant operators, which resulted in the power-generating industry purchasing a large quantity of RTCs and depleting the supply of available RTCs. The average price of NOx RTCs for compliance year 2000, traded in the year 2000 increased sharply to over $45,000 per ton compared to the average price of $4,284 per ton traded in 1999. Since the RTC price for NOx exceeded the backstop price of $15,000 per ton, an evaluation of the RECLAIM program was triggered.

The Governing Board, at its October 2000 meeting, directed staff to examine the issues affecting the high price of NOx RTCs and recommend actions to stabilize NOx RTC prices. Additionally, the Governing Board directed the Executive Officer to form an Advisory Committee to provide input to staff regarding possible approaches to stabilize NOx RTC prices. Fourteen power producing facilities, each with a generating capacity of 50 megawatts (MW) or greater, purchased 67 percent of the NOx RTCs that were traded during compliance year 2000, suggesting that the increased demand and high prices of NOx RTCs were primarily due to the power producers. However, the annual allocations for all the power producers only accounted for approximately 14 percent of total RECLAIM annual allocations for compliance year 2000. At the same time, the RECLAIM program reached the ‘cross-over point’ where emissions equal allocations because many RECLAIM facilities, relying on previously low RTC prices, did not determine that it was more cost-effective to begin installing controls until after the RTC prices had peaked.

In recognition of the inherent lag time between the ability of facility operators to actually install and operate new control equipment, the Governing Board concluded that immediate changes to the RECLAIM program were necessary and, at the January 19, 2001 Board Meeting, directed staff to form a working group to develop and propose amendments to the RECLAIM program. The goal of the proposed amendments was to implement realistic, effective solutions to reduce and stabilize the prices of NOx RTCs. In May 2001, Regulation XX was amended to place trading restrictions on power producing facilities with the caveat that they could fully rejoin the trading market in the 2004 compliance year, provided that the Governing Board determined prior to July 2003 that their re-entry would not result in any negative effect on the remainder of the RECLAIM facilities or on California’s energy security needs. In addition, the amendments also required the power plants to install BARCT and introduced credit generating rules. Lastly, a Mitigation Fee Program was established for the power plants to make up excess emissions through an option to pay a fee used to mitigate emissions through alternative means or programs.

Pursuant to these requirements, SCAQMD staff examined the energy security needs of California and the potential impacts on the RECLAIM market. The Governing Board determined that reentry of the power plants would not be expected to have a negative effect on California’s energy security needs or on other RECLAIM facilities. Overall, power plants equipped with BARCT have reduced their NOx emission rates by approximately 80 percent or more from previously uncontrolled levels.

Based on these emission levels, the 14 power producing facilities are anticipated to emit a total of 1,395 tons per year of NOx and their total annual allocations are 1,705 tons per year for each year from 2003 to 2010. Further, the RTC holdings for the compliance years 2003 through 2010 range from 1,550 to 2,330 tons per year of NOx. This represented a surplus in the NOx RTC holdings at the time ranging from 155 to 935 tons per year. When considering the data relative to the typical annual operational capacity of a power producing unit at below 30 percent, except for 2001 when in-Basin units operated at 35 percent capacity, on average it would take all units operating at a capacity of 55 percent to cause a shortage in NOx RTCs. Therefore, based on the projected excess RTCs and typical operating capacities, power producers were then considered likely to be sellers of NOx RTCs in the RECLAIM program. For these reasons, the Governing Board at the June 6, 2003 public hearing, made the finding that lifting the trading restrictions for power producers in the RECLAIM trading market would not have a negative effect on the remainder of the RECLAIM facilities or on California's energy security needs. Subsequently, the Governing Board adopted proposed changes to RECLAIM Rules 2007, 2011, and 2012 at the December 5, 2003 public hearing which removed most of the trading restrictions on power producers. As a result, effective September 2004, the power producers were given unrestricted use of RTCs.

On January 7, 2005, amendments were made to the NOx RECLAIM program that resulted in a reduction of RTCs across the board by 7.7 tons per day, based on a BARCT evaluation. The RTCs were reduced from compliance years 2007 to 2011. The total RTCs in the NOx RECLAIM universe allocated in compliance year 2011 amounted to 26.5 tons per day. The audited emissions in compliance year 2011 were 20.01 tons per day, equating to 6.49 tons per day of excess holdings. The proposed RTC shave reduction will be based on compliance year 2011 activity levels for the affected facilities.

PROJECT DESCRIPTION

The proposed project will affect the following types of equipment and processes at the top NOx emitting facilities in the NOx RECLAIM program: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. The proposed amendments to the RECLAIM regulation contain the following key elements:

- Amend Rule 2002 - Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx), to establish procedures and criteria for reducing NOx RTCs and NOx RTC adjustment factors for year 2016 and later.
- Amend Rule 2002 to add new BARCT emission factors ending in 2021 for an assortment of equipment/process categories.
- Amend Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Sulfur (SOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures)
- Amend Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping Oxides of Nitrogen (NOx) Emissions (Attachment C – Quality Assurance and Quality Control Procedures)
- Make administrative and other minor changes such as correcting typographical errors as well as clarifying and updating the rule and rule protocol language for consistency.

The following is a summary of the key proposed amendments. A copy of the proposed amended Rule (PAR) 2002 can be found in Appendix A of this NOP/IS. A copy of the proposed amended protocols for Rules 2011 and 2012 can be found in Appendices B and C, respectively.

PAR 2002

Annual Allocations for NOx and SOX and Adjustments to RTC Holdings – subdivision (f)

- Change compliance year "2011 and after" to "2011 to 2015" for the existing NOx RTC adjustment factors in subparagraph (f)(1)(A).
- Add new RTC adjustment factors to subparagraph (f)(1)(B) in order to achieve projected NOx emission reductions from NOx RTC holders beginning in compliance year 2016 and later. It should be noted that the proposed rule language describes an evenly distributed percent of NOx RTC reductions applicable to all RECLAIM facilities. However, an alternate approach of distributing the NOx RTC reductions among the top NOx RECLAIM facilities would not be precluded.
- Clarify procedures for entering the RECLAIM program after January 7, 2005 in subparagraph (f)(1)(I) to reflect the new RTC adjustment factors added to subparagraph (f)(1)(B).

RTC Reduction Exemption – subdivision (i)

- Clarify paragraph (i)(1) that the RTC reduction exemption does not include RTC holdings for compliance year 2016 and thereafter.
- Clarify subparagraph (i)(1)(B) that the application for an RTC reduction exemption needs to demonstrate that the reported emissions for Compliance Year 2013 are not from equipment listed in existing Table 3 or new Table 6 and that the achieved emission rates are less than the emission factors listed in existing Table 3 or new Table 6, whichever is lower.
- Clarify subparagraph (i)(1)(C) that the application for an RTC reduction exemption needs to demonstrate that the RTCs for Compliance Year 2016 have never been transferred or sold by the facility.
- Clarify clause (i)(1)(D)(i) to allow the exclusion of control costs for any equipment listed in existing Table 3 or new Table 6.
- Clarify paragraph (i)(3) that an application for an RTC reduction exemption shall be submitted no later than six months after the adoption of the proposed project.
- Clarify paragraph (i)(8) to require a facility qualifying for an exemption to include emissions from equipment listed in existing Table 3 or new Table 6 in its Annual Permit Emission Program (APEP) report.

RECLAIM NOx 2021 Ending Emission Factors – new Table 6

- Add new BARCT emission factors ending in 2021 for certain boilers and heaters, cement kilns, FCCUs, gas turbines, container glass melting furnaces, permitted ICEs, metal heat treating furnaces, petroleum coke calciners, sodium silicate furnaces, and SRU/TGUs.

Rule 2011 Appendix A (SOx Protocol for Rule 2011)

<u>Attachment C - Quality Assurance and Quality Control Procedures</u>

- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of a major source.
- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of an electrical generating facility (EGF).

Rule 2012 Appendix A (NOx Protocol for Rule 2012)

<u>Attachment C - Quality Assurance and Quality Control Procedures</u>

- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of a major source.
- Add new procedures and criteria for postponing the due date of semi-annual or annual assessments of an electrical generating facility (EGF).

TECHNOLOGY OVERVIEW

<u>**NOx Emission Sources**</u>

The NOx RECLAIM program currently consists of 276 facilities as of the 2011 compliance year. Of these, 139 facilities operate NOx emitting equipment for which there is no new BARCT identified. For this reason, the proposed project will focus on reducing NOx emissions from the major and large sources of the top emitters of NOx for which new BARCT has been identified (e.g., facilities that emit 85 percent of the total NOx emissions from all RECLAIM facilities). However, a BARCT assessment for approximately ICEs that are operating at the 139 remaining NOx RECLAIM facilities would not be precluded from the proposed project. The following are the top emitters of NOx in the RECLAIM program:

- Six refineries owned by five companies operate FCCUs, refinery boilers and heaters, refinery gas turbines, and SRU/TGUs: Tesoro (two locations: Wilmington and Carson); Phillips 66 (two locations: Wilmington and Carson); Chevron; ExxonMobil; and, Ultramar (also referred to as Valero)
- One coke calciner plant: Tesoro (Wilmington location)
- One cement manufacturing plant: California Portland Cement (CPCC)
- One container glass manufacturing plant: Owens-Brockway Glass Container Inc.
- One sodium silicate manufacturing plant: PQ Corporation
- One steel plant operating two metal heat treating furnaces rated > 150 million British Thermal Units per hr (mmBTU/hr): California Steel
- Seven facilities operating gas turbines: Southern California Gas Company, SDGE, THUMS Long Beach, Wheelabrator Norwalk Energy, LA City Dept. of Airports, Tin Inc., and Berry Petroleum
- Three facilities operating IC Engines: SDGE and Southern California Gas Company (two facilities)

Of the above-listed facilities, six refineries operate one FCCU each, one SRU/TGU each, and a multitude of refinery process heaters and boilers and refinery gas turbines. The quantity of major and large source NOx emissions from the six refineries alone comprises approximately 54 percent of the total NOx emitted from the universe of RECLAIM facilities. The major and large sources belonging to non-refineries among the top NOx emitting facilities emit 25 percent of the RECLAIM universe's total. The remaining 11 percent of emissions that contribute to the 85 percent total come from process units and equipment that is exempt from SCAQMD Rule 219 - Equipment Not Requiring A Written Permit Pursuant To Regulation II.

Combustion Equipment

To appreciate the mechanics of NOx control equipment and techniques, it is necessary to first understand how NOx emissions are generated from the affected equipment and processes. Combustion is a high temperature chemical reaction resulting from burning a gas, liquid, or solid fuel (e.g., natural gas, diesel, fuel oil, gasoline, propane, and coal) in the presence of air (oxygen and nitrogen) to produce: 1) heat energy; and, 2) water vapor or steam. An ideal combustion reaction is when the entire amount of fuel needed is completely combusted in the presence of air so that only carbon dioxide (CO2) and water are produced as by-products. However, since fuel contains other components such as nitrogen and sulfur plus the amount of air mixed with the fuel can vary, in practice, the combustion of fuel is not a "perfect" reaction. As such, uncombusted fuel plus smog-forming by-products such as NOx, SOx, carbon monoxide (CO), and soot (solid carbon) can be discharged into the atmosphere.

Of the total NOx emissions that can be generated, there are two types of NOx formed during combustion: 1) thermal NOx; and, 2) fuel NOx. Thermal NOx is produced from the reaction between the nitrogen and oxygen in the combustion air at high temperatures while fuel NOx is formed from a reaction between the nitrogen already present in the fuel and the available oxygen in the combustion air. As the source of nitrogen in fuel is more prevalent in oil and coal, and is negligible in natural gas, the amount of fuel NOx generated is dependent on fuel type. For example, with oil that contains significant amounts of fuel-bound nitrogen, fuel NOx can account for up to 50 percent of the total NOx emissions generated. Though boilers, process heaters, petroleum coke calciners, FCCUs, gas turbines, and other miscellaneous equipment have varying purposes in commercial, industrial, and utility applications, at a minimum, they all generate thermal NOx as a combustion by-product. The following provides a brief description of the various types of existing combustion equipment that may be affected by the proposed amendments to Regulation XX and subsequently retrofitted with NOx control equipment.

REFINERY CATEGORY

Refinery Process Heaters and Boilers

Refinery process heaters and boilers are used extensively throughout various processes in refinery operations such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking.

A process heater is a type of combustion equipment that burns liquid, gaseous, or solid fossil fuel for the purpose of transferring heat from combustion gases to heat water or process streams. Process heaters are not kilns or ovens used for drying, curing, baking, cooking, calcining, or vitrifying; or any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment.

A typical boiler, also referred to as a steam generator, is a steel or cast-iron pressure vessel equipped with burners that combust liquid, gas, or solid fossil fuel to produce steam or hot water. Boilers are classified according to the amount of energy output in millions of British Thermal Units per hour (mmBTU/hr), the type of fuel burned (natural gas, diesel, fuel oil, etc.), operating steam pressure in pounds per square inch (psi), and heat transfer media. In addition, boilers are further defined by the type of burners used and air pollution control techniques. The burner is where the fuel and combustion air are introduced, mixed, and then combusted.

There are about 23 boilers and 189 heaters in the refineries classified as major or large NOx sources. There are a total of 212 boilers and heaters classified as major and large NOx sources at the refineries. Collectively, the 212 boilers and heaters emitted approximately 7.39 tons per day in 2011.

Refinery process heaters and boilers are primarily fueled by refinery gas, one of several products generated at the refinery. In addition, most of the refinery process heaters and boilers are designed to also operate on natural gas, but liquid or solid fuels are rarely used. The combustion of fuel generates NOx, primarily "thermal" NOx with small contribution from "fuel" NOx and "prompt" NOx.

Commercially available technologies for controlling NOx from refinery boilers and process heaters are selective catalytic reduction (SCR), Great Southern Flameless Heaters, and LoTOx™ applications with scrubbers. Other potential technologies on the horizon are ClearSign, Cheng Low NOx and KnowNOx™. All of these control technologies can be designed to reach two parts per million by volume (ppmv) NOx at three percent oxygen. For a full description of these control technologies, see the NOx Control Technologies section. The Draft PEA will evaluate the possibility that each refinery may rely on any of these control technologies in order to comply with the refinery process heaters and boilers portion of the proposed project.

<u>Refinery Gas Turbines</u>

Gas turbines are used in refineries to produce both electricity and steam. Refinery gas turbines are typically combined cycle units that use two work cycles from the same shaft operation. Refinery gas turbines also have an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are power plant turbines (turbines that produce solely electric utility power) and some of these units are cogenerating units that, in addition to producing in-house power, also recover the useful energy from heat recovery for producing process steam. There are a total of 21 gas turbines/duct burners classified as major NOx sources at the refineries in the SCAQMD. Collectively, the 21 gas turbines/duct burners emitted about 1.33 tons per day of NOx in 2011.

Frame gas turbines are exclusively used for power generation and continuous base load operation ranging up to 250 MW with simple-cycle efficiencies of approximately 40 percent and combined-cycle efficiencies of 60 percent. The existing gas turbines operating at the refineries are rated from seven MW to 83 MW. Most of the refinery gas turbines are operated with duct burners, heat recovery steam generator (HRSG), SCR, and CO catalysts. In addition, some refinery gas units utilize water or steam injection, Ammonia Slip Catalysts (ASC), Cheng Low NOx, and Dry Low Emissions (DLN or DLE) combustors. Figure 1-2 shows a typical layout of a combined cycle utility gas turbine with a duct burner, HRSG, and control system.

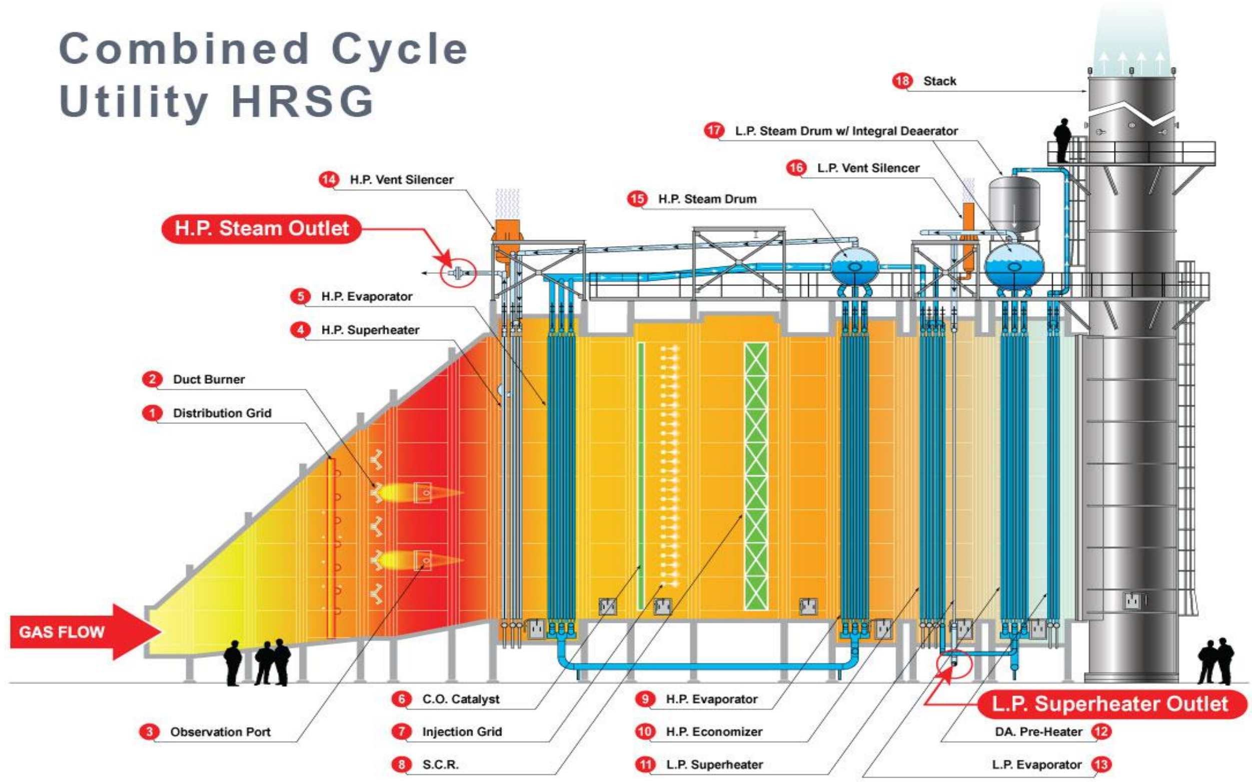

Figure 1-2: Gas Turbine with Duct Burner

The type of NOx control option to be utilized for refinery gas turbines will depend on each refinery's individual operations and the current control technologies and techniques in place. For a full description of these control technologies, see the NOx Control Technologies section. The Draft PEA will evaluate the possibility that each refinery may rely on any of these control technologies in order to comply with the refinery gas turbines portion of the proposed project.

Sulfur Recovery Units and Tail Gas Units (SRU/TGUs)

Refinery SRU/TGTUs, including their incinerators, are classified as major sources of both NOx and SOx emissions. Because sulfur is a naturally occurring and undesirable component of crude oil, refineries employ a sulfur recovery system to maximize sulfur removal. A typical sulfur removal or recovery system will include a sulfur recovery unit (e.g., Claus unit) followed by a tail gas treatment unit (e.g., amine treating) for maximum removal of hydrogen sulfide (H_2S). A Claus unit consists of a reactor, catalytic converters and condensers. Two chemical reactions occur in a Claus unit. The first reaction occurs in the reactor, where a portion of H_2S reacts with air to form sulfur dioxide (SO_2) followed by a second reaction in the catalytic converters where SO_2 reacts with H_2S to form liquid elemental sulfur. Side reactions producing carbonyl sulfide (COS) and carbon disulfide (CS_2) can also occur. These side reactions are problematic for Claus plant operators because COS and CS_2 cannot be easily converted to elemental sulfur and carbon dioxide. Liquid sulfur is recovered after the final condenser. The combination of two converters with two condensers in series will generally remove as much as 95 percent of the sulfur from the incoming acid gas. To increase removal efficiency, some newer sulfur recovery units may be designed with three to four sets of converters and condensers.

To recover the remaining sulfur compounds after the final pass through the last condenser, the gas is sent to a tail gas treatment process such as a SCOT or Wellman-Lord treatment process. For example, the SCOT tail gas treatment is a process where the tail gas is sent to a catalytic reactor and the sulfur compounds in the tail gas are converted to H_2S. The H_2S is absorbed by a solution of amine or diethanol amine (DEA) in the H_2S absorber, steam-stripped from the absorbent solution in the H_2S stripper, concentrated, and recycled to the front end of the sulfur recovery unit. This approach typically increases the overall sulfur recovery efficiency of the Claus unit to 99.8 percent or higher. However, the fresh acid gas feed rate to the sulfur recovery unit is reduced by the amount of recycled stream, which reduces the capacity of the sulfur recovery unit. The residual H_2S in the treated gas from the absorber is typically vented to a thermal oxidizer where it is oxidized to sulfur dioxide (SO_2) before venting to the atmosphere.

The Wellman-Lord tail gas treatment process is when the sulfur compounds in the tail gas are first incinerated to oxidize to SO_2. After the incinerator, the tail gas enters a SO_2 absorber, where the SO_2 is absorbed in a sodium sulfite (Na_2SO_3) solution to form sodium bisulfite ($NaHSO_3$) and sodium pyrosulfate ($Na_2S_2O_5$). The absorbent rich in SO_2 is then stripped, and the SO_2 is recycled back to the beginning of the Claus unit. The residual sulfur compounds in the treated tail gas from the SO_2 absorber is then vented to a thermal (or catalytic) oxidizer (incinerator) where the residual H_2S in the tail gas is oxidized to SO_2 before venting to the atmosphere. NOx is a by-product of operating the incinerator.

There are three main strategies that can be employed to further reduce NOx emissions from each SRU/TGU operating at the six refineries: 1) increase the efficiency of the sulfur recovery unit; 2) improve the efficiency of the tail gas treatment process; and, 3) install a wet gas scrubber (WGS) as an alternative to the thermal oxidizer[5]. The type of NOx control option to be utilized in response to this portion of the proposed project will depend on each refinery's individual operations and the current control technologies and techniques in place. Commercially available control technologies for NOx emissions are SCR, LoTOx™ with scrubber, and KnowNOx™. While SCR is considered as a high temperature NOx reduction technology, LoTOx™ and KnowNOx™ technologies are known for low temperature multi-pollutant control systems since they can be integrally connected with a WGS to reduce NOx, SOx, PM, VOC, hazardous air pollutants (HAPs), and other toxic compounds. For a full description of these control technologies, see the NOx Control Technologies section.

The Draft PEA will evaluate the possibility that each refinery may rely on any of these control technologies in order to comply with the SRU/TGU portion of the proposed project.

<u>Petroleum Coke Calciner</u>

Petroleum coke, the heaviest portion of crude oil, cannot be recovered in the normal oil refining process. Instead, it is processed in a delayed coker unit to generate a carbonaceous solid referred to as "green coke," a commodity. To improve the quality of the product, if the green coke has a low metals content, it will be sent to a calciner to make calcined petroleum coke. Calcined petroleum coke can be used to make anodes for the aluminum, steel, and titanium smelting industry. If the green coke has a high metals content, it is used as fuel grade coke by the fuel, cement, steel, calciner and specialty chemicals industries.

[5] All six refineries have thermal oxidizers at the end of their tail gas treatment units.

As shown in Figure 1-3, the process of making calcined petroleum coke begins when the green coke feed produced by the delayed coker unit is screened and transported to the calciner unit where it is stored in a covered coke storage barn. The screened and dried green coke is introduced into the top end of a rotary kiln and is tumbled by rotation under high temperatures that range between 2000 and 2500 degrees Fahrenheit (^oF). The rotary kiln relies on gravity to move coke through the kiln countercurrent to a hot stream of combustion air produced by the combustion of natural gas or fuel oil. As the green coke flows to the bottom of the kiln, it rests in the kiln for approximately one additional hour to eliminate any remaining moisture, impurities, and hydrocarbons. Once discharged from the kiln, the calcined coke is dropped into a cooling chamber, where it is quenched with water, treated with de-dusting agents to minimize dust, carried by conveyors to storage tanks. Eventually, the calcined coke is transported by truck to the Port of Long Beach for export, or is loaded onto railcars for shipping to domestic customers. As the green coke is processed under high heat conditions in the rotary kiln, NOx emissions are generated. NOx is also generated from combusting fuel oil to generate high heating values in the rotary kiln.

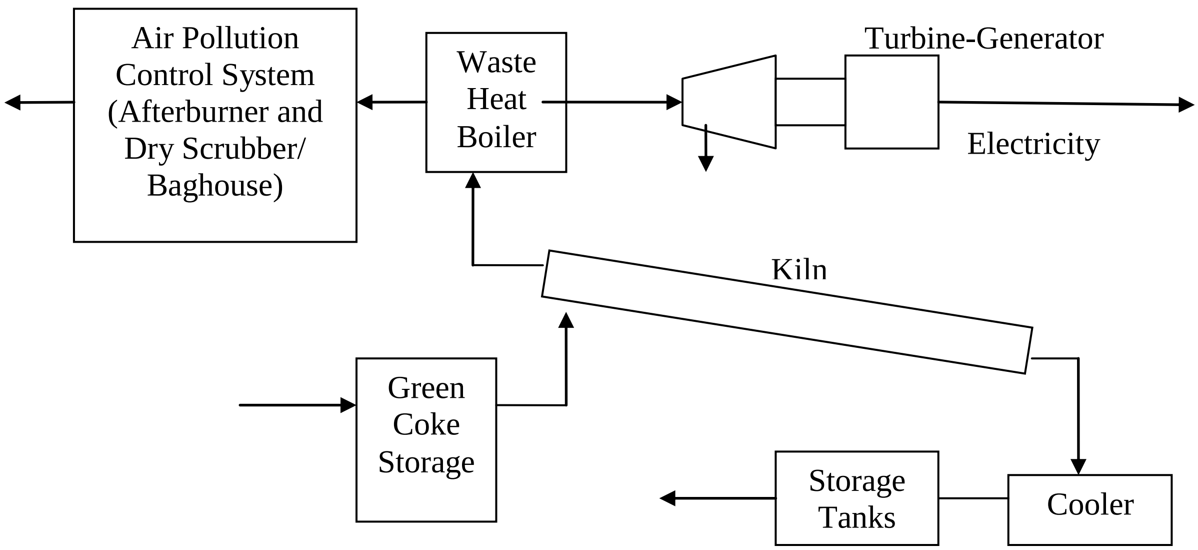

Figure 1-3: Coke Calciner Process

The Tesoro Wilmington coke calciner is only petroleum coke calciner in the Basin and produces approximately 400,000 short tons per year of calcined products. This petroleum coke calciner is a global supplier of calcined coke to the aluminum industry, and fuel grade coke to the fuel, cement, steel, calciner, and specialty chemicals businesses. The existing control system also includes a spray dryer, a reverse-air baghouse, a slurry storage system, a slurry circulating system, and a pneumatic conveying system. Calcium hydroxide (CaOH) slurry is the absorbing medium for SO_2 control.

There are two commercially available multi-pollutant control technologies for the low temperature removal of NOx emissions from the coke calciner: 1) LoTOx™ with scrubber; and, 2) UltraCat. For a full description of these control technologies, see the NOx Control Technologies section. The type of NOx control option to be utilized for the coke calciner in response to the proposed project will depend on this facility's individual operations and the current control technologies and techniques in place. Thus, the Draft PEA will evaluate the possibility that operators of the petroleum coke calcining facility may rely on either of the above-mentioned control technologies to further control NOx emissions in order to comply with the BARCT requirements for the petroleum coke calcining portion of the proposed project.

FCCUs

The purpose of an FCCU at a refinery is to convert or "crack" heavy oils (hydrocarbons), with the assistance of a catalyst, into gasoline and lighter petroleum products. Each FCCU consists of three main components: a reaction chamber, a catalyst regenerator and a fractionator. All six refineries each operate one FCCU.

As shown in Figure 1-4, the cracking process begins in the reaction chamber where fresh catalyst is mixed with pre-heated heavy oils (crude) known as the fresh feed. The catalyst typically used for cracking is a fine powder made up of tiny particles with surfaces covered by several microscopic pores. A high heat-generating chemical reaction occurs that converts the heavy oil liquid into a cracked hydrocarbon vapor mixed with catalyst. As the cracking reaction progresses, the cracked hydrocarbon vapor is routed to a distillation column or fractionator for further separation into lighter hydrocarbon components than crude such as light gases, gasoline, light gas oil, and cycle oil.

Towards the end of the reaction, the catalyst surface becomes inactive or spent because the pores are gradually coated with a combination of heavy oil liquid residue and solid carbon (coke), thereby reducing its efficiency or ability to react with fresh heavy liquid oil in the feed. To prepare the spent catalyst for re-use, the remaining oil residue is removed by steam stripping. The spent catalyst is later cycled to the second component of the FCCU, the regenerator, where hot air burns the coke layer off of the surface of each catalyst particle to produce reactivated or regenerated catalyst. Subsequently, the regenerated catalyst is cycled back to the reaction chamber and mixed with more fresh heavy liquid oil feed. Thus, as the heavy oils enter the cracking process through the reaction chamber and exit the fractionator as lighter components, the catalyst continuously circulates between the reaction chamber and the regenerator.

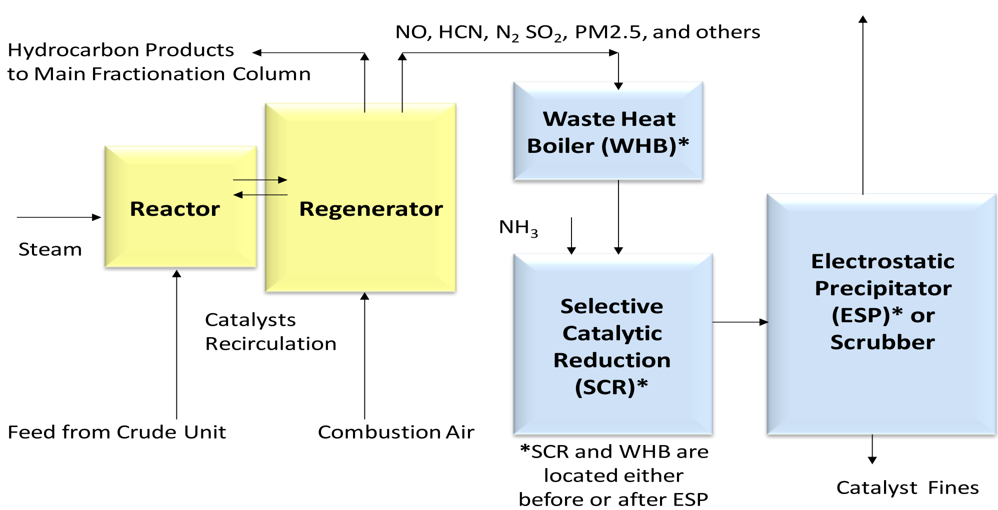

Figure 1-4: Simplified Schematic of FCCU Process

During the regeneration cycle, large quantities of catalyst are lost in the form of catalyst fines or particulates thus making FCCUs a major source of primary particulate emissions (PM10 and

PM2.5) at refineries. In addition, particulate (PM) precursor emissions such as SOx (because crude oil naturally contains sulfur) and NOx, additional secondary particulates (i.e., formed as a result of various chemical reactions), plus carbon monoxide (CO) and carbon dioxide (CO_2) are produced due to coke burn-off during the regenerator process.

Approximately 90 percent of the NOx generated from the FCCUs are from the nitrogen in the feed that is accumulated in the coke which is then burned-off in the regenerator. This portion of the NOx is called "fuel" NOx. "Fuel" NOx is a combination of nitric oxide (NO), nitrogen dioxide (NO_2), and nitrous oxide (N_2O). The remaining 10 percent of the NOx generated from the FCCUs are "thermal" NOx which is generated in the high temperature zones in the regenerator, and "prompt" NOx generated from the reaction between nitrogen and oxygen in the combustion air. The potential available control technologies to reduce NOx emissions from a FCCU are: 1) SCR; 2) LoTOx™ with scrubber; and/or, 3) NOx reducing additives.

The type of NOx control option to be utilized for FCCUs in response to the proposed project will depend on each refinery's individual operations and the current control technologies and techniques in place. Thus, the Draft PEA will evaluate the possibility that refinery operators of the FCCUs may rely on the above-mentioned control technologies to further control NOx emissions in order to comply with the BARCT requirements for FCCUs.

NON-REFINERY / NON-POWER PLANT CATEGORY

<u>Portland Cement Kilns</u>

In the NOx RECLAIM program, there is one facility (CPCC) with two cement kilns capable of producing gray cement from limestone, sand, shale, and clay raw materials. The CPCC facility, under normal operation, has typically been among the highest NOx emitters in the RECLAIM program. However, on November 20, 2009, CPCC operators announced the shutdown of both cement kilns. CPCC operators indicated that the shutdown is not permanent to the extent that when the economy improves, they plan to bring the cement kilns back on-line.

The manufacturing of gray Portland cement follows a four-step process of: 1) acquiring raw materials; 2) preparing the raw materials to be blended into a raw mix; 3) pyroprocessing of the raw mix to make clinker (e.g., lumps of limestone and clay); and, 4) grinding and milling clinker into cement. The raw materials used for manufacturing cement include calcium, silica, alumina and iron, with calcium having the highest concentration. These raw materials are obtained from a limestone quarry for calcium, sand for silica; and shale and clay for alumina and silica.

The raw materials are crushed, milled, blended into a raw mix and stored. Primary, secondary and tertiary crushers are used to crush the raw materials until they are about ¾-inch or smaller in size. Raw materials are then conveyed to rock storage silos. Belt conveyors are typically used for this transport. Roller mills or ball mills are used to blend and pulverize raw materials into fine powder. Pneumatic conveyors are typically used to transport the fine raw mix to be stored in silos until it is ready to be pyroprocessed.

The pyroprocess in a kiln consists of three phases during which clinker is produced from raw materials undergoing physical changes and chemical reactions. The first phase in a kiln, the drying and pre-heating zone, operates at a temperature between 70 ^{o}F and 1650 ^{o}F and evaporates any remaining water in the raw mix of materials entering the kiln. Essentially this is the warm-up phase which stabilizes the temperature of the refractory fire brick inside the mouth opening of the kiln. The second phase, the calcining zone, operates at a temperature between 1100 ^{o}F and 1650 ^{o}F and converts the calcium carbonate from the limestone in the kiln feed into calcium oxide and releases carbon dioxide. During the third phase, the burning zone operates on average at 2200 ^{o}F to 2700 ^{o}F (though the flame temperature can exceed 3400 ^{o}F) during which several reactions and side reactions occur. The first reaction is calcium oxide (produced during the calcining zone) with silicate to form dicalcium silicate and the second reaction is the melting of calcium oxide with alumina and iron oxide to form the liquid phase of the materials. Despite the high temperatures, the constituents of the kiln feed do not combust during pyroprocessing. As the materials move towards the discharge end of the kiln, the temperature drops and eventually clinker nodules form and volatile constituents, such as sodium, potassium, chlorides, and sulfates, evaporate. Any excess calcium oxide reacts with dicalcium silicate to form tricalcium silicate. The red hot clinker exits the kiln, is cooled in the clinker cooler, passes through a crusher and is conveyed to storage for protection from moisture. Since clinker is water reactive, if it gets wet, it will set into concrete.

Heat needed to operate CPCC's kilns is supplied through the combustion of different fuels such as coal, coke, oil, natural gas, and discarded automobile tires. The combustion gases are vented to a baghouse for dust control, and the collected dust is returned to the process or recycled if they meet certain criteria, or is discarded to landfills. CPCC does not currently have any post-combustion control for NOx emissions.

NOx emissions from the cement kilns are generated from the following: 1) from combusting fuel to generate high heating values in the kilns; and, 2) oxidation of sulfides (e.g., pyrites) in the raw materials entering the cement kiln. As is the case with CPCC, long, dry cement kilns have achieved NOx reductions to the 2000 (Tier 1) level by utilizing low NOx burners and mid-kiln firing with tire-derived fuel (TDF). With TDF, whole tires are introduced at an inlet location about midway along the kiln's calcining zone. TDF lowers NOx emissions by lowering the flame temperatures and reducing thermal NOx with the introduction of a slower burning fuel.

In the event that CPCC operators decide to fire up its kilns, the type of NOx control technology to be utilized to comply with the proposed project will depend on CPCC's individual operations and how the kilns will function with the current control technologies and techniques in place at CPCC (e.g., the baghouse). The potential available control technologies to reduce NOx emissions from cement kilns are: 1) SCR with or without a WGS; 2) UltraCat; or, 3) SNCR. For a full description of these control technologies, see the NOx Control Technologies section. Thus, the Draft PEA will evaluate the possibility that CPCC operators may rely on the above-mentioned control technologies to further control NOx emissions from cement kilns to comply with the proposed project.

Container Glass Melting Furnaces

In the NOx RECLAIM program there is one facility among the top NOx emitting facilities that operates glass melting furnaces. This facility produces container glass from dry, solid raw materials that are melted in the furnaces and then formed into glass container bottles.

A container glass melting furnace is the main equipment used for manufacturing glass products, such as bottles, glass wares, pressed and blown glass, tempered glass, and safety glass. The manufacturing process consists of four phases: 1) preparing the raw materials; 2) melting the mixture of raw materials in the furnace; 3) forming the desired shape; and, 4) finishing the final product. Raw materials, such as sand, limestone, and soda ash, are crushed and mixed with cullets (recycled glass pieces) to ensure homogeneous melting. The raw materials mixture is then conveyed to a continuous regenerative side-port melting furnace. As the mixture enters the furnace through a feeder, it melts and blends with the molten glass already in the furnace, and eventually flows to a refiner section, to a forming machine, and then, to annealing ovens. The final products undergo inspection, testing, packaging and storage. Any damaged or undesirable glass is transferred back to be recycled as cullet suitable for remelting.

NOx is generated from a container glass melting furnace in two ways: 1) during the decomposition of the silica in the raw materials; and, 2) from combusting fuel to generate high heating values in the furnace. The container glass melting furnace contributes over 99 percent of the total NOx emissions from a glass manufacturing plant. To effectively achieve the largest reduction of NOx emissions, SCR and UltraCat technologies are commercially available options for treating the flue gas of glass melting furnaces. For a full description of these control technologies, see the NOx Control Technologies section. The Draft PEA will evaluate the possibility that these control technologies may be relied up in order to comply with the glass melting furnace portion of the proposed project.

Sodium Silicate Furnace

In the NOx RECLAIM program, there is only one facility that produces sodium silicate in a melting furnace. Sodium silicate, a type of glass with a wide variety of industrial uses, should not to be confused with container or flat glass. Sodium silicate exists in a solid or liquid form, depending on the temperature. The combination of heating a batch-fed mixture of soda ash and sand causes the materials to produce sodium silicate and CO_2. NOx emissions are also created from combusting fuel needed to heat the furnace. In order to generate high heating values, the furnace is fired by several natural gas-fired burners. The flue gas then exits the furnace via a stack into the atmosphere.

Approximately 15 to 20 percent of NOx emission reductions can be achieved by utilizing blower air staging to lower the flue gas temperature in the furnace. To effectively achieve the largest reduction of NOx emissions, however, SCR technology is best suited for treating the flue gas of sodium silicate furnaces.

In addition, UltraCat, an alternate to SCR technology, is also available for multi-pollutant control. For a full description of these control technologies, see the NOx Control Technologies section. The Draft PEA will evaluate the possibility that these control technologies may be relied up in order to comply with the sodium silicate furnace portion of the proposed project.

Metal Heat Treating Furnaces

A metal melting furnace burns liquid or gaseous fuel to generate enough pre-heated air at a temperature high enough to melt solid metal and into a liquid molten consistency and to maintain the metal in a liquid state until it is ready for later use. The types of furnaces that are used for metal melting are reverberatory, cupola, induction, direct arc furnaces, sweat furnaces, and refining kettles. The burner flame and combustion products come in direct contact with the metal.

Heat treating operations are directly related to the metal producing and secondary metal processing industries. Materials handled by the heat treating industry are a variety of products provided by manufacturers that are used by other manufacturers, to make consumable or usable products. Typical materials used for heat treating are iron, steel, ferro-alloys, glass, and other nonferrous metals. Heat treatment furnaces are used for activities that include forging, hardening, tempering, annealing, normalizing, sintering, and case hardening of steels and solution and heat treatment of corrosion resistant and aluminum metals. Kilns are not considered heat treating furnaces. Among the top NOx emitting facilities in the NOx RECLAIM program, there is only one facility that processes steel in two metal heat furnaces with individual heat ratings above 150 mm BTU/hr.

As with all combustion sources, the type of burner used can affect the emissions. Some burners are lower NOx emitting than others. But for these types of furnaces, there are often dozens of burners that cumulatively require a high heat input. To achieve higher efficiency and to consume less fuel, recuperative and regenerative burners are used. These burners employ the principle of using preheated inlet air which is heated by the exhaust gases for more efficient combustion. However, to effectively achieve a substantial NOx reduction from these metal heat treating furnaces, SCR is the technology that is best suited for the flue gas treatment of NOx. For a full description of these control technologies, see the NOx Control Technologies section.

The Draft PEA will evaluate the possibility that the operator of the metal heat treating furnaces may rely on a combination of recuperative and regenerative burners along with SCR technology to further control NOx emissions in order to comply with the BARCT requirements for the metal heat treating furnace portion of the proposed project.

<u>Gas Turbines (Non-Refinery/Non-Power Plant)</u>
Stationary gas turbines are used primarily to drive compressors or to generate power. Gas turbines operate either in simple cycle or combined cycle. Simple cycle units use the mechanical energy of shaft work that is transferred to and used by a gas compressor, for example, or to run an electrical generator to produce electricity. A combined cycle unit adds an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Combined cycle units are more efficient due to their use of two work cycles from the same shaft operation. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are not power plant turbines (turbines that produce solely electric utility power). Some of these units are cogenerating units that, in addition to producing in-house power, also recover the useful energy from heat recovery for producing process steam.

Among the top non-power plant NOx emitting facilities in the RECLAIM universe, there are twenty gas turbines that are either major or large source units. Four of these units are currently utilizing some level of NOx control along with SCR. Six of these units are operated on an offshore oil drilling platform (outer continental shelf, or OCS). The OCS turbines, which are fired on diesel or process gas, have the highest NOx emission concentrations in this source category. Four of the OCS units with lower NOx parts per million (ppm) concentrations currently are equipped with SCR systems.

There are several methods of NOx control for gas turbines, with differing levels of reduction, such as steam or water injection, dry low emissions (DLE or DLN), and SCR. For a full description of these control technologies, see the NOx Control Technologies section. The type of NOx control option to be utilized for gas turbines will depend on the facility's individual operations and the current control technologies and techniques in place. The Draft PEA will evaluate the possibility that these control technologies may be relied up in order to comply with the stationary gas turbine portion of the proposed project.

<u>Internal Combustion Engines (Non-Refinery/Non-Power Plant)</u>
Stationary Internal Combustion Engines (ICEs) are used primarily to drive pumps, compressors, or to generate power. There are generally two types of engines, spark-ignited (SI) or compression ignited (CI) engines. SI engines ignite the air/fuel mixture with a spark while CI engines use the heat of compression to ignite the fuel that is injected into the combustion chamber. Engines can run at either stoichiometrically rich burn or lean burn conditions, depending on the air to fuel ratio. Rich burn combustion corresponds to an air-to-fuel ratio that is fuel-rich while lean burn combustion corresponds to a fuel-lean air-to-fuel ratio. Small SI engines typically run as rich burn, but many larger units as well as CI engines operate under lean burn conditions. For lean burn engines, more air is inducted than is required for complete combustion and the resultant exhaust oxygen level is high (over five percent). Rich burn engines typically operate very close to stoichiometric conditions by drawing only the necessary air to combust the fuel. SI engines are typically fired on gaseous fuels such as natural gas, while CI engines are fired on liquid fuels such as diesel.

Among the top NOx emitting facilities in the RECLAIM universe, there are 31 engines that are either major or large source units. Currently, there are nine rich burn engines equipped non-selective catalytic reduction (NSCR). Of the remaining 22 engines, there are 16 SI lean burn engines units and six CI lean burn units. The CI lean burn units are all operated on an offshore oil drilling platform (outer continental shelf, or OCS). The engine sizes range from a little over 700 brake horsepower (bhp) to 5,500 bhp. Diesel-fueled CI engines have the highest NOx emission concentrations in this source category while two-stroke SI engines have higher NOx emissions than four-stroke SI engines since the higher efficiencies in two-stroke engines translate to a hotter combustion temperature that can create more NOx.

Because the flue gas from rich burn engines has typically very low excess oxygen, NOx reductions can be achieved with NSCR technology. For lean burn exhaust with higher oxygen content, SCR is more effective at reducing NOx emissions. For a full description of these control technologies, see the NOx Control Technologies section. The type of NOx control option to be utilized for stationary ICEs will depend on the facility’s individual operations and the current control technologies and techniques in place. For the ICEs operating at the 139 remaining NOx RECLAIM faculties, the ICEs would also need to meet the BARCT levels on a programmatic basis. The Draft PEA will evaluate the possibility that these control technologies may be relied up in order to comply with the stationary ICEs portion of the proposed project.

<u>**NOx Control Technologies**</u>
As reducing NOx emissions is the main objective of the currently proposed amendments to the RECLAIM program, there are two primary approaches for reducing NOx emissions: 1) by combustion control techniques that minimize the amount of NOx formed by the combustion equipment; or, 2) by installing a device that controls the NOx after it has been generated or post-combustion. On an equipment/process basis, Table 1-1 summarizes the potential control technologies that will be considered as part of the BARCT analysis for the proposed project. The following discussions will elaborate on the various technologies listed in Table 1-1.

Table 1-1
BARCT Control Technology Options for Top NOx Emitting Equipment/Processes

Equipment/Process	BARCT Control Technology Options
FCCUs	1. SCR 2. LoTOx™ with scrubber 3. NOx reducing additives
Refinery Process Heaters and Boilers	1. SCR 2. LoTOx™ with scrubber 3. KnowNOx™ with scrubber 4. Great Southern Flameless Heaters 5. ClearSign 6. Cheng Low NOx
Refinery Gas Turbines	1. SCR 2. Ammonia Slip Catalyst (ASC) 3. CO Catalyst 4. Dry Low Emissions (DLE or DLN) 5. Cheng Low NOx
SRU/TGUs	1. SCR 2. LoTOx™ with scrubber 3. KnowNOx™ with scrubber
Petroleum Coke Calciner	1. LoTOx™ with scrubber 2. UltraCat
Portland Cement Kilns	1. SCR with or without scrubber 2. UltraCat 3. SNCR
Container Glass Melting Furnaces	1. SCR 2. UltraCat
Sodium Silicate Furnaces	3. SCR 4. UltraCat
Metal Heat Treating Furnaces	SCR
ICEs (Non-Refinery/Non-Power Plant)	1. SCR 2. NSCR
Non-Refinery/Non-Power Plant Gas Turbines	6. SCR 7. Flue Gas Recirculation 8. Staged Combustion/Low NOx Burners 9. Water/Steam Injection 10. Dry Low Emissions (DLE or DLN)

<u>Flue Gas Recirculation</u>

Flue Gas Recirculation (FGR) is a very common NOx reduction method used in boilers and process heaters that recycles a portion of low oxygen combustion by-products from the stack. These recirculated gases reduce the overall combustion temperature, which in turn, helps to reduce the formation of NOx. FGR can reduce thermal NOx emissions by as much as 70 percent or greater, depending on the method of introduction of the recirculated flue gases, the amount of FGR flow, and the type of fuel combusted. For example, when firing natural gas, typical NOx reductions are 45 percent with a 10 percent recirculation rate, and 75 percent with a 20 percent recirculation rate.

Staged Combustion & Low-NOx Burners

Staged combustion is another technique utilized in boilers, process heaters, metal melting furnaces, heat treating furnaces and other miscellaneous equipment to help achieve lower NOx emissions by dividing the combustion process into a number of stages in which the air-to-fuel ratio is varied to manipulate the conditions that would make NOx formation less ideal. Staged combustion is divided into two categories: staged air combustion and staged fuel combustion. Staged air combustion controls the formation of NOx by staging or staggering the total amount of air required for combustion to occur and can be achieved by installing low-NOx burners. Only a portion of the total air needed for combustion is used to form a fuel-rich primary combustion zone, in which all of the fuel is partially burned. Then, combustion is fully completed when the remainder of the combustion air is injected in a secondary zone which is located downstream of the fuel-rich primary zone. Because some heat is transferred prior to the completion of combustion, peak combustion temperatures are lower (which reduces formation of thermal NOx) with stage air combustion than with conventional combustion.

Without limiting the combustion air, staged fuel combustion controls the formation of NOx by staging the amount of fuel needed for combustion. With a high level of excess air in the primary combustion zone, the peak combustion temperature drops and subsequently reduces NOx formation. Additional fuel is later injected in the secondary combustion zone at a higher pressure and velocity than in the primary combustion zone, to stimulate FGR, further reduce combustion temperature, and decrease the availability of oxygen needed to form NOx.

Water/Steam Injection

The process of injecting water or steam into the flame in the combustion equipment reduces the flame temperature which lowers the formation of thermal NOx. Water/steam injection is typically used in conjunction with other NOx control methods such as FGR or burner modifications (e.g., low-NOx burners). Estimated reductions in NOx emissions from utilizing water/steam injection vary with the type of fuel combusted. For example, the use of water/steam injection and natural gas can achieve as much as 80 percent reduction in NOx.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is post-combustion control equipment that is considered to be BARCT, if cost-effective, for NOx control of existing combustion sources such as boilers, process heaters, and FCCUs as it is capable of reducing NOx emissions by as much as 95 percent or higher. A typical SCR system design consists of an ammonia storage tank, ammonia vaporization and injection equipment, a booster fan for the flue gas exhaust, an SCR reactor with catalyst, an exhaust stack plus ancillary electronic instrumentation and operations control equipment. The way an SCR system reduces NOx is by a matrix of nozzles injecting a mixture of ammonia and air directly into the flue gas exhaust stream from the combustion equipment. As this mixture flows into the SCR reactor that is replete with catalyst, the catalyst, ammonia, and oxygen (from the air) in the flue gas exhaust reacts primarily (i.e., selectively) with NO and NO_2 to form nitrogen and water in the presence of a catalyst. The amount of ammonia introduced into the SCR system is approximately a one-to-one molar ratio of ammonia to NOx for optimum control efficiency, though the ratio may vary based on equipment-specific NOx reduction requirements. There are two main types of catalysts: one in which the catalyst is coated onto a metal structure and a ceramic-based catalyst onto which the catalyst components are calcified. Commercial catalysts used in SCRs are available in two types of solid, block configurations or modules, plate or honeycomb type, and are comprised of a base material of titanium dioxide (TiO_2) that is coated with either tungsten trioxide (WO_3), molybdic anhydride (MoO_3), vanadium pentoxide (V_2O_5), iron oxide (Fe_2O_3), or zeolite catalysts. These catalysts are used for SCRs because of their high activity, insensitivity to sulfur in the exhaust, and useful life span of approximately five years or more. Ultimately, the material composition of the catalyst is dependent upon the application and flue gas conditions such as gas composition, temperature, et cetera.

For conventional SCRs, the minimum temperature for NOx reduction is 500 ^oF and the maximum operating temperature for the catalyst is 800 ^oF. Depending on the application, the type of fuel combusted, and the presence of sulfur compounds in the exhaust gas, the optimum flue gas temperature of an SCR system is case-by-case and will range between 550 ^oF and 750 ^oF to limit the occurrence of several undesirable side reactions at certain conditions. One of the major concerns with the SCR process is the poisoning of the catalyst due to the presence of sulfur and the oxidation of sulfur dioxide (SO_2) in the exhaust gas to sulfur trioxide (SO_3) and the subsequent reaction between SO_3 and ammonia to form ammonium bisulfate or ammonium sulfate. The formation of either ammonium bisulfate or ammonium sulfate depends on the amount of SO_3 and ammonia present in the flue gas and can cause equipment plugging downstream of the catalyst. The presence of particulates, heavy metals and silica in the flue gas exhaust can also limit catalyst performance. However, minimizing the quantity of injected ammonia and maintaining the ammonia temperature within a predetermined range will help avoid these undesirable reactions while minimizing the production of unreacted ammonia which is commonly referred to as 'ammonia slip.' Depending on the type of combustion equipment utilizing SCR technology, the typical amount of ammonia slip can vary between less than five ppmv when the catalyst is fresh and 20 ppmv at the end of the catalyst life.

In addition to the conventional SCR catalysts, there are high temperature SCR catalysts that can withstand temperatures up to 1200 ^oF and low temperature SCR catalysts that can operate below 500 ^oF.

<u>Non-Selective Catalytic Reduction</u>
Non-selective catalytic reduction (NSCR) is an add-on NOx control technology for high temperature exhaust streams with low O_2 content. NSCR uses a catalyst reaction to simultaneously convert NOx, CO, and VOC into water, CO_2, and nitrogen (N_2).

One type of NSCR system injects a reducing agent into the exhaust gas stream prior to the catalyst reactor to reduce the NOx. Another type of NSCR system has an afterburner and two catalytic reactors (one reduction catalyst and one oxidation catalyst). In this latter system, natural gas is injected into the afterburner to combust unburned hydrocarbons at a minimum temperature of 1,700 °F and the gas stream is cooled prior to entering the first catalytic reactor where CO and NOx are reduced. A second heat exchanger cools the gas stream to reduce the potential reformation of NOx before the second catalytic reactor where the remaining CO is converted to CO_2.

NSCR can achieve a NOx control efficiency ranging from 80 to 90 percent. The NOx reduction efficiency is dependent upon similar factors as for SCR, including the catalyst material and condition, the space velocity, and the catalyst bed operating temperature, air-to-fuel ratio, the exhaust gas temperature, and the presence of masking or poisoning agents. The operating temperatures for NSCR system range from approximately 700 °F to 1500 °F, depending on the catalyst. In order to achieve NOx reductions of 90 percent, the temperature must be between 800 °F and 1200 °F and the O_2 concentration must be less than four percent. To control NOx, CO, and VOC simultaneously, NSCR catalyst must operate in a narrow air-to-fuel ratio band (15.9-to-16.1 for natural gas-fired engines) that is close to stoichiometric. An electronic controller, which includes an oxygen sensor and feedback mechanism, is often necessary to maintain the air-to-fuel ratio in this narrow band. At this air-to-fuel ratio, the oxygen concentration in the exhaust is low, while concentrations of VOC and CO are not excessive.

Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is another post-combustion control technique typically used to reduce the quantity of NOx produced in the hot flue gas, by injecting ammonia. The main differences between SNCR and SCR is that the SNCR reaction between ammonia and NOx in the hot flue gas occurs without the need for a catalyst and at much higher temperatures (i.e., between 1200 ^oF to 2000 ^oF). The SNCR reaction is also affected by the short residence time of ammonia and the molecular ratio between ammonia and the initial quantities of NOx such that small quantities of unreacted ammonia remains (i.e., as ammonia slip) and is subsequently released in the flue gas. With a control efficiency ranging between 80 and 85 percent, SNCR does not achieve as great of NOx emission reductions as SCR. The need for the exhaust temperature to be high limits the applicability of SNCR to boilers, cement kilns, and in some cases, FCCUs. Therefore, the use of SNCR alone would not be considered equivalent to BARCT.

Wet Gas Scrubbers (WGSs)

WGS technology is a multi-pollutant control system that primarily controls SOx and PM emissions but can be installed to function with NOx control equipment. WGSs can be used to control emissions from FCCUs, refinery process heaters and boilers, SRU/TGUs, petroleum coke calciners, and cement kilns. There are two types of wet gas scrubbers: 1) caustic-based non-regenerative WGS; and, 2) regenerative WGS.

In non-regenerative wet gas scrubbing, caustic soda (sodium hydroxide - NaOH) or other alkaline reagents, such as soda ash, are used as an alkaline absorbing reagent (absorbent) to capture SO_2 emissions. The absorbent captures SO_2 and sulfuric acid mist (H_2SO4) and converts it to various types of sulfites and sulfates (e.g., $NaHSO_3$, Na_2SO_3, and Na_2SO_4). The absorbed sulfites and sulfates are later separated by a purge treatment system and the treated water, free of suspended solids, is either discharged or recycled.

One example of the caustic-based non-regenerative scrubbing system is the proprietary Electro Dynamic Venturi (EDV) scrubbing system offered by BELCO Technologies Corporation (see Figure 1-6). An EDV scrubbing system consists of three main modules: 1) a spray tower module; 2) a filtering module; and, 3) a droplet separator module. The flue gas enters the spray tower module, which is an open tower with multiple layers of spray nozzles. The nozzles supply a high density stream of caustic/water solution that is directed in a countercurrent flow to the gas flow and encircles, encompasses, wets, and saturates the flue gas. Multiple stages of liquid/gas absorption occur in the spray tower module and SO_2 and acid mist are captured and converted to sulfites and sulfates. Large particles in the flue gas are also removed by impaction with the water droplets.

The flue gas saturated with heavy water droplets continues to move up the wet scrubber to the filtering module where the flue gas reaches super-saturation. At this point, water continues to condense and the fine particles in the gas stream begin to cluster together, to form larger and heavier groups of particles. Next, the flue gas, super-saturated with heavy water droplets, enters the droplet separator module causing the water droplets to impinge on the walls of parallel spin vanes and drain to the bottom of the scrubber.

The spent caustic/water solution purged from the WGS is later processed in a purge treatment unit. The purge treatment unit contains a clarifier that removes suspended solids for disposal. The effluent from the clarifier is oxidized with agitated air to help convert sulfites to sulfates and also reduce the chemical oxygen demand (COD) so that the effluent can be safely discharged to a wastewater system.

A regenerative WGS removes SO_2 from the flue gas by using a buffer solution that can be regenerated. The buffer is then sent to a regenerative plant where the SO_2 is extracted as concentrated SO_2. The concentrated SO_2 is then sent to a sulfur recovery unit (SRU) to recover the liquid SO_2, sulfuric acid and elemental sulfur as a by-product. When the inlet SO_2 concentrations are high, a substantial amount of sulfur-based by-products can be recovered and later sold as a commodity for use in the fertilizer, chemical, pulp and paper industries. For this reason, the use of a regenerative WGS is favored over a non-regenerative WGS.

One example of a regenerative scrubber is the proprietary LABSORB offered by BELCO Technologies Corporation [6, 7]. The LABSORB scrubbing process uses a patented non-organic aqueous solution of sodium phosphate salts as a buffer. This buffer is made from two common available products, caustic and phosphoric acid. The LABSORB system consists of: 1) a quench pre-scrubber; 2) an absorber; and, 3) a regeneration section which typically includes a stripper and a heat exchanger.

In the scrubbing side of the regenerative scrubbing system, the quench pre-scrubber is used to wash out any large particles that are carried over, plus any acid components in the flue gas such as hydrofluoric acid (HF), hydrochloric acid (HCl), and SO_3. The absorption of SO_2 is carried out in the absorber. The absorber typically consists of one single, high-efficiency packed bed scrubber filled with high-efficiency structural packing material. However, if the inlet SO_2 concentration is low, a multiple-staged packed bed scrubber, or a spray-and-plate tower scrubber, may be used instead to achieve an ultra-low outlet SO_2 concentration.

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[6] *Evaluating Wet Scrubbers*, Edwin H. Weaver of BELCO Technologies Corporation, Petroleum Technology Quarterly, Quarter 3, 2006.

[7] *A Logical and Cost Effective Approach for Reducing Refinery FCCU Emissions.* S.T. Eagleson, G. Billemeyer, N. Confuorto, and E. H. Weaver of BELCO, and S. Singhania and N. Singhania of Singhania Technical Services Pvt., India, Presented at PETROTECH 6th International Petroleum Conference in India, January 2005.

The third step in the regenerative wet gas scrubbing system is the regenerative section in which the SO_2-rich buffer stream is steam heated to evaporate the water from the buffer. The buffer stream is then sent to a stripper/condenser unit to separate the SO_2 from the buffer. The buffer free of SO_2 is returned to the buffer mixing tank while the condensed-SO_2 gas stream is sent back to the SRU for further treatment.

LoTOx™ Application with Scrubber

The LoTOx™ is a registered trademark of Linde LLC (previously BOC Gases) and was later licensed to BELCO of Dupont for refinery applications. LoTOx™ stands for "Low Temperature Oxidation" process in which ozone (O_3) is used to oxidize insoluble NOx compounds into soluble NOx compounds which can then be removed by absorption in a caustic, lime or limestone solution. The LoTOx™ process is a low temperature application, optimally operating at about 325 ^oF.

A typical combustion process produces about 95 percent NO and five percent NO_2. Because both NO and NO_2 are relatively insoluble in an aqueous solution, a WGS alone is not efficient in removing these insoluble compounds from the flue gas stream. However, with a LoTOx™ system and the introduction of O_3, NO and NO_2 can be easily oxidized into a highly soluble compound N_2O_5 (see Reactions 5 and 6) and subsequently converted to nitric acid (HNO_3) (see Reaction 7). Then, in a wet gas scrubber for example, the HNO_3 is rapidly absorbed in caustic (NaOH) (see Reaction 8), limestone or lime solution (see Reactions 9 and 10). In addition, because the rates of oxidizing reactions for NOx (see Reactions 5 and 6) are fast compared to the very slow SO_2 oxidation reaction (see Reaction 11), no ammonium bisulfate ($(NH_4)HSO_4$) or sulfur trioxide (SO_3) is formed.

$NO + O_3 \rightarrow NO_2 + O_2$	(Reaction 5 - Fast)
$2\ NO_2 + O_3 \rightarrow N_2O_5 + O_2$	(Reaction 6 – Fast)
$N_2O_5 + H_2O \rightarrow 2\ HNO_3$	(Reaction 7)
$HNO_3 + NaOH \rightarrow NaNO_3 + H_2O$	(Reaction 8)
$2HNO3 + CaCO3 \rightarrow Ca(NO_3)_2 + H_2O + CO_2$	(Reaction 9)
$2HNO3 + Ca(OH) \rightarrow Ca(NO_3)_2 + 2H_2O$	(Reaction 10)
$SO_2 + O_3 \rightarrow SO_3 + O_2$	(Reaction 11 - Very slow)

The LoTOx™ process requires a source of oxygen and generates O_3 on site. Typically oxygen (O_2) is stored as a liquid in vacuum-jacketed vessels or is delivered by pipeline. O_3 is an unstable gas and it is typically generated on demand from the O_2 supply using an O_3 generator. An O_3 generator is shaped similar to a shell and tube heat exchanger and uses a corona discharge to dissociate the O_2 molecules into individual atoms so that the individual oxygen atoms combine with each other to form O_3. The LoTOx™ process contains an ozone injection manifold designed to achieve uniform distribution and complete mixing. A ratio of 1.75 parts NOx to 2.5 parts O_3 is needed in order to achieve a NOx conversion and reduction of 90 percent to 95 percent. Since sulfur dioxiode (SO_2) is an ozone scavenger because it readily bonds with O_3 to form sulfur trioxide (SO_3), the LoTOx™ process typically has a very low O_3 slip (excess O_3) that ranges from zero ppmv to three ppmv. Figure 1-5 shows a schematic of the O_3 generation process.

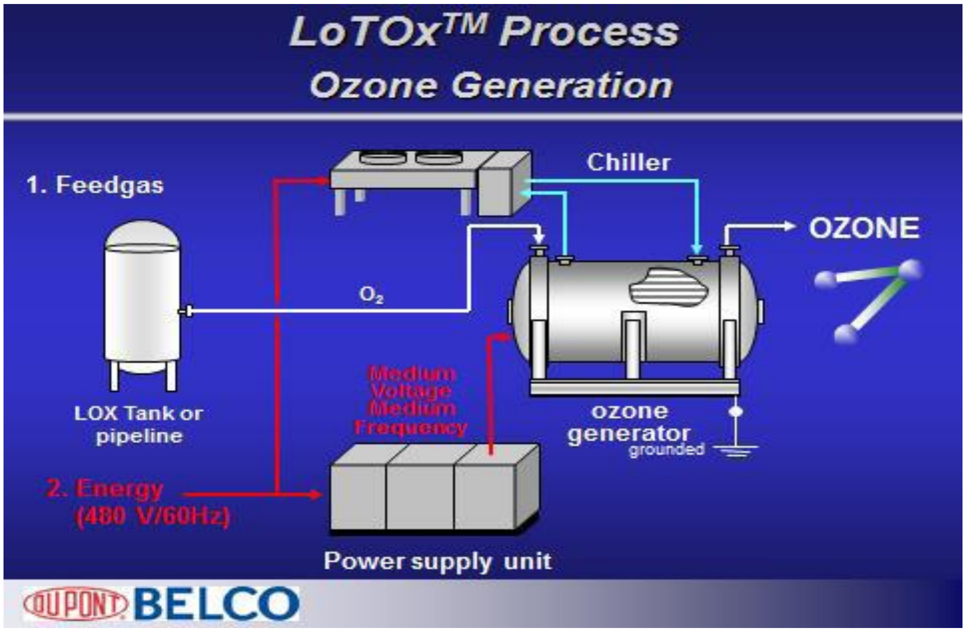

Figure 1-5: Ozone Generation Process

The LoTOx™ process can be integrated with any type of wet scrubbers (e.g., venturi, packed beds), semi-dry scrubbers, or wet electrostatic precipitators (ESPs). For example, Linde has engineered more than 24 LoTOx™ applications for EDV™ scrubbers engineered by BELCO since 2007 for refinery FCCU applications. A LoTOx™ system with an EDV™ scrubber is shown in Figure 1-6.

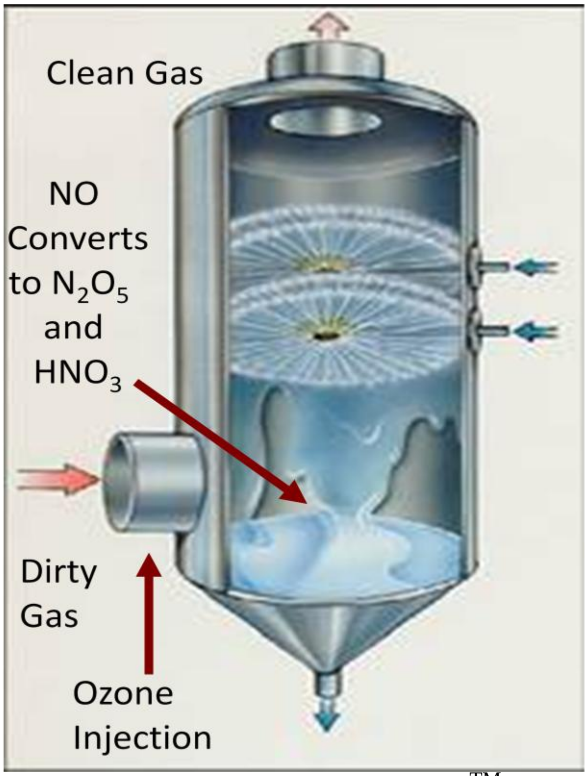

Figure 1-6: EDV Scrubber with LoTOx™ Application

In addition, MECS, BELCO's sister company, has engineered more than two dozen DynaWave scrubbers with LoTOx^{TM} systems specifically designed for refinery SRU/TGUs. Figure 1-7 shows a schematic for a DynaWave scrubber with a LoTOx^{TM} application.

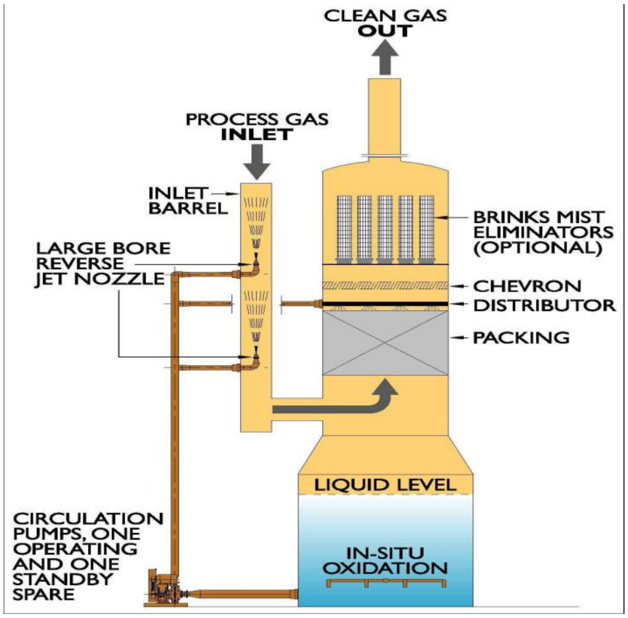

Figure 1-7: DynaWave Scrubber with LoTOx^{TM} Application

When compared to SCR technology, the LoTOx^{TM} application has several advantages, as follows:

- Unlike SCR which operates at high temperatures, LoTOx^{TM} is a low temperature operating system that does not require additional heat input to maintain operational efficiency and enable maximum heat recovery of high temperature combustion gases.
- Unlike SCR which is primarily designed to reduce only NOx, LoTOx^{TM} can be integrally connected to a scrubber (e.g., wet or semi-dry scrubber, or wet electrostatic ESP) and become a multi-component air pollution control system capable of reducing NOx, SOx and PM in one system.
- There is no formation of ammonia slip, SO_3, or $(NH_4)HSO_4$ with the LoTOx^{TM} process.

<u>KnowNOx^{TM} Application with Scrubber</u>

In lieu of using O_3 to convert NO and NO_2 to N_2O_5 and HNO_3, the KnowNOx^{TM} technology uses chlorine dioxide ClO_2. The manufacturer of KnowNOx^{TM} claims that the conversion reactions (see Reactions 12 and 13) are in the gas phase, which can occur much faster than the liquid phase reactions with O_3 (see Reactions 5 through 8 in the previous LoTOx^{TM} Application discussion).

$$5\,NO + 2\,ClO_2 + H_2O \rightarrow 5\,NO_2 + 2\,HCl \qquad \text{(Reaction 12 - Gas Phase)}$$
$$5\,NO_2 + ClO_2 + 3\,H_2O \rightarrow 5\,HNO_3 + 2\,HCl \qquad \text{(Reaction 13 – Gas Phase)}$$
$$5\,SO_2 + 2\,ClO_2 + 6\,H_2O \rightarrow 5\,H_2SO_4 + 2\,HCl \qquad \text{(Reaction 10)}$$

With the KnowNOx™ technology, it takes less than 0.5 seconds to achieve 99.8 percent or more conversion. The reactions require a smaller vessel relative to the size needed for the LoTOx™ reaction chamber. In addition, the KnowNOx™ process can simultaneously reduce NOx, SO_2, PM and other contaminants.

The KnowNOx™ process includes a three-staged scrubbing system: 1) SO_2 is removed via a DynaWave scrubber; 2) then ClO_2 is injected into the scrubber exhaust stream where the NO and NO_2 are converted into HNO_3 and other soluble salts; and, 3) any H_2S that is generated during the second stage is converted to soluble salts. To date, the KnowNOx™ technology has been installed at two locations in the U.S. but has not yet been tested in any refinery applications. Figure 1-8 shows a schematic of a scrubber with KnowNOx™.

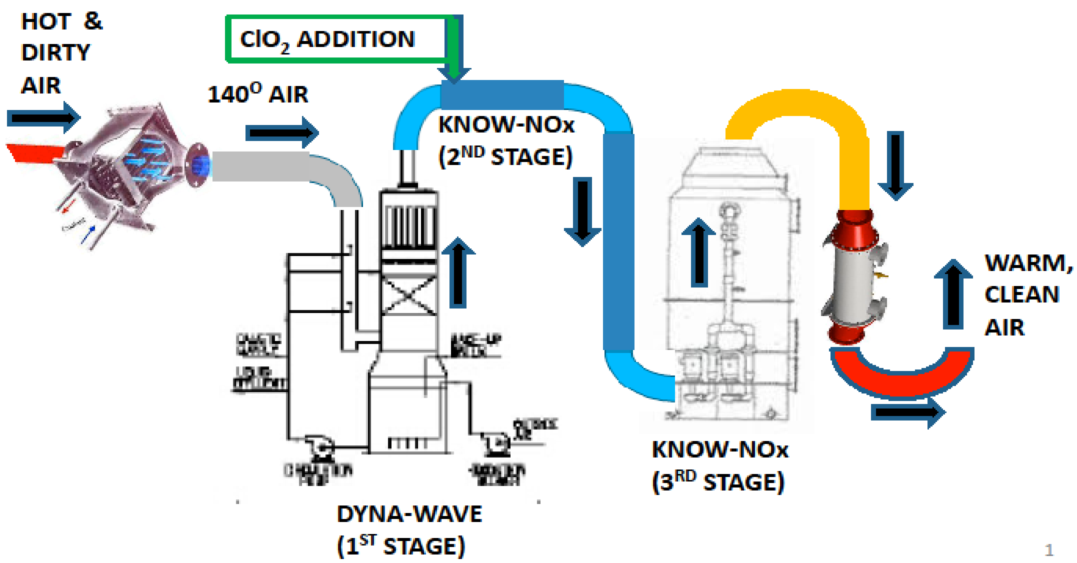

Figure 1-8: Scrubber with KnowNOx™ Application

NOx Reducing Additives

Combustion in a FCCU regenerator generates various pollutants (e.g., NO, N_2O, NO_2, HCN, NH_3, SO_2, etc.) and their dynamic interaction with each other is complex. "Fuel" nitrogen in the coke is first converted to HCN. HCN is thermodynamically unstable and it is converted to NH_3, N_2, NO, N2O, and NO_2. The rates of these reactions depend heavily on the FCCU regenerator temperatures and configuration. NOx reducing additives can be used to promote the conversion of NOx, HCN, and NH_3 to elemental nitrogen (N_2) and reduce NOx emissions. The removal efficiency for NOx reducing additives can range between 50 percent and 80 percent. A simplified version of the chemical reactions in the FCCU regenerator is shown in Figure 1-9.

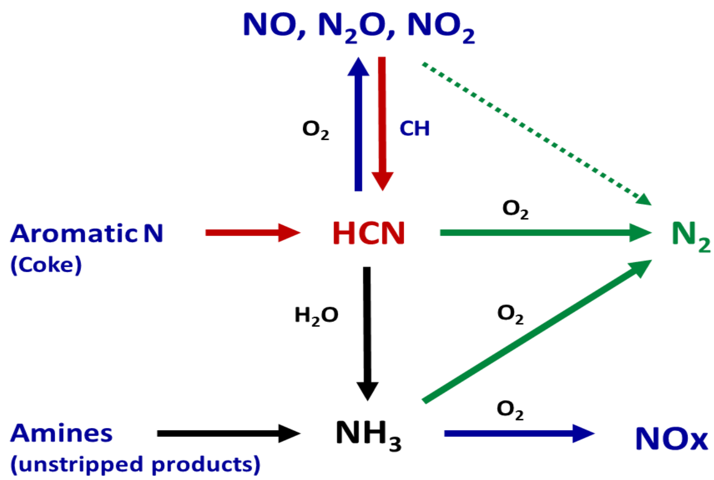

Figure 1-9: Nitrogen Chemistry in the FCCU Regenerator

When using NOx reducing additives, manufacturers recommend the following best practices to minimize the formation of NOx and simultaneously promote the conversion of CO to CO_2: 1) minimize excess oxygen since higher amounts of excess oxygen favors the undesirable formation of NOx rather than N_2; 2) reduce nitrogen in the feed stream; and, 3) utilize non-platinum CO promoters.

Ammonia Slip Catalyst (ASC) and CO Catalyst

SCR manufacturers have developed Ammonia Slip Catalyst (ASC) which is a layer of catalyst that is installed downstream of the SCR catalyst to enhance the selective reduction of NO to N2 and supporting the oxidation of CO to CO2 while suppressing the oxidation of NH3 to NOx. Early generation of ASCs were based on precious metal which is highly active for NH_3 oxidation. The use of ASCs allow for operations at higher NH_3/NOx ratios to ensure complete NOx conversion while maintaining low ammonia slip.

Similar to ASC, CO catalyst is used in conjunction with the SCR catalyst to concurrently reduce NOx to N2 and oxidize CO and hydrocarbon to CO2 and water. CO catalyst is typically made of platinum, palladium or rhodium, and is capable of removing approximately 90 percent of CO and 85 percent to 90 percent of hydrocarbon or hazardous air pollutants from an exhaust stream.

Great Southern Flameless Heaters

In 2012, Coffeyville Resources purchased the world's first flameless crude heater designed by Great Southern Flameless for their Coffeyville refinery in Kansas to comply with a Consent Decree issued by the U.S. EPA. The flameless heater has been in operation for over one year and has proven an achieved-in-practice performance of five ppmv NOx at three percent O_2 with pilot lights in operation, and three ppmv NOx without pilot lights for flameless technology.

Great Southern can supply flameless heaters or oxy-fuel flameless heaters with maximum rating from 10 mmBTU/hr to 320 mmBTU/hr (e.g., equivalent to 240 mmBTU/hr process duty.) Their production capacity is 30 heaters per year. The modules are designed and fabricated in Oklahoma and then they are shipped in pieces to the field where they are assembled at the site. The heaters can use the same foundation of the conventional heaters. From cold start, the heater is brought up in natural draft mode in the same manner as any typical conventional heater. The firing rate of the heater is gradually increased to the required level while the combustion air is gradually increased to 850 ^{o}F. Once the combustion air temperature exceeds 850 ^{o}F, it will sustain the automatic ignition of fuel, and the heater is transitioned into the staged fuel firing mode with pilots off-line. The heater is operated in the staged firing mode until steady state operation is achieved. At this point, the heater is transitioned into flameless firing mode. Visible flame from the conventional nozzles disappears and the NOx emissions decrease substantially in the flameless mode operation. The heater can also be designed for combustion with oxygen.

According to Great Southern Flameless, flameless heaters can be designed to achieve: 1) five ppmv NOx at three percent O_2; or, 2) two ppmv NOx at three percent O_2 with the pilot lights off during flameless firing and with a fuel mix of 25 percent natural gas and 75 percent refinery gas. In addition, oxy-fuel flameless heaters can be designed to achieve: 1) two ppmv NOx at three percent O_2; or, 2) one ppmv with the pilot lights off during flameless firing.

<u>UltraCat</u>

UltraCat is a commercially available multi-pollutant control technology designed to remove NOx and other pollutants such as SO_2, PM, HCl, Dioxins, and HAPs such as mercury in low temperature applications. UltraCat technology is comprised of filter tubes which are made of fibrous ceramic materials embedded with proprietary catalysts. The optimal operating temperature range of an UltraCat system is approximately 350 ^{o}F to 750 ^{o}F. In order to achieve a NOx removal efficiency of approximately 95 percent, aqueous ammonia is injected upstream of the UltraCat filters. In addition, to remove SO_2, HCl, and other acid gases with a removal efficiency ranging from 90 percent to 98 percent, dry sorbent such as hydrated lime, sodium bicarbonate or trona is also injected upstream of the UltraCat filters. UltraCat is also capable of controlling particulates to a level of 0.001 grains per standard cubic foot of dry gas (dscf).

The UltraCat filters are arranged in a baghouse configuration with a low pressure drop such as five inches water column (inH20) across the system. The UltraCat system is equipped with a reverse pulse-jet cleaning action that back flushes the filters with air and inert gas to dislodge the PM deposited on the outside of the filter tubes. Depending on the loading, catalytic filter tubes need to be replaced every five to 10 years. The UltraCat system is shown in Figure 1-10.

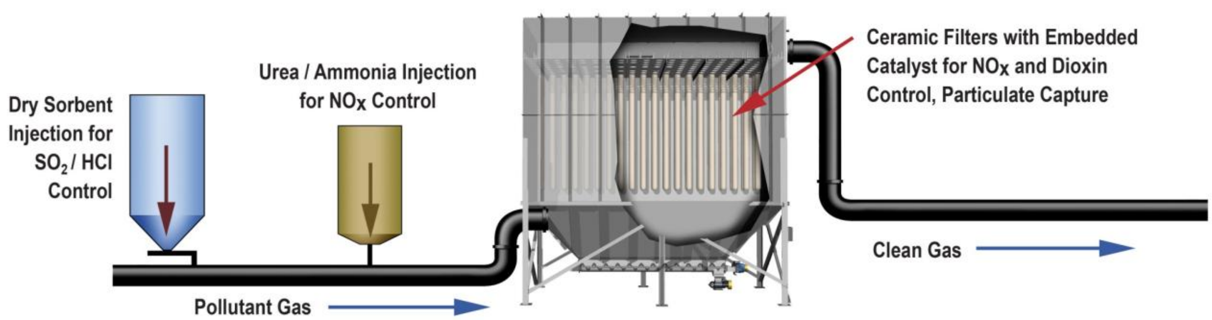

Figure 1-10: UltraCat System

<u>ClearSign Technology</u>

The ClearSign Combustion Corporation in Seattle has developed two technologies applicable for boilers and heaters: 1) DUPLEX™ technology; and, 2) Electrodynamic Combustion Control (ECC™). These technologies are expected to generate very low NOx and CO emissions without the need for FGR, SCR, or large quantities of excess air.

DUPLEX™ technology can be installed in new boilers or heaters. Also, existing boilers and heaters can be retrofit with DUPLEX™ technology. The DUPLEX™ technology comprises a proprietary DUPLEX™ tile installed downstream of the conventional burners. The hot combustion flame from the conventional burners impinges onto the DUPLEX™ tile, and the tile helps evenly radiate the heat with a high emissivity to the combustion products. The DUPLEX™ operation also creates more mixing and shorter flames. Since the flame length is one parameter that limits the total heat release in a furnace, decreased flame length can allow for significantly higher process throughputs. The DUPLEX™ tile is expected to have a three- to five-year lifespan.

The ECC™ technology uses an electric field to effectively shape the flame, accelerate flame speed, and improve flame stability. The total electrical field power required to generate such effects is less than 0.1 percent of the firing rate. Emission performance from a bench test has been demonstrated for both DUPLEX™ and ECC™ and the NOx and CO emissions were both demonstrated to be less than five ppmv as long as the furnace temperatures were steadily maintained between 1200 ^{o}F and 1800 ^{o}F. Beside the benefits of reducing air pollution, ClearSign believes that their burners will provide substantial economic benefits from more uniform heat distribution, improved process throughput, and potentially reduced maintenance costs.

<u>Cheng Low NOx</u>
Cheng Low NOx burner technology applies steam injection to the inlet fuel for combustion in the gas turbine. This is different than traditional steam injection which involves the injection of the steam to the compressed combustion air before entering the combustion chamber. The burner retrofits involve the installation of a new set of nozzles that can deliver a uniform, homogenous mix of steam and fuel to the combustion chamber, and in turn, will reduce NOx formation. Steam injection also provides an added boost to the gas turbine's output power due to the increased mass flow rate. The heat recovery steam generator (HRSG) typically will produce the process steam for the system. The NOx emission level that can be achieved by utilizing Cheng Low NOx burner technology is typically under five ppm and can go as low as two ppm with a 3:1 or 4:1 steam-to-fuel ratio.

<u>Dry Low NOx (DLN) or Dry Low Emissions (DLE)</u>
Staged combustion is identified through a variety of names, including Dry Low NOx (DLN) and Dry Low Emissions (DLE), and is a type of dry control which involves a major modification to a turbine's combustion system. The majority of gas turbines manufactured today are lean-premix dual-staged combustion turbines. Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower flame temperatures and higher concentrations of CO and H_2, because of incomplete combustion, while decreasing the amount of oxygen available for the formation of NOx. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. Thus, by staging DLE combustors so that the air and fuel is pre-mixed and combusting the mixture to produce a lower flame temperature, lower NOx emissions (e.g., in the range between three ppm and 25 ppm for gaseous fuel and 10 ppm for liquid fuel) are created as a by-product.

ALTERNATIVES

The Draft PEA will discuss and compare a range of reasonable alternatives to the proposed project as required by CEQA Guidelines §15126.6 and by SCAQMD Rule 110 where there are potential significant adverse environmental impacts. Alternatives must include realistic measures for attaining the basic objectives of the proposed project and provide a means for evaluating the comparative merits of each alternative. In addition, the range of alternatives must be sufficient to permit a reasoned choice and it need not include every conceivable project alternative. The key issue is whether the selection and discussion of alternatives fosters informed decision making and public participation. A CEQA document need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative.

SCAQMD Rule 110 does not impose any greater requirements for a discussion of project alternatives in an environmental assessment than is required for an Environmental Impact Report under CEQA. Alternatives will be developed based in part on the major components of the proposed project. The rationale for selecting alternatives rests on CEQA's requirement to present "realistic" alternatives; that is alternatives that can actually be implemented. CEQA also requires an evaluation of a "No Project Alternative."

SCAQMD's policy document Environmental Justice Program Enhancements for fiscal year (FY) 2002-03, Enhancement II-1 recommends that all SCAQMD CEQA environmental assessments include a feasible project alternative with the lowest air toxics emissions. In other words, for any major equipment or process type under the scope of the proposed project that creates a significant environmental impact, at least one alternative, where feasible, shall be considered from a "least harmful" perspective with regard to hazardous air emissions.

The Governing Board may choose to adopt any portion or all of any alternative presented in the PEA with appropriate findings as required by CEQA. The Governing Board is able to adopt any portion or all of any of the alternatives presented because the impacts of each alternative will be fully disclosed to the public and the public will have the opportunity to comment on the alternatives and impacts generated by each alternative. Written suggestions on potential project alternatives received during the comment period for the Initial Study will be considered when preparing the Draft PEA.

CHAPTER 2

ENVIRONMENTAL CHECKLIST

INTRODUCTION

The environmental checklist provides a standard evaluation tool to identify a project's adverse environmental impacts. This checklist identifies and evaluates potential adverse environmental impacts that may be created by adopting the proposed amendments to Regulation XX.

GENERAL INFORMATION

Project Title:	Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)
Lead Agency Name:	South Coast Air Quality Management District
Lead Agency Address:	21865 Copley Drive, Diamond Bar, CA 91765
CEQA Contact Person:	Barbara Radlein, (909) 396-2716
Regulation XX Contact Person:	Minh Pham, (909) 396-2613
Project Sponsor's Name:	South Coast Air Quality Management District
Project Sponsor's Address:	21865 Copley Drive, Diamond Bar, CA 91765
General Plan Designation:	Not applicable
Zoning:	Not applicable
Description of Project:	SCAQMD staff is proposing amendments to Regulation XX – RECLAIM, Rule 2002 – Allocations for NOx and SOx, to reduce the allowable NOx emission limits based on current BARCT to achieve additional NOx emission reductions for the following industrial equipment and processes: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. Additional amendments are proposed to establish procedures and criteria for reducing NOx RTCs and NOx RTC adjustment factors for year 2016 and later. For clarity and consistency throughout the regulation, other minor changes are proposed to: 1) Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping SOx Emissions (Attachment C – Quality Assurance and Quality Control Procedures); and, 2) Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping NOx Emissions (Attachment C – Quality Assurance and Quality Control Procedures). The Initial Study identifies the following environmental topics as areas that may be adversely affected by the proposed project: aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. Impacts to these environmental areas will be further analyzed in the Draft PEA.
Surrounding Land Uses and Setting:	Industrial, commercial, and residential
Other Public Agencies Whose Approval is Required:	Not applicable

POTENTIALLY SIGNIFICANT IMPACT AREAS

The following environmental impact areas have been assessed to determine their potential to be affected by the proposed project. Any checked items represent areas that may be adversely affected by the proposed project. An explanation relative to the determination of impacts can be found following the checklist for each area.

☑	Aesthetics	☐	Geology and Soils	☐	Population and Housing
☐	Agriculture and Forest Resources	☑	Hazards and Hazardous Materials	☐	Public Services
☑	Air Quality and Greenhouse Gas Emissions	☑	Hydrology and Water Quality	☐	Recreation
☐	Biological Resources	☐	Land Use and Planning	☑	Solid and Hazardous Waste
☐	Cultural Resources	☐	Mineral Resources	☑	Transportation and Traffic
☑	Energy	☐	Noise	☑	Mandatory Findings of Significance

DETERMINATION
On the basis of this initial evaluation:

☐ I find the proposed project, in accordance with those findings made pursuant to CEQA Guideline §15252, COULD NOT have a significant effect on the environment, and that an ENVIRONMENTAL ASSESSMENT with no significant impacts has been prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will NOT be significant effects in this case because revisions in the project have been made by or agreed to by the project proponent. An ENVIRONMENTAL ASSESSMENT with no significant impacts will be prepared.

☑ I find that the proposed project MAY have a significant effect(s) on the environment, and an ENVIRONMENTAL ASSESSMENT will be prepared.

☐ I find that the proposed project MAY have a "potentially significant impact" on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENTAL ASSESSMENT is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier ENVIRONMENTAL ASSESSMENT pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier ENVIRONMENTAL ASSESSMENT, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Date: December 4, 2014 **Signature:** Michael Krause

Michael Krause
Program Supervisor, CEQA Section
Planning, Rules, and Area Sources

ENVIRONMENTAL CHECKLIST AND DISCUSSION

Since NOx is a precursor pollutant to fine particulate matter (PM10 and PM2.5) and ozone, SCAQMD staff is proposing amendments to Regulation XX – RECLAIM, to achieve additional NOx emission reductions as outlined in the Final 2012 AQMP. Specifically, amendments are proposed to Rule 2002 – Allocations for NOx and SOx to address BARCT requirements, which may require installation or modification of NOx emission control equipment or techniques. For clarity and consistency throughout the regulation, other minor changes that are administrative in nature and include minor clarifications are proposed to: 1) Rule 2011 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping SOx Emissions (Attachment C – Quality Assurance and Quality Control Procedures); and, 2) Rule 2012 Appendix A – Protocol for Monitoring, Reporting, and Recordkeeping NOx Emissions (Attachment C – Quality Assurance and Quality Control Procedures).

The amendments proposed in Rule 2002 for the overall reductions in NOx RTC allocations, which include the anticipated feasible NOx emissions reductions due to compliance with proposed BARCT requirements, are expected to involve physical changes at affected facilities which may cause potentially significant impacts to the following environmental topics: aesthetics; air quality and GHG emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. Therefore, the type of emission reduction projects that may be undertaken to comply with the proposed project, primarily the reduced total amounts of NOx credits available in the RECLAIM program, are the main focus of the analysis in this Initial Study.

Preliminary review of the SCAQMD's RECLAIM database indicates that certain equipment at the top emitting NOx RECLAIM facilities are currently not operating at proposed BARCT levels. This analysis assumes that operators at RECLAIM facilities will elect to reduce emissions at their facilities through further control of emissions from equipment not operating at BARCT rather than purchasing NOx RTCs, as is currently allowed under the RECLAIM program. The rationale for this assumption is that controlling emissions from equipment not operating at BARCT will produce the most conservative analysis of secondary adverse environmental impacts. The physical changes involved with the type of emission control strategies that are expected to occur focus on the installation of new or the modification of existing NOx emission control equipment for the following industrial equipment and processes: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. To control NOx emissions from these sources, an assortment of technologies may be applied individually or in combination to meet proposed BARCT, depending on the source category, as follows (in alphabetical order): Cheng Low NOx; ClearSign; Dry Low Emissions (DLE or DLN); Flue Gas Recirculation; Great Southern Flameless Heaters; KnowNOx™ with scrubber; LoTOx™ with scrubber; NOx reducing additives; NSCR; SCR with or without scrubber; SNCR; Staged Combustion/Low NOx Burners; UltraCat; and Water/Steam Injection. For the purpose of the CEQA analysis, the selection of certain control technology is based on the potential to cause secondary adverse environmental impacts in order to render the analysis conservative regardless of costs. It is important to note that the rule development process, including the proposed BARCT determination and RTC shave methodology, are ongoing and as such may be revised based on input from stakeholders and the public. As additional information becomes available, the project will be updated and any additional environmental impacts will be evaluated in the Draft PEA.

It must be also noted that the projects assumed to occur as a means of reducing NOx emissions in response to the proposed amendments could occur voluntarily under the existing RECLAIM program. In addition, as with the current regulation or with the proposed project, affected facilities may purchase NOx RTCs instead of implementing physical changes to achieve a reduction in NOx emissions. However, the proposed amendments to the RECLAIM program would further induce such control strategies to occur as facility allocations are being reduced.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
I.	**AESTHETICS.** Would the project:				
a)	Have a substantial adverse effect on a scenic vista?	☐	☐	☐	☑
b)	Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☐	☐	☑
c)	Substantially degrade the existing visual character or quality of the site and its surroundings?	☑	☐	☐	☐
d)	Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	☐	☐	☑	☐

Significance Criteria

The proposed project impacts on aesthetics will be considered significant if:

- The project will block views from a scenic highway or corridor.
- The project will adversely affect the visual continuity of the surrounding area.
- The impacts on light and glare will be considered significant if the project adds lighting which would add glare to residential areas or sensitive receptors.

Discussion

I. a) & b) No Impact. Depending on how the affected facilities choose to comply with the proposed NOx reductions, implementation of the proposed project could involve construction activities related to the modification of existing equipment at the top NOx emitting RECLAIM facilities.

The physical changes involved with the type of NOx emission control strategies that are expected focus on the installation of new or the modification of existing control equipment at the following stationary sources of NOx: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns; and, 11) metal heat treating furnaces. To control NOx emissions from these sources, an assortment of technologies may be applied individually or in combination to meet proposed BARCT, depending on the source category, as follows (in alphabetical order): Cheng Low NOx; ClearSign; Dry Low Emissions (DLE or DLN); Flue Gas Recirculation; Great Southern Flameless Heaters; KnowNOx™; LoTOx™ with scrubber; NOx reducing additives; NSCR; SCR with or without scrubber; SNCR; Staged Combustion/Low NOx Burners; UltraCat; and Water/Steam Injection.

Construction activities are expected as part of the proposed project. However, the construction activities would be temporary and would not be expected to adversely impact views and aesthetics resources since most of the heavy equipment and activities would be expected to occur within the confines of each existing facility and would be expected to introduce only minor visual changes to areas outside each facility, if at all, depending on the location of the construction activities within the facility. Except for the potential use of cranes, the majority of the construction equipment is expected to be low in height and not substantially visible to the surrounding area due to existing fencing along the property lines and existing structures currently within the facilities that would buffer the views of the construction activities. Further, the construction activities are expected to be temporary in nature and will cease following completion of the equipment installation or modifications.

Depending on the type of NOx emissions control employed, the proposed project could potentially introduce minor visual changes at some facilities. The affected units, depending upon their locations within each facility, could potentially be visible to areas outside of each facility. However, the affected units are expected to be about the same size profile relative to the existing equipment or structures present at each affected facility. The general appearance of the affected units is not expected to differ significantly from other equipment units such that no significant impacts to aesthetics are expected. Further, no scenic highways or corridors are located in the vicinities of the affected facilities such that the proposed project would not obstruct scenic resources or degrade the existing visual character of a site, including but not limited to, trees, rock outcroppings, or historic buildings. Accordingly, these impact issues will not be further analyzed in the Draft PEA. Further, since no significant aesthetics impacts were identified for these issues, no mitigation measures are necessary or required.

I. c) Potentially Significant Impact. All construction and operational activities associated with the proposed project are expected to take place within the boundaries of the existing RECLAIM facilities. As explained in 1. a) and b), during construction, cranes may be needed during construction and they may be visible to the surrounding areas. However, except for the use of cranes, the majority of construction equipment that will be used to comply with the proposed project will be low in height and will not be visible to the surrounding areas due to the presence of existing fences and other structures that buffer views. Since the construction activities are temporary in nature, all construction equipment will be removed following completion of the proposed project.

Of the new equipment that may be installed, or the existing equipment that may be modified as part of the proposed project, all of the control technologies except for WGSs will be similar in size, appearance, and profile to the existing equipment and surrounding structures. Thus, no operational aesthetics impacts from the installation or application of the following technologies would be expected to substantially degrade the existing visual character or quality of the site and its surroundings: Cheng Low NOx; ClearSign; Dry Low Emissions (DLE or DLN); Flue Gas Recirculation; Great Southern Flameless Heaters; KnowNOx^{TM}; NOx reducing additives; NSCR; SCR without scrubber; SNCR; Staged Combustion/Low NOx Burners; UltraCat; and Water/Steam Injection.

However, wet gas scrubber (WGS) technology in combination with LoTOx^{TM} or an SCR is potentially BARCT for five FCCUs, six SRU/TGUs, multiple refinery process heaters and boilers, a petroleum coke calciner, and Portland cement kilns. If a WGS scrubber is installed for any of these source categories, upon completion of construction, the operation of the WGS will emit flue gas that is saturated with water that, depending on weather conditions, could form a visible steam plume. Depending on the size of the WGS installed, the flue gas stack could be as tall as 200 feet above grade. For this reason, each WGS, its stack, and subsequent steam plume may have the potential to generate significant aesthetic impacts. Therefore, these potential impacts to aesthetics will be addressed in the Draft PEA for the proposed project.

I. d) Less Than Significant Impact. There are no components in the proposed project that would require construction activities to occur at night. Therefore, no additional lighting at the affected facilities would be required as a result of complying with the proposed project. However, if facility operators determine that the construction schedule requires nighttime activities, temporary lighting may be required. Nonetheless, since construction of the proposed project would be completely located within the boundaries of each affected facility, additional temporary lighting is not expected to be discernable from the existing permanent night lighting.

Some facilities, such as refineries for example, operate 24 hours per day, so lighting is already part of the existing setting. However, additional permanent light sources may be installed on any installation of new equipment, to provide illumination for operations personnel at night, in accordance with applicable safety standards. Similarly, any existing equipment that would be modified as part of the proposed project are located in existing structures or areas that already have lighting systems in place for the same reasons. These additional light sources are not expected to create an impact because each component of the proposed project will be located within an existing industrial facility that operates up to 24 hours per day and the equipment is not restricted to operate during a specific time of day. The proposed project contains no provisions that would require affected equipment to operate differently during existing daytime or nighttime operations. Further, any new lighting that will be installed on the proposed equipment will be consistent in intensity and type with the existing lighting on equipment and other structures within each affected facility. While residential areas are located near some of the affected facilities, any additional lighting will be placed by and focused on the new equipment. For the aforementioned reasons, the proposed project is not expected to create a new source of substantial light or glare that would adversely affect day or nighttime views in the area. Therefore, less than significant impacts to light and glare are expected from the proposed project. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant aesthetics impacts were identified for this issue, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to aesthetics may occur from implementing the proposed project and thus, impact issue I. c) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
II. AGRICULTURE AND FOREST RESOURCES. Would the project:				
a) Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland mapping and Monitoring Program of the California Resources Agency, to non- agricultural use?	☐	☐	☐	☑
b) Conflict with existing zoning for agricultural use, or a Williamson Act contract?	☐	☐	☐	☑
c) Conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code §12220(g)), timberland (as defined by Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code §51104 (g))?	☐	☐	☐	☑
d) Result in the loss of forest land or conversion of forest land to non-forest use?	☐	☐	☐	☑

Significance Criteria

Project-related impacts on agriculture and forest resources will be considered significant if any of the following conditions are met:

- The proposed project conflicts with existing zoning or agricultural use or Williamson Act contracts.
- The proposed project will convert prime farmland, unique farmland or farmland of statewide importance as shown on the maps prepared pursuant to the farmland mapping and monitoring program of the California Resources Agency, to non-agricultural use.

- The proposed project conflicts with existing zoning for, or causes rezoning of, forest land (as defined in Public Resources Code §12220 (g)), timberland (as defined in Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code § 51104 (g)).
- The proposed project would involve changes in the existing environment, which due to their location or nature, could result in conversion of farmland to non-agricultural use or conversion of forest land to non-forest use.

Discussion

II. a), b), c), & d) No Impact. Land use, including agriculture- and forest-related uses, and other planning considerations are determined by local governments. While implementation of the proposed project may cause air pollution control equipment to be installed and operated on existing equipment to control NOx emissions, these activities will occur at established NOx RECLAIM facilities which are located on previously developed land in primarily industrial areas and are not located in the vicinity of agricultural or forest areas.

Further, no new construction of buildings or other structures is expected that would require conversion of farmland to non-agricultural use or conflict with zoning for agricultural uses or a Williamson Act contract. Further, because the proposed project does not require construction or operation activities within an area designated as forest land, implementation of the proposed project is not expected to conflict with any forest land zoning codes or convert forest land to non-forest uses. Similarly, there is nothing in the proposed project that would affect or conflict with existing land use plans, policies, or regulations or require conversion of farmland to non-agricultural uses or forest land to non-forest uses. Thus, no agricultural land use or planning requirements will be altered by the proposed project.

Finally, in the event the proposed project is implemented, the installation of NOx control equipment will ensure that projected NOx emission reductions will occur and that air quality in the region will improve. Thus, assuring that these air quality improvements occur could provide benefits to agricultural and forest land resources by reducing the adverse oxidation impacts of ozone on plants and animals located in the Basin. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

Based upon these considerations, significant agricultural and forest resources impacts are not expected from implementing the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant agriculture and forest resources impacts were identified for any of the issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
III. AIR QUALITY AND GREENHOUSE GAS EMISSIONS. Would the project:				
a) Conflict with or obstruct implementation of the applicable air quality plan?	☐	☐	☐	☑
b) Violate any air quality standard or contribute to an existing or projected air quality violation?	☑	☐	☐	☐
c) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard (including releasing emissions that exceed quantitative thresholds for ozone precursors)?	☑	☐	☐	☐
d) Expose sensitive receptors to substantial pollutant concentrations?	☑	☐	☐	☐
e) Create objectionable odors affecting a substantial number of people?	☑	☐	☐	☐
f) Diminish an existing air quality rule or future compliance requirement resulting in a significant increase in air pollutant(s)?	☐	☐	☐	☑
g) Generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment?	☑	☐	☐	☐
h) Conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of greenhouse gases?	☐	☐	☑	☐

Significance Criteria

To determine whether or not air quality and GHG impacts from adopting and implementing the proposed project are significant, impacts will be evaluated and compared to the criteria in Table 2-1. The project will be considered to have significant adverse air quality impacts if any one of the thresholds in Table 2-1 are equaled or exceeded.

Table 2-1
SCAQMD Air Quality Significance Thresholds

Mass Daily Thresholds [a]		
Pollutant	**Construction [b]**	**Operation [c]**
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
PM2.5	55 lbs/day	55 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day

Toxic Air Contaminants (TACs), Odor, and GHG Thresholds	
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Cancer Burden > 0.5 excess cancer cases (in areas ≥ 1 in 1 million) Chronic & Acute Hazard Index ≥ 1.0 (project increment)
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402
GHG	10,000 MT/yr CO2eq for industrial facilities

Ambient Air Quality Standards for Criteria Pollutants [d]	
NO2 1-hour average annual arithmetic mean	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.18 ppm (state) 0.03 ppm (state) and 0.0534 ppm (federal)
PM10 24-hour average annual average	 10.4 μg/m^3 (construction)[e] & 2.5 μg/m^3 (operation) 1.0 μg/m^3
PM2.5 24-hour average	 10.4 μg/m^3 (construction)[e] & 2.5 μg/m^3 (operation)
SO2 1-hour average 24-hour average	 0.25 ppm (state) & 0.075 ppm (federal – 99^{th} percentile) 0.04 ppm (state)
Sulfate 24-hour average	 25 μg/m^3 (state)
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) and 35 ppm (federal) 9.0 ppm (state/federal)
Lead 30-day Average Rolling 3-month average Quarterly average	 1.5 μg/m^3 (state) 0.15 μg/m^3 (federal) 1.5 μg/m^3 (federal)

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea and Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
[d] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.
[e] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day; ppm = parts per million; μg/m^3 = microgram per cubic meter; ≥ = greater than or equal to; MT/yr CO2eq = metric tons per year of CO2 equivalents; > = greater than

Discussion

Upon initial examination of the proposed project, the main focus of this analysis pertains to establishing BARCT for the multiple stationary source categories in the NOx RECLAIM program. To control NOx emissions from these sources, an assortment of technologies may be applied individually or in combination to meet proposed BARCT, depending on the source category, as follows (in alphabetical order): Cheng Low NOx; ClearSign; Dry Low Emissions (DLE or DLN); Flue Gas Recirculation; Great Southern Flameless Heaters; KnowNOx^{TM}; LoTOx^{TM} with scrubber; NOx reducing additives; NSCR; SCR with or without scrubber; SNCR; Staged Combustion/Low NOx Burners; UltraCat; and Water/Steam Injection.

The physical changes involved with the type of NOx emission control strategies that are expected to be utilized focus on the installation of new or the modification of existing control equipment. The possibility of these types of NOx control technologies being used to comply with the proposed project and potential secondary adverse air quality and GHG impacts they may generate will be further evaluated in the Draft PEA. The remaining portions of the proposed project are procedural in nature and will not result in any physical changes that could cause an adverse air quality impact.

III. a) No Impact. The SCAQMD is required by law to prepare a comprehensive district-wide AQMP which includes strategies (e.g., control measures) to reduce emission levels to achieve and maintain state and federal ambient air quality standards, and to ensure that new sources of emissions are planned and operated to be consistent with the SCAQMD's air quality goals. The AQMP's air pollution reduction strategies include control measures which target stationary, mobile and indirect sources. These control measures are based on feasible methods of attaining ambient air quality standards. Pursuant to the provisions of both the state and federal Clean Air Acts, the SCAQMD is required to attain the state and federal ambient air quality standards for all criteria pollutants, including PM10 and PM2.5. Although the District is currently classified as in attainment for both state and federal NO_2 ambient air quality standards, NOx is a precursor pollutant to PM10, PM2.5, and ozone. The proposed project implements 2012 AQMP Control Measure #CMB-01 which will bring the NOx RECLAIM program up-to-date with the latest BARCT requirements to achieve, at a minimum, the proposed NOx emission reductions in #CMB-01 (e.g., at least three to five tons per day by 2023). Therefore, the proposed project will not obstruct or conflict with the implementation of the 2012 AQMP.

Although the proposed project has the potential to temporarily increase criteria pollutants and TAC emissions (as diesel PM) that could exceed the air quality significance thresholds for construction activities, the proposed project is not expected to interfere with achieving at least three to five tons per day of NOx emission reductions by the year 2023, which is consistent with the goals of the 2012 AQMP to achieve additional NOx emission reductions (and reduce NOx precursors as PM 2.5 and PM10) from stationary sources, which will assist in attaining state and federal PM2.5 and PM10 ambient air quality standards. Further, the temporary increase in criteria pollutant and TAC emissions (as diesel PM) due to construction is not expected to impede the emission reduction goals of the 2012 AQMP because the inventory prepared for the 2012 AQMP already takes into account the future emission estimates from all construction activities associated with implementing the proposed control measures[8]. Further, implementation of all other SCAQMD NOx rules along with AQMP control measures, when considered together, is expected to reduce NOx emissions throughout the region overall by 2023. Therefore, implementing the proposed project will not conflict or obstruct implementation of the AQMP. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

III. b) Potentially Significant Impact. The objective of the proposed project is to reduce NOx emissions from the top NOx emitting stationary sources in the NOx RECLAIM program. The proposed project is estimated to reduce emissions, at a minimum, of up to three to five tons per day of NOx by 2023 from these affected sources. Compliance with the proposed project is expected to be achieved by applying a wide assortment of NOx technologies, either individually or in combination on the affected sources.

Implementation of the proposed project is expected to involve construction activities related to the installation or modification of the aforementioned NOx control technologies at the top NOx emitting facilities. The proposed project may also involve the construction of new buildings or other structures as part of installation or modification of the NOx controls. Construction-related activities are also expected to generate emissions from worker vehicles, trucks, and construction equipment. Due to the large scale of construction that would be expected from implementing the proposed project, project-specific construction emissions are potentially significant.

While the operational-related activities are expected to reduce emissions of NOx, a simultaneous increase in emissions of other criteria pollutants are expected from operations of stationary support equipment associated with the installed or modified NOx control equipment, as well as operational emissions associated with periodic truck deliveries of supplies and waste haul trips associated with operation and maintenance of the NOx control equipment. Thus, the air quality impacts associated with the construction and operational phases of the proposed project are potentially significant and will be evaluated in the Draft PEA.

III. c) & g) Potentially Significant Impact. The anticipated NOx emission reductions that would result from implementing the proposed project are expected to improve the overall air quality in the Basin by enhancing the probability of attaining and maintaining state and federal ambient air quality standards for PM10 and PM2.5. The primary effect of implementing the proposed project would be the installation of various types of air pollution control equipment to reduce NOx emissions. Because construction equipment may be utilized to install air pollution control equipment, air pollutants, including GHG emissions, would be generated during their use. Some types of air pollution control equipment contemplated by the proposed project could have the potential to create secondary adverse air quality impacts, including GHG emissions. For this reason, operational activities associated with the proposed project also have the potential to increase emissions of air pollutants and GHGs. Thus, while the purpose of the proposed project is to reduce NOx emissions from the top NOx emitting facilities in the NOx RECLAIM program, a simultaneous increase in GHG emissions could occur from the operation of some

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[8] SCAQMD Final Program Environmental Impact Report for the 2012 Air Quality Management Plan, SCH# 2012061093, November 2012. http://www.aqmd.gov/home/library/documents-support-material/lead-agency-scaqmd-projects/aqmd-projects---year-2012/aqmp-2012

types of air pollution control equipment, if installed. Thus, the secondary construction and operation impacts associated with reducing NOx have the potential for creating significant adverse cumulative air quality impacts that will be evaluated in the Draft PEA. These potential increases will also be evaluated in the Draft PEA as part of the cumulative impacts discussion.

III. d) Potentially Significant Impact. Emission sources associated with the construction-related activities as a result of implementing the proposed project may temporarily emit TACs. Further, emissions sources associated with the operational-related activities as a result of implementing the proposed project may also emit TACs. The impact of these emissions on sensitive populations, including individuals at hospitals, nursing facilities, daycare centers, schools, and elderly intensive care facilities, as well as residential and off-site occupational areas, will be evaluated in the Draft PEA.

III. e) Potentially Significant Impact. The installation of NOx control equipment could result in combustion-source criteria pollutant emissions from construction activity through the use of heavy-duty construction equipment and from vehicle trips generated by construction workers/haul trucks traveling to and from the project site, as well as fugitive dust emissions related to site work and general grading. Mobile source emissions, primarily NO_x and diesel PM, typically result from the use of diesel-fueled construction equipment such as graders, scrapers, bulldozers, wheeled loaders, cranes, etc. During structure erection/finishing phases, paving operations and the application of architectural coatings (e.g., paints) and other building materials, VOCs would be released. Operation-period impacts, which could include criteria pollutant and TAC emissions from permitted stationary sources, may also occur. Depending on the type of control equipment installed, the proposed project could potentially result in an increase in vehicle trips (both passenger vehicles and trucks) on local roadways, which could in turn result in an increase in operational-period criteria pollutant emissions. As such, the impacts of implementing the proposed project could create objectionable odors affecting a substantial number of people. Thus, the potential impacts of objectionable odors affecting a substantial number of people will be analyzed in the Draft PEA.

III. f) No Impact. The proposed project will be required to comply with all applicable SCAQMD, CARB, and EPA rules and regulations. Thus, the proposed project is not expected to diminish an existing air quality rule or future compliance requirements. Further, adopting and implementing the proposed project enhances existing air pollution control rules that are expected to assist the SCAQMD in its efforts to attain and maintain with a margin of safety the state and federal ambient air quality standards for PM10 and PM2.5. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

III. h) Less Than Significant Impact. As mentioned in the discussion in Section III. b), c) and g), construction equipment may be utilized as part of implementing the proposed project and as such, GHG emissions would be generated during their use. Although the primary effect of installing air pollution control equipment is to reduce NOx emissions, some types of control equipment contemplated by the proposed project could also have the potential to create secondary adverse air quality impacts, including GHG emissions. While the purpose of the proposed project is to reduce NOx emissions from the top NOx emitting facilities in the NOx RECLAIM program, a simultaneous increase in GHG emissions could occur from the operation of some types of air pollution control equipment, if installed.

In December 2010, CARB adopted regulations establishing a cap and trade program for the largest sources of GHG emissions in the state that altogether are responsible for about 85 percent of California's GHGs. While the proposed project would not be subject to a GHG reduction plan, all of the affected facilities are currently subject to individual GHG emission reductions pursuant to AB32, the state-wide GHG reduction plan. Among these facilities are fossil-fuel fired power plants, including both plants that generate power within California's borders, and those located outside of California that generate power imported to the state. GHG emissions from this universe of sources were capped for 2013 at a level approximately two percent below the emissions level forecast for 2012, and the cap will steadily decrease at a rate of two to three percent annually from now to 2020. Sources regulated by the cap must reduce their GHG emissions or buy credits from others who have done so. This means that the any additional power needed to operate air pollution control equipment as a result of the proposed project cannot result in an increase in GHG emissions from the increased use of third-party power, compared to GHG emissions at the time of issuance of this NOP/IS. Further, even in the event that some of the affected facilities may experience increases in GHG emissions as a result of implementing the proposed project, the affected facilities would still be required to comply with their overall GHG reduction requirements pursuant to AB32. For these reasons, the proposed project would not conflict with AB32 as well as any applicable GHG reduction plan, policy, and regulations that have been adopted to implement AB32. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since less than significant impacts were identified for this issue, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to air quality and GHGs may occur from implementing the proposed project and thus, impact issues III. b), c), d), e), and g) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
IV. BIOLOGICAL RESOURCES. Would the project:				
a) Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☐	☑

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
b)	Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☐	☑
c)	Have a substantial adverse effect on federally protected wetlands as defined by §404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	☐	☐	☐	☑
d)	Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?	☐	☐	☐	☑
e)	Conflicting with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☐	☐	☐	☑
f)	Conflict with the provisions of an adopted Habitat Conservation plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?	☐	☐	☐	☑

Significance Criteria

Impacts on biological resources will be considered significant if any of the following criteria apply:

- The project results in a loss of plant communities or animal habitat considered to be rare, threatened or endangered by federal, state or local agencies.
- The project interferes substantially with the movement of any resident or migratory wildlife species.

- The project adversely affects aquatic communities through construction or operation of the project.

Discussion

IV. a), b), c), & d) No Impact. The proposed project would only affect units operating at the top NOx emitting facilities in the NOx RECLAIM program facilities with locations scattered throughout the District. All of the affected units operating at existing facilities are located primarily in developed industrial areas, which have already been greatly disturbed and paved. These areas currently do not support riparian habitat, federally protected wetlands, or migratory corridors. Additionally, special status plants, animals, or natural communities are not expected to be found within close proximity to the affected facilities. Therefore, the proposed project would have no direct or indirect impacts that could adversely affect plant or animal species or the habitats on which they rely in the SCAQMD's jurisdiction. The current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions. A conclusion in the Final Program EIR for the 2012 AQMP was that population growth in the region would have greater adverse effects on plant species and wildlife dispersal or migration corridors in the basin than SCAQMD regulatory activities, (e.g., air quality control measures or regulations). In addition, by reducing air pollutants, biological resources will benefit. Moreover, the current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

IV. e) & f) No Impact. The proposed project is not envisioned to conflict with local policies or ordinances protecting biological resources or local, regional, or state conservation plans. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the proposed project. Additionally, the proposed project will not conflict with any adopted Habitat Conservation Plan, Natural Community Conservation Plan, or any other relevant habitat conservation plan, and would not create divisions in any existing communities because all activities associated with complying with the proposed project will occur at existing industrial facilities. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

Based upon these considerations, significant biological resources impacts are not expected from implementing the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant biological resources impacts were identified for any of the issues, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
V.	**CULTURAL RESOURCES.** Would the project:				
a)	Cause a substantial adverse change in the significance of a historical resource as defined in §15064.5?	☐	☐	☐	☑
b)	Cause a substantial adverse change in the significance of an archaeological resource as defined in §15064.5?	☐	☐	☐	☑
c)	Directly or indirectly destroy a unique paleontological resource, site, or feature?	☐	☐	☐	☑
d)	Disturb any human remains, including those interred outside formal cemeteries?	☐	☐	☐	☑

Significance Criteria

Impacts to cultural resources will be considered significant if:

- The project results in the disturbance of a significant prehistoric or historic archaeological site or a property of historic or cultural significance to a community or ethnic or social group.
- Unique paleontological resources are present that could be disturbed by construction of the proposed project.
- The project would disturb human remains.

Discussion

V. a) No Impact. There are existing laws in place that are designed to protect and mitigate potential impacts to cultural resources. Since construction-related activities associated with the implementation of the proposed project are expected to be confined within the existing footprint of the affected facilities that have been fully developed and paved, no impacts to historical resources are expected to occur as a result of implementing the proposed project. Accordingly, this impact issue will not be further analyzed in the Draft PEA.

V. b), c), & d) No Impact. Installing or modifying add-on controls and other associated equipment to comply with the proposed project may require disturbance of previously disturbed areas at the affected existing industrial facilities. However, since construction-related activities are expected to be confined within the existing footprint of the affected facilities that have been fully developed and paved, the proposed project is not expected to require physical changes to the environment, which may disturb paleontological or archaeological resources. Furthermore, it is envisioned that these areas are already either devoid of significant cultural resources or whose cultural resources have been previously disturbed. Therefore, the proposed project has no potential to cause a substantial adverse change to a historical or archaeological resource, directly or indirectly destroy a unique paleontological resource or site or unique geologic feature, or disturb any human remains, including those interred outside a formal cemeteries. The proposed project is, therefore, not anticipated to result in any activities or promote any programs that could have a significant adverse impact on cultural resources in the District. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

Based upon these considerations, significant cultural resources impacts are not expected from implementing the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant cultural resources impacts were identified for any of the issues, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VI.	**ENERGY.** Would the project:				
a)	Conflict with adopted energy conservation plans?	☐	☐	☐	☑
b)	Result in the need for new or substantially altered power or natural gas utility systems?	☑	☐	☐	☐
c)	Create any significant effects on local or regional energy supplies and on requirements for additional energy?	☑	☐	☐	☐
d)	Create any significant effects on peak and base period demands for electricity and other forms of energy?	☑	☐	☐	☐
e)	Comply with existing energy standards?	☐	☐	☐	☑

Significance Criteria

Impacts to energy and mineral resources will be considered significant if any of the following criteria are met:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses non-renewable resources in a wasteful and/or inefficient manner.

Discussion

The proposed project would reduce emissions of NOx from various stationary sources at facilities that are the top NOx emitters in the NOx RECLAIM program. The expected options for compliance are either installing or modifying air pollution control equipment appropriate to the type of process unit. Further, it is expected that the installation and operation of any equipment used to comply with the proposed project will also comply with all applicable existing energy standards.

VI. a) & e) No Impact. The proposed project is not subject to any existing energy conservation plans. If a facility that is subject to Regulation XX and the proposed project is also subject to energy conservation plans, it is not expected that the proposed project will affect in any way or interfere with that facility's ability to comply with its energy conservation plan or energy standards. Further, project construction and operation activities will not utilize non-renewable energy resources in a wasteful or inefficient manner. Accordingly, these impact issues will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for these issues, no mitigation measures are necessary or required.

VI. b), c) & d. **Potentially Significant Impact.** Installation or modification of air pollution control equipment to comply with the proposed project is expected to increase demand for gasoline and diesel fuel to operate construction equipment and to fuel worker vehicles and haul/delivery trucks. In addition, installation or modification of air pollution control equipment to comply with the proposed project is also expected to increase demand for energy used (e.g., electricity) for operating the primary equipment as well as support equipment such as pumps, fans, controllers, et cetera. Any additional electricity required is typically either supplied by each affected facility's cogeneration units, for those that have them, or by the local electrical utility, as appropriate. It is possible that some facilities may need new or substantially altered power utility systems to be built to accommodate any additional electricity demands created by the proposed project. In some cases, an increase in natural gas use may also be needed for operations subject to the proposed project. Finally, operation and maintenance activities associated with operating the installed or modified air pollution control equipment may also increase demand for gasoline and diesel fuel for worker vehicles and haul/delivery trucks.

Based upon these considerations, significant adverse impacts to energy may occur from the implementation of the proposed project and thus, impact issues VI. b), c), and d) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VII. GEOLOGY AND SOILS. Would the project:				
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:	☐	☐	☐	☑
• Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault?	☐	☐	☐	☑
• Strong seismic ground shaking?	☐	☐	☐	☑
• Seismic–related ground failure, including liquefaction?	☐	☐	☐	☑
b) Result in substantial soil erosion or the loss of topsoil?	☐	☐	☐	☑
c) Be located on a geologic unit or soil that is unstable or that would become unstable as a result of the project, and potentially result in on- or off-site landslide, lateral spreading, subsidence, liquefaction or collapse?	☐	☐	☐	☑
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?	☐	☐	☐	☑
e) Have soils incapable of adequately supporting the use of septic tanks or alternative wastewater disposal systems where sewers are not available for the disposal of wastewater?	☐	☐	☐	☑

Significance Criteria

Impacts on the geological environment will be considered significant if any of the following criteria apply:

- Topographic alterations would result in significant changes, disruptions, displacement, excavation, compaction or over covering of large amounts of soil.

- Unique geological resources (paleontological resources or unique outcrops) are present that could be disturbed by the construction of the proposed project.
- Exposure of people or structures to major geologic hazards such as earthquake surface rupture, ground shaking, liquefaction or landslides.
- Secondary seismic effects could occur which could damage facility structures, e.g., liquefaction.
- Other geological hazards exist which could adversely affect the facility, e.g., landslides, mudslides.

Discussion

VII. a) No Impact. Since the proposed project would result in construction activities at existing RECLAIM facilities located in developed industrial settings to install or modify NOx control equipment, little site preparation is anticipated that could adversely affect geophysical conditions in the jurisdiction of the SCAQMD. Southern California is an area of known seismic activity. Accordingly, the installation of add-on controls at existing affected facilities to comply with the proposed project is expected to conform to the Uniform Building Code and all other applicable state and local building codes. As part of the issuance of building permits, local jurisdictions are responsible for assuring that the Uniform Building Code is adhered to and can conduct inspections to ensure compliance. The Uniform Building Code is considered to be a standard safeguard against major structural failures and loss of life. The basic formulas used for the Uniform Building Code seismic design require determination of the seismic zone and site coefficient, which represents the foundation condition at the site. The Uniform Building Code requirements also consider liquefaction potential and establish stringent requirements for building foundations in areas potentially subject to liquefaction. Thus, the proposed project would not alter the exposure of people or property to geological hazards such as earthquakes, landslides, mudslides, ground failure, or other natural hazards. As a result, substantial exposure of people or structures to the risk of loss, injury, or death involving the rupture of an earthquake fault, seismic ground shaking, ground failure or landslides is not anticipated. Accordingly, this impact issue will not be further analyzed in the Draft PEA.

VII. b) No Impact. Since add-on controls will likely be installed at existing developed facilities, during construction of the proposed project, a slight possibility exists for temporary erosion resulting from excavating and grading activities, if required. These activities are expected to be minor since the existing facilities are generally flat and have previously been graded and paved. Further, wind erosion is not expected to occur to any appreciable extent, because operators at dust generating sites would be required to comply with the best available control measure (BACM) requirements of SCAQMD Rule 403 – Fugitive Dust. In general, operators must control fugitive dust through a number of soil stabilizing measures such as watering the site, using chemical soil stabilizers, revegetating inactive sites, etc. The proposed project involves the installation or modification of add-on control equipment at existing facilities, so that grading could be required to provide stable foundations. Potential air quality impacts related to grading are addressed elsewhere in this Initial Study (as part of construction air quality impacts). No unstable earth conditions or changes in geologic substructures are expected to result from implementing the proposed project. Accordingly, this impact issue will not be further analyzed in the Draft PEA.

VII. c) No Impact. Since the proposed project will affect existing facilities, it is expected that the soil types present at the affected facilities will not be made further susceptible to expansion or liquefaction. Furthermore, subsidence is not anticipated to be a problem since only minor excavation, grading, or filling activities are expected occur at affected facilities. Additionally, the affected areas are not envisioned to be prone to new landslide impacts or have unique geologic features since the affected equipment units are located at existing facilities in industrial areas. Accordingly, this impact issue will not be further analyzed in the Draft PEA.

VII. d) & e) No Impact. Since the proposed project will affect equipment units at existing facilities located in industrial zones, it is expected that people or property will not be exposed to new impacts related to expansive soils or soils incapable of supporting water disposal. Further, typically each affected facility has some degree of existing wastewater treatment systems that will continue to be used and are expected to be unaffected by the proposed project. Sewer systems are available to handle wastewater produced and treated by each affected facility. Each existing facility affected by the proposed project does not require installation of septic tanks or alternative wastewater disposal systems. As a result, the proposed project will not require facility operators to utilize septic systems or alternative wastewater disposal systems. Thus, implementation of the proposed project will not adversely affect soils associated with a septic system or alternative wastewater disposal system. Accordingly, these impact issues will not be further analyzed in the Draft PEA.

Based upon these considerations, significant geology and soils impacts are not expected from the implementation of the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant geology and soils impacts were identified for any of the issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant With Mitigation**	**Less Than Significant Impact**	**No Impact**
VIII. HAZARDS AND HAZARDOUS MATERIALS. Would the project:				
a) Create a significant hazard to the public or the environment through the routine transport, use, and disposal of hazardous materials?	☑	☐	☐	☐
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset conditions involving the release of hazardous materials into the environment?	☑	☐	☐	☐

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
c)	Emit hazardous emissions, or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	☑	☐	☐	☐
d)	Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code §65962.5 and, as a result, would create a significant hazard to the public or the environment?	☐	☐	☑	☐
e)	For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public use airport or a private airstrip, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☐	☑
f)	Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	☐	☐	☐	☑
g)	Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?	☐	☐	☐	☑
h)	Significantly increased fire hazard in areas with flammable materials?	☑	☐	☐	☐

Significance Criteria

Impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.

- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels.

Discussion

VIII. a) & b) Potentially Significant Impact. In general, the major types of public safety risks associated with hazards and hazardous materials consist of impacts resulting from toxic substance releases, fires, and explosions. At the affected RECLAIM facilities, a number of hazardous materials are currently in use. However, the proposed project may alter the hazards associated with these facilities because new or modified air pollution control equipment and related components could be installed at any or all of the affected facilities such that their operations may increase the quantity of hazardous materials (e.g., catalysts, scrubbing agents) used by the control equipment. In addition, any increases in the shipping, handling, storing, and disposing of hazardous materials inherently poses a certain risk of a release to the environment. Thus, the routine transport of hazardous materials, use, and disposal of hazardous materials may increase as a result of implementing the proposed project.

For example, if the control option chosen by each affected facility operator involves the installation of a wet gas scrubber, the proposed project may alter the transportation modes for catalyst and scrubbing agent feedstock and any other associated chemicals to/from the existing facilities. In addition, since SCR and SNCR technologies utilize ammonia, a toxic air contaminant (TAC) and acutely hazardous material, adverse hazard and hazardous materials impacts could occur as a result of the use, transport and storage of ammonia as well as the potential for an accidental release of ammonia into the environment. Moreover, the utilization of ammonia in these technologies can release unreacted ammonia referred to ammonia slip.

For these reasons, implementation of the proposed project may alter the hazards associated with the existing affected facilities. Therefore, potential hazards impacts as a result of implementing the proposed project are potentially significant and will be addressed in the Draft PEA.

VIII. c) Potentially Significant Impact. Some affected facilities may be located within one-quarter mile of a sensitive receptor (e.g., a day care center). Therefore, a potential for significant impacts from hazardous emissions or the handling of acutely hazardous materials, substances and wastes near sensitive-receptors may occur and will be addressed in the Draft PEA.

VIII. d) Less Than Significant Impact. Government Code §65962.5 refers to the "Hazardous Waste and Substances Site List," which is a list of facilities that may be subject to the Resource Conservation and Recovery Act (RCRA) corrective action program. While none of the affected facilities are included on the list prepared by the Department of Toxic Substances Control (DTSC) pursuant to Government Code §65962.5, some of the facilities are included on a list of RCRA-permitted sites that require corrective action as identified by DTSC. Furthermore, some of the affected facilities may be subject to corrective action under the Spill Cleanup Program (SCP) formerly "Spills, Leaks, Investigation & Cleanup (SLIC) Program" administered by the Regional Water Quality Control Board (RWQCB) pursuant to California Water Code §13304.

In the event that the installation of new or modification of existing air pollution control equipment would involve soil disturbing activities such as grading and excavation during construction of the proposed project, there is the potential for uncovering some contaminated soil. Contaminated soil is defined in SCAQMD Rule 1166 - Volatile Organic Compound Emissions From Decontamination of Soil, as soil with the potential to meet or exceed a VOC concentration of 50 ppmv. Rule 1166 includes requirements for SCAQMD notification at least 24 hours prior to the start of excavation activities, monitoring (at least once every 15 minutes, within three inches of the excavated soil surface), as well as implementation of a mitigation plan when VOC-contaminated soil is detected. To ensure compliance with SCAQMD Rule 1166, the affected facility or a construction contractor will need to obtain a pre-approved SCAQMD Rule 1166 VOC-Contaminated Soil Mitigation Plan (Plan) in order to assure that fugitive emissions will be controlled prior to the start of excavation activities. In general, a SCAQMD Rule 1166 Plan will require the contaminated soil pile to be covered with heavy plastic sheeting and will include watering requirements to assure the soil remains moist and will require removal of the VOC-contaminated soils from the disturbed site within 30 days from the time of excavation.

Soil remediation activities are also under the jurisdiction of the RWQCB and are implemented via a Soil Management Plan for the management of small quantities of contaminated soil. Following SCAQMD approval of a Rule 1166 Plan, a Soil Management Plan will need to be submitted to the RWQCB for approval. The RWQCB, when considering the Soil Management Plan, relies on the analysis in this CEQA document and the SCAQMD Rule 1166 Plan.

In the event that any excavated soils contain concentrations of certain substances, such as heavy metals and hydrocarbons, the handling, processing, transportation and disposal of the contaminated soil would also be subject to applicable hazardous waste regulations (i.e., Title 22 of the California Code of Regulations and other local and federal rules). Title 22, Division 4.5 - Environmental Health Standards for the Management of Hazardous Waste has multiple requirements for hazardous waste characterization, handling, transport, and disposal, such as requirements to use approved disposal and treatment facilities, to use certified hazardous waste transporters, and to have manifests for tracking the hazardous materials. If discovered, contaminated excavated soil would be properly characterized to determine an appropriate offsite processing method(s). These methods may include recycling of the soil if it is considered a non-hazardous waste, off-site treatment to reduce the contaminant concentrations to non-hazardous levels so that the treated soil could be used as landfill cover, or disposal as a hazardous waste at a permitted hazardous waste facility.

In addition, there are other regulatory requirements that address the discovery and remediation of contaminated sites, including the discovery of such sites during construction activities. Further, health and safety plans, worker training, and various other activities which serve to protect workers from exposure to contamination are also required. The following federal and state regulatory requirements are specific to worker protection and contaminated soil discovery:

- Hazardous Waste Operations and Emergency Response Standard (HAZWOPER, Fed-OSHA, 29 CFR 1910.120 and Cal-OSHA HAZWOPER, 8 CCR 5192) including the requirements for health and safety plans, worker training, evaluation of the potential for chemical exposure, and physical hazards at the site.

- Resource Conservation and Recovery Act and Associated Hazardous and Solid Waste Amendments (40 CFR 260) are the federal laws and regulations that govern the generation, transportation, treatment, and disposal of hazardous waste.

- Hazardous Waste Control Law (California Health and Safety Code, Chapter 6.5) governs the generation, transportation, treatment, and disposal of hazardous waste.

- Cal-OSHA Construction Worker Safety Orders in Title 8 CCR including Permissible Exposure Levels (8 CCR 5155), injury and illness prevention plans, and workplace safety.

Hazardous wastes from the existing affected facilities are required to be managed in accordance with applicable federal, state, and local rules and regulations. Thus, while the types of additional waste that may be generated from implementing the proposed project could potentially change from the existing setting, the affected facilities would still be required to comply with all of the aforementioned regulations. For example, if the use of a new or increased use of an existing catalyst is needed to operate the installed or modified air pollution control equipment, for those affected facilities which already use catalyst for other operational activities on-site, the additional collected spent catalyst will continue to be handled in the same manner as currently handled such that it will be disposed and/or recycled at approved facilities. Further, if any of other affected facilities are new to handling catalyst waste, the same disposal/recycling procedures are expected to be followed.

For any affected RECLAIM facility that is designated pursuant to Government Code §65962.5 as a large quantity generator of hazardous waste, complying with the proposed project will not alter in any way how each facility would manage their hazardous wastes and each affected facility would be expected to continue to be managed in accordance with all applicable federal, state, and local rules and regulations. Similarly, for any affected RECLAIM facility that is not designated pursuant to Government Code §65962.5 as a large quantity generator, implementing the proposed project would not change a facility's status regarding hazardous waste generation. Thus, implementing the proposed project would not be expected to interfere with site cleanup activities or create additional site contamination. Thus, for the aforementioned reasons, less than significant hazards impacts from the soil disturbing activities as well as the disposal and/or recycling of hazardous materials are expected from implementing the proposed project. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

VIII. e) No Impact. Federal Aviation Administration, 14 CFR Part 77 – Safe, Efficient Use and Preservation of the Navigable Airspace[9], provides information regarding the types of projects that may affect navigable airspace. Projects may adversely affect navigable airspace if they involve construction or alteration of structures greater than 200 feet above ground level within a specified distance from the nearest runway or objects within 20,000 feet of an airport or seaplane base with at least one runway more than 3,200 feet in length and the object would exceed a slope of 100:1 horizontally (100 feet horizontally for each one foot vertically from the nearest point of the runway).

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[9] Department of Transportation. Federal Aviation Administration, 14 CFR Part 77 [Docket No. FAA–2006–25002; Amendment No. 77–13] RIN 2120–AH31. *Safe, Efficient Use and Preservation of the Navigable Airspace*. 42296 Federal Register / Vol. 75, No. 139 / Wednesday, July 21, 2010 / Rules and Regulations. http://www.gpo.gov/fdsys/pkg/FR-2010-07-21/pdf/2010-17767.pdf.

Construction activities from implementing the proposed project are expected to occur within the existing confines of the affected facilities. However, some of these facilities may be located within two miles of an airport (either public or private) and are located within an airport land use plan. Nonetheless, the installation of the NOx control devices is expected to be constructed according to the all appropriate building, land use and fire codes and operated at a low enough height relative to existing flight patterns so that the structure would not interfere with plane flight paths consistent with Federal Aviation Regulation, Part 77. Such codes are designed to protect the public from hazards associated with normal operation. Therefore, the proposed project is not expected to result in a safety hazard for people residing or working in the area of the affected facilities even if construction would occur within the vicinity of an airport. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

VIII. f) No Impact. Health and Safety Code §25506 specifically requires all businesses handling hazardous materials to submit a business emergency response plan to assist local administering agencies in the emergency release or threatened release of a hazardous material. Business emergency response plans generally require the following:

- Identification of individuals who are responsible for various actions, including reporting, assisting emergency response personnel and establishing an emergency response team;
- Procedures to notify the administering agency, the appropriate local emergency rescue personnel, and the California Office of Emergency Services;
- Procedures to mitigate a release or threatened release to minimize any potential harm or damage to persons, property or the environment;
- Procedures to notify the necessary persons who can respond to an emergency within the facility;
- Details of evacuation plans and procedures;
- Descriptions of the emergency equipment available in the facility;
- Identification of local emergency medical assistance; and
- Training (initial and refresher) programs for employees in:
  1. The safe handling of hazardous materials used by the business;
  2. Methods of working with the local public emergency response agencies;
  3. The use of emergency response resources under control of the handler;
  4. Other procedures and resources that will increase public safety and prevent or mitigate a release of hazardous materials.

In general, every county or city and all facilities using a minimum amount of hazardous materials are required to formulate detailed contingency plans to eliminate, or at least minimize, the possibility and effect of fires, explosion, or spills. In conjunction with the California Office of Emergency Services, local jurisdictions have enacted ordinances that set standards for area and business emergency response plans. These requirements include immediate notification, mitigation of an actual or threatened release of a hazardous material, and evacuation of the emergency area. Emergency response plans are typically prepared in coordination with the local city or county emergency plans to ensure the safety of not only the public (surrounding local communities), but the facility employees as well.

The existing industrial facilities affected by the proposed project already have their own emergency response plans in place. The proposed project would not impair implementation of, or physically interfere with any adopted emergency response plan or emergency evacuation plan. However, depending on the physical changes that may be taken in order to reduce NOx emissions such as installing NOx control equipment, an affected facility's emergency response plan may need to be updated to accommodate any changes that may occur. For example, if additional storage of hazardous materials (e.g., ammonia) is needed in order to operate a new SCR unit at an affected facility, then such modifications may require a revision to an affected facility's emergency response plan. However, these modifications would not be expected to interfere with the existing emergency response procedures in place.

Thus, the proposed project is not expected to impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan, but may require changes or updates. Accordingly, this impact issue will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

VIII. g) No Impact. Flammable materials such as natural gas, diesel and gasoline are currently used at several of the affected facilities and additional fuels may be used during either construction or operation of the proposed project. While the hazards associated with these fuels could result in a torch fire in the event that a release occurred and caught fire, a torch fire would be expected to remain on-site because the affected RECLAIM facilities are located at existing, established industrial sites in urban areas where wildlands are not prevalent. In addition, no substantial or native vegetation typically exists on or near the affected facilities (specifically because they could be a fire hazard), so the proposed project is not expected to expose people or structures to wild fires. For these reasons, the proposed project is not expected to increase the existing risk of fire hazards in areas with flammable brush, grass, or trees, so there would be no public exposure to fire hazards and as such no risk of loss or injury associated with wildland fires would be expected. Accordingly, this impact issue will not be further evaluated in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

VIII. h) Potentially Significant Impact. The Uniform Fire Code and Uniform Building Code set standards intended to minimize risks from flammable or otherwise hazardous materials. Local jurisdictions are required to adopt the uniform codes or comparable regulations. Local fire agencies require permits for the use or storage of hazardous materials and permit modifications for proposed increases in their use. Permit conditions depend on the type and quantity of the hazardous materials used. Permit conditions may include, but are not limited to, specifications for sprinkler systems, electrical systems, ventilation, and containment. The fire departments make annual business inspections to ensure compliance with permit conditions and other appropriate regulations. Further, businesses are required to report increases in the storage or use of flammable and otherwise hazardous materials to local fire departments. Local fire departments ensure that adequate permit conditions are in place to protect against the potential risk of upset.

For any affected facility that installs NOx control equipment as a result of implementing the proposed project, the increased transport, handling, or use of flammable or hazardous materials could occur. For example, for control equipment that utilizes ammonia (e.g., SCR or SNCR), explosion risks resulting from the industrial handling of aqueous ammonia solutions could increase. As such, the potential for increased probability of explosion, fire, or other hazards will be addressed in the Draft PEA. Impacts related to public exposure to toxic air contaminants will be addressed in the "Air Quality and Greenhouse Gas" section of the Draft PEA.

Based upon these considerations, significant adverse impacts to hazards and hazardous materials may occur from implementing the proposed project and thus, impact issues VIII. a), b), c), and h) will be further analyzed in the Draft PEA.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
IX.	**HYDROLOGY AND WATER QUALITY.** Would the project:				
a)	Violate any water quality standards, waste discharge requirements, exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board, or otherwise substantially degrade water quality?	☑	☐	☐	☐
b)	Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g. the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted)?	☑	☐	☐	☐
c)	Substantially alter the existing drainage pattern of the site or area, including through alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in substantial erosion or siltation on- or off-site or flooding on- or off-site?	☐	☐	☑	☐

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
d)	Create or contribute runoff water which would exceed the capacity of existing or planned storm water drainage systems or provide substantial additional sources of polluted runoff?	☐	☐	☑	☐
e)	Place housing or other structures within a 100-year flood hazard area as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map, which would impede or redirect flood flows?	☐	☐	☐	☑
f)	Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam, or inundation by seiche, tsunami, or mudflow?	☐	☐	☐	☑
g)	Require or result in the construction of new water or wastewater treatment facilities or new storm water drainage facilities, or expansion of existing facilities, the construction of which could cause significant environmental effects?	☑	☐	☐	☐
h)	Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed?	☑	☐	☐	☐
i)	Result in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments?	☑	☐	☐	☐

Significance Criteria

Potential impacts on water resources will be considered significant if any of the following criteria apply:

Water Demand:

- The existing water supply does not have the capacity to meet the increased demands of the project, or the project would use more than 262,820 gallons per day of potable water.
- The project increases demand for total water by more than five million gallons per day.

Water Quality:

- The project will cause degradation or depletion of ground water resources substantially affecting current or future uses.
- The project will cause the degradation of surface water substantially affecting current or future uses.
- The project will result in a violation of National Pollutant Discharge Elimination System (NPDES) permit requirements.
- The capacities of existing or proposed wastewater treatment facilities and the sanitary sewer system are not sufficient to meet the needs of the project.
- The project results in substantial increases in the area of impervious surfaces, such that interference with groundwater recharge efforts occurs.
- The project results in alterations to the course or flow of floodwaters.

Discussion

IX. a), g) & i) Potentially Significant Impact. In the event that the proposed project is implemented, operators of the affected RECLAIM facilities may install new or modify existing air pollution control equipment to reduce NOx emissions. Operational activities associated with some types of NOx control equipment utilize water such that if there is an increase in the demand for water, a subsequent increase in the amount wastewater discharged at an affected facility may occur. For example, water/steam injection and WGS technology both utilize water in their processes. In addition, operators of the affected RECLAIM facilities could choose to install control equipment that utilize SCR or SNCR, which both utilize ammonia, a TAC and acutely hazardous material, that if spilled, an accidental ammonia release into the environment could cause adverse water quality impacts.

Depending on the type of NOx controls employed, the impacts of the proposed project on each affected facility's wastewater discharge and the Industrial Wastewater Discharge Permit could be potentially significant. Thus, implementing the proposed project may result in the potential for generating increased volumes of wastewater that could adversely affect water quality standards or waste discharge requirements resulting in the need for new or increased wastewater treatment capacity. Accordingly, these topic areas will be evaluated further in the Draft PEA.

IX. b) & h) Potentially Significant Impact. In the event that the proposed project is implemented, operators of the affected RECLAIM facilities may install new or modify existing air pollution control equipment to reduce NOx emissions. Construction activities associated with the proposed project may require site preparation/earthmoving activities such as grading and the limited use of water may be utilized as a dust suppressant. In addition, operational activities associated with some types of NOx control equipment utilize water such that there may be an increase in the demand for water. For example, water/steam injection and WGS technology both utilize water in their processes.

In addition, each affected facility may not have sufficient water supplies available for implementing the proposed project since WGSs could be installed along with NOx control equipment at the affected facilities and WGSs heavily rely on water for their operation. Thus, the need for new or expanded water supply entitlements may be necessary. While it is not possible to predict water availability in the future, existing entitlements and resources in the district are currently at historically low drought levels. Thus, the water demand that would result from implementing the proposed project may result in significant adverse water impacts.

Thus, implementing the proposed project would require additional water, some of which could come from ground water supplies, require new water supply facilities, or require an expansion of existing water supply facilities. Accordingly, these topic areas are potentially significant and as such, will be evaluated further in the Draft PEA.

IX. c) & d) Less Than Significant Impact. Changes to each affected RECLAIM facility's storm water collection systems are expected to be less than significant since most of the changes that may be associated with the proposed project will occur within existing units (e.g., by installing NOx control equipment). Further, typically most of the areas likely to be affected by the proposed project are currently paved and are expected to remain paved. Any new units constructed will be curbed and the existing units will remain curbed to contain any runoff. Any runoff occurring will continue to be handled by each affected facility's wastewater system and sent to an on-site wastewater treatment system prior to discharge. The surface water runoff is expected to be handled with each affected facility's current wastewater treatment system. Storm water runoff will be collected and discharged in accordance with each facility's discharge permit terms and conditions. Storm Water Pollution Prevention Plans may need to be updated, as necessary, to reflect any operational modifications and included additional Best Management Practices, if required. Thus, the proposed project would not be expected to substantially increase the rate or amount of surface runoff in a manner that would result in substantial erosion or siltation on- or off-site or flooding on- or off-site. Further, any construction that may occur as a result of implementing the proposed project will occur at the existing affected facilities, and as such, would not involve modifications that would alter the course of a stream or river.

Therefore, less than significant storm water quality impacts may result from the operation of the proposed project. Accordingly, these impact issues will not be further evaluated in the Draft PEA. Further, since no significant impacts were identified for these issues, no mitigation measures are necessary or required.

IX. e) No Impact. Once implemented, the proposed project is not expected to require additional workers, except during construction activities. Further, the proposed project is expected to involve construction activities located at the affected RECLAIM facilities and would not require the construction of any new housing so it would not place new housing in 100-year flood areas as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood delineation map. Since the proposed project would not require locating new facilities within a flood zone, it is not expected that implementation of the proposed project would expose people or property to any known water-related flood hazards.

As a result, the proposed project would not be expected to create or substantially increase risks from flooding or expose people or structures to significant risk of loss, injury or death involving flooding. Consequently, this topic will not be evaluated further in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

IX. f) No Impact. The proposed project does not require construction in areas that could be affected by tsunamis. Of the RECLAIM facilities affected by the proposed project, some are located near the Ports of Long Beach, Los Angeles, and San Pedro. The port areas are protected from tsunamis by the construction of breakwaters. Construction of breakwaters combined with the distance of each facility from the water is expected to minimize the potential impacts of a tsunami or seiche so that no significant impacts are expected. The proposed project does not require construction of facilities in areas that are susceptible to mudflows (e.g., hillside or slope areas). Existing affected facilities that are currently located on hillsides or slope areas may be susceptible to mudflow, but this would be considered part of the existing setting. As a result, the proposed project is not expected to generate significant adverse mudflow impacts. Finally, the proposed project will not affect in any way any potential flood hazards inundation by seiche, tsunami, or mud flow that may already exist at the affected RECLAIM facilities. Accordingly, this impact issue will not be further evaluated in the Draft PEA. Further, since no significant impacts were identified for this issue, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to hydrology and water quality may occur from implementing the proposed project and thus, impact issues IX. a), b), g), h), and i) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
X. LAND USE AND PLANNING. Would the project:				
a) Physically divide an established community?	☐	☐	☐	☑
b) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	☐	☐	☐	☑

Significance Criteria

Land use and planning impacts will be considered significant if the project conflicts with the land use and zoning designations established by local jurisdictions.

Discussion

X. a) No Impact. The proposed project does not require the construction of new facilities, but any physical effects that will result from the proposed project, will occur at existing RECLAIM facilities located in heavy industrial areas and would not be expected to go beyond existing boundaries. Thus, implementing the proposed project will not result in physically dividing any established communities.

X. b) No Impact. There are no provisions in the proposed project that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the proposed project. Further, the proposed project would be consistent with the typical industrial zoning of the affected facilities. Typically, all proposed construction activities are expected to occur within the confines of the existing facilities. The proposed project would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. Further, no new development or alterations to existing land designations will occur as a result of the implementation of the proposed project. Therefore, present or planned land uses in the region will not be affected as a result of implementing the proposed project.

Based upon these considerations, significant land use planning impacts are not expected from the implementation of the proposed project, and thus, will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for any of these issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XI. MINERAL RESOURCES. Would the project:				
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	☐	☐	☐	☑
b) Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	☐	☐	☐	☑

Significance Criteria

Project-related impacts on mineral resources will be considered significant if any of the following conditions are met:

- The project would result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state.
- The proposed project results in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Discussion

XI. a) & b) No Impact. There are no provisions in the proposed project that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state such as aggregate, coal, clay, shale, et cetera, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Based upon these considerations, significant mineral resource impacts are not expected from the implementation of the proposed project, and thus, will not be further analyzed in the Draft PEA. Since no significant mineral resource impacts were identified for any of these issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XII. NOISE. Would the project result in:				
a) Exposure of persons to or generation of permanent noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	☐	☐	☑	☐
b) Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?	☐	☐	☑	☐
c) A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☐	☑	☐

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
d) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public use airport or private airstrip, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☑	☐

Significance Criteria

Noise impact will be considered significant if:

- Construction noise levels exceed the local noise ordinances or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three decibels (dBA) at the site boundary. Construction noise levels will be considered significant if they exceed federal Occupational Safety and Health Administration (OSHA) noise standards for workers.
- The proposed project operational noise levels exceed any of the local noise ordinances at the site boundary or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three dBA at the site boundary.

Discussion

XII. a), b), & c) Less Than Significant Impact. Modifications or changes associated with the implementation of the proposed project will take place at existing RECLAIM facilities that are located in heavy industrial settings. The existing noise environment at each of the affected facilities is typically dominated by noise from existing equipment onsite, vehicular traffic around the facilities, and trucks entering and exiting facility premises. Construction activities associated with implementing the proposed project may generate some noise associated with the use of construction equipment and construction-related traffic. However, noise from the proposed project is not expected to produce noise in excess of current operations at each of the existing facilities. If NOx control devices are installed or existing devices are modified, the operations phase of the proposed project may add new sources of noise to each affected facility. However, control devices are not typically equipment that generate substantial amounts of noise. Nonetheless, for any noise that may be generated by the control devices, it is expected that each facility affected will comply with all existing noise control laws or ordinances. Further, Occupational Safety and Health Administration (OSHA) and California-OSHA (Cal/OSHA) have established noise standards to protect worker health. These potential noise increases are expected within the allowable noise levels established by the local noise ordinances for industrial areas, and thus are expected to be less than significant. Therefore, less than significant noise impacts are expected to result from the operation of the proposed project will not be further evaluated in the Draft PEA. Accordingly, these impact issues will not be further evaluated in the Draft PEA.

XII. d) Less Than Significant Impact. Though some of the facilities affected by the proposed project are located at sites within an airport land use plan, or within two miles of a public airport, the addition of new or modification of existing NOx control equipment would not expose people residing or working in the project area to the same degree of excessive noise levels associated with airplanes. All noise producing equipment must comply with local noise ordinances and applicable OSHA or Cal/OSHA workplace noise reduction requirements. Therefore, less than significant noise impacts are expected to occur at sites located within an airport land use plan, or within two miles of a public airport. Accordingly, this impact issue will not be further evaluated in the Draft PEA.

Based upon these considerations, significant noise impacts are not expected from the implementation of the proposed project and will not be further analyzed in the Draft PEA. Further, since no significant impacts were identified for any of these issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant With Mitigation**	**Less Than Significant Impact**	**No Impact**
XIII. POPULATION AND HOUSING. Would the project:				
a) Induce substantial growth in an area either directly (for example, by proposing new homes and businesses) or indirectly (e.g. through extension of roads or other infrastructure)?	☐	☐	☐	☑
b) Displace substantial numbers of people or existing housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☑

Significance Criteria

Impacts of the proposed project on population and housing will be considered significant if the following criteria are exceeded:

- The demand for temporary or permanent housing exceeds the existing supply.
- The proposed project produces additional population, housing or employment inconsistent with adopted plans either in terms of overall amount or location.

Discussion

XIII. a) No Impact. The construction activities associated with the proposed project at each affected facility are not expected to involve the relocation of individuals, require new housing or commercial facilities, or change the distribution of the population. The reason for this conclusion is that operators of affected facilities who need to perform any construction activities to comply with the proposed project can draw from the large existing labor pool in the local southern California area. Further, it is not expected that the installation of new or the modification of existing NOx control equipment will require new employees during operation of the equipment. In the event that new employees are hired, it is expected that the number of new employees at any one facility would be small. Human population within the jurisdiction of the SCAQMD is anticipated to grow regardless of implementing the proposed project. As a result, the proposed project is not anticipated to generate any significant adverse effects, either direct or indirect, on population growth in the district or population distribution.

XIII. b) & c) No Impact. Because the proposed project includes modifications and/or changes at existing facilities located in heavy industrial settings, the proposed project is not expected to result in the creation of any industry that would affect population growth, directly or indirectly induce the construction of single- or multiple-family units, or require the displacement of people or housing elsewhere in the district.

Based upon these considerations, significant population and housing impacts are not expected from the implementation of the proposed project, and thus, will not be further evaluated in the Draft PEA. Since no significant population and housing impacts were identified for any of these issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	**Less Than Significant With Mitigation**	**Less Than Significant Impact**	**No Impact**
XIV. PUBLIC SERVICES. Would the proposal result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the following public services:				
a) Fire protection?	☐	☐	☑	☐
b) Police protection?	☐	☐	☑	☐
c) Schools?	☐	☐	☐	☑
d) Other public facilities?	☐	☐	☐	☑

Significance Criteria

Impacts on public services will be considered significant if the project results in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, or the need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response time or other performance objectives.

Discussion

XIV. a) & b) Less Than Significant Impact. Implementation of the proposed project is expected to cause facility operators to install new or modify existing NOx control devices, all the while continuing current operations at existing affected facilities. The proposed project may result in a greater demand for catalyst, scrubbing agents and other chemicals, which will need to be transported to the affected facilities to support the function of NOx control equipment and stored onsite prior to use. As first responders to emergency situations, police and fire departments may assist local hazmat teams with containing hazardous materials, putting out fires, and controlling crowds to reduce public exposure to releases of hazardous materials. In addition, emergency or rescue vehicles operated by local, state, and federal law enforcement agencies, police and sheriff departments, fire departments, hospitals, medical or paramedic facilities, that are used for responding to situations where potential threats to life or property exist, including, but not limited to fire, ambulance calls, or life-saving calls, may be needed in the event of an accidental release or other emergency. While the specific nature or degree of such impacts is currently unknown, the affected facilities have existing emergency response plans so any changes to those plans would not be expected to dramatically alter how emergency personnel would respond to an accidental release or other emergency. In addition, due the low probability and unpredictable nature of accidental releases, the proposed project is not expected to increase the need or demand for additional public services (e.g., fire and police departments and related emergency services, et cetera) above current levels. Accordingly, these impact issues will not be further evaluated in the Draft PEA.

XIV. c) No Impact. As noted in the previous "Population and Housing" discussion, the proposed project is not expected to induce population growth in any way because the local labor pool (e.g., workforce) is expected to be sufficient to accommodate any construction activities that may be necessary at affected facilities and operation of new or modified NOx control equipment is not expected to require additional employees. Therefore, there will be no increase in local population and thus no impacts are expected to local schools or parks. Accordingly, this impact issue will not be further evaluated in the Draft PEA.

XIV. d) No Impact. The proposed project is expected to result in the use of new or modified add-on control equipment for NOx control. Besides permitting the equipment or altering permit conditions by the SCAQMD, there is no need for other types of government services. The proposed project would not result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives. There will be no increase in population and, therefore, no need for physically altered government facilities. Accordingly, this impact issue will not be further evaluated in the Draft PEA.

Based upon these considerations, significant public services impacts are not expected from the implementation of the proposed project and will not be further evaluated in the Draft PEA. Since no significant public services impacts were identified for any of these issues, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XV. RECREATION.				
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	☐	☐	☐	☑
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment or recreational services?	☐	☐	☐	☑

Significance Criteria

Impacts to recreation will be considered significant if:

- The project results in an increased demand for neighborhood or regional parks or other recreational facilities.
- The project adversely affects existing recreational opportunities.

Discussion

XV. a) & b) No Impact. As discussed earlier under the topic of "Population and Housing," there are no provisions in the proposed project that would affect or increase the demand for or use of existing neighborhood and regional parks or other recreational facilities or require the construction of new or the expansion of existing recreational facilities that might have an adverse physical effects on the environment because the proposed project will not directly or indirectly increase or redistribute population. Based upon these considerations, including the conclusion of "no impact" for the topic of "Population and Housing," significant recreation impacts are not expected from implementing the proposed project, and thus, this topic will not be further analyzed in the Draft PEA. Since no significant recreation impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVI. SOLID AND HAZARDOUS WASTE. Would the project:				
a) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?	☑	☐	☐	☐
b) Comply with federal, state, and local statutes and regulations related to solid and hazardous waste?	☐	☐	☐	☑

Significance Criteria

The proposed project impacts on solid and hazardous waste will be considered significant if the following occurs:

- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.

Discussion

XVI. a) Potentially Significant Impact. Construction activities associated with installing new or modifying existing NOx control equipment such as demolition and site preparation/grading/excavating could generate solid waste as result of implementing the proposed project. Demolition activities could generate demolition waste while site preparation, grading, and excavating could uncover contaminated soils since the facilities affected by the proposed project are located in existing heavy industrial areas. Excavated soil, which may be contaminated, will need to be characterized, treated, and disposed of offsite in accordance with applicable regulations. Where appropriate, the soil will be recycled if it is considered or classified as non-hazardous waste or it can be disposed of at a landfill that accepts non-hazardous waste. Otherwise, the material will need to be disposed of at a hazardous waste facility. (Potential soil contamination is addressed in the Hazards and Hazardous Materials discussion in Section VIII. d.)

Solid or hazardous wastes generated from construction-related activities would consist primarily of materials from the demolition and/or alteration of any existing structure to make room for the new equipment to be installed. Construction-related waste would be disposed of at a Class II (industrial) or Class III (municipal) landfill. In addition, the generation of solid or hazardous waste could occur if air pollution control equipment is installed that relies on activated carbon, filters, and catalysts to function.

Solid waste impacts would be significant if the additional potential waste volume exceeded the existing capacity of landfills in the District. The potential solid and hazardous waste impacts from implementing the proposed project will be analyzed in the Draft PEA.

XVI. b) No Impact. Implementation of the proposed project is not expected to interfere with the affected RECLAIM facilities' abilities to comply with federal, state, or local statutes and regulations related to solid and hazardous waste handling or disposal. Further, nothing in the proposed project would interfere with the compliance requirements for waste handling or disposal. Thus, this specific topic will not be further evaluated in the Draft PEA. Since no significant solid and hazardous waste impacts were identified for this topic, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to solid and hazardous waste may occur from implementing the proposed project and thus, impact issue XVI. a) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVII. TRANSPORTATION AND TRAFFIC. Would the project:				
a) Conflict with an applicable plan, ordinance or policy establishing measures of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit?	☑	☐	☐	☐
b) Conflict with an applicable congestion management program, including but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways?	☑	☐	☐	☐
c) Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?	☐	☐	☐	☑

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
d)	Substantially increase hazards due to a design feature (e.g. sharp curves or dangerous intersections) or incompatible uses (e.g. farm equipment)?	☐	☐	☐	☑
e)	Result in inadequate emergency access?	☐	☐	☐	☑
f)	Conflict with adopted policies, plans, or programs regarding public transit, bicycle, or pedestrian facilities, or otherwise decrease the performance or safety of such facilities?	☐	☐	☐	☑

Significance Criteria

Impacts on transportation and traffic will be considered significant if any of the following criteria apply:

- Peak period levels on major arterials are disrupted to a point where level of service (LOS) is reduced to D, E or F for more than one month.
- An intersection's volume to capacity ratio increase by 0.02 (two percent) or more when the LOS is already D, E or F.
- A major roadway is closed to all through traffic, and no alternate route is available.
- The project conflicts with applicable policies, plans or programs establishing measures of effectiveness, thereby decreasing the performance or safety of any mode of transportation.
- There is an increase in traffic that is substantial in relation to the existing traffic load and capacity of the street system.
- The demand for parking facilities is substantially increased.
- Water borne, rail car or air traffic is substantially altered.
- Traffic hazards to motor vehicles, bicyclists or pedestrians are substantially increased.
- The need for more than 350 employees
- An increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round trips per day
- Increase customer traffic by more than 700 visits per day.

Discussion

XVII. a) & b) Potentially Significant Impact. Construction activities resulting from implementing the proposed project may generate a temporary increase in traffic in the areas of each affected facility associated with construction workers, construction equipment, and the delivery of construction materials. Also, the proposed project may exceed, either individually or cumulatively, the current level of service of the areas surrounding the affected facilities. The impacts of the traffic load and capacity of the street system during construction will be analyzed in the Draft PEA.

The work force at each affected facility is not expected to significantly increase during operations of the proposed project operations because few, if any, new employees are expected to be needed to operate any new or modified NOx control equipment. As a result, operation-related traffic is expected to be limited more towards supply deliveries and waste haul trips, but less than significant. Thus, the operational traffic impacts will not be evaluated further in the Draft PEA.

XVII. c) No Impact. Though some of the facilities that will be affected by the proposed project are located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, actions that would be taken to comply with the proposed project, such as installing new or modifying existing NOx control equipment, are not expected to significantly influence or affect air traffic patterns. Further, the size and type of air pollution control devices that would be installed would not be expected to affect navigable air space. Thus, the proposed project would not result in a change in air traffic patterns including an increase in air traffic levels or a change in location that results in substantial safety risks. As such, this specific topic will not be further evaluated in the Draft PEA. Since no significant transportation and traffic impacts were identified for this topic, no mitigation measures are necessary or required.

XVII. d) & e) No Impact. The siting of each affected facility is consistent with surrounding land uses and traffic/circulation in the surrounding areas of the affected facilities. Thus, the proposed project is not expected to substantially increase traffic hazards or create incompatible uses at or adjacent to the affected facilities. Aside from the temporary effects due to a slight increase in truck traffic for those facilities that will undergo construction activities during installation of air pollution control equipment, the proposed project is not expected to alter the existing long-term circulation patterns. Further, the proposed project is not expected to require a modification to circulation, thus, no long-term impacts on the traffic circulation system are expected to occur. The proposed project is not expected to involve the construction of any roadways, so there would be no increase in roadway design feature that could increase traffic hazards. Emergency access at each affected facility is not expected to be impacted by the proposed project because each affected facility is expected to continue to maintain their existing emergency access gates. Thus, these specific topics will not be further evaluated in the Draft PEA. Since no significant transportation and traffic impacts were identified for this topic, no mitigation measures are necessary or required.

XVII. f) No Impact. Construction and operation activities resulting from implementing the proposed project are not expected to conflict with policies supporting alternative transportation since the proposed project does not involve or affect alternative transportation modes (e.g.

bicycles or buses) because the construction and operation activities related to the proposed project will occur solely in existing industrial areas. Thus, this specific topic will not be further evaluated in the Draft PEA. Since no significant transportation and traffic impacts were identified for this topic, no mitigation measures are necessary or required.

Based upon these considerations, significant adverse impacts to transportation and traffic may occur from implementing the proposed project and thus, impact issues XVII. a) and b) will be further analyzed in the Draft PEA.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVIII. MANDATORY FINDINGS OF SIGNIFICANCE.				
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	☐	☐	☐	☑
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)	☑	☐	☐	☐
c) Does the project have environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?	☑	☐	☐	☐

Discussion

XVIII. a) No Impact. The proposed project is not expected to reduce or eliminate any plant or animal species or destroy prehistoric records of the past. As indicated in the Biological Resources discussion in Section IV., each site affected by the proposed project is part of an existing facility, which has been previously graded, such that the proposed project is not expected to extend into environmentally sensitive areas. In addition, overall air quality improvements that are expected to occur as a result of implementing the proposed project will also be expected to benefit plant and animal life.

XVIII. b) Potentially Significant Impact. The Environmental Checklist indicates that the proposed project has potentially significant adverse impacts on the following topic areas: aesthetics; air quality and GHG emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic. The potential for cumulative impacts on these resources will be evaluated in the Draft PEA.

XVIII. c) Potentially Significant Impact. Even though the objective of the proposed project is to reduce NOx emissions from the top emitters in the RECLAIM program, the proposed project may result in secondary effects, emissions of regulated air pollutants, toxic air contaminants, GHGs and may also increase the hazards at some of the affected facilities. The potential for these impacts to have adverse impacts on human beings, either directly or indirectly, will be evaluated in the Draft PEA.

APPENDIX A

PROPOSED AMENDED RULE 2002 – ALLOCATIONS FOR OXIDES OF NITROGEN (NOX) AND OXIDES OF SULFUR (SOX)

The BARCT evaluation and the RTC shaving methodology are ongoing, so a RECLAIM industry's required RTC shave may change due to the public review process. The programmatic RTC shave could range from five to 14 tons per day. To provide a worst case scenario of adverse environmental impacts, the adjustment factors and the Non-tradable/Non-usable NOx RTC adjustment factors in Proposed Amended Rule 2002 subparagraph (f)(1)(B) reflect an RTC shave at the higher end of the range to capture a conservative estimate of potential control technologies needed that could generate secondary environmental impacts. As the staff proposal is being refined, if a lesser RTC shave is proposed, the adverse environmental impacts would be less and the Draft PEA and its alternatives will also be further defined.

(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)
(PAR2002 120214)

PROPOSED 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.

(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=Σ [A 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:

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

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	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2007	0.883	0
2008	0.856	0.027
2009	0.829	0.054
2010	0.802	0.081
2011 ~~and after~~ through 2015	0.775	0.108

RTCs designated as non-tradable/non-usable pursuant to this subparagraph shall be held, but shall not be used or traded. The adjustment factors in this subparagraph are subject to change pursuant to paragraph (i)(5).

(B) The Executive Officer will adjust NOx RTC holdings, as of (Date of Amendment) for compliance years 2016 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	Non-tradable/ Non-usable NOx RTC Adjustment Factor
2016	0.925	0
2017	0.849	0.031
2018	0.774	0.063
2019	0.698	0.094
2020	0.623	0.126
2021	0.547	0.157
2022 and after	0.512	0.189

RTCs designated as non-tradable/non-usable pursuant to this subparagraph shall be held, but shall not be used or traded. The adjustment factors in this subparagraph are subject to change pursuant to paragraph (i)(5).

(~~B~~C) 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. 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.

(~~C~~D) ~~Notwithstanding the requirements of non-tradable/non-usable credits specified in subparagraphs (f)(1)(A), i~~In the event that the NOx RTC prices exceed $15,000 per ton based on the 12-month rolling average calculated pursuant to subparagraph (f)(1)(~~B~~C), the Executive Officer will report to the Governing Board. Notwithstanding the requirements of non-tradable/non-usable credits specified in subparagraphs (f)(1)(B) and ~~I~~if the Governing Board finds that the 12-month rolling average RTC price exceeds $15,000 per ton, then the incremental NOx reductions as specified in subparagraph (f)(1)(~~D~~E) shall be converted to Tradable/Usable NOx RTCs upon Governing

Board concurrence. 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 60 days from Executive Officer determination.

(~~D~~E) The incremental NOx RTCs restored shall be the difference between the Non-tradable/Non-usable Adjustment Factors, as specified in subparagraph ~~(f)(1)(A)~~(f)(1)(B), of the current compliance year and the most recent prior year the adjustment factor was implemented.

(~~E~~F) RTC conversion pursuant to subparagraph (f)(1)(~~C~~D) shall~~-~~ only occur in the compliance year in which Cycle 1 facilities are operating.

(~~F~~G) Notwithstanding the adjustment factors required pursuant to subparagraph ~~(f)(1)(A)~~ (f)(1)(B), beginning with the following December and each year thereafter that the Governing Board finds the $15,000 per ton NOx RTC price is exceeded pursuant to subparagraph (f)(1)(~~C~~D), the Executive Officer will publish the applicable adjustment factors for the next compliance year beginning January 1. The adjustment factors will be published at a public hearing during a regularly scheduled Board Meeting. The adjustment factors will be determined as follows:

(i) If the 12-month rolling average falls below $15,000 per ton for at least 6 consecutive months, then the emission adjustment factors for the following compliance year shall equal the next more stringent adjustment factors listed in subparagraph ~~(f)(1)(A)~~ (f)(1)(B) than the factors currently in effect; otherwise;

(ii) The next compliance year adjustment factors shall equal the compliance year adjustment factors currently in place.

The Executive Officer need no longer comply with the annual public hearing requirement once the adjustment factors for the 2022~~10~~ compliance year have been implemented for a 12-month period.

(~~G~~H) The NOx RTC adjustment factors for compliance years 20~~08~~19 through 20~~10~~21 shall not be submitted for inclusion into the State Implementation Plan until the adjustments have been in effect for one full compliance year. The 2022~~11~~ NOx RTC adjustment factors shall not be submitted for inclusion into the State Implementation Plan until 12-months after the adjustments have been in effect for one full compliance year.

(~~H~~I) NOx Allocations for facilities that enter RECLAIM after January 7, 2005 for compliance years 2007 and after shall be determined by applying the Tradable/Usable and Non-tradable/Non-usable NOx RTC Adjustment Factors under subparagraph (f)(1)(A) to the facility's Compliance Year 2006 Allocation and under subparagraph (f)(1)(B) to the facility's Compliance Year 2015 Allocation.

(~~I~~J) 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

(~~J~~K) The Executive Officer shall determine Tradable/usable SOx RTC Adjustment Factors for each compliance years after 2012 as follows:

$$F_{compliance\ year\ i} = 1 - [X_i / (A_i + B_i + C_i)]$$

Where:

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

A_i = Total SOx RTCs for compliance year i held as of November ~~11~~5, 2010, by all RTC holders, except those listed in Table 5

B_i = Total SOx RTCs for compliance year i credited to any facilities listed in Table 5 between August 29, 2009 and ~~(rule adoption date)~~November 5, 2010, and not includes in C_i

C_i = Total SOx RTCs held as of (rule adoption date) by facilities listed in Table 5 for compliance year i in excess of allocations as determined pursuant to subdivision (e).

X_i = Amount to be reduced for compliance year i starting with 2013 as listed in subparagraph (f)(1)(~~I~~J).

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

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

Where:

$N_{compliance\ year\ j}$ = 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)(~~J~~K)

j = 2017 through 2019

Fcompliance year 2016 = Tradable/usable SOx RTC Adjustment Factor for compliance year 2016 as determined pursuant to subparagraph (f)(1)(~~J~~K)

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

(~~L~~M) 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)(~~M~~N) 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)(~~M~~N) 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)(~~M~~N) 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)(~~M~~N) more than once.

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

(~~N~~O) 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.

(~~O~~P) 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)(~~N~~O), 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)(~~K~~L) and (f)(1)(~~L~~M), 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)(~~P~~Q).

(~~P~~Q) The Executive Officer will not submit the emission reductions obtained through subparagraph (f)(1)(~~I~~J) 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.

(~~Q~~R) 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.

(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.

(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_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 = $(\Sigma [A \text{ X } B_1])$ - 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) RTC Reduction Exemption

(1) A facility may file an application for Executive Officer approval to be exempted from all or a portion of the requirements pursuant to subparagraph (f)(1)(~~A~~B) with the exception of RTC holdings as of ~~January 7, 2005 for compliance year 2007~~ (Date of Amendment) for compliance year 2016 and thereafter in excess of the initial allocation. For the purposes of this rule, initial allocation refers to the RTCs issued by the District to a facility upon entering the RECLAIM program. The

application shall contain sufficient data to demonstrate to the satisfaction of the Executive Officer that the facility meets the following criteria:

(A) the facility has been in the program since the start of RECLAIM, or existed prior to 1994, but subsequently entered RECLAIM pursuant to Rule 2001 because facility emissions exceeded 4 tons per year;

(B) at least 99 percent of the facility's emissions reported for ~~the most recent completed c~~Compliance ~~y~~Year 2013 ~~prior to the date of filing an application~~ is from equipment not listed in Table 3 or Table 6 and the achieved emission rates for each and every piece of equipment at the facility is less than or equal to the 2000 (Tier I) Ending Emission Factor listed in Table 1 or the emission factor listed in Table 3, whichever is lower, for the corresponding equipment type;

(C) RTCs that were part of the total initial allocation for the facility have never been transferred or sold by the facility for Compliance Year~~year~~ 2016~~07~~ or later~~ compliance years~~; and

(D) the cumulative NOx compliance costs incurred by the facility up to the submittal date of the application as specified in paragraph (i)(3) to comply with the RECLAIM Allocation as required under Rule 2004(b) and (d)(1) exceed the compliance costs that otherwise would have occurred to meet and maintain emission limits specified in Table 1 or 3, whichever is lower, for each and every piece of equipment at the facility. The compliance costs shall be based on the following parameters:

(i) cost of controlling emissions using the parameters and procedures for determining total direct and indirect capital investment and total annual costs as specified in the most recent edition of the Control Cost Manual published by the U.S. EPA Office of Air Quality and Planning Standards, excluding control costs for any equipment listed in Table 3 or Table 6, if any;

(ii) realized and anticipated revenues and expenditures of the Facility Permit holder resulting from buying and selling any RTCs that are or were held by the facility where the contract of sale or purchase was executed prior to the date of application for exemption pursuant to paragraph (i)(1);

(iii) costs associated with compliance with the New Source Review provisions of Rule 2005, Rule 2012(c), or other applicable state or federal requirements shall not be included;

(iv) costs that result only in improving process efficiency or product quality, costs of projects that were initiated before the date the facility was subject to RECLAIM requirements, or legal costs or any other costs that do not directly reduce NOx emissions shall not be included; and

(v) any cost savings that resulted in implementing any NOx emissions strategy, such as fuel savings, increased production or sale; or

(2) A facility may file an application for Executive Officer approval to be exempted from all or a portion of the requirements pursuant to subparagraph (f)(1)(~~A~~B) for the initial allocations portion of a facility's RTC holdings provided that the facility meets all of the following:

(A) The facility's starting and year 2000 Allocations were calculated using the same emission factors that are equal to or lower than the 2000 (Tier 1) emission factors listed in Table 1;

(B) Emission rate achieved for each source at the facility is less than or equal to the emission factors listed in Table 3 for the corresponding equipment type; and

(C) RTCs for ~~2007~~ 2016 or later compliance years for the facility have never been transferred or sold.

(3) A facility shall submit the applications specified pursuant to paragraphs (i)(1) or (i)(2) no later than ~~July 7, 2005~~ six months after adoption of rule amendment~~ or between January 1 and March 31, 2006~~, pay the appropriate evaluation fee pursuant to Rule 306, and accept enforceable permit conditions to ensure compliance with the provisions of this subdivision, in order for the Executive Officer to approve the exemption. If approved, the facility's initial RTC allocation shall be designated as

non-tradable and additional RTCs purchased above the initial allocation shall be subject to the RTC adjustments specified in subparagraph (f)(1)(~~A~~B), as appropriate. The Executive Officer shall deny an application that is not filed within the time periods specified in this paragraph, lacks any information specified under paragraph (i)(7), or fails to demonstrate that it meets the requirements in paragraphs (i)(1) or (i)(2).

(4) Upon approval the exemption shall:

(A) be limited to the adjustment factors specified in subparagraph (f)(1)(~~A~~B);

(B) begin the next compliance year following the exemption approval; and

(C) not apply to reductions resulting from future periodic BARCT review.

(5) RTC adjustments exempted pursuant to this subdivision shall be distributed proportionally among the remainder of the RTC holders and implemented two years from the compliance year of the applicable exemption and are subject to applicable paragraph (f)(1) provisions. Public notification of the distributed reductions shall occur at least one year prior to implementation.

(6) A Facility Permit holder has the right to appeal the denial of the exemption application to the Hearing Board in the same manner as a permit denial as specified in Health and Safety Code Section 42302.

(7) An application submitted to request an exemption from the RTCs reduction pursuant to paragraphs (i)(1) or (i)(2) shall include the following information.

(A) Detailed description of each project and itemized listing of how it relates to meeting the RECLAIM reduction requirements;

(B) Date of start and completion of each project listed in (A);

(C) Detailed calculations or emissions data demonstrating NOx emission reductions resulting from each project or combination of projects directly resulting in reductions. The emission levels achieved shall be based on actual CEMS data or source tests results;

(D) Itemized revenue and expenditures for each RTC trading activity since participation in the RECLAIM program;

(E) Itemized costs for each project and corresponding receipts or other equivalent documentation as approved by the Executive Officer for such expenditures; and

(F) Cost savings resulting from each project(s) (e.g. fuel savings, improved productivity, increased sales, etc.) and documentation of the values of such savings.

(8) A facility qualifying for exemption shall report as part of its Annual Permit Emission Program (APEP) report, submitted pursuant to Rule 2004(b)(4), whether or not emissions from equipment listed in Tables 3 and 6, if any, remain less than or equal to 1 percent of the total facility emissions on an annual basis for the duration of the exemption. If the emissions exceed 1 percent, the facility shall be in violation of the rule for each and every day of the compliance year and the Executive Officer shall reduce the facility's initial allocation for the next compliance year to the emissions level specified for that year pursuant to subparagraph (f)(1)(~~A~~B).

(9) A facility applying for exemption shall have 1 percent of its initial allocations subject to the requirements pursuant to subparagraph (f)(1)(~~A~~B).

(10) Non-tradable RTC allocations designated pursuant to paragraph (i)(3) shall become tradable in the event the facility permanently ceases to operate.

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

* 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 *
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

* 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 *
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

** 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 *
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
** 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.

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 ppmv 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/mmscft)
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 Paragraph (f)(1)

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 2021 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	2 ppm
Sodium Silicate Furnace	80% reduction (1.28 lb/ton glass pulled)
SRU/Tail Gas Unit	95% reduction 2ppm

APPENDIX B

PROPOSED AMENDED RULE 2011 APPENDIX A – PROTOCOL FOR MONITORING, REPORTING, AND RECORDKEEPING OXIDES OF SULFUR (SOX) EMISSIONS (ATTACHMENT C – QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES)

RULE 2011 PROTOCOL - ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

TABLE OF CONTENTS

ATTACHMENT C - QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. QUALITY CONTROL PROGRAM

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

Explain how each component of the CEMS shall be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that shall be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However, facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the SOx protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be given is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments during each day in which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, during each day that emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Test, record, and compute the calibration error of each SO_2 pollutant concentration monitor, fuel gas sulfur content monitor, if applicable, and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Chapter 2, Subdivision B, Paragraph 1, Subparagraph a, Clause ii of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration or the fuel gas sulfur content has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration or the fuel gas sulfur content has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales.

i. Design Requirements for Calibration Error Testing of SO_x Concentration Monitors, the Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Design and equip each SO_x concentration monitor, fuel gas sulfur content monitor, and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor, fuel gas sulfur content and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for SO_x Concentration Monitors, Fuel Gas Sulfur Content Monitors, and O_2 Monitors

Measure the calibration error of each SO_2 concentration analyzer, fuel gas sulfur analyzer, and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials (CRM), or shall be certified according to "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking on all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the SO_X concentration monitors, the fuel gas sulfur content monitors, and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = Percentage calibration error based on the span range

R = Reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = Actual monitoring system response to the calibration gas.

S = Span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation:

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Chapter 2, Subdivision B, Paragraph 1, Subparagraph c of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the SOx monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an SO_2 concentration monitor or a fuel gas sulfur content monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, dscfh, and percent volume. Program monitors that automatically adjust data to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the SO_X pollutant concentration monitor, flow monitoring system, and SOx emission rate measurement system is 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are disconnected and flanges are placed at both ends of the disconnected lines, and

ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

For any hour that fuel flow records are not available to verify no fuel flow, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, SOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that only operates under a California Independent System Operator (Cal ISO) contract may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows the semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment is due but the assessment was not completed due to lack of adequate operational time, and a CGA is conducted and passed within the calendar quarter when the assessment is due.

~~a.~~e. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each $S0_2$ pollutant concentration monitor, fuel gas sulfur content monitor, stack gas volumetric flow rate measurement systems, and the $S0_2$ mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, and 12 and Attachment B of the Protocol for ~~Proposed~~ Rule 2011. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Chapter 2, Subdivision B, Paragraphs 10, 11, and 12 and Attachment B (bias test) of the ~~Draft~~ Protocol for ~~Proposed~~ Rule 2011.

~~b.~~f. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an SO_2 pollutant concentration monitor, a fuel gas sulfur content monitor, or the $S0_2$ emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

~~c.~~g. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

d.h. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.ae.; and

III. conducted an alterative alternative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.dh.iii.

If any of the requirements under Subclauses B.2.dh.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2011, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than 240 cumulative operating hours and no more than 72 consecutive hours-; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

APPENDIX C

PROPOSED AMENDED RULE 2012 APPENDIX A – PROTOCOL FOR MONITORING, REPORTING, AND RECORDKEEPING OXIDES OF NITROGEN (NOX) EMISSIONS (ATTACHMENT C – QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES)

RULE 2012 PROTOCOL - ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

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ATTACHMENT C - QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

ATTACHMENT C

QUALITY ASSURANCE AND QUALITY CONTROL PROCEDURES

A. Quality Control Program

Develop and implement a quality control program for the continuous emission monitoring systems and their components. As a minimum, include in each quality control program a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities:

1. Calibration Error Test Procedures

   Identify calibration error test procedures specific to the CEMS that may require variance from the procedures used during certification (for example, how the gases are to be injected, adjustments of flow rates and pressures, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error, determination of interferences, and when calibration adjustments should be made).

2. Calibration and Linearity Adjustments

   Explain how each component of the CEMS will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each CEMS.

3. Preventative Maintenance

   Keep a written record of procedures, necessary to maintain the CEMS in proper operating condition and a schedule for those procedures.

4. Audit Procedures

   Keep copies of written reports received from testing firms/laboratories of procedures and details specific to the installed CEMS that were to be used by the testing firms/laboratories for relative accuracy test audits, such as sampling and analysis methods. The testing firms/laboratories shall have received approval from the District by going through the District's laboratory approval program.

5. Record Keeping Procedures

Keep a written record describing procedures that will be used to implement the record keeping and reporting requirements.

Specific provisions of Section A-3 and A-5 above of the quality control programs shall constitute specific guidelines for facility personnel. However facilities shall be required to take reasonable steps to monitor and assure implementation of such specific guidelines. Such reasonable steps may include periodic audits, issuance of periodic reminders, implementing training classes, discipline of employees as necessary, and other appropriate measures. Steps that a facility commits to take to monitor and assure implementation of the specific guidelines shall be set forth in the written plan and shall be the only elements of Section A-3 and A-5 that constitute enforceable requirements under the written plan, unless other program provisions are independently enforceable pursuant to other requirements of the NO_x protocols or District or federal rules or regulations.

B. FREQUENCY OF TESTING

There are three situations which will result in an out-of-control period. These include failure of a calibration error test, failure of a relative accuracy test audit, and failure of a BIAS test, and are detailed in this subdivision. Data collected by a CEMS during an out-of-control period shall not be considered valid.

The frequency at which each quality assurance test must be performed is as follows:

1. Periodic Assessments

For each monitor or CEMS, perform the following assessments on each day during which the unit combusts any fuel or processes any material (hereafter referred to as a "unit operating day"), or for a monitor or a CEMS on a bypass stack/duct, on each day during which emissions pass through the bypass stack or duct. These requirements are effective as of the date when the monitor or CEMS completes certification testing.

a. Calibration Error Testing Requirements for Pollutant Concentration Monitors and O_2 Monitors

Test, record, and compute the calibration error of each NO_x pollutant concentration monitor and O_2 monitor at least once on each unit operating day, or for monitors or monitoring systems on bypass stacks/ducts on each day that emissions pass through the bypass stack or duct. Conduct calibration error checks, to the extent practicable, approximately 24 hours apart. Perform the daily calibration error test according to the procedure in Paragraph B.1.a.ii. of this Attachment.

For units with more than one span range, perform the daily calibration error test on each scale that has been used since the last calibration error test. For example, if the emissions concentration has not exceeded the low-scale span range since the previous calendar day, the calibration error test may be performed on the low-scale only. If, however, the emissions concentration has exceeded the low-scale span range since the previous calibration error test, perform the calibration error test on both the low- and high-scales

i. Design Requirements for Calibration Error Testing of NO_x Concentration Monitors and O_2 Monitors

Design and equip each NO_x concentration monitor and O_2 monitor with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. For extractive and dilution type monitors, all monitoring components exposed to the sample gas, (for example, sample lines, filters, scrubbers, conditioners, and as much of the probe as practical) are included in the measurement system. For in situ type monitors, the calibration must check against the injected gas for the performance of all electronic and optical components (for example, transmitter, receiver, analyzer).

Design and equip each pollutant concentration monitor and O_2 monitor to allow daily determinations of calibration error (positive or negative) at the zero-level (0 to 20 percent of each span range) and high-level (80 to 100 percent of each span range) concentrations.

ii. Calibration Error Test for NO_x Concentration Monitors and O_2 Monitors

Measure the calibration error of each NO_x concentration analyzer and O_2 monitor once each day according to the following procedures:

If any manual or automatic adjustments to the monitor settings are made, conduct the calibration error test in a way that the magnitude of the adjustments can be determined and recorded.

Perform calibration error tests at two concentrations: (1) zero-level and (2) high level. Zero level is 0 to 20 percent of each span range, and high level is 80 to 100 percent of each span range. All calibration gases used during certification tests and quality assurance and quality control activities shall be NIST/EPA approved standard reference materials (SRM), certified reference materials CRM), or shall be certified according to “EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,” September 1997, EPA 600/R-97/121 or any subsequent version published by EPA.

Introduce the calibration gas at the gas injection port as specified above. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as practical. For in situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the NO_x concentration monitors and the O_2 monitors once with each gas. Record the monitor response from the data acquisition and handling system. Use the following equation to determine the calibration error at each concentration once each day:

$$CE = \frac{|R-A|}{S} \times 100 \qquad \text{(Eq. C-1)}$$

Where:

CE = The percentage calibration error based on the span range

R = The reference value of zero- or high-level calibration gas introduced into the monitoring system.

A = The actual monitoring system response to the calibration gas.

S = The span range of the instrument

b. Calibration Error Testing Requirements for Stack Flow Monitors

Test, compute, and record the calibration error of each stack flow monitor at least once within every 14 calendar day period during which at anytime emissions flow through the stack; or for monitors or monitoring systems on bypass stacks or ducts, at least once within every 14 calendar day period during which at anytime emissions flow through the bypass stack or duct. Introduce a zero reference value to the transducer or transmitter. Record flow monitor output from the data acquisition and handling systems before and after any adjustments. Calculate the calibration error using the following equation :

$$CE = \frac{|R - A|}{S} \times 100 \qquad \text{(Eq. C-2)}$$

Where:

CE = Percentage calibration error based on the span range

R = Zero reference value introduced into the. transducer or transmitter.

A = Actual monitoring system response.

S = Span range of the flow monitor.

c. Interference Check for Stack Flow Monitors

Perform the daily flow monitor interference checks specified in Paragraph B.1.c.i. of this Attachment at least once per operating day (when the unit(s) operate for any part of the day).

i. Design Requirements for Flow Monitor Interference Checks

Design and equip each flow monitor with a means to ensure that the moisture expected to occur at the monitoring location does not interfere with the proper functioning of the flow monitoring system. Design and equip each flow monitor with a means to detect, on at least a daily basis, pluggage of each sample line and sensing port, and malfunction of each resistance temperature detector (RTD), transceiver, or equivalent.

Design and equip each differential pressure flow monitor to provide (1) an automatic, periodic backpurging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the probe and lines sufficiently free of obstructions on at least a daily basis to prevent sensing interference, and (2) a means to detecting leaks in the system at least on a quarterly basis (a manual check is acceptable).

Design and equip each thermal flow monitor with a means to ensure on at least a daily basis that the probe remains sufficiently clean to prevent velocity sensing interference.

Design and equip each ultrasonic flow monitor with a means to ensure on at least a daily basis that the transceivers remain sufficiently clean (for example, backpurging the system) to prevent velocity sensing interference.

d. Recalibration

Adjust the calibration, at a minimum, whenever the calibration error exceeds the limits of the applicable performance specification for the NO_x monitor, O_2 monitor or stack flow monitor to meet such specifications. Repeat the calibration error test procedure following the adjustment or repair to demonstrate that the corrective actions were effective. Document the adjustments made.

e. Out-of-Control Period – Calibration Test

An out-of-control period occurs when the calibration error of an NO_x concentration monitor exceeds 5.0 percent based upon the span range value, when the calibration error of an O_2 monitor exceeds 1.0 percent O_2, or when the calibration error of a flow monitor exceeds 6.0 percent based upon the span range value, which is twice the applicable specification. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if 2 or more valid readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5.

An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour of completion of an interference check that is passed.

f. Data Recording

Record and tabulate all calibration error test data according to the month, day, clock-hour, and magnitude in ppm, DSCFH, and percent volume. Program monitors that automatically adjust data to the calibrated corrected calibration values (for example, microprocessor control) to record either: (1) the unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment. Record the following applicable flow monitor interference check data: (1) sample line/sensing port pluggage, and (2) malfunction of each RTD, transceiver, or equivalent.

2. Semi-annual Assessments

a. For each CEMS, perform the following assessments once semi-annually thereafter, as specified below for the type of test. These semi-annual assessments shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested for certification purposes (initial and recertification) or within three months of the end of the calendar quarter in which the District sent notice of a provisional approval for a CEMS, whichever is later. Thereafter, the semi-annual tests shall be completed within six months of the end of the calendar quarter in which the CEMS was last tested. For CEMS on bypass stacks/ducts, the assessments shall be performed once every two successive operating quarters in which the bypass stacks/ducts were operated. These tests shall be performed after the calendar quarter in which the CEMS was last tested as part of the CEMS certification, as specified below for the type of test.

Relative accuracy tests may be performed on an annual basis rather than on a semi-annual basis if the relative accuracies during the previous audit for the NO_X pollutant concentration monitor, flow monitoring system, and NOx emission rate measurement system is 7.5 percent or less.

b. For CEMS on any stack or duct through which no emissions have passed in two or more successive quarters, the semi-annual assessments must be performed within 14 unit operating days after emissions pass through the stack/duct.

c. The due date for a semi-annual or annual assessment of a major source may be postponed to within 14 unit operating days from the first re-firing of the major source if the major source is physically incapable of being operated and all of the following are met:

i. All fuel feed lines to the major source are disconnected and flanges are placed at both ends of the disconnected lines, and

ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

For any hour that fuel flow records are not available to verify no fuel flow, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation.

Prior to re-starting operation of the major source, the Facility Permit Holder shall: (1) provide written notification to the District no later than 72 hours prior to starting up the source, (2) start the CEMS no later than 24 hours prior to the start-up of the major source, and (3) conduct and pass a Cylinder Gas Analysis (CGA) prior to the start-up of the major source. The emissions data from the CEMS after the re-start of operations is considered valid only if the Facility Permit Holder passes the CGA test. Otherwise, for a non-passing CGA, the CEMS data is considered invalid until the semi-annual or annual assessment is performed and passed. As such, NOx emissions shall be calculated using the maximum valid hourly emissions from the last 30 days of operation commencing with the hour of start up and continuing through the hour prior to performing and passing the semi-annual or annual assessment.

d. An electrical generating facility that only operates under a California Independent System Operator (Cal ISO) contract may postpone the due date for a semi-annual or annual assessment of a major source to the next calendar quarter provided that the facility shows the semi-annual or annual assessment was scheduled to be performed during the first 45 days of the calendar quarter in which the assessment is due but the assessment was not completed due to lack of adequate operational time, and a CGA is conducted and passed within the calendar quarter when the assessment is due.

~~a.~~e. Relative Accuracy Test Audit

Perform relative accuracy test audits and bias tests semi-annually and no less than 3 months apart for each NO_X pollutant concentration monitor, stack gas volumetric flow rate measurement systems, and the NO_X mass emission rate measurement system in accordance with Chapter 2, Subdivision B, Paragraph 10, Chapter 2, Subdivision B, Paragraph 11, and Chapter 2, Subdivision B, Paragraph 12. The relative accuracy of the pollutant concentration monitor and the mass emission rate measurement system shall be less than or equal to 20.0 percent, and the relative accuracy of the stack gas volumetric flow rate measurement system shall be less than or equal to 15.0 percent. For monitors on bypass stacks/ducts, perform relative accuracy test audits once every two successive bypass operating quarters in accordance with Paragraphs 2.B.10, 2.B.11, and 2.B.12.

~~b.~~f. Out-of-Control Period – Relative Accuracy Test Audit

An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an NO_X pollutant concentration monitor or the NO_X emission rate measurement system exceeds 20.0 percent; (2) the relative accuracy of the flow rate monitor exceeds 15.0 percent; or (3) failure to conduct a relative accuracy test audit by the due date for a semi-annual assessment. The out-of-control period begins with the hour of completion of the failed relative accuracy test audit and ends with the hour of completion of a satisfactory relative accuracy test audit.

~~c.~~g. Out-of-Control Period – BIAS Test

An out-of-control period occurs if all the following conditions are met:

i. Failure of a bias test as specified in Attachment B of this Appendix;

ii. The CEMS is biased low relative to the reference method (i.e. Bias Adjustment Factor (BAF), as determined in Attachment B of this Appendix, is greater than 1); and

iii. The Facility Permit holder does not apply the BAF to the CEMS data.

The out-of-control period begins with the hour of completion of the failed bias test audit and ends with the hour of completion of a satisfactory bias test.

~~d.~~h. Alternative Relative Accuracy Test Audit

i. The Facility Permit holder of a major source, that has received written approval from the Executive Officer as an intermittently operated source, may postpone the due date for a semi-annual assessment to the end of the next calendar quarter if the Facility Permit holder:

I. operated the source no more than 240 cumulative operating hours and no more than 72 consecutive hours during the calendar quarter when a semi-annual assessment is due; and

II. conducted a relative accuracy test audit on the CEMS serving the source during the previous four calendar quarters and meeting the accuracy criteria as set forth under Subparagraph B.2.~~a~~e.; and

III. conducted an alterative relative accuracy test audit on the CEMS serving the source during the calendar quarter when a semi-annual assessment is due and meeting the criteria specified under Clause B.2.~~d~~h.iii

If any of the requirements under Subclauses B.2.~~d~~h.i.I, II and III is not met and the source did not have passing RATA during the calendar quarter when the semi-annual assessment is due, emissions from the source shall be determined pursuant to the Missing Data Procedures as specified under Rule 2012, Appendix A, Chapter 2, Subdivision E after the semi-annual assessment due date until the hour of completion of a satisfactory relative accuracy test audit.

ii. The Facility Permit holder may submit a written request to designate a major source as an intermittently operated source provided the Facility Permit holder demonstrates that:

I. During any calendar quarter within the previous two compliance years, the source was operated no more than 240 cumulative operating hours and no more than 72 consecutive hours ; or

II. During any calendar quarter within the next two compliance years, the source will be operated no more than 240 cumulative operating hours and no more than 72 consecutive hours.

iii. An alternative relative accuracy shall consist of a Cylinder Gas Analysis (CGA) method as defined under 40 CFR, Part 60, Appendix F, combined with a flow accuracy verification. For sources equipped with stack flow monitors, the flow accuracy shall be verified by calibrating the transducers and transmitters installed on the stack flow monitors using procedures under Paragraph B.3 of this attachment. For sources equipped with fuel flow meters and no stack flow monitors, the flow accuracy shall be verified by calibrating the fuel flow meters either in-line or offline in accordance with the procedures outlined in 40CFR Part 75, Appendix D. Passing flow accuracy verification results that were obtained within the past 4 quarters may be used in lieu of performing a flow accuracy verification during the calendar quarter when a semi-annual assessment is due. The calculated accuracy for the analyzer responses for NO_x and O_2 concentration shall be within 15 percent or 1 ppm, whichever is greater, as determined by the CGA method as defined under 40 CFR, Part 60, Appendix F. Successive alternative relative accuracy test audits shall be performed no less than 45 days apart.

3. Calibration of Transducers and Transmitters on Stack Flow Monitors

All transducers and transmitters installed on stack flow monitors must be calibrated every two operating calendar quarters, in which an operating calendar quarter is any calendar quarter during which at anytime emissions flow through the stack. Calibration must be done in accordance with Executive Officer approved calibration procedures that employ materials and equipment that are NIST traceable.

When a calibration produces for a transducer and transmitter a percentage accuracy of greater than ± 1%, the Facility Permit holder shall calibrate the transducer and transmitter every calendar operating quarter until a subsequent calibration which shows a percentage accuracy of less than ± 1% is achieved. An out-of-control period occurs when the percentage accuracy exceeds ±2%. If an out-of-control period occurs, the Facility Permit holder shall take corrective measures to obtain a percentage accuracy of less than ±2% prior to performing the next RATA. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour of completion of following an effective recalibration. Whenever the failed calibration, corrective action, and effective recalibration occur within the same hour, the hour is not out-of-control if two or more valid data readings are obtained during that hour as required by Chapter 2, Subdivision B, Paragraph 5, Subparagraph a.

APPENDIX G

COMMENT LETTERS RECEIVED ON THE NOP/IS AND RESPONSES TO COMMENTS

INTRODUCTION

A Notice of Preparation/Initial Study (NOP/IS) was released for a 57-day public review and comment period from December 5, 2014 to January 30, 2015 which identified the environmental topics of aesthetics; air quality and greenhouse gas emissions; energy; hydrology and water quality; hazards and hazardous materials; solid and hazardous waste; and, transportation and traffic, as potentially being significantly adversely affected by the project. The SCAQMD received eight comment letters regarding the preliminary analysis in the NOP/IS during the public comment period.

The comment letters have been numbered (see Table G-1 below) and individual comments within each letter have been bracketed and numbered. Following each comment letter is SCAQMD staff's responses to the individual comments.

Table G-1
List of Comment Letters Received Relative to the NOP/IS

Comment Letter	Commentator
#1	Baker Commodities
#2	Air Products
#3	CalPortland
#4	Los Angeles Department of Water and Power (LADWP)
#5	Charles F. Timms, Jr. on behalf of City of Burbank Department of Water and Power
#6	California Council for Environmental and Economic Balance (CCEEB) et al
#7	Paramount Petroleum
#8	Public Solar Power Coalition

Comment Letter #1

January 29, 2015

South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765
Attn: Barbara Radlein

Re: Comments on "Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)"

Ms. Radlein:

SCAQMD has recognized that a small percentage of facilities are responsible for a majority of NOx emissions in the South Coast air basin. These high-producing NOx facilities, owned by major corporations and utility companies, have the resources available to invest in the technologies outlined in the BARCT analysis and achieve substantial reductions in their NOx emissions. However, SCAQMD is proposing a shave of nearly half of all RECLAIM Trading Credits (RTCs) from both large and small facilities alike. Baker Commodities ("Baker") does not feel that small companies such as ours should be punished for the emissions of a select few large facilities. 1-1

Baker is not a major source of NOx amongst RECLAIM facilities, cannot achieve significant emission reductions by implementing any control technology, and does not have the resources available to invest in them. Moreover, at current RTC prices, purchasing additional RTCs to make up for a reduced allocation will place an equally onerous burden on Baker's operations. 1-2

The proposed RTC shave translates to a reduction of .015 potential tons of NOx per day for Baker's facility. If Baker were to invest in control technology, such as selective catalytic reduction (costing upwards of $1 million), we are likely to see an actual reduction of approximately .012 tons of NOx per day. In such scenario, Baker is looking at a figure that amounts to less than 0.5% of SCAQMD's 5 tons per day reduction target, per CMB-01. With the currently proposed amendments to Rule 2002 targeting a reduction greater than 5 tons per day, investment by Baker in such technology seems immaterial and like a poor return on the investment. 1-3

Baker requests that only those facilities that are significant contributors of NOx and have the potential for major reductions in their emissions, such as the top emitters that are the focus of the BARCT analysis, be subject to the currently proposed NOx RTC shave. 1-4

Sincerely,

Chris Hassler
Environmental Compliance Specialist, Baker Commodities

RESPONSES TO COMMENT LETTER #1
(Baker Commodities - January 29, 2015)

1-1 This comment points out that a small percentage of facilities are responsible for a majority of NOx emissions in the SCAB and these facilities have the resources to invest in the technologies outlined in the BARCT analysis in order to achieve NOx reductions. This comment also claims that a proposed shave of nearly half of all RTCs from both large and small facilities, would disproportionately punish small facilities, including the commentator's facility.

SCAQMD staff conducted a BARCT assessment of the NOx RECLAIM program which resulted in adjusting BARCT levels for both equipment and source categories in the refinery and non-refinery sectors. For the refinery sector, a new level of BARCT is proposed for FCCUs, refinery boilers/heaters rated greater than 40 mmBTU/hr, refinery gas turbines, coke calciners, and SRU/TGUs. For the non-refinery sector, a new BARCT level is proposed for container glass melting furnaces, cement kilns, sodium silicate furnaces, metal melting furnaces rated greater than 150 mmBTU/hr, gas turbines and ICEs not located on the outer continental shelf (OCS). No new BARCT is proposed for power plants. Overall, a total of 14 tpd of NOx RTC reductions from the current RTC holdings of 26.5 tpd is proposed. For the 275 facilities that are in the NOx RECLAIM program, the 14 tpd of NOx RTC reductions will only affect 65 facilities plus the investors that, together, hold 90 percent of the NOx RTC holdings. Investors are included in the refinery sector and treated as one facility. For the remaining 210 facilities that hold 10 percent of the 26.5 tpd of the NOx RTCs, no NOx RTC shave is proposed because no new BARCT was identified for the types of equipment and source categories at these facilities.

Tables 7 and 8 in PAR 2002 list the facilities that would have RTC adjustments. The commentor's facility is not included in either of these tables. This facility is included in the facilities for which there is not a proposed shave.

1-2 The commentator states that their facility is not a major source of NOx emissions among RECLAIM facilities, cannot achieve significant emission reductions by implementing any control technology, and does not have the resources to invest in control technology. This comment claims that the cost of purchasing RTCs will place an onerous burden on the commentator's facility operations.

This facility is considered a major source of NOx emissions because it is a Title V facility with NOx emissions that have ranged over the last decade from 7 to 13 tons per year. The commentator's facility is not included in the categories of facilities that have a proposed RTC reduction, see Tables 6 and 7 in PAR 2002. See also Response 1-1.

1-3 This comment claims that the proposed shave represents 0.015 tons per day NOx RTC reductions for the commentator's facility and if control technology such as SCR were installed at a cost of $1 million, the actual NOx emission reductions would be 0.012 tons per day which amounts to less than 0.5 percent of SCAQMD's NOx emission reduction goal of five tons per day.

The commentator's facility is not included in the categories of facilities that have a proposed RTC reduction, see Tables 7 and 8 in PAR 2002. See also Response 1-1.

1-4 This comment requests that only significant contributors of NOx (e.g., top emitters) with the potential to achieve major reductions in NOx emissions should be subject to the NOx RTC shave.

This comment is a summary of the concerns expressed in Comments 1-1 through 1-3. See Responses 1-1 through 1-3.

Comment Letter #2

AIR PRODUCTS

Air Products and Chemicals, Inc.
23300 S. Alameda Street
Carson, CA 90810
Telephone (310) 847-7300

30 January 2015

Attn: Barbara Radlein
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Subject: Air Products and Chemicals, Inc. – Comments on Proposed NOx RECLAIM Shave Approach

Dear Ms. Radlein:

On behalf of Air Products and Chemicals, Inc. (Air Products) we appreciate the opportunity to comment on the approach that should be utilized for conducting a NOx RECLAIM shave. Air Products operates two (2) "new" RECLAIM facilities: Carson Hydrogen Plant (Facility ID 3417) and Wilmington Hydrogen Plant (Facility ID 101656). Both facilities' primary RECLAIM equipment are major source reforming furnaces (>750 MMBTU/hr) and both utilize selective catalytic reduction (SCR) for NOx control. 2-1

Our primary concern is regarding our Carson Hydrogen Plant where we had purchased two (2) infinite block streams of RECLAIM Trading Credits (RTCs) well before the 2005 NOx RECLAIM shave. These infinite block streams were acquired to cover facility NOx emissions (reforming furnace is only RECLAIM source at Carson) based on an initial, permitted BACT NOx limit of 5 ppmv @3% O2 (3-hr average). Our understanding, based on any recent/similar permitting projects, is that this level of NOx is still considered BACT at this time for hydrogen reforming furnaces. 2-2

Upon review of District staff draft report "Proposed Amendments to Regulation XX – Regional Clean Air Incentives Market (RECLAIM)" (December 2004), it does not appear either of Air Products reforming furnaces, as non-refinery heaters >750 MMBTU/hr and not subject to Rule 1146, were evaluated for BARCT. Nonetheless, Carson Hydrogen Plant, like all of the RECLAIM facilities, was subjected to the ~20% across-the-board shave; however, the facility has since been able to continue to cover NOx emissions using the reduced infinite block streams through increased SCR ammonia injection and more frequent SCR catalyst change-outs. 2-3

Fast forward to the currently proposed across-the-board shave of ~50% and it appears that still neither of Air Products reforming furnaces was evaluated for BARCT. Based on the cumulative effect (~60%) of the 2005 reduction (~20%) and currently proposed reduction (~50%), the District is essentially forcing the Carson Hydrogen Plant, as a source where no BARCT limit has been identified and no more stringent BACT limit exists, to either operate at ≤2 ppmv NOx levels (which would likely not be possible without significant and expensive SCR equipment modifications due to current system limitations and/or taking into account NH3 slip limit) or purchase RTCs on the market whose cost, as an infinite block stream, could easily exceed $1 million. 2-4

-2-

We feel that the most fair and equitable manner is to apply the shave such that it is only impacting facilities where actual reductions have been identified through new 2014 BARCT limits. By applying the shave across the board there can be, as described above for example, significant financial impacts to sites and sources that were not evaluated and may already be operating at levels considered as current BACT. While Air Products appreciates the complexity of doing something other than an across the board shave in a free trade market such as RECLAIM; we feel that the District has a responsibility to look closer at possible methods that could exempt sources from a shave where no reductions have been evaluated and identified; such as:

- Segregating all RTCs into two different types that can be used to cover sources/facility emissions; one type where a 2014 BARCT limit has been identified and one type where a 2014 BARCT limit has not been identified.
- An option to "lock-in" current infinite block stream(s) a facility holds (as of some previous date) for life or until any future RECLAIM shave may occur with an applicable BARCT limit for that facility.

2-5

Please feel free to contact me at (310) 847-7300 or by email at reebeljc@airproducts.com if you have any questions or would like to discuss further. Thank you.

Sincerely,

Jim Reebel
Principal Environmental Engineer

cc: Chris McWilliams, So Cal Plant Manager
Brent Walker, Area Business Manager
Brian Keck, Environmental Manager

File: CA/Carson/AQMD Correspondence

RESPONSES TO COMMENT LETTER #2
(Air Products and Chemicals, Inc. - January 30, 2015)

2-1 This comment introduces the commentator's facilities and identifies the primary equipment sources of NOx RECLAIM emissions. No response is necessary.

2-2 This comment inquires as to whether BACT for a hydrogen reforming furnace is going to remain at five ppmv NOx at 3% O_2 because the commentator's facility had previously acquired two infinite block streams of NOx RTCs prior to the 2005 NOx RECLAIM shave to cover emissions from this type of equipment.

SCAQMD staff did not propose a new BARCT for reforming furnaces. SCAQMD staff conducted a BARCT analysis for several source categories among the top emitting facilities for compliance year 2011. The analysis demonstrated that SCR is the preeminent technology for achieving NOx emission levels at two ppm at 3% O_2 for combustion sources. As part of the BARCT analysis, some equipment, such as boilers and engines, were also evaluated for those facilities outside the range of the top emitting facilities. While the process is referred to as hydrogen reforming, the equipment is considered a heater/furnace with a heat rating greater than 50 MMBTU/hr. This is not different from a large boiler/heater or a refinery boiler and heater that would be subject to 2ppm BARCT. While there were many refinery boilers and heaters that were analyzed do have cost-effective BARCT, the analysis of reforming furnaces was based on the vast majority of the boilers and heaters in the non-refinery sector and determined to be not cost effective. Thus, SCAQMD staff did not propose a new BARCT for reforming furnaces.

2-3 This comment states that the staff report for the 2005 NOx RECLAIM amendments did not conduct a BARCT evaluation of reforming furnaces or non-refinery heaters rated greater than 750 MMBTU/hr and not subject to Rule 1146. This comment also states that in response to the 20 percent shave applicable to all NOx RECLAIM facilities as part of the 2005 NOx RECLAIM amendments, the commentator's facility, in response to that shave, increased ammonia injection into the SCR and implemented more frequent SCR catalyst change outs in addition to applying the purchased infinite block streams to cover the emissions.

For any gaseous fueled heater that is rated above five MMBTU/hr and is operated at a facility that is not subject to the RECLAIM program, the requirements in Rule 1146 would apply. Thus, contrary to the comment, RECLAIM heaters were subject to BARCT as part of the 2005 NOx RECLAIM amendments. Since the shave for that rule amendment was an across the board approach, all facilities in NOx RECLAIM had their RTCs reduced.

2-4 This comment claims that the current proposal of a 50 percent shave also does not include a BARCT evaluation of reforming furnaces. This comment states that the cumulative effect of the 2005 NOx shave, when combined with the current proposed 50 percent shave, will have an overall effect of reducing RTCs at the commentator's facility by 60 percent. The comment also claims that the commentator's facility will either need to operate at less than or equal to two ppmv NOx levels by making expensive modifications to existing SCR equipment or by purchasing over $1 million of RTCs.

As explained in Response 2-2, SCAQMD staff did not propose a new BARCT for reforming furnaces. The commentator is correct that no BARCT analysis was conducted for reforming furnaces. The staff proposal does not shave offsets at the commentator's facility; the emission reduction calculations and associated costs are not germane to the current staff proposal. The current staff proposal, in addition to relying on a BARCT analysis, also proposes to shave excess RTCs in the market since unused RTCS can be used to emit at levels exceeding BARCT.

2-5 This comment suggests that the shave be applied only to facilities where actual reductions have been identified via new 2014 BARCT limits to avoid significant financial impacts to sites and sources that were not evaluated and that may already be operating at current BACT levels. This comment suggests exempting sources/facilities from the RTC shave if no 2014 BARCT limit has been identified. This comment also suggests that the proposed amendments include a provision that would segregate RTCs into two categories – one for equipment with BARCT and one without or allow an option to "lock in" current infinite block streams that a facility holds, until such time that a future BARCT limit would apply specifically to that facility's equipment.

Certain facilities are included in the shave even though there may be no new 2014 BARCT because they hold large amounts of RTCs that are not needed. See also Response 2-4 regarding the proposed RTC shave. CEQA alternatives which would have an across the board reduction have been included due to comments from some industry representatives. However, the staff proposal has the reductions described in previous responses.

Regarding the suggestion to have different classifications for RTCs, doing so would introduce significant complexity to the program and create uncertainties in the market, which staff does not support.

Comment Letter #3

CALPORTLAND

January 30, 2015

South Coast Air Quality Management District
Ms. Barbara Radlein (c/o CEQA)
21865 Copley Drive
Diamond Bar, CA 91765

Sent via E-mail (bradlein@aqmd.gov)

RE: California Portland Cement Company
695 S. Rancho Ave., Colton
Facility ID#800181

Dear Ms. Radlein:

CalPortland is submitting the attached comments for the proposed amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM). If you have any questions, please contact Jay Grady at (626) 852-6262 or jgrady@calportland.com.

Sincerely,

Jay M. Grady
Director, Environmental Affairs

Cc: Kevin Orellana (korellana@aqmd.gov)

CalPortland Company 2025 E. Financial Way Glendora, CA 91741
626.852.6200
www.calportland.com

Comments on Initial Study for: Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM) December 2014, and the Following Support Documents: ETS Inc.'s NOx RECLAIM BARCT Independent Evaluation of Cost Analysis Performed by SCAQMD Staff for BARCT in the Non-refinery Sector dated November 26, 2014.

January 30, 2015

COMMENTS PREPARED FOR: CalPortland Company for Submittal to SCAQMD

COMMENTS PREPARED BY: Schreiber, Yonley & Associates

Table of Contents

1.0 Summary of Key Comments

After a thorough review of the Draft Program Environmental Assessment (PEA) for the proposed amendments to SCAQMD Regulation XX, Regional Clean Air Incentives Market (RECLAIM) dated December 2014, and related support documents by ETS, Inc., CalPortland and its consultants Schreiber, Yonley & Associates have identified significant problems with the documents and the process utilized to develop the control options in those documents and the associated emissions reductions contained in these documents. The following comments address these deficiencies:

1.1 The Administrative Process was Flawed

During the public meetings and throughout the rulemaking process, CalPortland Company (CalPortland) and their technical consultants were given no opportunities to provide critical process details to either the SCAQMD, its contractors, or the vendors providing proposed control technology options, cost quotations for the proposed controls, or proposed control efficiencies for those control options. Furthermore, although CalPortland began requesting the detailed cost spreadsheets from which the Cost Effectiveness Table for cement kilns was derived as early as July 2014, none of this information was made available to CalPortland until late in the day on January 23, 2015. That information contained only very general spreadsheets (which leave many questions and concerns unanswered). Further, Confidential Appendices A of the ETS, Inc. Final Report, dated November 26, 2014, was not provided to CalPortland until January 20, 2015, ten days before the comment period ended. CalPortland was told that vendor communications, design details, cost details, warranty information and/or clarification information was confidential. We are at a loss as to how vendor information regarding control strategies would be confidential from the affected facility but this is what they were told by District staff.

The failure to provide critical documents related to the cost estimates and control technology design information during the regulatory development process has essentially denied CalPortland a voice in this regulatory process. Further, CalPortland was treated differently in this regard than other regulated industries. Not only does the withholding of critical information during this process deny CalPortland an opportunity to be heard during the process, but also prevents CalPortland from having the ability to thoroughly evaluate the PAE and the ETS, Inc. review of the cost analysis, it further denies CalPortland the ability to determine if the technical basis/design basis for the controls, the proposed control efficiencies and therefore the basis for the proposed emissions reductions in the proposed amendments to the regulation. Essentially, the flawed process prevents CalPortland from making fully informed comments on the proposed amendments.

1.2 Inconsistencies Exist Between the PEA and Cost Analysis Control Options

The three control technology options listed in the PEA are not consistent with the control technologies listed and evaluated in the Cost Analysis and the ETS evaluation of the cost analysis.

1.3 There are Significant Technical Concerns with the Control Options in the Cost Analysis

The characteristics of the emissions from cement kilns vary from kiln to kiln due to differences in the type of cement kiln, the fuels utilized, and the chemical characteristics of the raw materials. The vast majority of the raw materials utilized by cement kilns are mined onsite and not only vary from site to site, but also may vary within the onsite quarries. These site specific conditions are critical to the design of emissions control equipment. Critical site-specific characteristics include process information that is not included in reports/documents submitted to regulatory agencies. Critical design parameters include not only the average values, but also the minimums and maximums. The failure to allow CalPortland access to the vendor documents jeopardized the validity of the design basis. Further, based upon knowledge of the differences between the CalPortland kilns and the kiln gas characteristics from the limited number of other kilns which have utilized SCR systems, the CalPortland kilns are significantly different. The SCR systems on other kilns operate at significantly higher gas temperatures. Further, when a low temperature catalyst was pilot tested on a cement kiln at similar gas temperature and which also experiences SO_2 spikes similar to CalPortland, the catalyst was poisoned within less than three months. The Ultracat option to our knowledge has not had any long term application on a cement kiln.

Finally, the SO_2 control options proposed to control the SO_2 spikes will have little to no impact on typical SO_2 emissions levels at CalPortland. This is because the average SO_2 emissions from CalPortland are below concentrations where these controls are effective. While there may be control during the SO_2 spikes, either SO_2 control option proposed by the vendors will have a lag time to react to the increased concentrations during emissions spikes, and therefore the catalyst will not be sufficiently protected from SO_2 poisoning.

1.4 Cost Effectiveness Analysis

The estimated costs provided in the cost analysis are impossible to fully evaluate without having the design basis and supporting detailed cost estimation spreadsheets. Nevertheless, the capital and annual costs appear to be too low and it is unclear if they fully address site specific construction conditions, costs for treatment of the wastes generated by the WGS, a realistic frequency for catalyst replacement/reactivation/disposal and other site specific costs. CalPortland acknowledges that even with corrected cost estimates, the cost effectiveness is unlikely to exceed SCAQMD criteria of $50,000 per ton pollutant removed. However, the cost analysis fails to address one way in which CalPortland differs from the majority of the other industry categories impacted by the Proposed Amended Regulation XX. CalPortland will not be able to pass these cost on to customers through increases in the price for cement. The cement industry is highly competitive. The proposed controls would result in an increase of $10 or more per ton of cement. This will not only price CalPortland out of the local market with local competitors that are not subject to SCAQMD RECLAIM program, but for that price difference cement can be imported from Asia at a lower price.

1.5 CalPortland's Emissions Rate

To our knowledge CalPortland's current NO_x emissions limit of 2.73 lb/T clinker (T_c) already represents the lowest emission limitation for long dry cement kilns. Typical long dry kiln emission rates are in the range of 8-12 lb NO_x/T_c, which is represents the uncontrolled emissions rate from the Colton kilns, and the existing limitation is already a 65-77% reduction in NO_x emissions for a typical uncontrolled long dry kiln.

BARCT emissions limits should be essentially the same as BACT. Retrofit controls should not be expected to be more stringent than controls that are designed and integral to a new source. The emissions limit under the New Source Performance Standards for a new cement kiln is 1.5 lb/Tc which was adopted recently by EPA after a very thorough technology review (which included a review of SCR). CalPortland has proposed to add SNCR to the NO_x controls already in place at the plant and believes that an additional reduction in NO_x emissions of 30-40% can be achieved. The result would be an emissions rate in the range of 1.64 -1.91 lb NO_x/T_c. At that emissions rate, it is believed that the emissions from the Colton kilns would be lower than the emissions from the Joppa, IL long dry kiln which utilizes SCR.

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2.0 Introduction

In a cement kiln, raw materials containing the necessary ratios of calcium, alumina, silica and iron are blended, ground to the required fineness in the raw mill and pyroprocessed at very high temperatures (material temperatures of 2700F) at which the materials liquefy and react to form a complex mixture of compounds referred to as clinker. **Note that clinker is not "..lumps of limestone and clay)" as stated in paragraph 5, page 1-16, of the PEA.** The chemistry of the raw materials and fuels and the operation of the kiln are critical to making clinker that will meet cement quality specifications. NO_x emissions are the result of the combustion of the nitrogen found in the fuels and the oxidation of the nitrogen in the combustion air due to the high temperatures in the combustion zone. **Note that the statement found in the PEA, Page 1-17, paragraph 3, ..., 2) oxidation of sulfides (e.g. pyrites) in the raw materials entering the cement kiln." is incorrect. The oxidation of sulfides form SO_2 not NO_x.**

There are several types of cement kilns in operation in the United States today, these are: long wet kilns, long dry kilns (CalPortland's Colton, CA kilns are this type), preheater kilns, and preheater/precalciner kilns. All new kilns built today are preheater/precalciner kilns (PH/PC). PH/PC kilns are more energy efficient, minimize waste (significantly reduce or eliminate the generation of cement kiln dust (CKD) requiring landfilling) and are designed to produce lower pollutant emissions, including GHG, than the earlier kiln designs. Pollutant emissions from cement kilns are directly related to the chemistry of the raw materials utilized. Because the vast majority of these raw materials are mined onsite, typically 85 percent or greater, the emissions from each kiln are site-specific. Therefore, the design of emissions controls must also be site-specific as will be the potential reduction in emissions from those controls.

3.0 Comments on Proposed Control Options

The draft PEA, page 1-17, paragraph 4 lists the 3 potential available control technologies for cement kilns as:

1. SCR with or without a WGS;
2. Ultracat; or
3. SNCR

All of the cost effectiveness documents list and evaluate the following three control options:

1. Vendor 1: SCR system installed between waste heat boiler and baghouse
2. Vendor 2: Dry scrubbing and ceramic filter system installed after the waste heat boiler and replacing the baghouse
3. Wet gas scrubber and SCR system with heat exchanger installed after the waste heat boiler and replacing the baghouse.

Note that the cost effectiveness documents do not include analysis of SNCR nor did the PEA discuss the heat exchanger option with SCR. The remaining comments in this section will focus on the three alternatives evaluated in the cost effectiveness documents first focusing on technical concerns with the proposed technologies and then addressing the cost estimates themselves.

The existing gas flow is as follows: the gas exits the kiln and passes through a series of 4 cyclones and a multiclone then is ducted to a waste heat boiler (WHB). Then the gas is ducted back to the inlet to the baghouse and then exits through the kiln stack. The temperature of the gas entering the waste heat boiler is in the 900 - 1200°F range and the temperature exiting the waste heat boiler is around 350°F. Figure 1 below illustrates the existing gas flow.

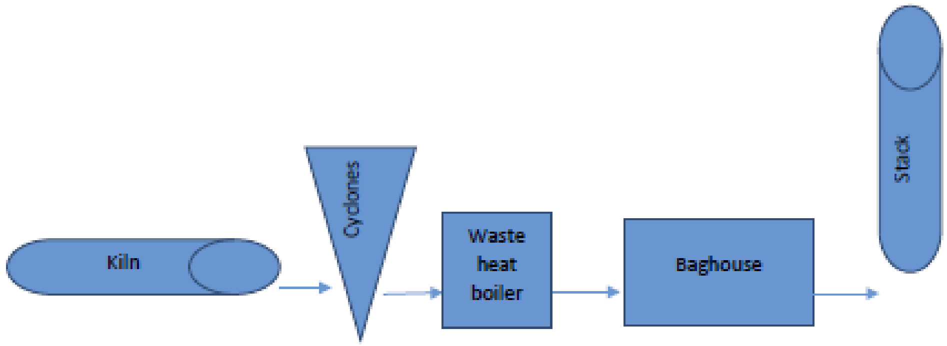

Figure 1: Existing Kiln Gas Flow Diagram

3.1 Vendor 1

Vendor 1 proposed to install a SCR between the waste heat boiler and the baghouse. In reality, the SCR would not physically be located between the waste heat boiler and the baghouse as there is physically no room to install an SCR there on either kiln. Figure 2 is a photograph of the kiln baghouses and stacks and illustrates the physical constraints and physical size of the equipment.

Figure 2: Photo of Kilns and Baghouses

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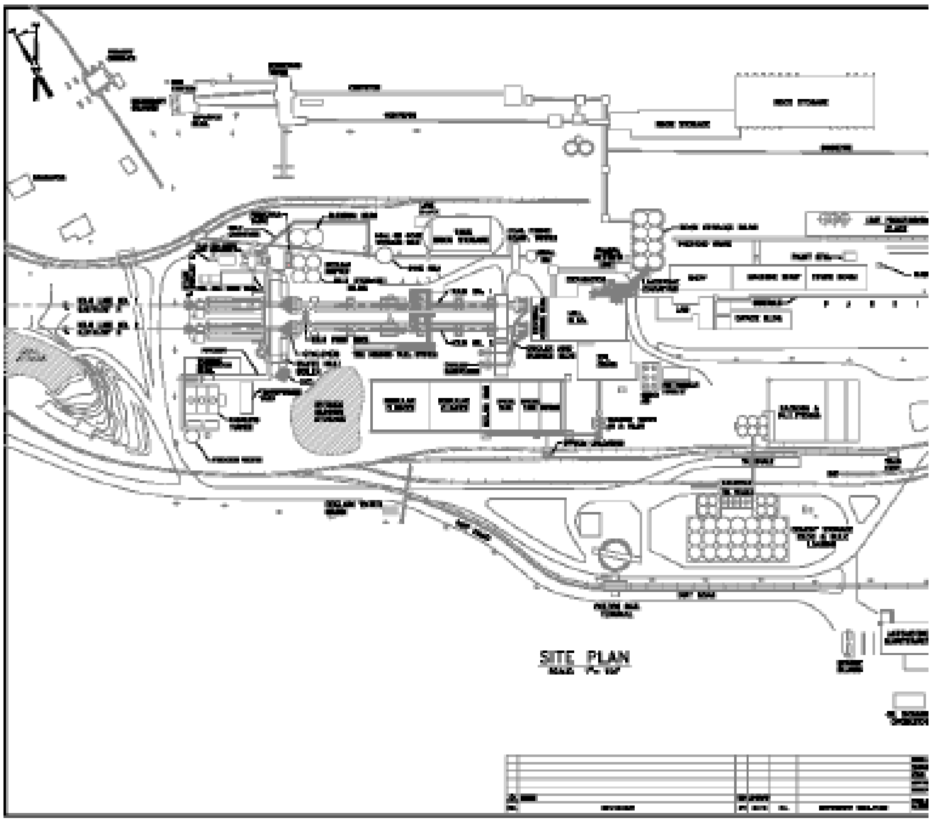

Figure 3: Site Plan

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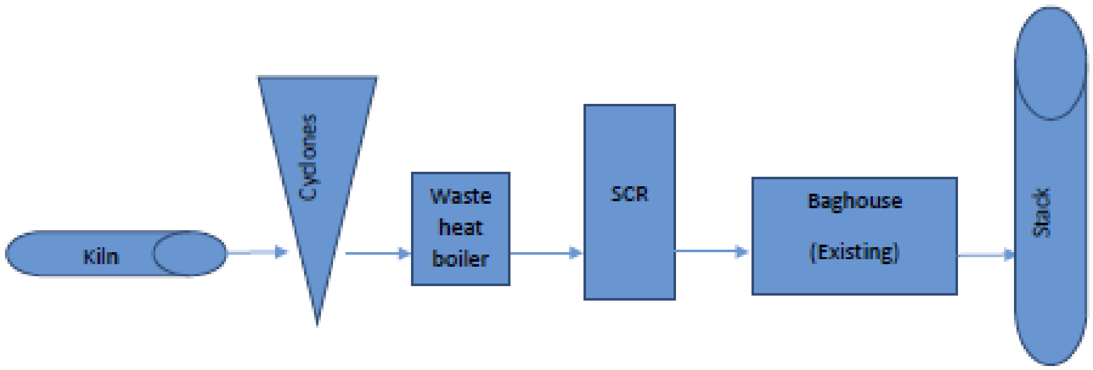

Figure 4: Gas Flow Diagram for Vendor 1 Option

Figure 3 above shows the existing equipment at the site. As is obvious from the site plan and the photo in Figure 2, the SCRs cannot physically be located between the waste heat boilers and the baghouses. The existing coal pile and handling systems are north of the baghouses and cannot be moved due to fugitive emissions constraints as well as proximity to coal unloading and handling equipment. Therefore, the SCRs would need to be located in the area north of the kilns, Co-generation facility or rail lines, requiring the ductwork to go above existing equipment 150-200 feet to the SCR and then back 150 -200 feet to the baghouse inlets. This ductwork would need to be insulated and the SCR and ductwork construction would need to comply with local seismic construction codes. As noted in the initial summary. CalPortland has been denied access to the vendor design basis based on confidentiality of the vendor information and the cost spreadsheets provided on January 23, 2015 do not contain sufficient detail to make a determination. Therefore, it is unknown whether the increased construction costs, potentially 20% or more, to comply with local seismic codes were included in their cost estimates.

ETS noted in their report that there has been conflicting information provided regarding the temperature of the gas returning from the waste heat boilers. Initially 300-350°F, then an indication that it might be 450-500° F and then in October 2014, 350°F. ETS indicated that Vendor 1 indicated that an additional layer of catalyst would be needed at a lower temperature of 450°F. Obviously, since their costs were provided to the SCAQMD prior to that time, and have not been revised by ETS other than to include a 15% contingency, the cost for the SCR both capital and annual would need to be increased to include the costs for installing and operating with an additional catalyst.

It is also unclear whether the current ID fan would be adequate to meet the additional pressure loss across the SCR and the lengthy ductwork to and from the SCR, or whether the cost for replacement ID fan was included in the vendor cost estimate. CalPortland believes a new fan would be necessary. Based upon knowledge of costs for other cement SCR systems, even with the ETC contingency adjustment, Vendor 1's costs appear to be significantly low.

However, the greatest concern with the Vendor 1 proposal is the impact of the gas temperature on the efficiency of the catalyst to control NO_x, and more importantly, the impact of the SO_2 emissions on the catalyst when the SO_2 spikes. The catalyst converts SO_2 to SO_3. . Below 450°F, any ammonia injected for the NO_x reaction will react to form ammonium salts, $(NH_4)_2SO_4$ and NH_4HSO_4 , which poison and plug the catalyst (see chart in Appendix A). This is particularly true for the more reactive catalyst formulations required for lower gas temperature applications. A pilot test with a low temperature catalyst on a cement plant with similar gas temperature and which although SO_2 was typically low, experienced occasional spikes in SO_2 was unsuccessful due to sulfur poisoning. Even with duct burners, as suggested by ETS to address temperature loss between the waste heat boiler and SCR, temperatures would not be expected to be above the 450°F necessary to prevent the formation of ammonium salts and catalyst poisoning. Therefore, regardless of the addition of duct burners, which would generate additional combustion emissions including NO_x, the SCR proposed by Vendor 1 is unlikely to be technically feasible.

3.2 Vendor 2

Vendor 2 proposed to place a dry scrubbing system after the waste heat boiler to address concerns with SO_2 emissions then follow that with a ceramic filter system in place of the existing baghouse. Figure 5 below is a diagram of the gas flow for this scenario.

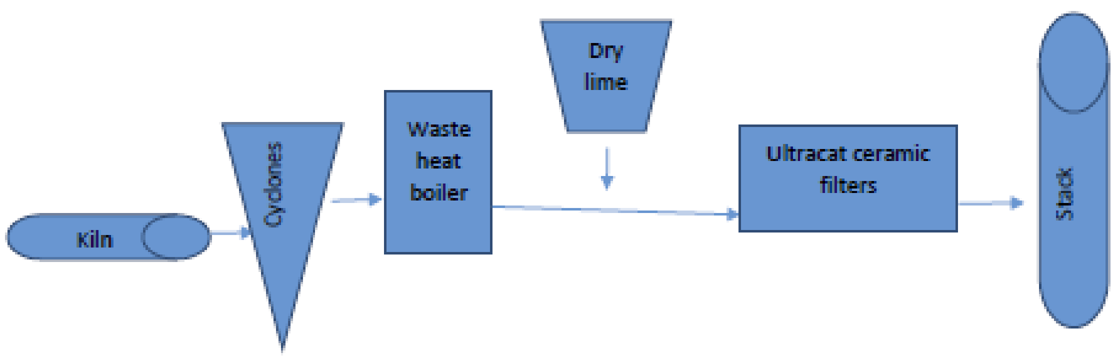

Figure 5: Vendor 2 Proposed Control Gas Flow Diagram

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It is believed that Vendor 2 included the dry scrubbing system to address concern with catalyst poisoning due to the SO_2 concentrations and the gas temperatures. However, there are two technical concerns with this approach. First, the temperature of the gas stream exiting the waste heat boiler is at or near the temperature for the lowest SO_2 reduction efficiency, perhaps 30% control. Second, because of the high dust loading in the gas stream as well as other factors, a CEMS system to monitor the SO_2 concentration prior to the lime injection location, upstream of the ceramic catalyst (Ultracat) system cannot be used because the sample probe cannot endure the conditions in the gas stream (high dust concentration). Therefore, the stack CEMS would be the first indicator of the SO_2 spike and by this point the catalyst would already have some exposure to the increased SO_2 levels. By the time a spike is noted and the control system increases the lime injection rate, some level of catalyst damage would likely have already occurred.

Ultracat's vendor literature, available from the internet, and conversations with the vendor for a different, but similar application, indicate that NO_x control becomes effective at 350°F but does not achieve high (90%) efficiency until gas temperatures above 400°F.

Without access to the vendor's design basis and more details than the spreadsheets provided on January 23, 2015 include, it is not possible to comment on the proposed cost effectiveness calculations other than to express concerns on whether the costs account for construction compliant with seismic codes and the need for a contingency. Given that, to our knowledge, the Ultracat system has not been installed for full scale, long term application at a cement kiln, a contingency of greater than 15% would be warranted. Further, annual costs are somewhat speculative due to unknown life of the ceramic catalyst filter system in a cement application.

The Ultracat ceramic filter system is untried on a full-scale long-term application for a cement kiln. Given the differences in cement plant applications compared to other applications, CalPortland does not believe that it meets the criteria for a demonstrated control technology for this application especially for a definition of a best available "retrofit" technology. Further, although the vendor literature indicates that their product will control particulate emissions to levels that comply with the 40 CFR Part 63, Subpart LLL (the NESHAPS for portland cement manufacturing), CalPortland is unaware of any long-term application of the technology on a cement kiln and cannot verify that it will comply with the new emissions limitations for PM in routine cement application.

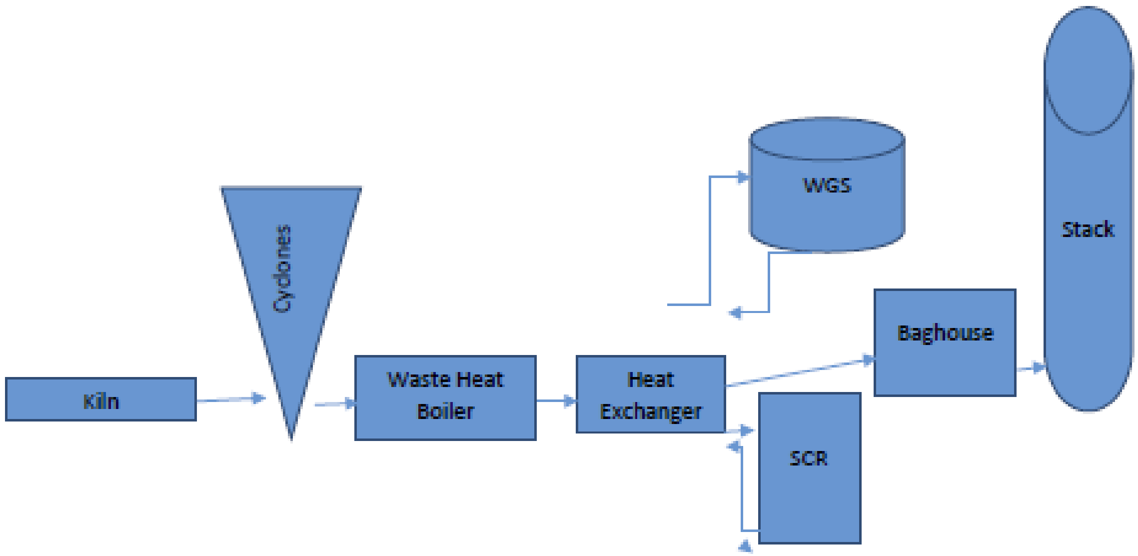

Figure 6: Vendor 3 Proposed Control Gas Flow System

3.3 Vendor 3

Vendor 3 proposes to utilize a wet gas scrubber to address the SO_2 in the gas exiting the waste heat boilers, a heat exchanger to increase the gas temperature for the SCR and then replace the existing baghouse. Figure 6 below illustrates the kiln gas flow through this control system.

The wet gas scrubber is proposed to reduce SO_2 emissions prior to the SCR. However, the typical concentration of SO_2 in the gas stream is between zero and 10 ppm and typically in the 2 ppm range. Discussions with a wet scrubber vendor confirmed that there is a lower limit/concentration that they will guarantee. For a wet lime scrubber, the type currently utilized at the few cement kilns with wet scrubbers, the lower limit for the warranty for the concentration of SO_2 in the scrubber exit gas is 10-12 ppm, a caustic scrubber, as proposed by Vendor 3, might be slightly lower, but still would have no impact on a 2 ppm stream. Therefore, under typical kiln operations the WGS will provide no impact/control of SO_2 because the emissions are below the effectiveness of the technology. Essentially, when a control technology utilizes a reagent which must react with the pollutant in the gas stream, the pollutant molecule and the reagent molecule must come into contact with each other for the reaction to occur. The lower the concentration of the pollutant, the lower the potential for the reaction to occur. Therefore, during typical operations the WGS would be utilizing significant energy, for little to

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no reduction in SO_2. The same issue exists for a CEMS probe for this control options as existed for the Vendor 2 option in the probe in the WGS inlet duct will not survive. Therefore an alternate mechanism for determining the necessary molar concentration for the regent in the scrubber liquid and the reagent addition rate is needed. The vendor contacted indicated that the control system measures the acidity of the scrubber liquid and when it reaches a set point, additional reagent is added. The control loop takes some time to fully address a spike situation. Like the dry reagent/lime addition proposed by Vendor 2, some damage to the SCR catalyst will occur before the system can react to the spike. It is not clear why the vendor specified a caustic scrubber when lime scrubbers are typically utilized for a cement kiln application. Further, the cost spreadsheets do not appear to include the capital costs for a scrubber wastewater treatment system or the costs for the disposal/discharge of the wastewater after treatment.

It is unclear at what temperature the SCR in this control option would operate. There is no discussion of an additional heat source to raise the gas temperature above the temperature at which it exits the waste heat boiler. Therefore it is assumed that the heat exchanger is proposed to maintain that temperature rather than to increase the temperature to the temperature range of the currently operating SCR systems on cement kilns.

Table 1 below lists the gas inlet temperatures for the cement kiln SCR applications. This information was taken either from the vendor website for a particular plant, or from papers presented by either the vendor or owner of the cement plant.

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Location	Operating Temperature (°F)
Solnhofen, Germany	572-608
Monselice, Italy	608-626
Sarche, Italy	666-750
Mergelstetten, Germany	716-750
Rohrdorf, Germany	550-660
Mannersdorf, Austria	570-660
Joppa, Illinois	572
Rezzato, Italy	590-626

Table 1: Operating Temperatures of Existing Cement Kiln SCRs

It is important to note that, whether the SCR is low-dust, semi-dust or high-dust application, the gas inlet temperature to the SCR is between 550°F and 750°F. Only one of these applications reheats the gas stream, and in that instance there are no waste heat boilers utilizing the available waste heat from the process to minimize/eliminate the combustion of additional fuels which would generate combustion emissions.

ETS, in their review indicate that they corresponded with USEPA regarding the SCR on the Joppa, IL cement kiln. The plant has not yet completed their written report on the SCR, but USEPA reported that 70-80% NOx reductions were being achieved. Although the Joppa kiln is also a long dry kiln, it is not equipped with waste heat boilers. In addition, the hot kiln gases are routed through a hot ESP which significantly reduces the dust-loading prior to the gas entering the SCR. Therefore, the Joppa SCR utilizes a typical high temperature catalyst, operating at 572°F versus the 350°F at CalPortland's Colton kilns, the catalyst is not as reactive to SO_2 as the catalyst formulation necessary for CalPortland. The Joppa SCR operates at a temperature well

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above the temperature below which ammonium salts are a problem (450°F). Further, the dust loading to the catalyst is significantly reduced improving catalyst reliability.

3.4 Summary of Control Technology Evaluation

Due to the temperature of the gas stream exiting the waste heat boilers, there are concerns with the technical feasibility of all three control options evaluated for cost effectiveness. As previously discussed these concerns are directly related to the impact of SO_2 spikes combined with gas temperatures in the range where ammonium salts form (below 450°F). These salts poison the catalyst. The only SCR application which utilized a lower temperature catalyst in a cement plant application that we are aware of, was a pilot test which was a failure due to catalyst poisoning. Of the SCRs listed in Table 1, Sarche and Rohrdorf are low dust applications and therefore have not, and would not be expected to experience problems with dust loading on the catalyst. However all of the others with the exception of Joppa and Rezzato, for which information is not yet publically available, the SCRs experienced significant issues with the catalysts in the first years of operation and replaced and/or regenerated the catalysts multiple times in the first years of operation until catalyst pitch sizing was addressed and dust removal mechanisms were modified and became operational. Each cement kiln has site-specific gas chemistry and characteristics. CalPortland's Colton kilns are not currently operating and thus key design parameters cannot be measured or analyzed.

The current allowable NO_x emissions rate for CalPortland's Colton kilns is 2.73 lb NO_x/T_c. This represents a reduction of approximately 65-77% from uncontrolled emissions rates (uncontrolled NO_x emissions ranged from 8-12 lb/T_c). CalPortland believes that the addition of SNCR to their current controls will reduce NO_x emissions another 30-40% for a final emissions rate between 1.64-1.91 lb NO_x/T_c, which would constitute roughly a 75-85% reduction in emissions below the uncontrolled emissions rate and result in a total control efficiency in the same range as what the Joppa plant is achieving with a high temp, semi-clean, SCR system. At that emissions rate CalPortland believes that their emissions might actually be lower than the emissions rate achieved by Joppa. The emissions level at Joppa will not be available until the Joppa Demonstration Report is submitted. Further, SNCR is not adversely impacted by SO_2 spikes, can be installed and operational on the Colton kilns at or shortly after startup of the kilns. In contrast, the installation of any of the three vendor control options will take at least a year for pilot testing and multiple years to install.

4.0 Flaws in the Administrative Process

4.1 CalPortland Denied Access to Vendor Information

Throughout the rulemaking process, CalPortland repeatedly requested access to the vendors' design basis and the details of the vendors' cost information and requested to meet with the vendors to ensure that they fully understood the kilns system and kiln gas characteristics that impact design, CalPortland has not had any opportunity to discuss vendor information with the District or the vendors and was not provided the detailed design basis or detailed cost spreadsheets necessary to determine the validity of the design or costs. CalPortland was told that the information was confidential. We are at a loss as to how vendor information regarding control strategies would be confidential from the affected facility, but this is what CalPortland was told by SCAQMD staff. The very basic cost spreadsheets provided on January 23, 2015, do not address all of CalPortland's questions or concerns.

Questions not addressed or answered by the vendor cost spreadsheets that were provided are as follows:

1. Were the vendors notified of the updated temperature information for the gas stream after the October 2014 site visit by ETS? Vendor costs were not changed from the summary cost spreadsheet provided in July 2014 to the spreadsheets and costs in the November ETS and December PEA. ETS indicates that Vendor 1 modified their design to include more catalyst after they were notified of a temperature of 450°F. Would additional changes need to be made for the actual temperature of 350°F? Further, given that the actual temperature is well below the temperature for ABS formation, would any of the vendors warranty the designs they quoted at this lower temperature given the additional knowledge that emissions of SO_2 spike up to 1500 ppm?

2. The annual costs for catalyst replacement vary significantly between Vendor 1 and Vendor3 for the same control of the same gas stream. There is no explanation for the discrepancy. Further, although the two vendors are consistent in indicating 3-year catalyst life, this life is questionable given the history of SCR at other kilns. CalPortland has knowledge of a recent SCR catalyst warranty of two years. There is no indication in the spreadsheets provided that pilot testing of a gas slip-stream is planned or included in the costs. Even with pilot testing, previously constructed SCR systems on cement plants have routinely had to change out catalysts multiple times in the first years of operation.

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3. There is no mention in the, PEA, the ETS documents or the vendor spreadsheets regarding the need for the controls to operate for the gas stream at both potential operating conditions. While the waste heat boilers operate when the kilns operate under normal conditions, they may not always do so. For example, a malfunction or need for maintenance on the WHB would not result in shutting down the kiln. First, it takes significant amounts of time to safely and properly shut down a cement kiln. Further, some level of thermal shock to the kiln refractory occurs even when kilns are shut down properly. Therefore, the kilns would continue to operate even if the associated WHB needed to be taken offline. The emissions control systems would need to be able to operate at both gas stream conditions, higher temperature (in excess of 900°F) when the WHB is offline and the low 350°F temperature when the WHB are in use.

4. There is no mention or apparent cost included by any of the vendors to replace the existing kiln ID fans. The additional pressure drop resulting from any of the three control scenarios would necessitate the replacement of the kiln ID fans.

5. The reports and the vendor spreadsheets make no mention of the additional construction costs associated with construction to the new stringent seismic codes. It does not appear that the these additional costs, which could be as much as 20% or more, have been included in the vendor costs.

6. As previously noted, it does not appear that Vendors 1 and 3 have included the costs and time required to conduct a slip stream pilot test prior to the design and construction of the full scale control systems. Pilot testing is essential to allow the design to address site-specific conditions.

7. Vendors 2 and 3 propose removal of the existing baghouses and footnote their spreadsheets that they haven't adjusted their costs for any salvage value of the existing baghouses. However, they do not specify whether their costs include the demolition costs for the existing baghouses.

8. Without being provided all of the correspondence related to the gas stream specifications requested by and provided to the vendors, it is not clear whether the vendors are aware of the extremely low typical concentrations of SO_2, 2ppm range, and the magnitude of the spikes which can reach 1500 ppm.

9. Vendor 2 proposes a product that to our knowledge has not been in long-term cement plant application. Does the vendor warranty that the system can comply with the particulate limits in 40 CFR Part 60, Subpart LLL? Can this technology even be considered to be demonstrated technology in this application?

10. Vendor 3 proposes a caustic scrubber for SO_2 control. The costs do not appear to include the capital costs for a waste water treatment system or the costs to operate that system or dispose/discharge treatment residues/wastewater. The few existing wet scrubber systems on cement kilns utilize lime rather than caustic for compatibility with the process. No information was included to justify the use of caustic rather than lime in the scrubbers for CalPortland.

Confidential Appendix A of the ETS Final Report, dated November 25, 2014 was not provided to CalPortland until January 20, 2015, only ten days before the close of the comment period. Although ETS notes in Section B, Paragraph number 3 on Page 3 of the Confidential Appendix A that: "Project documentations shows much contact and discussions with some willing vendors on the subjects of potential problems and steps for resolving them. Problems and concerns were presented by the facility were factored into the costing, e.g. adding caustic scrubbers, a heat exchanger system and soot blowers." There was no direct communication between CalPortland and the vendors and CalPortland was never provided the details of the design basis utilized by the vendors. Without an opportunity to speak directly to the vendors to provide site specific information critical to design that was not requested by the SCAQMD nor contained in documents or reports requested or required to be submitted to the District, or at the very least an opportunity to review and comment on the information provided to the vendors and by the vendors CalPortland was denied the opportunity to constructively participate in the control selection and evaluation process. Without access to the design basis details of what equipment is included in the cost estimates, CalPortland cannot fully evaluate the technical feasibility of the proposed control options, the reported costs for those controls or whether those controls can actually achieve the emissions limit contained in the proposed amended Regulation XX.

4.2 Vendor Costs were not revised even though SCAQMD and ETS were made aware Lower Gas Temperatures at least by Mid-October 2014.

CalPortland acknowledges that there were discrepancies in gas stream temperatures discussed with SCAQMD at different points in time. However, the gas temperature for the gas exiting the waste heat boiler/entering the baghouse provided to SCAQMD in February 2014 was 300-350°F and the temperature provided in October 2014 was 350 °F. There was adequate time for the vendors to revise costs estimates to address this lower temperature. In review of ETS's discussion on Page 4 of the Confidential Appendix A, it appears that either the SCAQMD told the vendors initially to utilize the temperature of the gas exiting the kiln, prior to the waste heat

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boilers, or provided some other temperature. Section C, Paragraph No. 1 on Page 4 as the discussion notes that ""...All vendors offered technical advice as well as costing revisions (if warranted) to account for the lower temperature range of (450-500°F after the WHB)." Paragraph No. 4 on the same page confuses the temperatures even more. Further, after the October 2014 site visit where ETS was informed that the gas temperatures were 350°F, no revisions were made to the costs to address this lower temperature although ETS speculates that duct burners can be utilized. It is unclear whether the vendors were ever made aware of the 350°F gas temperature. This is critical to the validity of the design, costs, technical feasibility of the proposed control options, and the ability of those controls to achieve the proposed amended emissions limit. As noted previously in the discussion of the control options, gas temperatures below 500°F would require a different, more reactive, catalyst formula than systems operating at gas temperatures above 500°F. And, as also previously stated, the only known application of a low temperature catalyst in a cement plant application was a slip-stream pilot test which failed due to catalyst poisoning. None of the operating SCR systems in cement kiln applications operate below 550°F. Further SCAQMD acknowledges on page 1-23 of the PEA, paragraph 2, that: "..., and the presence of sulfur compounds in the exhaust gas , the optimum flue gas temperature of an SCR system is case-by-case and will range between 550 °F and 750°F to limit the occurrence of several undesirable side reactions at certain conditions." CalPortland, does not know if the vendors were made aware of the actual expected gas temperature of around 350°F or whether they would still warranty their systems to perform and achieve the proposed emissions limit at this stack condition.

4.3 Vendors not Adequately Informed Regarding SO_2 Emissions

As also discussed the effectiveness of the SO_2 control technologies proposed by Vendors 2 and 3 are questionable at the actual emissions concentrations of the gas stream. The low temperature of the gas stream, the concentration of the SO_2 in the gas stream, and the humidity/moisture content of the gas stream negatively impact the potential effectiveness of the dry scrubbing technology. First, the low temperature by itself would imply that the control efficiency would be very low. (Reference 1). Consultation with a supplier of hydrated lime indicated that optimum control efficiency for dry lime injection is impacted by both temperature and moisture content. The moisture content is the kiln gas is less than 1-3 %. Further, USEPA in their ACT for cement NO_x controls, acknowledges in Section 8.4.3 that: "Reaction kinetics decrease as the concentration of reactants decreases." In layman's terms, the molecule of pollutant must find and react with a molecule of reagent. The fewer molecules of pollutant in the gas the lower the probability that the pollutant and reagent will find each other and react. During typical operations the concentration of SO_2 in the gas is well below 10 ppm and often around 2 ppm. At these concentrations, reaction kinetics would indicate little to no impact on the SO_2 concentration from injecting dry reagent. Then the question is whether this control system would protect the catalyst during the periods when the SO_2 spikes to 1500 ppm.

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Discussions with a WGS vendor indicated that at the low typical SO_2 concentrations no reductions in the SO_2 concentration would be achieved. Further, although a WGS will reduce SO_2 down to somewhere between 5 and 12 ppm depending upon the reagent used, there would be a lag between the beginning of the spike and the time the control would effectively control the higher concentration. Discussions between CalPortland and the Vendors, where the actual typical and spike emissions rates and gas temperatures would have identified these concerns. Based upon knowledge of the gas conditions, and the operation of the proposed control technologies, CalPortland questions whether either the SO_2 or NO_x controls will perform as proposed and further questions if the Vendors would warranty them. CalPortland has no way of knowing if the Vendors were ever made aware of the range of pollutant concentrations and gas temperatures when proposing their technologies and costs.

Further, the options as proposed, do not appear to address the fact that although CalPortland would not routinely operate the kilns without operating the waste heat boilers as the boilers provide energy to either the plant or the grid and result in lower emissions, of GHG and other combustion pollutants for the required energy usage. The kilns can operate without the waste heat boilers, and in situations where a waste heat boiler (WHB) needs to be offline for repair or due to a malfunction, the kiln would not be shutdown. First, it takes significant amount of time (days rather than hours) to safely shut the kiln down. Further, because of the high temperatures within the kiln, the refractory is thermally shocked to some degree during startup and shutdown, unnecessary startups and shutdowns result in unnecessary damage to the refractory. Therefore, the NO_x control systems would need to be designed to either operate at the higher temperature when the WHB is not in operation or would need to either bypass the NOx control until gas temperatures are reduced or include mechanism to rapidly cool the gas to the acceptable range to protect the catalyst. There is no indication in either the available PEA or the ETS documents to indicate that this alternate operating scenario was contemplated. Further, from a technical perspective, the catalyst formulations are different for low temperature and the more common higher temperature applications.

4.4 Determination of BARCT

Best Available Retrofit Control Technology (BARCT) is the retrofit of an additional control technology on an existing industrial process. By the very nature of retrofit of a control versus integrating the control into the initial design of a process, and the fact that the uncontrolled emissions rates for existing, older process design are in most cases higher than those from a new process, the control technologies and the achievable emissions reductions/ emissions rates after the installation of BARCT in many instances will not achieve the emissions reductions and ultimate pollutant emissions rates from Best Available Control Technology (BACT) required for new process equipment or major modifications to existing process equipment. Therefore, BARCT should not establish an emissions limit lower, than that which would be achieved by A

BACT for a new source. The Proposed emissions limit of 0.5 lb NO_x/T_c is 33% of the new limit established by the New Source Performance Standards (NSPS) for a new PH/PC kiln system, the only new kiln type being constructed which has a limit of 1.5 lb NO_x/Tc. A review of the RBLC indicates that the lowest BACT limit for a new PH/PC kiln is 1.4 lb NO_x/T_c and the lowest/only LAER limit for a cement kiln, also a new PH/PC kiln, is 1.2 lb NO_x/T_c. The NOx limit proposed for BARCT (0.5 lb NO_x/T_c) is approximately 60% lower than for a new kiln constructed in a non-attainment area and for a kiln type with significantly lower uncontrolled emissions rate. Establishing a BARCT limit at this level is inappropriate and not supported by practical application of the technologies or common sense.

4.5 Evaluation of Cost Effectiveness based solely on the cost per ton of pollutant removed is inappropriate for Cement Application.

Cement is a commodity product and as such pricing is competitive with competitors with the general vicinity of the cement plant as well as imports. Particularly in locations with nearby ports for imports from Asia where production costs are lower and environmental controls are less stringent. Unlike other industrial categories the high capital and annual operational costs to implement the controls proposed as necessary to achieve the unrealistic emissions limitation in the proposed amended Regulation XX cannot be recovered by increases in the price of the cement product. While as noted previously, CalPortland has serious concerns about whether the estimated capital and annual operating costs provided by the three vendors, the costs provided will result in an increase in the price of cement from the plant of as much of $10 per ton of cement or more. At this price differential, cement from CalPortland's plant will have no market.

The implementation of SNCR to the existing NO_x controls on CalPortland's Colton kilns will achieve an overall NOx reduction of approximately 75% below the uncontrolled emissions rate., This represents a control efficiency in the same range as the reported control efficiency (70-80% control) of the Joppa kiln, which is the only existing long dry kiln operating an SCR for NO_x control. Further, the resulting emissions rate achieved by the use of SNCR at CalPortland's kilns, 1.64-1.91 lb NO_x/T_c is believed to be at or below the emissions rate of the Joppa kiln.

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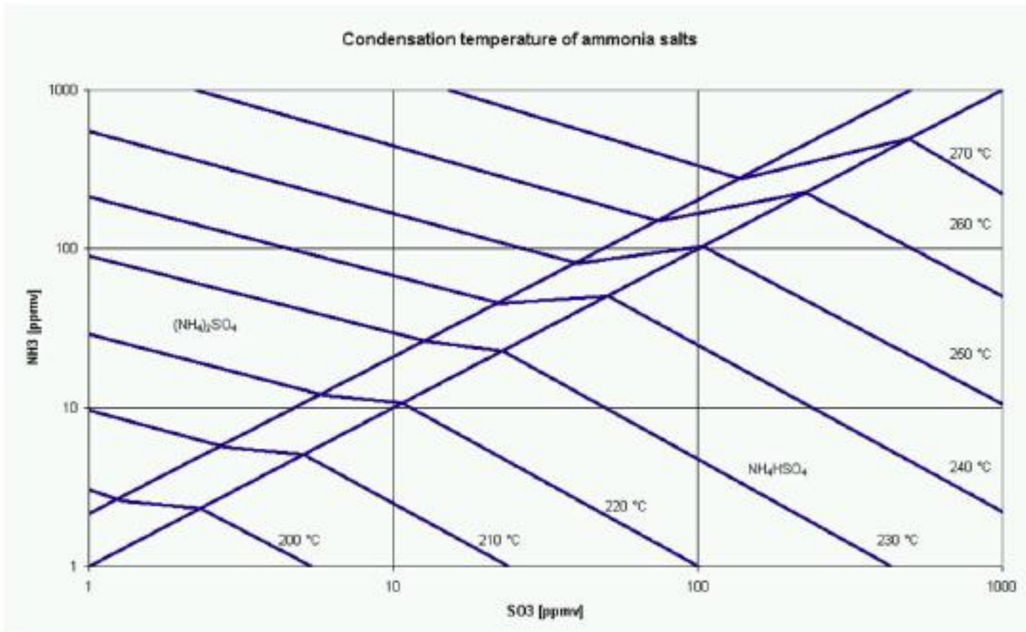
5.0 Conclusions

1. The Administrative Process for the development of the proposed emissions rate in Proposed Amended Regulation XX is flawed and did not provide CalPortland the opportunity for input to the Vendors, thereby potentially and CalPortland believes did indeed compromise the technical feasibility of the proposed control options and emissions limit. Failure to provide, at a minimum, access to the details of the design basis utilized by the vendors and the detailed cost spreadsheets and assumptions denied CalPortland the opportunity to provide fully informed comments on the proposal.
2. CalPortland, based upon knowledge of the process and gas characteristics at the Colton plant and based upon knowledge of the existing cement kiln SCR operations, does not believe that the control technologies are technically feasible or the Colton kilns.
3. CalPortland believes that the proposed emissions limit is unachievable for the long dry kilns at Colton and further that setting a BARCT emissions limit that is one third of the NSPS and BACT limits established for new preheater/precalciner kiln systems and 60% lower than a LAER emissions limit for a new kiln is inappropriate and well beyond the intent of BARCT.
4. The proposed emissions rate is technically unachievable with the proposed controls, and further will result in the inability of CalPortland's cement product to compete in a commodity market.

Appendix A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220 °C
230 °C
240 °C
250 °C
260 °C
270 °C

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RESPONSES TO COMMENT LETTER #3
(Cal Portland Company - January 30, 2015)

On April 9, 2015, after the release of the NOP/IS for public review and comment, the Cal Portland Company (CPCC) operators surrendered their operating permits for the Portland cement kilns and have applied for Emission Reduction Credits (ERCs). Thus, because CPCC operators are no longer operating the Portland cement kilns and they no longer hold current SCAQMD operating permits for these units, the existing setting or NOx emissions baseline for the Portland cement kilns at CPCC is zero. Further, if CPCC operators decide to restart the Portland cement kilns in the future, applications for new SCAQMD permits to operate would be required. Further, these permit applications would be subject to an extensive permit review process such that that the Portland cement kilns would be treated as a new installation that would be subject to a new CEQA review and BACT requirements, instead of BARCT. In addition, CPCC would need to purchase RTCs to offset any NOx or SOx emissions as well as ERCS to offset other non-attainment pollutants as required by Regulation XIII. Because of CPCC's current permitting status for these Portland cement kilns, CPCC operators will not be able to retrofit the Portland cement kilns with air pollution control equipment in response to the proposed project without first dealing with the permitting issues for the Portland cement kilns.

Because this comment letter does not contain any CEQA-related comments, and because the CPCC facility is no longer affected by the proposed project, responses to this comment letter have not been prepared.

Comment Letter #4

Los Angeles Department of Water & Power

January 30, 2015

Ms. Barbara Radlein
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Dear Ms. Radlein:

Subject: Los Angeles Department of Water and Power's (LADWP) Comments on Notice of Preparation of a Draft Program Environmental Assessment Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

The LADWP appreciates the opportunity to provide comments on the *Notice of Preparation (NOP) of a Draft Program Environmental Assessment on the Proposed Amended Regulation XX – RECLAIM*. The LADWP remains committed to working with South Coast Air Quality Management District (SCAQMD) to further develop efficient and effective policies to reduce NOx emissions from RECLAIM facilities in order to meet the federal Ozone standards in the South Coast Air Basin.

Serving approximately 1.4 million customers in Los Angeles with a generating capacity of over 7,300 megawatts, the LADWP is the largest municipal electric utility in the nation, and the third largest electric utility in California. The LADWP is a vertically integrated utility, owning and operating a diverse portfolio of generation, transmission, and distribution assets spanning several states. As part of its modernization efforts, since the 1990's, the LADWP has been replacing its existing, less efficient utility boilers in the South Coast Air Basin with new, state-of-the-art combined-cycle and simple cycle turbine systems equipped with selective catalytic reduction technology to minimize NOx emissions. During this modernization process, the LADWP's generating facilities have been subject to New Source Review and are equipped with Best Available Control Technology, or BACT which reduces NOx emissions by at least 90 percent. 4-1

The LADWP also continues to make unprecedented investments in renewable energy resources, energy efficiency and transportation electrification to improve the

Ms. Barbara Radlein
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January 30, 2015

environment. The LADWP is on track to meet 33 percent of its energy sales from renewable energy resources, has a goal to achieve 15 percent energy savings by 2020, and is continuing to implement programs to support the electrification of the transportation sector to reduce greenhouse gases and criteria pollutants, including NOx, and as a potential solution to absorb over-generation from solar renewable sources. 4-1 Concluded

Comments on the Notice of Preparation
Draft Program Environmental Assessment Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

1. Project Description Does Not Reflect Language in the Proposed Amended Rule 2002 – Allocations of Oxides of Nitrogen (NOx) and Oxides of Sulfur

The NOP states that the project will affect the following types of equipment and process of the top NOx emitting facilities in the NOx RECLAIM program:

- Fluid catalytic cracking units (FCCUs)
- Refinery boilers and heaters
- Refinery gas turbines
- Sulfur recovery units/Tail gas treatment units (SRU/TGUs)
- Non-refinery/Non-power plant gas turbines
- Non-refinery sodium silicate furnaces
- Non-refinery/Non-Power Plant internal combustion engines (ICEs)
- Container glass melting furnaces
- Coke calcining
- Portland cement kilns
- Metal heat treating furnaces

4-2

The NOP *Technological Overview* section further states that the project will focus on reducing NOx emissions from "the major and large sources of the top emitters of NOx" for which new Best Available Retrofit Control Technology (BARCT) has been identified, but not yet applied. This description is clearly inconsistent with the proposed amendments in Proposed Amended Rule (PAR) 2002, which establishes new NOx RECLAIM Trading Credit (RTC) adjustment factors (reductions) for all affected RECLAIM facilities (including electric generating facilities) starting in year 2016.

Notably, the proposed draft regulatory language does not explicitly state that the reductions in NOx RTC holdings would only be applied to the eleven types of equipment and processes listed in the NOP/Initial Study. Rather, the draft regulatory text on the proposed NO_x RTC adjustment is broadly written. This interpretation of the proposed regulatory language is confirmed in the NOP/Initial

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Study, which states: "It should be noted that the proposed rule language describes an evenly distributed percent of NOx RTC reductions applicable to *all* RECLAIM facilities. [emphasis added]" Thus, the proposed NOx adjustment factors in PAR 2002 would decrease the NOx RECLAIM Trading Credits (RTCs) for all RECLAIM facilities by 49% by 2020. This reduction in NO_x RTCs would apply across the board to all facilities, regardless of whether the facility operates any of the equipment or processes listed above or not. 4-2 Concluded

If the SCAQMD determines that a NO_x RTC shave is necessary, this adjustment should focus only on the eleven types of equipment or processes with newly identified BARCT and not also apply to electric generating facilities that already have reduced RTC allocations based on most current BARCT performance levels. By contrast, the expanded scope of the RTC adjustment, as proposed in regulatory text of PAR 2002, is inappropriate given that there would likely be significant impacts to other RECLAIM facilities impacted by an across-the-board shave in RTC holdings.

2. Initial Study does not address the impacts of an across-the-board 49 percent reduction in RTC holdings on energy supply

Because SCAQMD, in the NOP, did not consider the across-the-board NOx RTC reductions as proposed in PAR 2002, it did not address the potential impacts on energy supply. Reduction in allocations will create significant impacts on energy supply by restricting power generation operations. LADWP's in-basin generating facilities' would be faced with the following operational constraints and needs: 4-3

- Transmission constraints – The LADWP is currently reaching its maximum transmission system capability. As the LADWP integrates renewables in the generation mix, increased frequency of ramp-ups to mitigate variable output from renewables would lead to corresponding increases in the in-basin NOx emissions from electric generating facilities regulated under RECLAIM program. Limiting internal generation capability by the shave would require the LADWP to import power from out-of-basin generation, which could further strain the transmission system. 4-4
- Need for local generation to support local renewables - Local renewables are not reliable sources of sustained electricity and are significantly less reliable than Photovoltaic (PV) and wind projects, especially during peak periods. Due to the nature of the connection between local solar sources (*i.e.*, roof-top PV panels) and the local grid, the connection automatically disconnects during unstable voltages due to high demands by heat waves. As a result, local, dispatchable generation is very important to support local renewables. 4-5

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- Certain minimum amounts of inertia in-basin are required to import out-of-basin generation - This is a location specific requirement to maintain the stability of in-basin local transmission system as well as the entire transmission system and to smooth out the fluctuation of import of out-of-basin generation. The paradox of this requirement is as follows. The fewer generating units that are online in the basin, the less inertia (rotating mass of turbine and generator) is online. The less inertia that is online, the less transiently stable the local system will be following typical disturbances, such as transmission line short circuits that are normally cleared by very fast-acting relays and circuit breakers. The remedy for the lack of local inertia is to decrease imports into the basin from external sources. The physical paradox is the fewer generators that are on in the basin, the less one can import into the basin due to limits on imports due to transient instability. If the LADWP decreases local generation, it only decreases its ability to import. 4-6

- "Reliability Must-Run" Generation is needed in-basin - LADWP's local transmission system was never intended to be reliably operated without some local generation online. This generation is called "Reliability-Must-Run" (RMR) generation because the local transmission system can be operated in compliance with Federal and WECC reliability standards only when location-specific RMR units are in operation at minimum load levels. If the RMR generation is decreased due to lack of NOx credits, the only way to meet reliability standards under high load conditions would be to shed customer load, which is contrary to the LADWP's obligations to provide reliable supplies of electricity to our customers. 4-7

- Increased vehicle electrification will increase electricity demand – Although the LADWP's Integrated Resource Plan analyses show that LADWP's in-basin generating facility NOx emissions are projected to increase due to increased vehicle electrification, there would be a *net decrease* in NOx emissions in the South Coast Air Basin. LADWP urges SCAQMD to consider the potential net NOx reductions from transportation electrification in the design of the NOx RECLAIM program. Furthermore, the Clean Air Act (CAA or Act) allows SCAQMD to consider the offsetting NOx emission reductions from transportation electrification in developing an approvable implementation plan for the attainment and maintenance of the ozone standard. As SCAQMD has acknowledged, reaching the 2032 ozone attainment goal would require nearly complete transformation of passenger vehicles to zero-emission technologies, about 80 percent of the truck fleet to zero- to near-zero technology, and nearly all locomotives operating in the South Coast Air Basin to be using some form of zero-emission technology. In addition, Governor Brown's State of the State speech includes reducing today's petroleum use in cars and trucks by up 4-8 to 50 percent. This means that the only way for the State to achieve the Governor's goal, as well as the air goal goals under the CAA, is for SCAQMD to develop regulatory policies that allow for increased generation (and thereby emissions) from electric generating facilities in order to supply the necessary energy for electrifying the transportation sector. 4-8 Concluded

Alternative Regulatory Approaches

In the event that SCAQMD decides to impose an across-the-board RTC reduction on all affected RECLAIM facilities (including electric generating facilities), LADWP urges the SCAQMD alternatives to minimize the regulatory impacts of that RTC adjustment on the electric power sector. The development of such a regulatory alternative is appropriate given that affected electric generating units already meet the proposed BARCT based on SCAQMD's own analysis. Furthermore, additional reduction in NOx emissions at in-basin plants may not be feasible due to the fact that the only way to achieve additional reductions from these well-controlled plants is by reducing their generation output. As discussed above, reducing the utilization of in-basin gas-fired generation is not a viable option given the essential role these units play in ensuring a reliable supply of electricity in the basin. 4-9

The LADWP has identified a possible regulatory credit mechanism that could be developed to ensure that affected power plant facilities would not be penalized for increased NOx emissions resulting from an increased demand in electricity due to native load needs and increased transportation electrification. Such a crediting mechanism would incentivize the development and implementation of renewable energy and transportation electrification. This approach would be consistent with SCAQMD's position as described in its comment letter to U.S. Environmental Protection Agency (EPA), which states that "It is important that the 111(d) regulation recognizes California's unique situation and does not hinder the introduction of additional renewable energy generation." "The proposed regulation must be structured to support clean generation and renewable energy."[1] 4-10

The policy to be addressed is similar to the Clean Fuels Adjustment provision in that "Allocation adjustments are warranted because of the significant emission decreases that will be realized from mobile sources."[2] Thus, there is a precedent where SCAQMD has allowed RECLAIM affected entities to have sufficient RTCs for increased NOx emissions in the South Coast Air Basin decrease in order to

[1] November 26, 2014 letter to EPA regarding *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units – Proposed Rule*

[2] RECLAIM Rules staff report, October 1993, p. 2-19

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ensure attainment and maintenance of the ozone and other ambient air quality standards. Similarly, the purpose of this alternative approach would be to ensure sufficient RTCs are available for affected electric generating facilities to support the planned levels of transportation electrification that are necessary for achieving the air quality standards, as well as operate its in-basin generating stations to meet native load needs.

The California Air Resource Board's (CARB) Phase II reformulated gasoline production and federal Clean Fuel requirements adopted in the early 1990s require that cleaner burning fuel for automobiles be sold in California. The SCAQMD determined that the modifications to the refining facilities in California would be necessary to produce the reformulated gasoline. These plant modifications would result in emissions increases but the emissions increases would be offset more by mobile source reductions from the use of cleaner fuels by vehicles in the same air shed. As a result, SCAQMD developed criteria to allow for the emission increases while providing an upper bound of RTC allocations. Refinery owners could request an increase in RTC allocations when submitting an application for a permit amendment.

4-10 Continued

The Clean Fuels Adjustment provision establishes helpful precedent for SCAQMD providing flexibility in the implementation of the RECLAIM Program. The discussion below describes how a similar credit mechanism might be developed to ensure affected electric generating facilities had sufficient RTCs in the event that SCAQMD decides to impose an across-the-board RTC reduction on all affected RECLAIM facilities.

1. <u>Quantify the amount of RTCs needed to support native load and transportation electrification.</u>

The first step of the process would involve each affected electric utility quantifying the amount of NOx RTCs that it would need to cover its projected NOx emissions. The process for calculating each unit's generation level would be based on the amount of electricity that the utility would need to generate in order to meet its native load, along with the expected electricity demand increase resulting from the transportation electrification. This determination would likely be based on the Integrated Resource Plan (IRP) or similar process for estimating the utility's native load and the expected transportation electrification for the next 10 to 15 years. With respect to transportation electrification, the utility would need to work with the SCAQMD and CARB to estimate the expected number of electric vehicles (EVs) in the basin in order to determine the increased electricity demand resulting from electrification of the transportation sector.

Based on this quantification of future electricity demand and NOx emissions (which could be updated on an annual basis), the SCAQMD would allow the

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affected electric utilities to hold in their accounts sufficient number of NOx RTCs to cover their emissions on a system-wide basis. This amount of each utility's RTCs would not be deducted from its RECLAIM account and consequently remain available for use in meeting its RECLAIM credit-holding requirements.

2. Determine the amount of RTCs used for transportation electrification.

   Each utility sector would quantify the number of RTCs that are actually used to generate electricity for vehicle electrification. This quantification would be performed for each compliance year based on a method similar to CARB's Low Carbon Fuel Standard approach. A combination of meter kWh data and estimated kWh data applied to the number of EVs that a utility reports would be used to quantify the emissions due to the increase in electricity demand from electric transportation.

3. Label unused RTCs designated to cover transportation electrification as non-tradable.

   The RTCs that an electric utility retains based on the quantification of future electricity demand due to transportation electrification would be put into a utility's account and labeled non-tradable. The non-tradable RTCs could be used for compliance purposes only and allocated tradable RTCs would be used first for compliance. Thus, if a utility has NOx emissions that are lower than expected such that its non-tradable RTCs are unused, the utility would not be able to sell them to entities outside of the utility's system. At the end of the reconciliation period, the utility would surrender unused non-tradable RTCs to SCAQMD for credit toward reducing NOx emissions through the RECLAIM program and meeting attainment of the ozone standard.

State Implementation Plan crediting with respect to design of the NOx RECLAIM program to accommodate transportation electrification

There are uncertainties with respect to the level of transportation electrification and the level of in-basin generation needed to support future renewables which creates uncertainties as to the number of RTCs that electric generating facilities would need. LADWP believes that SCAQMD has the discretion to develop its NOx RECLAIM program to accommodate such uncertainties without having to determine the exact amount of the NOx reductions upfront for SIP credit purposes. LADWP is ready and willing to work with SCAQMD, CARB, and EPA to explore opportunities in creating an approach to include the benefits of transportation electrification as well as support clean generation and renewable energy.

4-10 concluded

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Comments of Proposed Amended Rule 2012 – Appendix A: Protocol for Monitoring, Reporting and Recordkeeping of Oxides of Nitrogen (NOx) – Attachment C – Quality Assurance and Quality Control Procedures

Section (B)(2) – LADWP supports SCAQMD's efforts to allow postponement of a RATA when a major source is physically incapable of being operated.

Section (B)(2) requires that a relative accuracy test audit (RATA) be performed on a major source on a semi-annual or annual basis within a specified time period. For example, the semi-annual assessment is required to be completed within six months of the end of the calendar quarter in which the continuous emission monitoring system (CEMS) was last tested for certification purposes or within three months of the end of the calendar quarter in which SCAQMD sent notice of a provisional approval for a CEMS, whichever is later. This requirement currently does not provide NOx RECLAIM facilities with the flexibility to reschedule a RATA when a unit is inoperable due to unexpected unit shutdowns or delays in completing unit's scheduled maintenance and repair. When this happens, the RECLAIM operator must seek a variance from the SCAQMD Hearing Board. LADWP supports SCAQMD's efforts to address these situations in Section (B)(2) to allow postponement of a RATA when the major source "is physically incapable of being operated."

The LADWP has experienced situations where its generating units were shut down due to unit damage or unexpected delays encountered during scheduled maintenance and repair of a unit. In such situations, LADWP's generating units were incapable of being operated at the time of the mandated RATA test. For example, in October 2013, LADWP's Haynes Unit 9 combustion turbine was operating at full generation capacity when it came to an abrupt stop; it was determined that the compressor section of the turbine was damaged such that procurement of replacement components and repair required several months. The unit's RATA was scheduled for early November 2013 to meet the December 31, 2014 regulatory deadline but could not be performed due to the length of time required to repair the unit. Although SCAQMD does allow postponement of a RATA for an "intermittently operated source" under Section (B)(2)(h), the provision is narrowly defined. In LADWP's case as described above, SCAQMD's regulatory requirements did not allow reschedule of the RATA. Because of the inflexibility with respect to reschedule of the RATA, LADWP needed to seek a variance from the SCAQMD Hearing Board. Thus, SCAQMD's efforts to postpone a RATA to address the situation where the major source is physically incapable of being operated would allow facilities to focus on bringing the unit back in operation rather than spending significant

4-11

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staff and Hearing Board time in the variance process for situations where there are no adverse air quality impacts. 4-11 Concluded

Section (B)(2)(c) and (B)(2)(d) Due Date for RATAs

The LADWP has the following concerns with the proposed language in this section:

- With respect to rescheduling of a RATA, there is inconsistent treatment between electrical generating facilities that only operate under a California Independent System Operator (Cal ISO) contract and those generating facilities such as LADWP's that do not. Generating facilities only operating under a Cal ISO contract would be able to postpone the due date for a RATA to the next calendar quarter whereas LADWP's generating facilities would not. If LADWP encountered a situation as described above where the unit is physically incapable of being operated, it would be able to postpone the RATA only to within 14 unit operating days from the first re-firing of the unit. It is unclear why there is inconsistent treatment when electrical generating facilities, whether they have a Cal ISO contract or not, face similar operational issues. 4-12
- The proposed 14 unit operating day window of time for conducting a RATA in the case where a major source is physically incapable of being operated is insufficient at LADWP generating facilities when a unit is inoperable for an extended period of time. Before a RATA can be performed, the LADWP must perform a series of tests to ensure reliable and safe operation of the unit. Tests to balance the turbine rotor and generator rotor must be performed when there is a repair that lasts longer than several months to ensure that the unit operates within the Original Equipment Manufacturer vibration limits. It may take several sets of these "balance shot" tests before the unit is operating within vibration limits and each balance shot typically takes several days to a week to complete. Based on LADWP's experience, we recommend that SCAQMD allow postponement of the due date for a RATA to the next calendar quarter similar to Section (B)(2)(d) or 30 unit operating days in order to safely conduct the tests and operate the unit and avoid the risk of damaging the unit. This 30-day extension is similar to the provision in 40 CFR Part 75, Appendix B. Section 2.3.3 in which EPA provides a 720-operating hour grace period if RATA cannot be performed on the due date. 4-13

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<u>Section (B)(2)(c)(i) and (ii) – Proposed requirement to disconnect and flange the fuel feed lines when a unit is physically incapable of operation is unnecessary and costly</u>

The proposed language requires that:

i. All fuel lines to the major source are disconnected and flanges are placed at both ends of the disconnected lines, and
ii. The fuel meter(s) for the disconnected fuel feed lines are maintained and operated and associated fuel records showing no fuel flow are maintained on site.

The proposed requirement to disconnect and flange the fuel feed lines would be costly and a significant task requiring scaffolding, crane support, procurement of equipment, and staff/labor time from pipefitters, welders, maintenance mechanics, pressure vessel group inspectors, engineering, drafting and operations. This requirement would unnecessarily create a significant health and safety risk if the fuel lines are insulated with asbestos-containing materials (ACM). The intact ACM would have to be removed to gain access to the fuel pipelines which would be against the general plant operating and maintenance best practices to leave intact ACM alone. This requirement would also take several weeks in order to procure the necessary materials and to complete construction. Since the fuel meters would be required to be maintained and associated fuel records be kept, SCAQMD would already have two sources of data as a check that the source is not operating. Thus, LADWP urges SCAQMD to delete Section (B)(2)(c)(i).

4-14

Again, the LADWP appreciates the opportunity to provide comments on the NOP. We would urge that LADWP and other stakeholders be provided a reasonable schedule for further development of any rule changes to RTC allocations that is consistent with the regulatory requirements and provides a reasonable opportunity for stakeholder review and comment.

If you have any questions or would like additional information, please contact Ms. Jodean Giese of my staff at (213) 367-0409.

4-15

Sincerely,

Mark J. Sedlacek
Director of Environmental Affairs

LL/JG:mg
c: Ms. Elaine Chang, SCAQMD
Mr. Joe Cassmassi, SCAQMD
Mr. Gary Quinn, SCAQMD
Ms. Jodean M. Giese

RESPONSES TO COMMENT LETTER #4
(Los Angeles Department of Water and Power - January 30, 2015)

4-1 This introductory comment summarizes the commentator's facilities, customer base, generating capacity, and control equipment and explains that this comment letter has been submitted in response to the proposed amendments to Regulation XX and the associated NOP/IS. Responses to specific concerns are presented in Responses to Comments 4-2 through 4-21.

4-2 This comment states that there is an inconsistency between the project description in the NOP/IS which focuses on achieving NOx emission reductions from the top emitting NOx RECLAIM facilities compared to the proposed rule language which shows a 50 percent shave across all NOx RECLAIM facilities. Further, this comment claims that the proposed rule language does not explicitly state that reductions in RTC holdings would only be applied to the 11 types of equipment/processes that are identified in the NOP/IS. This comment requests the shave, if determined by the SCAQMD to be necessary, to only focus on the 11 types of equipment/processes that are identified in the NOP/IS and not apply to electric generating facilities that already have reduced RTC allocations based on the most current BARCT performance levels.

Since the release of the NOP/IS, the proposed project has been modified to apply a shave to the holders of the top 90 percent of RTCs. However, it is likely that the required reductions will be obtained from the installation of NOx control equipment at 20 facilities, as well as from RTCs that are in the program but are being used for compliance purposes. Since only the installation and operation of NOx control equipment would have environmental impacts, the CEQA analysis focuses on these impacts. If some facilities purchase RTCs to meet their allocation targets, this will not have an additional environmental impact but will be considered in the socioeconomic analysis.

4-3 This comment claims that because the NOP does not consider an across the board shave that would affect more than 11 categories of equipment/processes as is proposed in PAR 2002, the NOP did not address the potential impacts on energy supply and the operational constraints on in-basin electrical generating facilities.

Contrary to the comment, the NOP/IS identified energy, including impacts on energy supply, as one of the environmental topic areas that may be adversely affected by the proposed project. PAR 2002 has been revised and the project description in the Draft PEA now correlates to the rule language. The proposal includes an adjustment account specifically for power generating facilities. The RTCs in this account could be accessed in the event of a power generation emergency declared by the Governor.

4-4 This comment states that the commentator's facilities are reaching the maximum transmission capability and limiting the internal generation capability as a result of the NOx shave would require power to be imported from out-of-basin generation, which could further strain the transmission system. This comment also claims that the increased reliance on renewable sources of energy with variable outputs will cause an increased frequency of ramp-ups and increased in-basin NOx emissions from electric generating facilities.

SCAQMD staff acknowledges that during times when maximum transmission capability is reached, there will be a need for peaker plants to ramp-up and there will be increases in emissions as a result. Staff does not believe transmission limitations will be significantly affected because the rule proposal provides a mechanism for access to additional RTCs if needed by power plants.

4-5 This comment maintains that local renewables are not reliable sources of sustained electricity and local, dispatchable generation is very important to support local renewables. For example, the connection between local solar sources and the local grid is automatically disconnected when there are unstable voltages due to high demand during heat waves.

SCAQMD staff acknowledges that there is a need to access local renewable sources of energy. The rule proposal has been modified to help generators ensure this availability.

4-6 This comment claims that there are certain minimum amounts of inertia in-basin that are required to import out-of-basin generation such that when fewer generators are operating in the basin, a lesser amount of electricity can be imported into the basin.

The staff proposal has been modified to allow needed generation for local inertia requirements.

4-7 This comment claims that if local electricity generation or "Reliability-Must-Run (RMR) is decreased due to a lack of NOx credits, the only way electricity demand can be met under high load condition would be shed customer load, which is contrary to the LADWP's obligations to provide reliable supplies of electricity to its customers.

The staff proposal has been modified to allow meeting electricity demand under high load conditions.

4-8 This comment claims that because increased vehicle electrification will increase electricity demand causing an increase in NOx created for electricity generation but decreasing overall NOx because electric vehicles will no longer be combusting fuel. This comment also claims that the SCAQMD should develop regulatory policies that allow for increased generation and increased emissions from generation in order to supply the necessary energy for electrifying the transportation sector.

Increased demand due to transportation electrification will occur gradually and will be monitored by staff. If such demand requires rule amendments, there will be time to implement them.

4-9 This comment requests the alternatives in the PEA minimize the regulatory impacts of the RTC shave on the electric power sector if there is an across the board shave for all facilities in the program.

The staff proposal does not recommend an across the board reduction for all facilities. The proposal contains a 47 percent NOx RTC shave on power plants and an adjustment account that could be accessed by power plants if the Governor declares an emergency that would require additional power generation. In addition, the PEA analyzes multiple alternatives, each with a varying NOx RTC shave on power plants. For example, Alternative 1 proposes a 53 percent NOx RTC shave on power plants and Alternative 2 proposes a 60 percent NOx RTC shave on power plants. In addition, of the shaves proposed, Alternative 3 contains the smallest shave percentage for power plants at 36 percent. In addition, the No Project alternative, Alternative 4, does not propose a NOx RTC shave on any facility, including power plants.

4-10 This comment suggests that a credit mechanism should be developed to ensure that affected electric generating facilities have sufficient RTCs if the SCAQMD proposes an across the board RTC shave. The example cited is the Clean Fuel Adjustment credits that have been available to refineries for the production of reformulated gasoline.

In response to the comment, the staff proposal would not be an across the board shave. The staff proposal would establish a separate adjustment account to hold RTCs for power plants to meet their NSR holding obligations. Many newer, peaking plants are required to hold RTCs at the potential to emit level each year even though their actual emissions are far below this level. The adjustment account would relieve power producing facilities from the obligation of purchasing RTCs in order to meet the NSR holding requirements of Rule 2005. RTCs either held or purchased by a facility would be for the purpose of reconciling annual emissions. Furthermore, if the demand for power results in a severe shortage that would lead to the state Governor declaring a state of emergency, a power producing facility would be able to access the adjustment account for non-tradable credits for offsetting annual emissions. The adjustment account would take the shaved RTC amount for the given compliance year according to the implementation schedule in the rule; each year would be an increment of the overall 47 percent shave.

The comment states that there would be increased demand due to increased transportation electrification and renewable power. If this power demand translates into an RTC demand, these credits would be purchased from the NOx RECLAIM market. If there is a shortage of credits which would result in an increase in the RTC price, a safety valve in the rule would provide access to non-usable, non-tradable credits in the event that the market price for discrete year credits rises above $15,000 per ton.

4-11 The comment expresses support regarding SCAQMD's efforts to allow a postponement of a RATA when a major source is physically incapable of being operated.

SCAQMD staff acknowledges your support for the proposed amendments in Rule 2012.

4-12 This comment claims that there are inconsistencies in how electrical generating facilities that only operate under a California Independent System Operator (Cal ISO) and how generating facilities operated by the commentator are treated when rescheduling a RATA.

Staff has revised the proposed rule language to include power plants operated by municipalities.

4-13 This comment claims that the proposed 14 unit operating day window of time for conducting a RATA where a major source is physically incapable of being operated is insufficient at the commentator's generating facilities when a unit is inoperable for an extended period of time. This comment recommends a postponement of the due date for a RATA to the next calendar quarter or 30 unit operating days.

Discussion with the commenter revealed that the concern here has to do with the potential for sequential equipment failures. However, the 14 unit operating day RATA extension being proposed would apply separately for each independent failure. That is, if equipment operating under the 14 operating day RATA postponement provision should experience an unrelated failure prior to successfully completing a RATA, the 14 day clock would restart. The staff report provides clarification on this point. Furthermore, an extension duration of 14 operating days is consistent with the existing provisions pertaining to the timing of RATA for CEMS on a stack or duct through which no emissions have passed in two or more successive quarters in Attachments C to Rules 2011 and 2012 and with variance conditions established by the SCAQMD Hearing Board in previous cases. Conversations between SCAQMD staff and facility operators also indicate that fourteen operating days provide sufficient time to conduct a RATA in such cases.

4-14 This comment requests deletion of the proposal to disconnect and flange the fuel feed lines because it would be a costly and a significant task involving construction workers and equipment and would create significant health and safety risks if fuel lines are insulated with asbestos-containing materials.

RECLAIM has existing provisions that address non-operated major SOx and NOx sources in Rule 2011 (c)(10) and Rule 2012 (c)(9), respectively. These requirements are imposes when the period of non-operability is relatively long. These provisions both require the operator to "disconnect fuel feed lines and place flanges at both ends of the disconnected lines." Similarly, Rule 2011 (c)(9) addresses infrequently-operated major SOx sources. One of the requirements with which a source must comply to be eligible to be an infrequently-operated major SOx source is that the "Facility Permit holder shall disconnect fuel or process feed line(s) and install, maintain, and operate a monitoring device, which has been approved by the Executive Officer, to provide a continuous positive indicator of the operation status of the source to the remote terminal unit (RTU) for the purposes of demonstrating the source is not operating and for preparing emissions reports." Collectively, the requirements of Rule 2011 (c)(9), Rule 2011 (c)(10), and Rule 2012 (c)(9) establish the appropriate precedents for the steps a facility must take to qualify for a reduced level of emissions monitoring of a major source that is out of operation for an extended period. In addition, the comments have not included any examples to demonstrate cases where disconnecting sections of fuel line is infeasible. Therefore, the proposed rule language's eligibility requirements for delaying RATA testing to the end of the next quarter of both disconnecting fuel lines and maintaining and operating the fuel meters are appropriate and consistent with existing, related provisions.

4-15 This comment expresses appreciation for the opportunity to provide comments on the NOP and requests a reasonable schedule and an opportunity to comment on rule development changes to RTC allocations.

SCAQMD staff appreciates the comments and input. All affected stakeholders will be notified of any changes and SCAQMD staff will continue to meet regularly with the stakeholders, which includes the commentator, to solicit input.

Comment Letter #5

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January 30, 2015

BY EMAIL (BRADLEIN@AQMD.GOV) AND U.S. MAIL

Barbara Radlein (c/o CEQA)
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, CA 91765-4178

Re: Comment Letter on Notice of Preparation of a Draft Program Environmental Assessment--Proposed Amended Regulation XX; City of Burbank, Department of Water and Power

Dear Ms. Radlein:

The City of Burbank, Department of Water and Power ("the City") appreciates the opportunity to present the following comments on the Notice of Preparation ("NOP") of a Draft Program Environmental Assessment on Proposed Amended Regulation XX. The comments address the need to evaluate potential adverse impacts of a proposed reduction of approximately 50% of each facility's NOx RECLAIM Trading Credits ("RTCs") ("NOx Shave"). The City operates two facilities regulated under the RECLAIM: its own power plant operated by its Department of Water and Power ("BWP") and the Magnolia Power Plant ("MPP"), a facility owned by the Southern California Public Power Authority ("SCPPA") but also operated by BWP. 5-1

SUMMARY

If power plants are subject to a 50% NOx Shave, as set forth in the draft rule attached to the NOP, then they may be operated less frequently due to the higher costs that the shave imposes. Their electricity production may be shifted to other, more polluting power plants, with adverse air quality impacts where those other power plants are located. The District must evaluate these potential adverse air quality impacts in the Environmental Assessment for the 5-2

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proposed NOx RTC shave, whether those impacts occur inside or outside the South Coast Air Basin. In addition, the District should analyze two alternative projects that may mitigate or eliminate these potential adverse impacts but still allow the project to achieve its basic objectives: (1) the alternative of no reduction of NOx RTCs for any power plant that already operates with either Best Available Control Technology ("BACT") or Best Available Retrofit Control Technology ("BARCT") installed, and (2) the alternative of a smaller reduction of, for example, 25% of each such power plant's NOx RTCs. 5-2 Concluded

ADDITIONAL DETAIL

Most of the power plants that would be subject to a 50% NOx shave are gas-fired peaking plants with BACT or BARCT already installed and NOx emissions in the range of 2-5 ppm. These power plants could not achieve cost-effective reductions of NOx emissions in response to a NOx shave. Instead, they would have to purchase more RTCs to maintain or increase their electricity production. If they are facilities that were newly-constructed under RECLAIM (Rule 2005), they also would have to purchase RTCs to cover their PTE at the start of each compliance year. 5-3

RTC purchases in response to the shave would increase the operating costs of these power plants. The increased costs may make it economical for the operators of these power plants to reduce their level of operation and purchase replacement power from other facilities outside the South Coast Air Basin. These other facilities likely have NOx emissions rates higher than the emissions rates of the power plants subject to the NOx shave. Therefore, NOx emissions per MWhr, and overall NOx emissions from power plants, may actually increase due to the shave. But these increased NOx emissions would occur mostly in areas outside of the South Coast Air Basin. The District must evaluate these potential adverse air quality impacts. 5-4

For example, we estimate that, in response to a 50% NOx RTC shave, MPP may have to spend as much as $17 million between 2018 and 2023 to maintain its NOx RTC allocation and cover its PTE at the beginning of the compliance year, assuming no increase in capacity factor. This cost could be reduced somewhat if the District made RTCs available to MPP on a temporary basis to cover its PTE at the beginning of the compliance year, thus making it unnecessary for MPP to purchase these RTCs. These costs assume that RTC prices rise to a level comparable to the last time there was a NOx shave, in 2005 ($250/lb of so-called "perpetuity RTC"). This increase in MPP's operating costs could result in a shift of production to power plants outside of the South Coast Air Basin that do not bear these same increased costs.

In addition to evaluating these potential adverse air quality impacts in areas where emissions would increase under the proposal in the NOP, the District should also evaluate two alternatives that may reduce any potential adverse air quality impacts identified in the environmental assessment but still allow the project to achieve its basic objectives. One alternative is no reduction in RTC allocation for any power plant that already operates with either BACT or BARCT installed. A second alternative is to reduce each such power plant's RTC 5-5

Barbara Radlein
January 30, 2015
Page 3

allocation by a smaller amount than the amount proposed in the NOP, such as a 25% reduction. Under both of these alternatives, facilities that have not yet achieved BARCT could have their NOx RTCs shaved by whatever percentage is needed to achieve the emissions reductions in the proposal, without asking power plants to help pay for those reductions by having their own RTC allocations shaved. 5-5 Concluded

We appreciate your consideration of our comments. Please let us know if you have any questions.

Sincerely,

Charles F. Timms, Jr.

RESPONSES TO COMMENT LETTER #5
(Charles F. Timms, Jr. on behalf of
City of Burbank Department of Water and Power - January 30, 2015)

5-1 This introductory comment explains that this comment letter has been submitted on behalf of the City of Burbank Department of Water and Power in response to the CEQA document and proposed shave for the proposed project. Thus, responses to the specific concerns are presented in Responses 5-2 through 5-5.

5-2 This comment suggests that the Draft PEA should evaluate the adverse environmental effects that the 50 percent NOx shave will have on power plants due to higher costs that will cause electricity production to drop and the possible shift to producing electricity from other, more polluting power plants, located either inside or outside the South Coast Air Basin (SCAB). This comment also suggests that the Draft PEA should analyze at two alternatives, as follows: 1) not imposing a shave on any power plant that already operates with BACT or BARCT; and, 2) a smaller reduction than a 50 percent shave, such as a 25 percent shave, on power plant NOx RTCs.

Regarding the comment relative to increased costs that would cause production to drop, SCAQMD staff understands that the power producers can pass costs on to consumers, so there would be no need to reduce local generation.

With regard to comment relative to alternatives, a full range of alternatives have been developed and analyzed in Chapter 5 of the PEA. Alternative 4, the no project alternative, does not impose a NOx RTC shave on any RTCs held by power plants. The proposed project would apply a 47 percent NOx RTC shave to power plant RTC holdings. When compared to the proposed project, Alternative 3 contemplates a lesser NOx RTC shave to power plant holdings of 33 percent. The two alternatives suggested by the commentator are within the range of the existing alternatives of this PEA, so specific additional alternatives are not necessary.

5-3 This comment claims that most of the power plants that would be subject to the shave are gas-fired peaking plants with BACT or BARCT already installed. This comment further claims that power plants would need to purchase more RTCs to maintain or increase electricity production levels.

SCAQMD staff acknowledges the unique situation that power generators have with regard to operating at BARCT or BACT and the requirement for RTC holdings for New Source Review (NSR) purposes. The project now contains a proposal which establishes an adjustment account which would contain the shaved RTCs from new power producing facilities for the purposes of satisfying the NSR requirements. Most power plants emissions are much less than their potential to emit, so this provision will help reduce the amount of RTCs that power plants will need to hold.

5-4 This comment claims that RTC purchases in response to the shave would increase power plant operation costs and would reduce local generation but increase NOx emissions from other power plants transmitted to the municipal utilities. The comment claims that the increase in power plant NOx emissions would be generated outside of the South Coast Air Basin and that the District should evaluate these impacts.

A sector-specific approach has been proposed with the establishment of an adjustment account. Power producing facilities would meet the NSR holding requirements without purchasing credits with this adjustment account. RTCs in this account would only be made usable for compliance with annual emissions if California's governor declares a state of emergency.

In the Draft PEA, an energy analysis was conducted and an estimated increase of electricity demand was provided in Subchapter 4.3 – Energy of this PEA. From the estimated increased electricity demand, increases in both criteria pollutants and GHG emissions were quantified for the affected facilities in Subchapter 4.2 – Air Quality and Greenhouse Gases in this PEA.

5-5 This comment duplicates the suggestions expressed in Comment 5-2. See Response 5-2.

Comment Letter #6

California Council for Environmental and Economic Balance

Southern California Air Quality Alliance

Regulatory Flexibility Group

WSPA Western States Petroleum Association

30 January 2015

Dr. Elaine Chang
Deputy Executive Officer, Planning, Rule Development & Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

SUBJECT: INDUSTRY COMMENTS ON THE NOTICE OF PREPARATION (NOP) OF A DRAFT PROGRAM ENVIRONMENTAL ASSESSMENT FOR PROPOSED AMENDED REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

Dear Dr. Chang:

These comments are presented on behalf of the members of leading Southern California businesses represented by the California Council for Environmental and Economic Balance ("CCEEB"), the Regulatory Flexibility Group ("RegFlex"), the Southern California Air Quality Alliance ("SCAQA"), and Western States Petroleum Association ("WSPA"). The members of these business groups are major Southern California employers who own and operate facilities in the Regional CLean Air Incentives Market ("RECLAIM") program.

This "Industry RECLAIM Coalition" formally offers the following comments on the Notice of Preparation and Initial Study for the Draft Program Environmental Assessment ("PEA") for Proposed Amended Regulation XX ("NOP/IS").[1] 6-1

1. *The PEA Project Description should specify the potential shave* <u>*as a range*</u> *since neither the Proposed Amended Rule nor the Staff's Technical Report is complete.*

The Project Description presented in the NOP and Initial Study ("NOP/IS") incorporates Proposed Amended Rule (PAR) 2002 language as presented in Appendix A of the NOP/IS. At the time of the NOP/IS release, the AQMD had not completed technical work on this rulemaking, with the third-party consultant reviews having not even been released. The cover page for NOP/IS Appendix A did include the following disclaimer: 6-2

> *"The BARCT evaluation and the RTC shaving methodology are ongoing, so a RECLAIM industry's required RTC shave may change due to the public review process. The*

[1] SCAQMD, Notice of Preparation (NOP) of a Draft Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), 4 December 2014.

Dr. Elaine Chang, SCAQMD
30 January 2015

> *programmatic RTC shave could range from five to 14 tons per day. To provide a worst case scenario of adverse environmental impacts, the adjustment factors and the Non-tradable/Non-usable NOx RTC adjustment factors in Proposed Amended Rule 2002 subparagraph (f)(1)(B) reflect an RTC shave at the higher end of the range to capture a conservative estimate of potential control technologies needed that could generate secondary environmental impacts. As the staff proposal is being refined, if a lesser RTC shave is proposed, the adverse environmental impacts would be less and the Draft PEA and its alternatives will also be further defined."*[2]

Now that the third-party contractor reviews have been released, we expect changes are needed to the technical analysis which would alter the technical calculations. Members of this coalition have unresolved questions and concerns about those reviews and the current analysis from AQMD staff. But these reviews and additional inputs from industry stakeholders will necessitate revisions to the draft PAR 2002 language, and more changes will undoubtedly be needed as the rulemaking process progresses. 6-2 Concluded

For this reason, we recommend that the PEA Project Description should explicitly specify the potential shave under this rulemaking as a range. This could be accomplished using language similar to that which was presented on the NOP/IS Appendix A cover page, however this disclosure should be noted in the Project Description section of the main PEA document; not left only in an Appendix.

2. *The PEA should explicitly address at least two project Alternatives: (1) AQMP control measure CMB-01 as approved by the Governing Board (i.e., shave of 3-5 tpd); and (2) the Industry RECLAIM Coalition proposal.*

Under the 2012 Air Quality Management Plan ("AQMP"), the Governing Board approved control measure CMB-01 which authorized further reductions from the NOx RECLAIM program. The control measure authorized by the Governing Board was based on a range of 3-5 tons per day ("TPD") of RECLAIM Trading Credits ("RTCs") being removed from the program. While stakeholders understood the eventual rulemaking could differ, the current Staff proposal as presented in the NOP/IS would be substantially larger at nearly 13 TPD.

This Industry RECLAIM Coalition has presented an alternative methodology for demonstrating command-and-control equivalency. The Industry proposal would reduce the program's quantity of RTCs by limiting the "shave" to only those reductions that can be directly attributed to the advancement of Best Available Retrofit Control Technology ("BARCT"). This Industry proposal could also result in RTC reductions greater than the approved AQMP control measure, but less than those which have been presented by the AQMD Staff. 6-3

We recommend that both of these alternatives should be fully considered as project Alternatives in the PEA, at a minimum.

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[2] SCAQMD, NOP/IS for Proposed Amended Regulation XX, Appendix A, 4 December 2014.

Dr. Elaine Chang, SCAQMD
30 January 2015

3. *Public stakeholders should be provided a schedule that is consistent with regulatory requirements while providing reasonable opportunity for stakeholder review and comment.*

The proposed rulemaking could potentially result in significant economic impacts to Southern California businesses and the regional economy. The technical analysis for this rulemaking is not yet complete, and the potential impacts have not yet been fully analyzed or considered. To date, only preliminary technical data has been made available to stakeholders. As such, thorough review and input by the RECLAIM Working Group or other stakeholders has not been possible. 6-4

This Industry RECLAIM Coalition respectfully requests that stakeholders be provided with a rulemaking schedule, including this PEA and the socioeconomic analysis, that is consistent with applicable regulatory requirements but also provides stakeholders a reasonable opportunity for review and comment of the technical bases.

The RECLAIM program remains vitally important to the health of Southern California's economy and environment. The members of this coalition have actively participated in this rulemaking through the NOx RECLAIM Working Group over these last two years, and we look forward to continuing to work with you and the District's Staff on the significant rulemaking. 6-5

Very truly yours,

Bill Quinn
California Council for Environmental and Economic Balance

Michael Carroll
Regulatory Flexibility Group

Curtis Coleman
Southern California Air Quality Alliance

Patty Senecal
Western States Petroleum Association

RESPONSES TO COMMENT LETTER #6
(California Council for Environmental and Economic Balance et al - January 30, 2015)

6-1 This introductory comment explains that this comment letter has been submitted on behalf of multiple business groups that own and operate RECLAIM facilities in response to the CEQA document for the proposed project. Thus, responses to the specific concerns are presented in Responses 6-2 through 6-5.

6-2 This comment suggests that the project description in the Draft PEA should specifically describe the potential shave as a range in the same manner as the disclosure language inserted in Appendix A before PAR 2002. Since the proposed amended rule language and corresponding staff report were not complete at the time the NOP/IS was released for public review due to pending third-party consultant reviews and now that the third-party consultant reviews have been released, the technical analysis along with the proposed rule language is expected to change and as such, the Draft PEA should also reflect these changes.

The contractor's assessments were considered in the staff proposal in the Preliminary Draft Staff Report, which is the project analyzed in this PEA. The alternatives in the PEA include a No Project alternative and other alternatives that include a range of emission reductions.

6-3 This comment suggests that the Draft PEA should analyze at least two alternatives to the project. The first alternative should analyze a shave ranging from three to five tons per day in accordance with AQMP control measure CMB-01. The second alternative should analyze the "Industry RECLAIM Coalition" proposal which would limit the shave to only reductions that can be directly attributed to BARCT.

It is not necessary to add these specific alternatives because the ranges are included within the alternatives for the PEA. SCAQMD staff has included Alternative 3, the Industry Proposal, in the Draft PEA analysis. Staff did not explicitly analyze a three to five ton shave alternative as this would be between Alternative 3 and the No Project alternative (Alternative 4).

6-4 This comment is requesting a rule development schedule, to include the PEA and socioeconomic analysis, in order for public stakeholders to provide a reasonable opportunity for review and comment. This comment claims that the technical analysis for this rulemaking is not complete and only preliminary technical data has been made available to stakeholders. This comment claims that stakeholders have not been able to provide a thorough review and input. This comment claims that potential impacts have not been fully analyzed or considered.

Rule development efforts for the proposed project were initiated over two and a half years ago when staff presented basic concepts to the NOx RECLAIM Working Group on January 31, 2013. Since the January 31, 2013 Working Group Meeting, staff has held 11 additional Working Group meetings at which members were given multiple and ample opportunities to provide comments. For example, in March 2013, equipment with the highest potential for achieving NOx emission reductions was presented to Working Group members. Then, in September 2013, a preliminary assessment quantified potential NOx emission reductions and detailed survey results. In October 2013, third party contractors conducted site visits and reviewed staff's technical analysis and their results were released in December 2014 and presented at the January 7, 2015 Working Group meeting.

In addition to Working Group meetings, staff has met frequently with the members of the Industry RECLAIM Coalition and other stakeholders throughout this rule-making to answer questions and discuss any concerns related to this proposed amendment. Also, staff has presented an update on the progress of this rule development to the Stationary Source Committee on March 21, 2014 and July 24, 2015. During the entire rulemaking process, staff has kept the public and stakeholders adequately informed on all upcoming milestones. Based on concerns that have been raised by the regulated community, the rulemaking schedule has been adjusted. At the earliest practical time staff will continue to apprise stakeholders of any future scheduling changes. To date there have not been any scheduling changes that would have given stakeholders less time to provide comments.

While it is true that the technical analysis for this rulemaking effort was not complete at the time the NOP/IS was released for public review and comment, the technical analysis for this proposed amendment is currently well-developed. The Draft PEA reflects the staff proposal for a 14 ton per day shave of NOx RTC holdings which is consistent with the project as described in the NOP/IS. In fact, the Draft PEA fully analyzes the potential environmental impacts that were identified in the NOP/IS as having potentially significant adverse effects.

The public hearing for these proposed rule amendments is currently scheduled for November. As the rule development process continues, there will be subsequent opportunities for the public and stakeholders to provide comments on staff's technical analysis, such as the 45-day public review and comment period provided for this Draft PEA.

6-5 This comment expresses the desire for commentators to continue to work with the SCAQMD on this rulemaking. SCAQMD staff appreciates the input of all stakeholders and looks forward to future discussions regarding the proposed changes to the NOx RECLAIM program.

Comment Letter #7

PARAMOUNT PETROLEUM

a subsidiary of ALON USA

14700 Downey Avenue
P.O. Box 1418
Paramount, CA 90723-1418
(562) 531-2060

January 30, 2015

Ms. Barbara Radlein
Mr. Joseph Cassmassi
South Coast Air Quality Management District
21865 E. Copley Dr.
Diamond Bar, CA 91765

Re: Comments on Proposed RECLAIM Regulation XX Amendment and associated CEQA Notice of Preparation and Initial Study (NOP/IS)

Dear Ms. Radlein and Mr. Cassmassi:

Paramount Petroleum Corporation (Paramount) appreciates the opportunity to comment on the District's proposed amendments to Regulation XX, and the associated CEQA document. In particular, Paramount's comments will focus on the Project Description contained in the CEQA document and the clear inconsistency between the Project Description and how the proposed rule changes will impact Paramount's refinery. These comments are being addressed to both the District's CEQA section and the Rule Development Division. We would like to begin our comments by stating that we were gratified that the District undertook efforts to visit the various refineries in the District and look at the cost effectiveness of various controls strategies. 7-1

The current Nitrogen Oxide (NOx) RECLAIM universe consists of approximately 276 facilities. The objective of the Proposed Project is to achieve additional NOx emission reductions on the top 39 RECLAIM facilities. However, the reduction allocation distribution currently being analyzed in the CEQA document is a single cut across the board of fifty percent shave to all RECLAIM facilities as a worse-case scenario. Paramount believes that there is clear discrepancy between the project's objectives and the scenario that is being analyzed. Thus we believe that the Project Description is flawed and the District cannot undertake a proper CEQA analysis. To demonstrate how the proposed project would adversely impact affected facilities, Paramount will use itself as an example. 7-2

The CEQA Project Description provided in the CEQA document identifies six refineries owned by five companies (Tesoro, Phillips 66, Chevron, Exxon/Mobile, and Ultramar (Valero)) that operate FCCUs (fluid catalytic cracking units), boilers and heaters, gas turbines, and SRU/TGU (sulfur recovery unit/tail gas unit), and proposes selective catalytic reduction (SCR) as BARCT for these process units and concludes that the proposed reduction is achievable and cost effective. Paramount does not dispute the 7-3

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District's analysis with respect to these facilities. But conspicuously absent from the Project Description's analysis is any mention of the Paramount Refinery. 7-3 Concluded

The top 39 facilities primarily consist of refineries and power plants. Paramount is twenty- ninth on this "top emitters" with aforementioned refineries taking the top seven spots. The average refinery NOx emissions excluding Paramount during the 2011 to 2013 time period was approximately 1.1 million pounds. Paramount's emissions averaged about 80,000 pounds or approximately 7 percent of the other refineries' average emissions. There is a clear size difference between Paramount and other refiners. 7-4

The District's proposed shave, which is based upon a BARCT of SCR, fails to take into account the equipment differences between complex fuel producing refineries and less complex refineries like Paramount. More importantly it fails to take into account that since the last shave in 2005, Paramount has accounted for third of SCR's installed and one-half of the sources controlled by SCR's at refineries. 7-5

If the rules proposed reductions were cost effective Paramount would not be preparing these comments. The District's own staff concluded that there is only one source at Paramount that meets the BARCT cost effectiveness criteria and the independent consultant hired by the District to review the cost effectiveness determinations concluded that none of the sources at Paramount meet the BARCT cost effectiveness criteria. 7-6

Paramount understands that there is a need to reduce NOx emissions within the Basin and therefore we are not asking to be excluded from the shave.[1] Instead we believe that the District needs to recognize, that not all refineries are the same and revises the Project Description and the rule to acknowledge that there is a distinct line between Paramount and other major refineries that justifies a separate shave percentage. 7-7

Paramount does not operate a FCCU or Coker, has a lower throughput and different product mix than most if not all of the other refineries in the Basin, and has installed more SCRs on its sources since 2005 than any other refineries. Therefore our opportunities to control sources are significantly more limited than the majors. The across the board fifty percent shave would impose a severe and unjustified burden on Paramount when compared to other refineries. 7-8

Moreover, Paramount is a Low Complexity-Low Energy refinery as defined in the proposed California Air Resources Board (CARB) Low Carbon Fuel Standard. The CARB Low Complexity-Low Energy means that Paramount is more fuel efficient in its processing operations on a per barrel bases than larger more complex refiners. It also means that Paramount is a lower NOx emitter on a per barrel bases than other refineries in the Basin. Attached to this letter is a bubble chart showing the 2013 Green House Gas 7-9

[1] Paramount is opposed to making any RECLAIM credits non-tradable and believes that doing so is contrary to the spirit and purpose of the RECLAIM Program.

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(GHG) emissions for the various refineries in the Basin. GHG emissions are a surrogate for fuel combustion. The Chart clearly demonstrates that there is a distinct line between us and the other refineries. Looking at average refinery NOx emissions of the subject refineries (excluding Paramount), the average mass of NOx emitted on a per barrel bases was 6.52 pounds per barrel of name plate capacity during the 2011 to 2013 time period. Paramount emitted approximately 3 pounds of NOx per barrel of name plate capacity using the highest annual NOx emissions from the past 10 years. Even if other refiners reduced their NOx emissions by fifty percent on a per barrel bases, their emissions would still be more than of Paramount. 7-9 Concluded

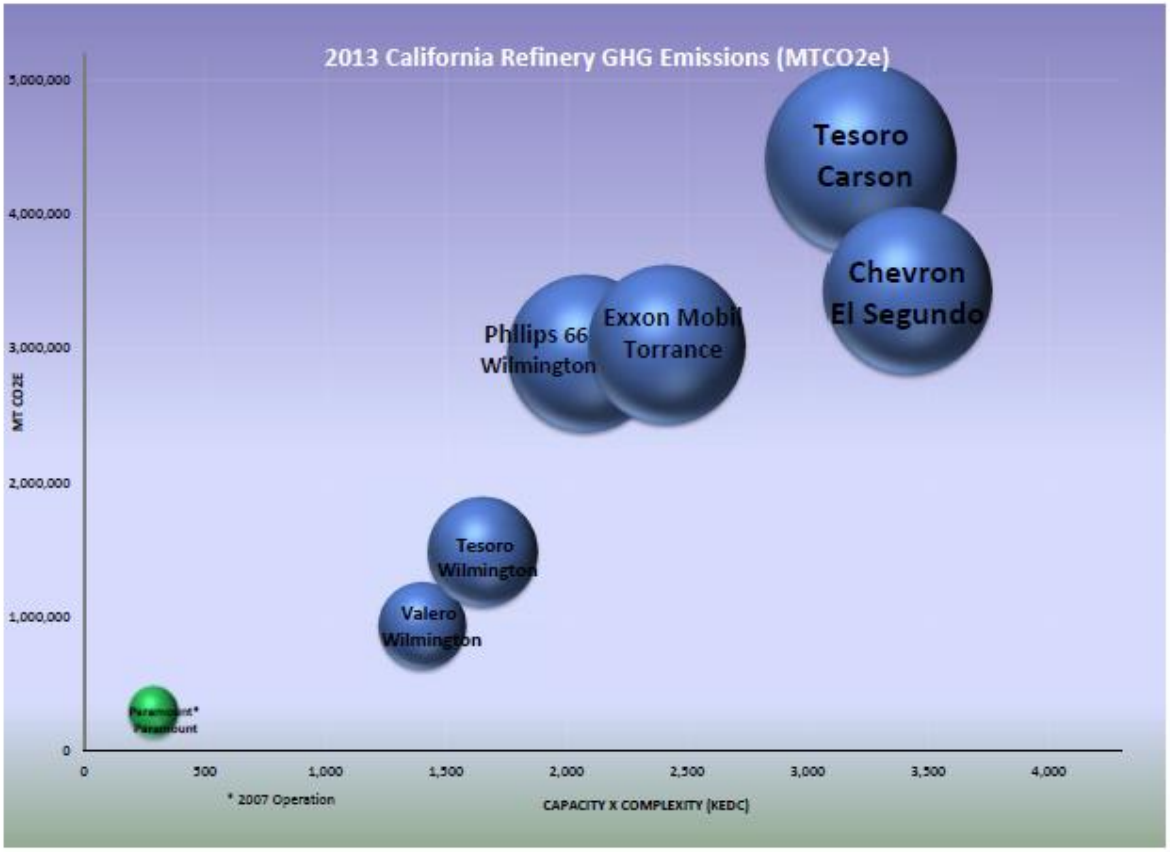
Since the necessitated AQMP emission reductions do not require that the District imposes a fifty percent shave across the board, Paramount believes that the District should use this flexibility to allow for subsets of facilities within the universe of facilities to be shaved and apply a different shave percentage to these facilities. In the case of the refining sector, refineries that do not have Cokers and FCCUs and/or meet the CARB definition of a Low Complexity-Low Energy refinery could be considered a separate subset of the refining sector subject to a lower shave percentage. Paramount would be happy to work with the District to craft appropriate language to define this subset. 7-10

Please feel free to contact me with any questions you may have.

Sincerely,

Matthew Jalali
Managing Director of Environmental Affairs

CC:
Gary Quinn, AQMD



2013 California Refinery GHG Emissions (MTCO2e)
MT CO2E
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
CAPACITY X COMPLEXITY (KEDC)
* 2007 Operation
Tesoro Carson
Chevron El Segundo
Exxon Mobil Torrance
Phillips 66 Wilmington
Tesoro Wilmington
Valero Wilmington

RESPONSES TO COMMENT LETTER #7
(Paramount Petroleum - January 30, 2015)

7-1 This introductory comment explains that this comment letter has been submitted in response to the proposed amendments to Regulation XX and the associated CEQA document and focuses on an alleged an inconsistency between the project description and project implementation. This comment also expresses appreciation for efforts made by SCAQMD staff to visit various refineries and to examine the cost effectiveness of various control strategies. Thus, responses to the specific concerns are presented in Responses 7-2 through 7-10.

7-2 This comment explains that there is a discrepancy between the objective of the proposed project (e.g., to achieve NOx emission reductions from the top 39 RECLAIM facilities out of a total of 276) versus the worst-case analysis in the CEQA document (e.g., a 50 percent shave across all 276 facilities). This comment asserts that the project description in the CEQA analysis is flawed and because of this flaw, a proper CEQA analysis cannot be done.

Since the release of the NOP/IS, the proposed project has been modified to apply a shave to the holders of the top 90 percent of RTCs. However, based on feasibility and cost-effectiveness, NOx controls would be installed at only 20 facilities. The remainder would surrender RTCs or purchase RTCs in order to comply with the proposed project. The environmental impacts would only be associated with the installation and operation of NOx control equipment.

7-3 This comment agrees that SCR is BARCT for FCCUs, boilers and heaters, gas turbines, and SRU/TGUs that are operated by six refineries owned by five companies and that the proposed reductions are achievable and cost-effective. This comment also points out that project description in the CEQA document does not mention the commentator's facility (e.g., Paramount Petroleum).

SCAQMD staff is pleased that you agree with its BARCT analysis related to the larger refiners. The proposed project was designed to apply BARCT to various types of equipment and processes operated by a multitude of industries, including but not limited to refineries. The equipment/processes for which BARCT was identified are as follows: 1) FCCUs; 2) refinery boilers and heaters; 3) refinery gas turbines; 4) SRU/TGUs; 5) non-refinery/non-power plant gas turbines; 6) non-refinery sodium silicate furnaces; 7) non-refinery/non-power plant ICEs; 8) container glass melting furnaces; 9) coke calcining; 10) Portland cement kilns, and, 11) metal heat treating furnaces. While Paramount Petroleum is considered a refinery that is part of the NOx RECLAIM program, Paramount Petroleum does not operate a FCCU or SRU/TGU. Paramount Petroleum operates refinery boilers and heaters that were analyzed for BARCT, but these units were found to be already at BARCT. For the proposed RTC shave calculation, Paramount has been included as part of the non-major refinery category that would be subject to a lesser shave than the major refineries. See Table 8 in PAR 2002.

7-4 This comment identifies Paramount Petroleum as being a relatively small emitter in the NOx RECLAIM program by being ranked 29th out of the top 39 emitters when compared to the other refiners that take the top seven spots.

SCAQMD staff agrees that there is a difference in NOx emissions between Paramount Petroleum and the other larger refiners operating in the District. However, because the Basin is designated as an "extreme" nonattainment area for the 8-hour ozone standard under federal law, and because NOx is a precursor to ozone formation, NOx emission reductions are being sought from a large variety of RECLAIM sources as part of this rulemaking as well as from non-RECLAIM facilities that emit considerably less emissions than Paramount (as part of other rulemaking activities in accordance with control measures in the Final 2012 AQMP).

7-5 This comment claims that the proposed shave does not take into account the equipment differences between complex fuel producing refineries and less complex refineries like Paramount Petroleum. This comment also claims that the proposed shave does not take into account that one-third of the SCRs that were installed in response to the 2005 NOx RECLAIM shave were installed at Paramount Petroleum.

The task of achieving RECLAIM NOx emission reductions has historically been approached in a programmatic manner. The size of a particular facility or the number of sources within a facility with potential emission reduction opportunities has not always been a determining factor as to whether a particular facility would be subject to a shave. As explained in Response 7-3, Paramount Petroleum operates refinery boilers and heaters that were analyzed for BARCT, but these units were found to be already at BARCT. For the proposed RTC shave calculation, Paramount has been included as part of the non-major refinery category that would be subject to a smaller shave than the major refineries.

7-6 This comment expresses disagreement with SCAQMD's position that the proposed BARCT that would only apply to one source at Paramount Petroleum is cost-effective. This comment claims that the consultant hired by the SCAQMD did not identify any sources at this facility that meets the BARCT cost-effectiveness criteria.

As explained in Response 7-3, Paramount Petroleum operates refinery boilers and heaters that were analyzed for BARCT, but these units were found to be already at BARCT. The proposed shave would affect those facilities that are among the top 90% of NOx RTC holders. For the proposed RTC shave calculation, Paramount has been included as part of the non-major refinery category that would be subject to a smaller shave than the major refineries at 47 percent. There is an opportunity within the current proposed rule that would exempt a facility from the requirements of the shave if the facility can demonstrate that their equipment is at BARCT, in addition to other criteria. The requirements to qualify for this exemption are outlined in Proposed Amended Rule 2002 (i).

7-7 This comment is requesting the SCAQMD to revise the project description to include a separate shave percentage for Paramount Petroleum.

Staff has not established an individual shave for Paramount Petroleum but this facility is included in the non-major refinery category and the NOx RTCs for this category would be subject to a 47 percent shave.

7-8 This comment claims that the opportunities to further control NOx emissions at the Paramount Petroleum facility are significantly limited and an across the board 50 percent shave would impose a "severe and unjustified" burden on this facility.

SCAQMD staff agrees that this facility is different than the major refineries based on the equipment they operate. The proposed project would apply a NOx RTC shave of 67 percent to the major refineries, while for non-major refining facilities, a NOx RTC shave of 47 percent would be applied.

SCAQMD staff is aware of Paramount Petroleum's concern about severe or unjustified burdens and have attempted to minimize the impact to this facility by applying a sector-based shave approach that excludes Paramount Petroleum from the major refineries category. In addition, there is a safety valve in the rule that may alleviate the burden of the shave to a facility's RTC allocation in the event of a shortage of RTCs in the market. If there is a shortage of credits which would result in an increase in the RTC price, the safety valve in the rule would provide access to non-usable, non-tradable credits in the event that the 12-month rolling average market price for discrete year credits rises above $15,000 per ton. Furthermore, as stated Response 7-6, a facility whose equipment is already at BARCT may apply to be exempted from the shave requirements if it meets the criteria in Rule 2002 (i).

7-9 This comment claims that Paramount Petroleum qualifies as a "Low Complexity-Low Energy" refinery as defined in CARB's Low Carbon Fuel Standard because of high fuel efficiency operations, lower NOx emissions per barrel and lower GHG emissions when compared to the other, larger refineries.

The commentator's assessment of NOx emissions on a per barrel bases appears to be correct. The proposed rule would reduce RTCs from this facility using a smaller percentage than applied to the other, larger refineries.

7-10 This comment claims that NOx emission reductions required by the AQMP do not require a 50 percent shave across the board and instead flexibility should be allowed to account for facility differences.

The staff proposal is the result of a much more rigorous and in-depth analysis as compared to the analysis that supported control measure CMB-01. For a market-based incentive program, SCAQMD staff is required by the California Health and Safety Code to conduct periodic BARCT assessments and demonstrate equivalency with command-and-control rules which would otherwise be developed as a result of BARCT assessment. CMB-01 anticipated this BARCT assessment but could not predict the results of the assessment, and therefore made commitments for a more modest reduction. This staff proposal recommends a reasonably available 14 tpd of NOx RTC reductions, based on

BARCT, as required by state law, and which are needed to help the Basin achieve the PM2.5 standards by 2019 and 2025 and the ozone standards by 2024 and 2032.

Also, as explained in Responses 7-6 and 7-8, this refinery will be excluded from the major refinery category and will be subject to a smaller shave percentage because of the differences in equipment operated.

Comment Letter #8

COMMENTS OF HARVEY EDER FOR SEF & PSPC PUBLIC SOLAR POWER COALITION ON THE RECLAIM NOW PROGRAM PAR CEQA DRAFT EA DUE TODAY JANUARY 30, 2015.

PUBLIC SOLAR POWER COALITION
1223 WILSHIRE BLVD. #647
SANTA MONICA, CA. 90403
harveyederpspc@yahoo.com
(310) 393 2589

ATT KEVIN ORELLANA

SEE ATTACHMENT A AN OVERVIEW OF THE KRAMER JUNCTION SEGS REPORT PERFORMANCE

1. SOLAR ENERGY IS BARCT AND SHOULD HAVE BEEN SUBMITTED AS THE BEST AVAILABLE RETROFIT TECHNOLOGY - OK. GO ON WITH THE BACK UP OPTIONS CITED BY STAFF BUT SOLAR THERMAL SYSTEM WITH LINE FOCUS CONCENTRATOR WITHIN 100 MILES OF THE DISTRICT SUPPLYING 354 MW (MEGAWATTS) HAVE BEEN OPERATING FOR 30 TO 20 YEARS - SEE POWER POINT PRINT OUT 9 PAGES ON SEGS SOLAR ENERGY ELECTRIC GENERATING SYSTEMS (9 IN ALL - 1 - 14 MW 6 30 MW AND 2 80 MW) THESE HAVE BEEN THE LARGEST OPERATION SOLAR THERMAL AT MODERATE TEMPERATURE 500 - 700° F & HIGHER TEMPS CAN BE OPERATED FOR USE WITH POINT DOUBLE AXIS SOLAR CONCENTRATORS OF 1000° F + + PLUS STORAGE (9 SEE THE 9 PAGE POWER POINT PRINT OUT PROVIDED BY PSPC/HE 8-1

2. PSPC/HE SHOULD BE HIRED AS CONSULTANT TO SHOW THE SOLAR OPTIONS BOTH SOLAR THERMAL & P.V. PHOTOVOLTAICS & HYBRIDS AS SOON AS POSSIBLE THIS CAN FORM THE CENTER OF ON, NEAR & FURTHER SOLAR THERMAL CHP COMBINED SOLAR COMBINED HEATING & COOLING - DISTRICT HEATING & COOLING SYSTEM (ABSORPTION VS. LIC DR. BROMIUM ETC. AS WELL AS ELECTRICITY - THE REPAIR OF SEWAGE AND WATER SYSTEMS WILL BE PLANNED AT THE SAME TIME AS WELL AS REPLACING OLD NAT GAS SYSTEM ALA SAN BRUNO EXPLOSION IN PG&E TERRITORY GT 8-2

PAGE 1 OF 3

"2. BACT IS A TECHNOLOGY FORCING" CONTROL MEASURE
CITE 2012 CALIFORNIA SUPREME COURT DECISION ON VOC IN
AMERICAN COATINGS ASS VS. SCAQMD, THE LAW IS CLEAR
AND AS POINTED OUT IN THE CURRENT LITIGATION THAT
THE COMMENTER HAS WITH THE DISTRICT (WITH A DRAFT
AMENDED FIX CARB + NOW FEDERAL EPA ETC.
YOU CAN PAY NOW FOR THE CONSERVATION AT A LOWER COSTS
OR PAY MORE LATER, RECENT STUDY BY THE PRESIDENTS
ECONOMIC ADVISORS SAYS + DEMONSTRATED THAT CLIMATE
CHANGE IMPLEMENTATION WILL COST 40%+ EACH 10 YEARS
THAT WE WAIT.

8-2 Concluded

3. THE SGES PLANTS WERE BROUGHT TO THE SCD DECADES
BY THE PLANT/CONSULTANT, THIS INFORMATION WAS PURGED
BETWEEN EARLY 1991 AQMP DRAFT & THE FINAL ADOPTED
IN MID YR JULY 1991 - OUR LITIGATION FOLLOWED BUT WITHOUT
A FOLLOW THROUGHT - THE TIME TO ACT IS NOW IF NOT
YESTERDAY

8-3

4. A FULL CEQA EIR MUST BE DONE

8-4

5. IN REFERENCE TO THE DEC 5, 2014 DOCUMENT AT LEAST
SOLAR ENERGY MUST BE STUDIED AS AN ALTERNATIVE
THE AREAS COVERED ARE ENERGY, GHG GREEN HOUSE GASES,
TRANSPORTATION & TRAFFIC AS WELL AS WATER (GIVEN THE
FACT THAT OVER 20% OF THE DISTRICT/STATE ENERGY
IS USED TO MOVE WATER

8-5

PAGE 2 OF 3

6. Immediate Total Solar Conversion means Now or Yesterday year. Climate change etc was addressed in the 1992 BC cases that are in the record in the Superior & Appellate Courts in the State as well as the Federal 9th Circuit Appeal Court. This time with a plethora of Environmental & Community Groups joining us HG/PSPC in litigation. The drought continues 8-6

7. The fact that almost 24 years ago the District had all of the information in hand during litigation with us from the Sunshot initial draft prepared by [illegible] herein as well as the complete sections of Solar Thermal & Solar Photovoltaic Technology - Sunshot is a play on words for Kennedys moon shot in the 1960's - over 60% on its way to all grid parity as of last year with only 40% of time passing this is for everywhere in the U.S.A. All other [illegible] in SC 119641 Eder vs SCAQMD as well as R251627 as well as the Federal Record & Federal Register Sep 3, 2014 and all information submitted to date as well as in the future are incorporated here into the record. 8-7

8. At the January 7 GB meeting Eder/PSPC stated that (as is part of the record) no consultant was hired to study solar energy as a part which has been before the District & CARB for decades! 8-8

9. As the cover article in this weeks Economist says Carpe Diem of Seize the Day. Gov. Brown set 50% solar renewables by 2030 OK fine but he's off by 100% in technology and 100%/50% off in the years to 2025! 8-9

Solar Conversion Now!

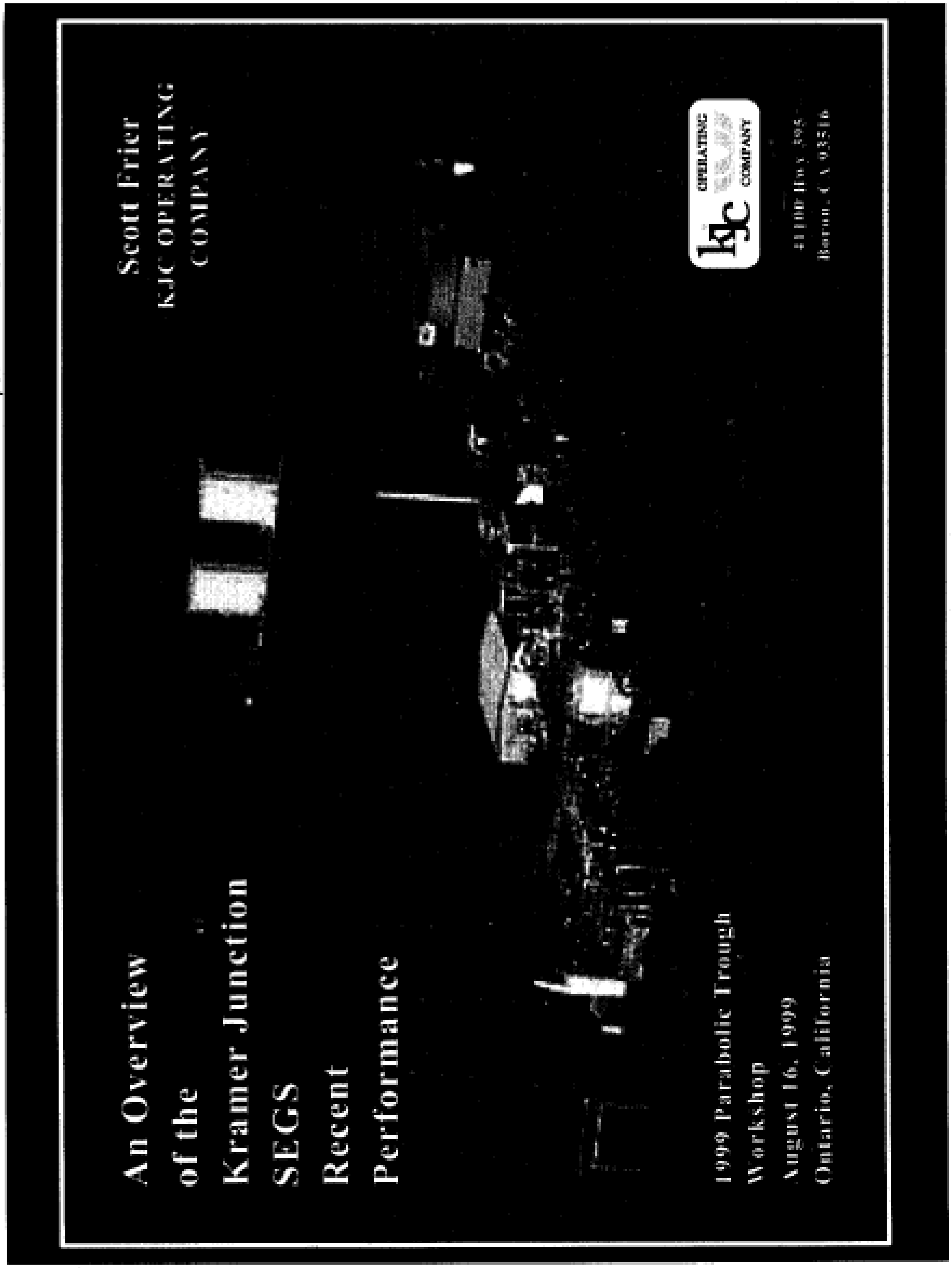
PS- As usual [illegible]

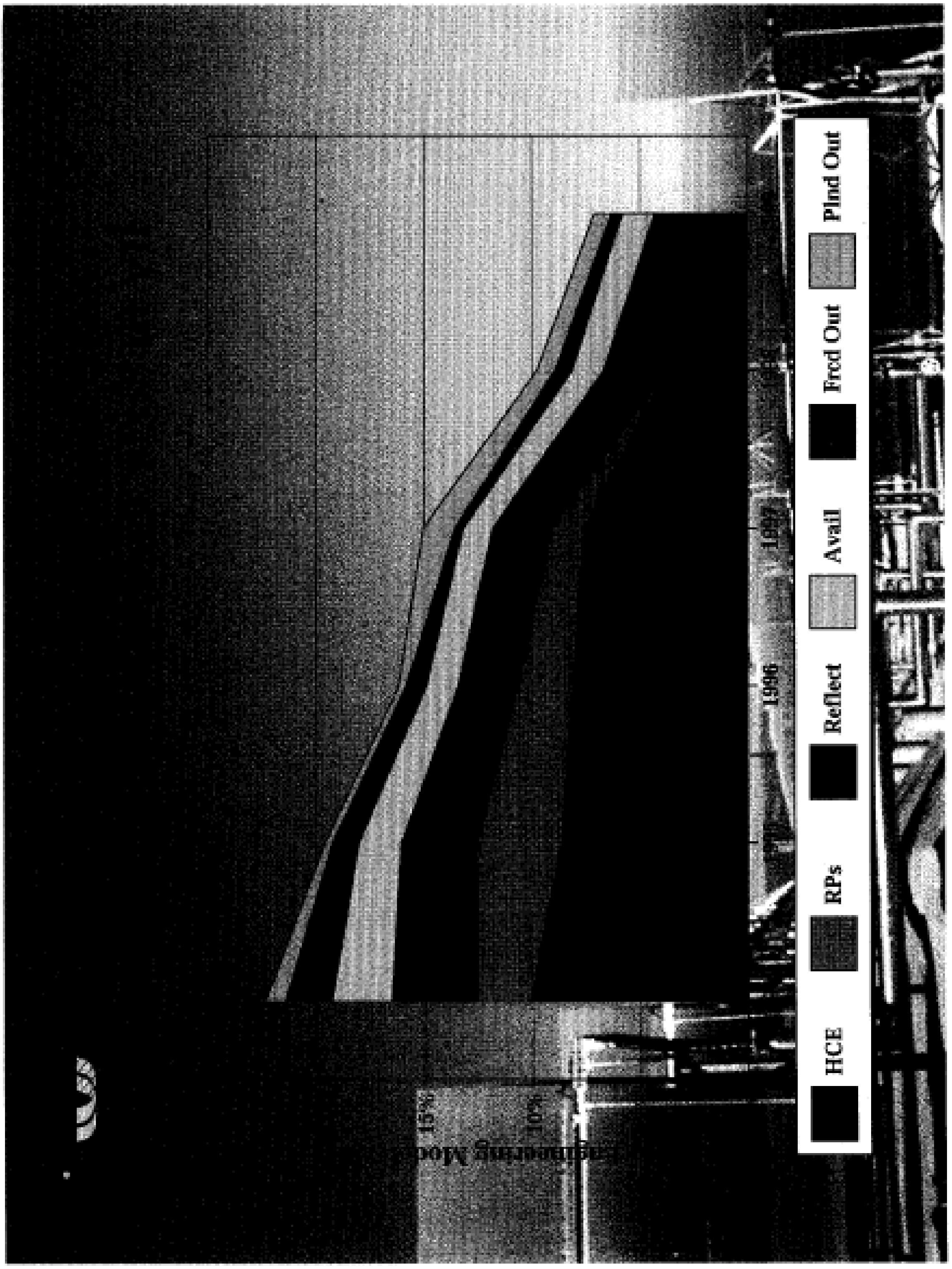
Page 3 of 3
+ Attachment A

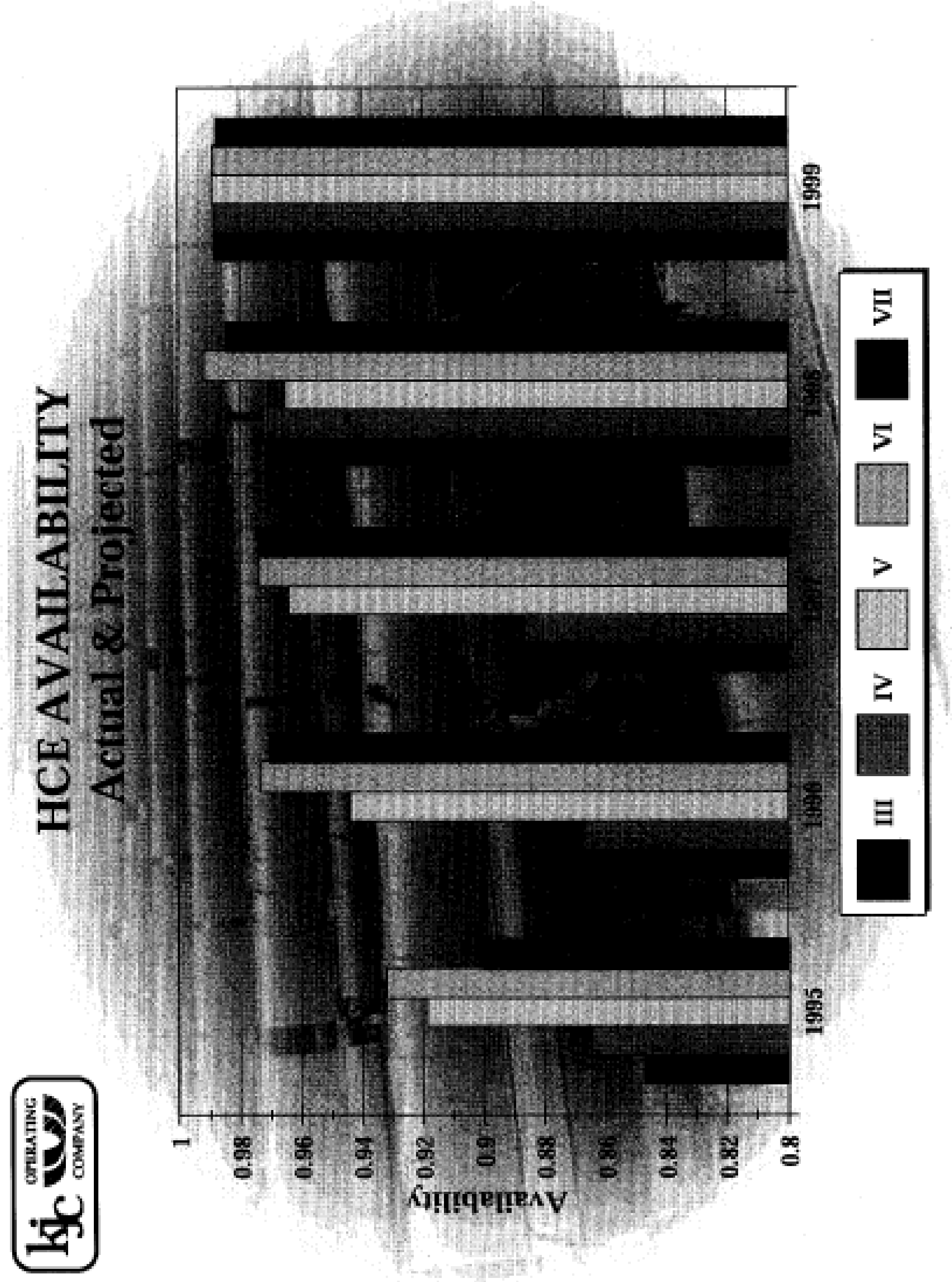
Public Solar Power Coalition
Harvey Eder/Director
1223 Wilshire Blvd. #607
Santa Monica CA. 90403
Since 1978
harveyederpspc@yahoo.com
(310) 393-2589
Solar Conversion Now!

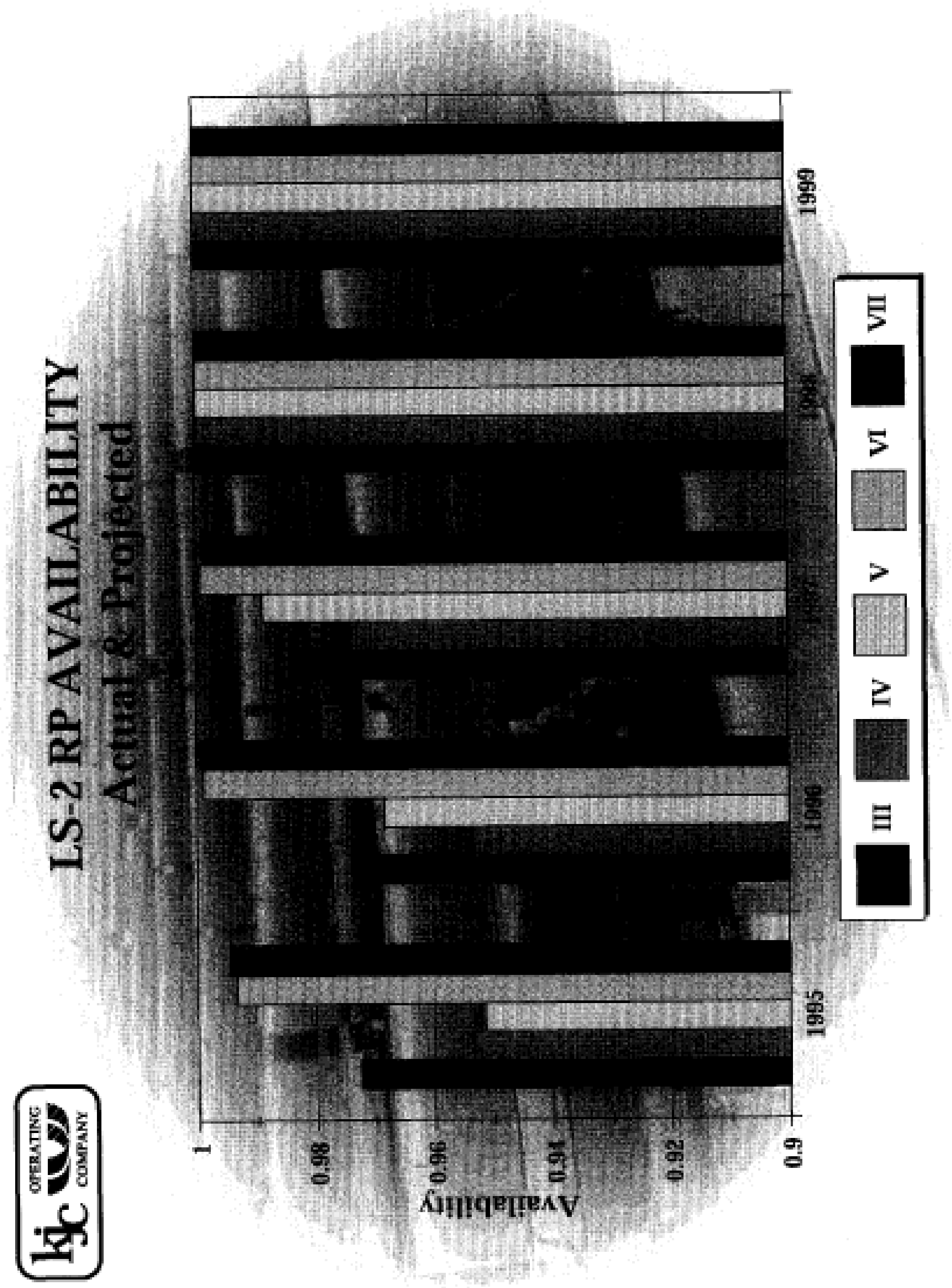
The sun makes the wind blow, water flow & plants grow.
It can be used directly or stored for days, weeks or months.

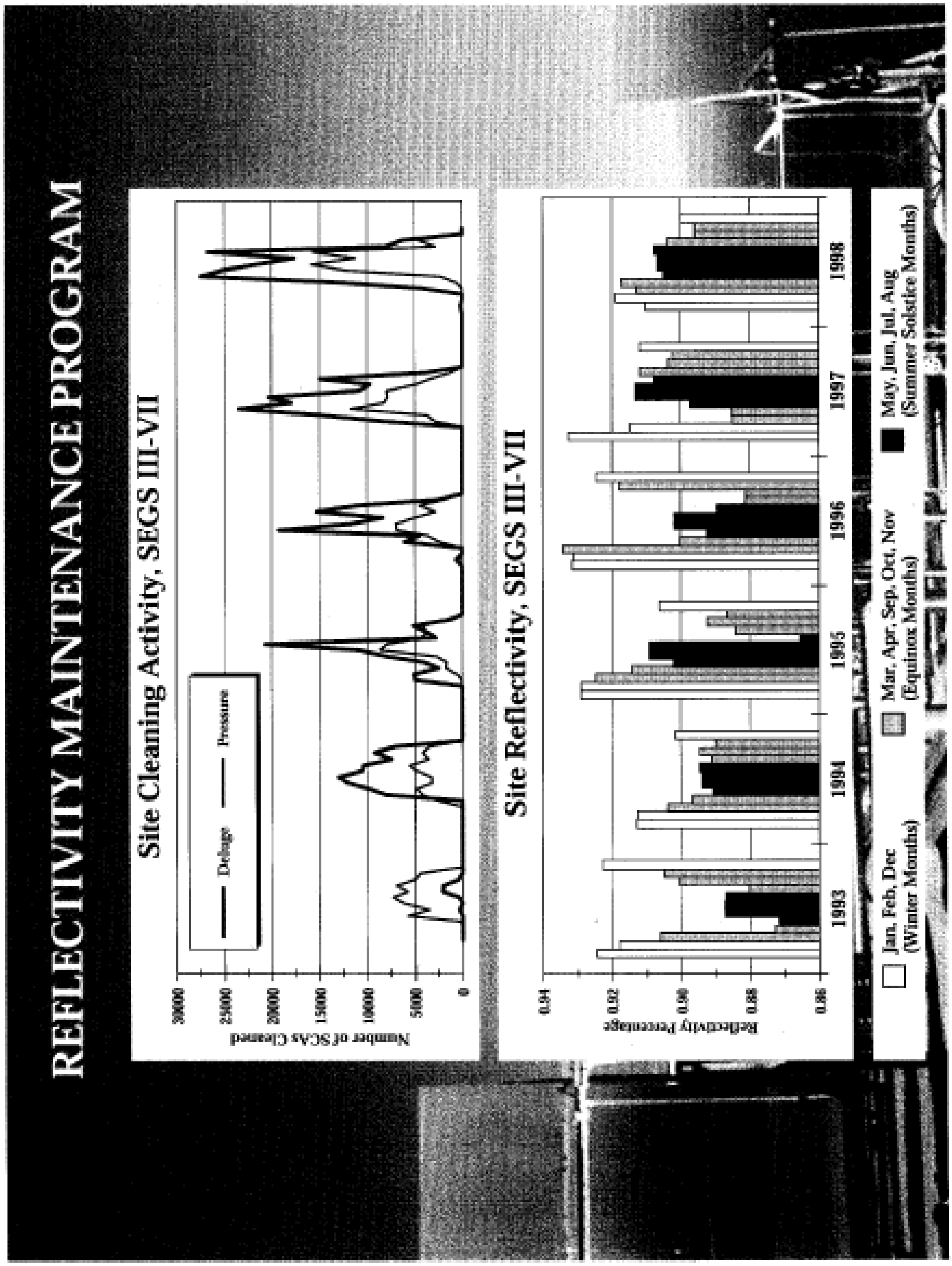
1/30/15 ATTACHMENT A WITH 3 PAGES OF COMMENTS OF HARVEY EDER FOR SEIE & PSPC PUBLIC SOLAR POWER COALITION

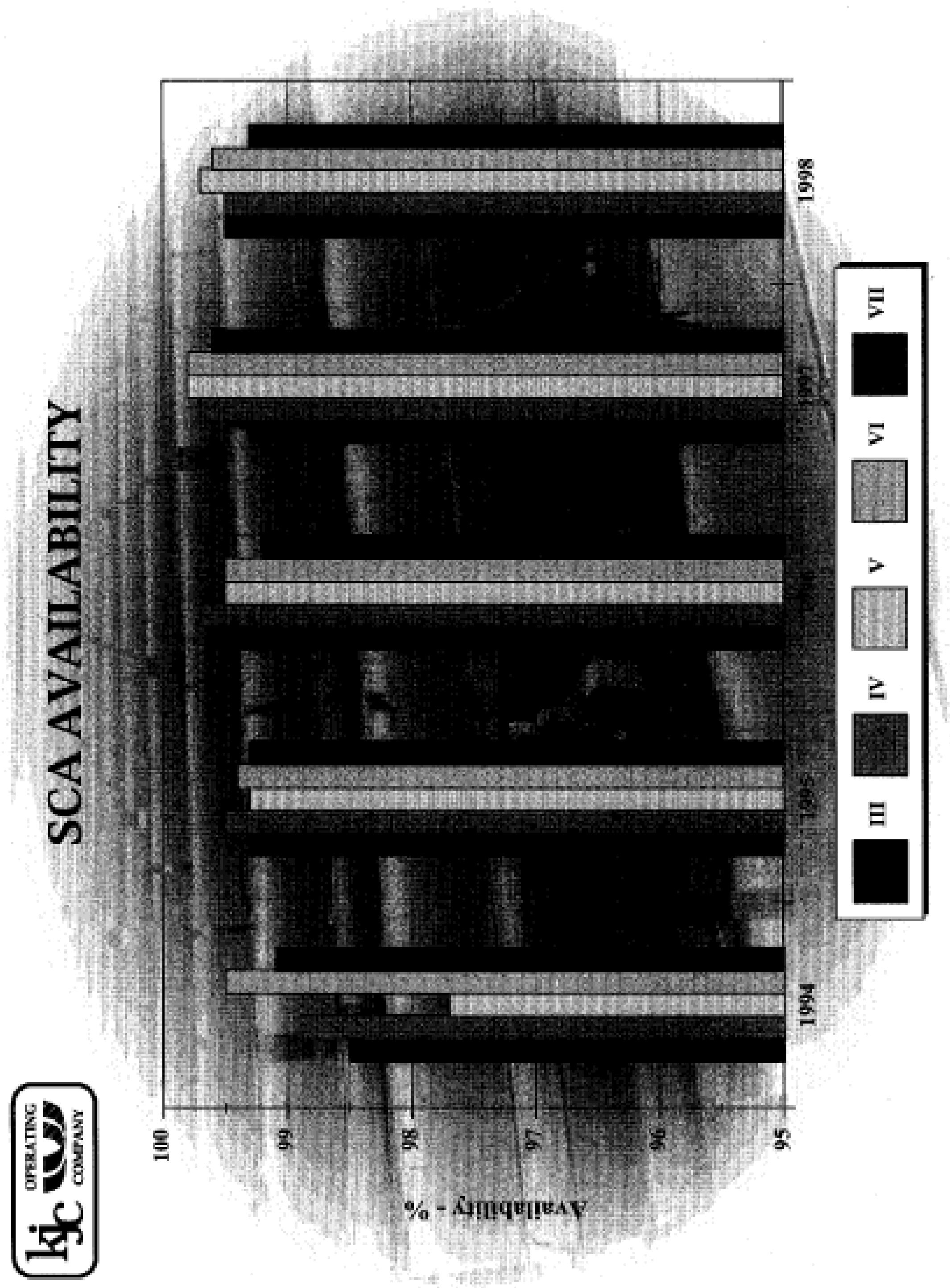



HCE
RPs
Reflect
Avail
Frcd Out
Plnd Out
1996
15%
10%


HCE AVAILABILITY
Actual & Projected
Availability
1
0.98
0.96
0.94
0.92
0.9
0.88
0.86
0.84
0.82
0.8
1995
1996
1999
III
IV
V
VI
VII
OPERATING COMPANY


LS-2 RP AVAILABILITY
Actual & Projected
Availability
1
0.98
0.96
0.94
0.92
0.9
1995
1996
1999
III
IV
V
VI
VII
kjc OPERATING COMPANY


REFLECTIVITY MAINTENANCE PROGRAM
Site Cleaning Activity, SEGS III-VII
Deluge
Pressure
Number of SCAs Cleaned
30000
25000
20000
15000
10000
5000
0
Site Reflectivity, SEGS III-VII
Reflectivity Percentage
0.94
0.92
0.90
0.88
0.86
1993
1994
1995
1996
1997
1998
Jan, Feb, Dec (Winter Months)
Mar, Apr, Sep, Oct, Nov (Equinox Months)
May, Jun, Jul, Aug (Summer Solstice Months)


SCA AVAILABILITY
kjc OPERATING COMPANY
Availability - %
100
99
98
97
96
95
1994
1995
1998
III
IV
V
VI
VII

GROSS SOLAR PRODUCTION (MWh)

Year	SEGS III	SEGS IV	SEGS V	SEGS VI	SEGS VII	III - VII
1987	42,772	[illegible]	0	0	0	87,253
1988	60,724	63,856	62,827	0	0	187,407
1989	63,087	70,552	65,281	48,045	38,868	285,843
1990	70,510	75,801	72,449	62,682	57,661	339,103
1991	60,132	64,307	59,009	64,155	58,259	305,862
1992	48,702	50,971	55,383	47,087	46,940	249,083
1993	58,248	58,935	67,685	55,725	54,110	294,703
1994	56,892	57,785	66,255	56,934	53,281	291,157
1995	56,663	54,929	63,757	63,650	61,210	300,209
1996	64,170	61,970	71,439	71,409	70,138	339,127
1997	64,677	64,503	75,936	70,019	69,186	344,321
1998	70,598	71,635	75,229	67,358	67,651	352,471

July YTD Gross Solar Electric Production (MWh)

Year	SEGS III	SEGS IV	SEGS V	SEGS VI	SEGS VII	III .. VII
1987	28,869	30,060	0	0	0	58,930
1988	40,929	41,414	41,553	0	0	123,896
1989	41,846	45,920	42,494	29,055	23,044	182,359
1990	45,251	47,321	45,137	38,156	35,160	211,025
1991	40,775	43,096	37,189	43,194	38,953	203,207
1992	30,886	31,704	34,536	28,944	29,177	155,247
1993	37,833	37,337	43,028	34,573	33,673	186,544
1994	37,706	38,283	43,369	37,616	34,678	191,653
1995	36,484	35,059	41,489	38,010	36,092	187,734
1996	42,082	41,063	46,246	46,664	46,073	222,128
1997	41,705	41,133	50,028	45,280	45,733	223,879
1998	45,468	45,588	48,555	42,460	43,508	225,580
1999	43,361	44,652	42,064	44,580	41,427	216,091

Kramer Junction Average Daily DNR Data (kWh/m2/day)

	Table 1	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Avg
Jan	**5.183**	**6.519**	5.852	4.754	4.740	3.401	5.852	3.027	6.401	4.861	5.011	5.655	5.098
Feb	**6.019**	6.145	5.879	6.613	4.290	4.241	5.111	6.851	4.849	**7.092**	4.613	6.365	5.641
Mar	**6.735**	7.325	6.984	6.630	3.870	6.539	7.410	6.170	7.316	**8.554**	7.500	6.930	6.839
Apr	**8.385**	8.707	7.535	8.896	6.670	8.149	7.546	8.144	**9.103**	8.393	8.416	7.330	8.081
May	**9.290**	9.190	9.368	9.596	6.927	8.463	8.612	7.674	**9.649**	9.242	8.562	9.318	8.782
Jun	**9.849**	10.360	10.312	10.166	8.675	9.554	**10.820**	10.044	10.620	9.929	10.662	10.498	10.149
Jul	**9.423**	9.906	9.624	9.194	8.549	10.239	9.288	10.402	9.335	9.845	**10.663**	9.471	9.683
Aug	**8.738**	9.594	9.355	8.850	8.091	9.466	8.935	**9.973**	9.253	9.176	9.572		9.227
Sep	**7.950**	8.528	8.807	7.261	7.524	**9.443**	8.115	9.370	9.375	7.780	7.981		8.418
Oct	**7.076**	7.261	8.208	7.503	6.108	6.904	7.149	8.140	7.661	**8.351**	7.802		7.509
Nov	**5.697**	**6.950**	6.905	6.496	5.994	6.176	6.830	6.683	6.448	5.445	6.814		6.474
Dec	**4.905**	6.330	6.283	4.290	4.374	6.141	5.070	5.408	4.782	6.008	**7.118**		5.580
Avg	**7.443**	8.077	7.938	7.521	6.337	7.409	7.573	7.654	7.922	7.896	7.913		7.642

Kramer Junction Average Daily DNR Data - YTD (kWh/m^2/day)

		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Avg
Jan	**5.183**	**6.519**	5.852	4.754	4.740	3.401	5.852	3.027	6.401	4.861	5.011	5.655	5.098
Feb	**5.580**	**6.342**	5.865	5.636	4.468	3.800	5.500	4.842	5.587	5.920	4.822	5.992	5.283
Mar	**5.978**	6.680	6.250	5.979	4.275	4.743	6.158	5.299	6.187	**6.827**	5.745	6.315	5.824
Apr	**6.580**	7.187	6.571	6.708	4.877	5.595	6.505	6.010	6.918	**7.219**	6.412	6.569	6.392
May	**7.136**	7.598	7.146	7.301	5.302	6.184	6.938	6.352	7.482	**7.634**	6.854	7.133	6.886
Jun	**7.586**	**8.056**	7.670	7.776	5.863	6.742	7.581	6.964	8.004	8.014	7.485	7.691	7.429
Jul	**7.854**	**8.326**	7.956	7.983	6.259	7.253	7.831	7.467	8.203	8.282	7.950	7.951	7.762
Aug	**7.967**	**8.488**	8.135	8.094	6.496	7.536	7.972	7.786	8.340	8.396	8.157		7.952
Sep	**7.965**	**8.493**	8.208	8.002	6.612	7.745	7.987	7.960	8.457	8.328	8.137		8.007
Oct	**7.874**	8.367	8.208	7.951	6.564	7.660	7.902	7.979	**8.380**	8.331	8.103		7.959
Nov	**7.679**	**8.240**	8.091	7.821	6.516	7.526	7.806	7.862	8.210	8.072	7.987		7.829
Dec	**7.443**	**8.077**	7.938	7.521	6.337	7.409	7.573	7.654	7.922	7.896	7.913		7.642

1998 ANNUAL PRODUCTION SUMMARY

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Insolation						
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Gross Electrical Prod						
Gross Solar - MWh	70698	71615	75229	67358	67651	352471
Gross Boiler - MWh	32563	32856	36887	31663	33470	167539
Gross Total - MWh	**103261**	**104491**	**112116**	**99021**	**101121**	**520010**
Net Elec Sold - A Chan						
On-Pk - MWh	16279	16074	16716	17143	16907	83119
Mid-Pk - MWh	58551	58897	63221	52574	54218	287462
Off-Pk - MWh	19166	19276	20410	17757	17639	94252
Super Off - MWh	0	0	0	0	0	0
Total - MWh	**93996**	**94250**	**100347**	**87474**	**88764**	**464832**
Net Purch - B Chan						
On-Pk - MWh	0	2	1	0	2	6
Mid-Pk - MWh	342	318	283	476	458	1877
Off-Pk - MWh	1254	1220	1407	1533	1474	6888
Super Off-Pk - MWh	617	568	665	711	696	3258
Total - MWh	**2214**	**2108**	**2356**	**2720**	**2631**	**12028**
Station Load						
Station Internal - MWh	9265	10241	11769	11547	12357	55178
Station Ext (B Ch) - MWh	2214	2108	2356	2720	2631	12028
Station Total - MWh	**11478**	**12349**	**14125**	**14267**	**14987**	**67206**
Station Internal - % of Gross	9.00%	9.80%	10.50%	11.70%	12.20%	10.60%
SCE Capacity Factor						
On-Pk - %	104	103	107	109	108	106
Mid-Pk - %	66	66	71	67	62	67
Off-Pk - %	17	17	18	17	15	17
Natural Gas Use						
Boiler - KSCF	411104	422372	455258	339460	359856	[illegible]
Heater - KSCF	20048	15476	23518	2118	1080	12447
Total - KSCF	**431152**	**437848**	**478770**	**341578**	**360436**	**409957**
FERC Calc (LHV)						
Solar Input - MMBtu	1186056	1203316	1317270	[illegible]	[illegible]	[illegible]
Gas Used - MMBtu	394820	400581	438508	[illegible]	[illegible]	[illegible]
Monthly FERC Ratio	**24.97**	**24.98**	**24.98**	**24.98**	**24.98**	**24.98**

Subcontractor Report

September 2000 • NREL/SR-550-27925

Survey of Thermal Storage for Parabolic Trough Power Plants

Period of Performance: September 13, 1999–June 12, 2000

Pilkington Solar International GmbH
Cologne, Germany

National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401-3393

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Contract No. DE-AC36-99-GO10337

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NREL Technical Monitor: Mary Jane Hale

Prepared under Subcontract No. AAR-9-29442-05

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Table of Contents

List of Tables

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List of Acronyms

ETDE	Energy Technology Data Exchange
EU	European Union
h	hour
HTF	heat transfer fluid
IEA	International Energy Agency
ISCCS	integrated solar combined cycle systems
kWh	kilowatt-hours
kWh_e	kilowatt-hours electric
kWh_t	kilowatt-hour thermal
MUSD	million U.S. dollar
MWe	megawatts electric
MW	megawatt
MWh	megawatt-hour
MWh_t	megawatt-hours thermal
NREL	National Renewable Energy Laboratory
PCM	phase change material
PNL	Pacific Northwest Laboratory
PNNL	Pacific Northwest National Laboratory
PSA	Plataforma Solar Alméria
PV	photovoltaics
RTR	reversible thermochemical reaction
SEGS	solar electric generating system
SERI	Solar Energy Research Institute
TES	thermal energy storage
ZSW	Center for Solar Energy and Hydrogen Research, Stuttgart, Germany

1.0 Introduction

The electrical output of a solar thermal electric plant is inherently in a state of change, being dictated by both predictable and unpredictable variations—the influences of time and weather. In either event, utility system needs may require a fully functional storage system to mitigate the changes in solar radiation or to meet demand peaks.

A distinct advantage of solar thermal power plants compared with other renewable energies, such as photovoltaics (PV) and wind, is the possibility of using relatively cheap storage systems. That is, storing the thermal energy itself. Storing electricity is much more expensive.

A thermal energy storage (TES) option can collect energy in order to shift its delivery to a later time, or to smooth out the plant output during intermittently cloudy weather conditions. Hence, the operation of a solar thermal power plant can be extended beyond periods of no solar radiation without the need to burn fossil fuel. Times of mismatch between energy supply by the sun and energy demand can be reduced.

When used with Integrated Solar Combined Cycle Systems (ISCCS), energy storage could provide another important advantage. If the plant operates at baseload, it will operate at full load only when enough solar energy is available. At part load, the turbine efficiency can decrease considerably. If fossil energy is used to augment turbine load (through the use of duct firing, a heat transfer fluid [HTF] heater, or a backup boiler) when solar is not available, the plant converts that fossil fuel at a substantially lower efficiency than if it had been used directly in the combined cycle. Using thermal energy storage instead of a fossil burner can help to overcome this problem.

Economic thermal storage is a key technological issue for the future success of solar thermal technologies.

1.1 Scope of this Report

The purpose of this report is to identify and selectively review previous work done on the evaluation and use of thermal energy storage systems applied to parabolic trough power plants. Appropriate storage concepts and technical options are first discussed, followed by a review of previous work. This review is divided into two parts: work done before 1990 and work done after that date. This division was chosen because much of the work currently cited in this field was carried out and reported prior to 1990, and a key objective of the review was to highlight more recent results though they are less plentiful. Finally, observations and conclusions on the status of TES systems for trough plants are put forward, based on the body of literature covered.

1.2 Storage Concepts for Solar Thermal Systems

The principle options for using TES in a solar thermal system highly depend on the daily and yearly variation of radiation and on the electricity demand profile. As noted above, the main options are:

- Buffering
- Delivery period displacement

- Delivery period extension
- Yearly averaging

The goal of a buffer is to smooth out transients in the solar input caused by passing clouds, which can significantly affect operation of a solar electric generating system (SEGS) plant. The efficiency of electrical production will degrade with intermittent insolation, largely because the turbine-generator will frequently operate at partial load and in a transient mode. If regular and substantial cloudiness occurs over a short period, turbine steam conditions and/or flow can degrade enough to force turbine trips if there is no supplementary thermal source to "ride through" the disturbance. Buffer TES systems would typically require small storage capacities (maximum 1 hour full load).

Delivery period displacement requires the use of a larger storage capacity. The storage shifts some or all of the energy collected during periods with sunshine to a later period with higher electricity demand or tariffs (electricity tariffs can be a function of hour of the day, day of the week, and the season). This type of TES does not necessarily increase either the solar fraction or the required collection area. The typical size ranges from 3 to 6 hours of full load operation.

The size of a TES for delivery period extension will be of similar size (3 to 12 hours of full load). However, the purpose is to extend the period of power plant operation with solar energy. This TES increases the solar fraction and requires larger solar fields than a system without storage.

Yearly averaging of electricity production requires much larger TES and solar fields. In general, these are very expensive systems and have not been given serious consideration in the literature, nor will they be considered here.

Definitive selection of storage capacity is site- and system-dependent. Therefore, detailed statistical analysis of system electrical demand and weather patterns at a given site, along with a comprehensive economic tradeoff analysis, are desirable in a feasibility study to select the best storage capacity for a specific application.

1.3 Design Criteria

A key issue in the design of a thermal energy storage system is its thermal capacity - the amount of energy that it can store and provide. However selection of the appropriate system depends on many cost-benefit considerations.

The cost of a TES system mainly depends on the following items:

- The storage material itself
- The heat exchanger for charging and discharging the system
- The cost for the space and/or enclosure for the TES

From the technical point of view, the crucial requirements are:

- High energy density (per-unit mass or per-unit volume) in the storage material
- Good heat transfer between heat transfer fluid (HTF) and the storage medium

- Mechanical and chemical stability of storage material
- Compatibility between HTF, heat exchanger and/or storage medium
- Complete reversibility for a large number of charging/discharging cycles
- Thermal losses
- Ease of control

The most important design criteria are:

- Nominal temperature and specific enthalpy drop in load
- Maximum load
- Operational strategy
- Integration into the power plant

All these facts have to be considered when deciding on the type and the design of thermal storage. This review focuses on thermal energy storage for parabolic trough power plants, which operate under certain temperature limits. TES capacities up to 8 hours full load will be considered, which could significantly increase the solar share of a hybrid power plant, such as an ISCCS.

2.0 Technical Storage Options

Thermal energy storage can be classified by storage mechanism (sensible, latent, chemical) and by storage concept (active or passive).

2.1 Storage Media

Thermal storage can utilize sensible or latent heat mechanisms or heat coming from chemical reactions.

Sensible heat is the means of storing energy by increasing the temperature of a solid or liquid. Latent heat, on the other hand, is the means of storing energy via the heat of transition from a solid to liquid state. For example, molten salt has more energy per unit mass than solid salt.

Table 1 shows the characteristics of candidate solid and liquid sensible heat storage materials and potential phase change (latent) heat storage media for a SEGS plant.

For each material, the low and high temperature limits are given these limits, combined with the average mass density and heat capacity, lead to a volume-specific heat capacity in kWh_t per cubic meter. The table also presents the approximate costs of the storage media in dollars per kilogram, finally arriving at unit costs in $\$/kWh_t$.

The average thermal (heat) conductivity given in the table has a strong influence on the heat transfer design and heat transfer surface requirements of the storage system, particularly for solid media (high conductivity is preferable). High volumetric heat capacity is desirable because it leads to lower storage system size, reducing external

3

piping and structural costs. Low unit costs obviously mean lower overall costs for a given thermal capacity.

2.1.1 Sensible Heat Storage

Thermal energy can be stored in the sensible heat (temperature change) of substances that experience a change in internal energy. The stored energy is calculated by the product of its mass, the average specific heat, and the temperature change. Besides the density and the specific heat of the storage material, other properties are important for sensible heat storage: operational temperatures, thermal conductivity and diffusivity, vapor pressure, compatibility among materials, stability, heat loss coefficient as a function of the surface areas to volume ratio, and cost.

Table 1. Candidate Storage Media for SEGS Plants (Geyer 1991)

Storage Medium	Temperature Cold (°C)	Temperature Hot (°C)	Average density (kg/m³)	Average heat conductivity (W/mK)	Average heat capacity (kJ/kgK)	Volume specific heat capacity (kWh$_t$/m³)	Media costs per kg ($/kg)	Media costs per kWh$_t$ ($/kWh$_t$)
Solid media								
Sand-rock-mineral oil	200	300	1,700	1.0	1.30	60	0.15	4.2
Reinforced concrete	200	400	2,200	1.5	0.85	100	0.05	1.0
NaCl (solid)	200	500	2,160	7.0	0.85	150	0.15	1.5
Cast iron	200	400	7,200	37.0	0.56	160	1.00	32.0
Cast steel	200	700	7,800	40.0	0.60	450	5.00	60.0
Silica fire bricks	200	700	1,820	1.5	1.00	150	1.00	7.0
Magnesia fire bricks	200	1,200	3,000	5.0	1.15	600	2.00	6.0
Liquid media								
Mineral oil	200	300	770	0.12	2.6	55	0.30	4.2
Synthetic oil	250	350	900	0.11	2.3	57	3.00	43.0
Silicone oil	300	400	900	0.10	2.1	52	5.00	80.0
Nitrite salts	250	450	1,825	0.57	1.5	152	1.00	12.0
Nitrate salts	265	565	1,870	0.52	1.6	250	0.70	5.2
Carbonate salts	450	850	2,100	2.0	1.8	430	2.40	11.0
Liquid sodium	270	530	850	71.0	1.3	80	2.00	21.0
Phase change media								
$NaNo_3$	308		2,257	0.5	200	125	0.20	3.6
KNO_3	333		2,110	0.5	267	156	0.30	4.1
KOH	380		2,044	0.5	150	85	1.00	24.0
Salt-ceramics ($NaCo_3$-$BaCO_3$/MgO)	500-850		2,600	5.0	420	300	2.00	17.0
NaCl	802		2,160	5.0	520	280	0.15	1.2
Na_2CO_3	854		2,533	2.0	276	194	0.20	2.6
K_2CO_3	897		2,290	2.0	236	150	0.60	9.1

2.1.1.1 Solid Media

For thermal storage, solid media usually are used in packed beds, requiring a fluid to exchange heat. When the fluid heat capacity is very low (e.g., when using air) the solid is the only storage material; but when the fluid is a liquid, its capacity is not negligible, and the system is called a dual storage system. Packed beds favor thermal stratification, which has advantages. Stored energy can easily be extracted from the warmer strata, and cold fluid can be taken from the colder strata and fed into the collector field.

An advantage of a dual system is the use of inexpensive solids such as rock, sand, or concrete for storage materials in conjunction with more expensive heat transfer fluids like thermal oil. However, pressure drop and, thus, parasitic energy consumption may be high in a dual system. This has to be considered in the storage design.

The cold-to-hot temperature limits of some solid media in Table 2 are greater than could be utilized in a SEGS plant because parabolic trough solar fields are limited to maximum outlet temperatures of about 400°C. Table 2 shows the effect on solid media by imposing this temperature limit on the storage medium temperature range, the unit heat capacities, and media costs.

Table 2. Solid Storage Media for SEGS Plants

Storage Medium	Heat Capacity kWh_t/m^3	Media Cost $\$/kWh_t$
Reinforced concrete	100	1
NaCl (solid)	100	2
Cast iron	160	32
Cast steel	180	150
Silica fire bricks	60	18
Magnesia fire bricks	120	30

Using these values and judging the options against the guidelines discussed above, the sand-rock-oil combination is eliminated because it is limited to 300°C. Reinforced concrete and salt have low cost and acceptable heat capacity but very low thermal conductivity. Silica and magnesia fire bricks, usually identified with high temperature thermal storage, offer no advantages over concrete and salt at these lower temperatures. Cast steel is too expensive, but cast iron offers a very high heat capacity and thermal conductivity at moderate cost.

2.1.1.2 Liquid Media

Liquid media maintain natural thermal stratification because of density differences between hot and cold fluid. To use this characteristic requires that the hot fluid be supplied to the upper part of a storage system during charging and the cold fluid be extracted from the bottom part during discharging, or using another mechanism to ensure that the fluid enters the storage at the appropriate level in accordance with its temperature (density) in order to avoid mixing. This can be done by some stratification devices (floating entry, mantle heat exchange, etc.).

The heat transfer fluid in a SEGS plant operates between the temperatures of 300°C and 400°C, approximately. Applying these limitations on temperature, and dropping mineral oil because it cannot operate at the upper temperature requirement gives the results shown in Table 3.

Table 3. Liquid Storage Media for SEGS Plants

Storage Medium	Heat Capacity kWh_t/m^3	Media Cost $\$/kWh_t$
Synthetic oil	57	43
Silicone oil	52	80
Nitrite salts	76	24
Nitrate salts	83	16
Carbonate salts	108	44
Liquid sodium	31	55

Both the oils and salts are feasible. The salts, however, generally have a higher melting point and parasitic heating is required to keep them liquid at night, during low insolation periods, or during plant shutdowns. Silicone oil is quite expensive, though it does have environmental benefits because it is a non-hazardous material, whereas synthetic oils may be classified as hazardous materials. Nitrites in salts present potential corrosion problems, though these are probably acceptable at the temperatures required here. (The U.S. Solar Two project has selected a eutectic of nitrate salts because of the corrosivity of nitrite salts at central receiver system temperature levels.)

2.1.2 Latent Heat Storage

Thermal energy can be stored nearly isothermally in some substances as the latent heat of phase change, that is, as heat of fusion (solid-liquid transition), heat of vaporization (liquid-vapor), or heat of solid-solid crystalline phase transformation. All substances with these characteristics are called phase change materials (PCMs). Because the latent heat of fusion between the liquid and solid states of materials is rather high compared to the sensible heat, storage systems utilizing PCMs can be reduced in size compared to single-phase sensible heating systems. However, heat transfer design and media selection are more difficult, and experience with low-temperature salts has shown that the performance of the materials can degrade after a moderate number of freeze-melt cycles. LUZ International Ltd. proposed evaluation of an innovative phase-change salt concept to the solar community that used a series of salts in a "cascade" design (to be discussed later).

Table 1 showed, for a number of potential salts, the temperature at which the phase change takes place as well as the heat capacity (heat of fusion). Data for the salts shown in that table that are applicable to SEGS plants are shown in Table 4 below. It can be seen that the heat capacities, at least for the nitrites, are high and unit costs are comparatively low.

Table 4. Latent Heat Storage Media for SEGS Plants

Storage Medium	Heat Capacity kWh_t/m^3	Media Cost $\$/kWh_t$
$NaNO_3$	125	4
KNO_3	156	4
KOH	85	24

2.1.3 Chemical Storage

A third storage mechanism is by means of chemical reactions. For this type of storage it is necessary that the chemical reactions involved are completely reversible. The heat produced by the solar receiver is used to excite an endothermic chemical reaction. If this reaction is completely reversible the heat can be recovered completely by the reversed reaction. Often catalysts are necessary to release the heat. This is even more advantageous as the reaction can then be controlled by the catalyst.

Commonly cited advantages of TES in a reversible thermochemical reaction (RTR) are high storage energy densities, indefinitely long storage duration at near ambient temperature, and heat-pumping capability. Drawbacks may include complexity, uncertainties in the thermodynamic properties of the reaction components and of the reaction's kinetics under the wide range of operating conditions, high cost, toxicity, and flammability.

Although RTRs have several advantages concerning their thermodynamic characteristics, development is at a very early stage. To date, no viable prototype plant has been built.

2.2 Storage Concepts

Storage concepts can be classified as active or passive systems. Active storage is mainly characterized by forced convection heat transfer into the storage material. The storage medium itself circulates through a heat exchanger. This heat exchanger can also be a solar receiver or a steam generator.

The main characteristic of a passive system is that a heat transfer medium passes through storage only for charging and discharging. The heat transfer medium itself does not circulate.

2.2.1 Active Thermal Energy Storage

Active thermal systems typically utilize tank storage. They can be designed as one tank or two tank systems.

Active storage is again subdivided into direct and indirect systems. In a direct system the heat transfer fluid, which collects the solar heat, serves also as the storage medium, while in an indirect system, a second medium is used for storing the heat.

Two prominent examples of two-tank systems for solar electric applications are the storage systems of the SEGS I (Kroizer 1984) and Solar Two plants (Kelly and Lessly 1994, Pacheco and Gilbert 1999, and Valenti 1995). Figure 1 shows a schematic flow diagram of SEGS I. An initial experience with a small-scale two-tank molten salt system has already been described (Chinen et al. 1983).

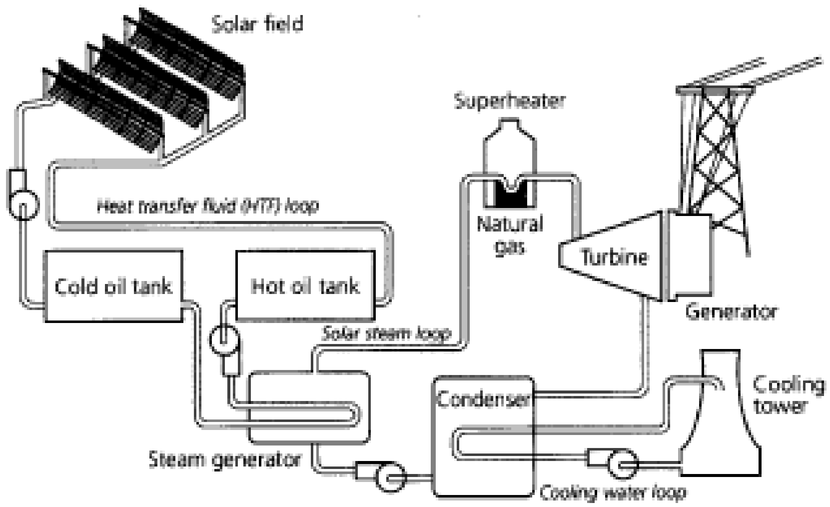

Figure 1. Schematic flow diagram of SEGS I plant

A two-tank system uses one tank for cold HTF coming from the steam generator and one tank for the hot HTF coming directly out of the solar receiver before it is fed to the steam generator. The advantage of this system is that cold and hot HTF are stored separately. The main disadvantage is the need for a second tank. In this type of system, the storage tanks are directly coupled to the HTF pressure levels (which is not necessarily a disadvantage).

The single-tank system reduces storage volume and cost by eliminating a second tank. However, in a single-tank system it is more difficult to separate the hot and cold HTF. Because of the density difference between hot and cold fluid, the HTF naturally stratifies in the tank, from coolest layers at the bottom to warmest layers at the top. These systems are called thermocline storage. Experience with thermocline storage was described by Castro et al. 1992, Dinter et al. 1990, Dugan 1980, and Kandari 1990. Maintaining the thermal stratification requires a controlled charging and discharging procedure, and appropriate methods or devices to avoid mixing. Filling the storage tank with a second solid storage material (rock, iron, sand etc.) can help to achieve the stratification.

2.2.2 Passive Thermal Energy Storage

Passive systems are generally dual medium storage systems. The HTF carries energy received from the energy source to the storage medium during charging and receives energy from the storage material when discharging. These systems are also called regenerators.

The storage medium can be a solid, liquid, or PCM. In general, a chemical storage system employs at least two media.

The main disadvantage of regenerators is that the HTF temperature decreases during discharging as the storage material cools down. Another problem is the internal heat transfer. Especially for solid materials, the heat transfer is rather low, and there is usually no direct contact between the HTF and the storage material as the heat is transferred via a heat exchanger.

3.0 State of the Art

3.1 Existing TES Systems in Solar Thermal Plants

Of eight installed thermal energy storage systems in solar thermal electric plants, seven have been of an experimental or prototype nature and one has been a commercial unit. Table 5 gives the characteristics of the existing units. All have been sensible heat storage systems: two single-tank oil thermocline systems, four single medium two-tank systems (one with oil and three with salt) and two dual medium single-tank systems. To put the size of these systems in perspective, a 30-MWe SEGS plant with a plant efficiency of 35% would require about 260 MWh_t for a 3-hour storage capability. This is considerably larger than any other solar thermal electric storage system built up to now.

All of these systems were successful to varying degrees, recognizing that most were development units that were expected to reveal design flaws or issues as a basis for future design improvements.

Two important characterizations of storage systems are the "round-trip efficiency" and the cost per unit of thermal energy delivery ($\$/kW_t$). The round-trip efficiency is, simply, the ratio of the useful energy recovered from the storage system to the amount of energy initially extracted from the heat source. This efficiency is affected by the laws of thermodynamics and by heat losses in the tanks, piping, and heat exchangers in the system; electric parasitic losses needed to circulate storage system fluids constitute additional losses.

Efficiency and cost experience from existing systems are informative but of limited relevancy to commercial plants because most of the existing facilities were one-of-a-kind development projects. Nevertheless, round-trip efficiencies of more than 90% were measured in many of the systems listed in Table 5, though some systems were as low as 70%. Both the oil systems and molten salt systems were shown to be technically feasible. While various problems arose due to mistakes in design, construction or operation, no fundamental issues surfaced for these approaches.

The SEGS I storage system cost $\$25/kW_t$ in 1984 dollars, with the oil representing 42% of the investment cost. The oil used in the later SEGS plants for operation up to 400°C costs approximately eight times more than the SEGS I oil. This was reason enough that a storage system similar to the SEGS I storage concept was not repeated in later SEGS plants. However, there were other important considerations, such as total system investment, very large tank size requirements, and inflexibility compared to a back-up system.

Table 5. Existing TES Systems

Project	Type	Storage Medium	Cooling Loop	Nominal Temperature Cold (°C)	Hot (°C)	Storage Concept	Tank Volume (m³)	Thermal Capacity (MWh$_t$)
Irrigation pump Coolidge, AZ, USA	Parabolic Trough	Oil	Oil	200	228	1 Tank Thermocline	114	3
IEA-SSPS Almeria, Spain	Parabolic Trough	Oil	Oil	225	295	1 Tank Thermocline	200	5
SEGS I Daggett, CA, USA	Parabolic Trough	Oil	Oil	240	307	Cold-Tank Hot-Tank	4160 4540	120
IEA-SSPS Almeria, Spain	Parabolic Trough	Oil Cast Iron	Oil	225	295	1 Dual Medium Tank	100	4
Solar One Barstow, CA, USA	Central Receiver	Oil/Sand/ Rock	Steam	224	304	1 Dual Medium Tank	3460	182
CESA-1 Almeria, Spain	Central Receiver	Liquid Salt	Steam	220	340	Cold-Tank Hot-Tank	200 200	12
THEMIS Targasonne, France	Central Receiver	Liquid Salt	Liquid Salt	250	450	Cold-Tank Hot-Tank	310 310	40
Solar Two Barstow, CA, USA	Central Receiver	Liquid Salt	Liquid Salt	275	565	Cold-Tank Hot-Tank	875 875	110

3.2 Summary of Work Performed Before 1990

This section reviews the most relevant investigations and evaluations carried out prior to about 1990. Selected literature from this period has been listed in the References, but only selected works are explicitly discussed here. A valuable overview of the applicability of thermal storage to solar power plants was provided by Geyer 1991. Table 6 shows the storage systems initially considered there, though of these only a few were investigated in detail. The final systems are listed in the following paragraphs.

Dual medium sensible heat systems

Two single-tank alternatives were analyzed, one in which HTF oil flows through a storage medium of concrete and another in which the storage medium is solid salt. Cast iron and cast steel were eliminated as storage media due to high cost, even though they offered thermodynamic advantages.

Table 6. Candidate Storage Concepts for SEGS Plants

TES Concepts	Storage Type	Status*	Assessment
Sensible Active	Two-Tank Oil	T	Basic concept, state-of-the-art
	HITEC	T	2 variants analyzed based on existing PSA/THEMIS designs
	Thermocline	T	Proved on pilot scale, no advantages over basic two tank system
Sensible DMS	Oil/Cast Iron	T	Proved on pilot scale, no advantages over basic two tank system
	Oil/Steel	LR	Used in chipboard presses
	Oil/Concrete	MR	Several variants analyzed
	Oil/Solid Salt	MR	Several variants analyzed
PCM	Oil/PC Salts	HR	Several cascade arrangements analyzed
Chemical	Oil/Metal Hybrids	HR	Early state of development, no lead concepts, no cost data
* Nomenclature: **T**: Tested / **LR**: Low Risk / **MR**: Medium Risk / **HR**: High Risk			

Sensible heat molten salt system

A two-tank system (similar to SEGS I) utilizing the HITEC salt was chosen. HITEC is a eutectic mixture of 40% $NaNO_2$, 7% $NaNO_3$ and 53% KNO_3 with a 142°C melt-freeze point.

Phase-change systems

These higher-risk systems were judged to have high uncertainty in technical feasibility and cost, but were evaluated for their potential in this application. Three different phase-change concepts were evaluated. The first was a LUZ design using five PCMs in a series, or cascade, design (SERI 1989); the second was a design by the Spanish company INITEC, which also used five PCMs but in a different heat exchanger configuration; the third design originated with the German companies Siempelkamp and Gertec (SGR) and used three commercially available PCMs along with concrete for the higher temperatures.

3.2.1 Overview of Results

Storage system designs for the SEGS conditions based on these five concepts were developed in Dinter et al. 1990. Summary results are presented here giving overall system volume, thermal storage capacity and utilization, and specific costs in $\$/kWh_t$ of capacity.

The utilization measure is an interesting aspect of storage systems. Earlier discussion described some of the aspects of temperature differences within the HTF fluid and between the HTF and a solid storage medium. Another aspect of storage design is the temperature difference within the medium itself. In a two-tank liquid system, for example, the entire fluid is heated to a charged temperature and hence the entire storage medium is utilized. PCM systems theoretically also have very high utilization factors. In a solid system, however, temperature gradients required for thermal conduction through the media itself prevent full utilization of the material. In this case, 100% utilization would be achieved if the entire solid medium were heated to the full charging temperature. Hence, the "potential" storage capacity might be two or three times higher than the practical storage capacity. Detailed heat transfer calculations on specific designs provide this type of information.

Figure 2 gives results on the total volume, storage capacity and utilization, and specific cost of the six candidate systems analyzed for SEGS plants. For comparison purposes, we will select the INITEC PCM design as representative of the PCM class, with the qualifier that there is much more uncertainty and technical risk in the PCM results than in the sensible heat oil-solid systems or in the sensible heat HITEC molten salt system.

With regard to volume, the concrete and salt media fill about 6,900 and 5,200 m^3 of space, respectively, whereas the molten salt and PCM system need 2,600 m^3. If the cross-sectional area perpendicular to the flow measured 13m by 13m, the length of the concrete system would be 41 m compared to a 15-m length for the PCM system. A major reason for the larger sizes of the concrete and solid salt systems is the poor volume utilization. The concrete system, for example, is utilized at 36% of its full potential capacity. The molten salt and PCM systems, on the other hand, have utilization factors up to 100%. The concrete system does, however, have cost advantages due to the very low cost of concrete, which results in a low system cost even though there is more structure required for this larger volume system.

Generally, the storage costs developed in this assessment vary from \$25–\$50/kWh_t (on the order of \$65–\$130/kWh_e). At the low end, TES units of 270 and 450 MWh_t capacity would have a capital cost of 6.8 MUSD and 11.3 MUSD, respectively.

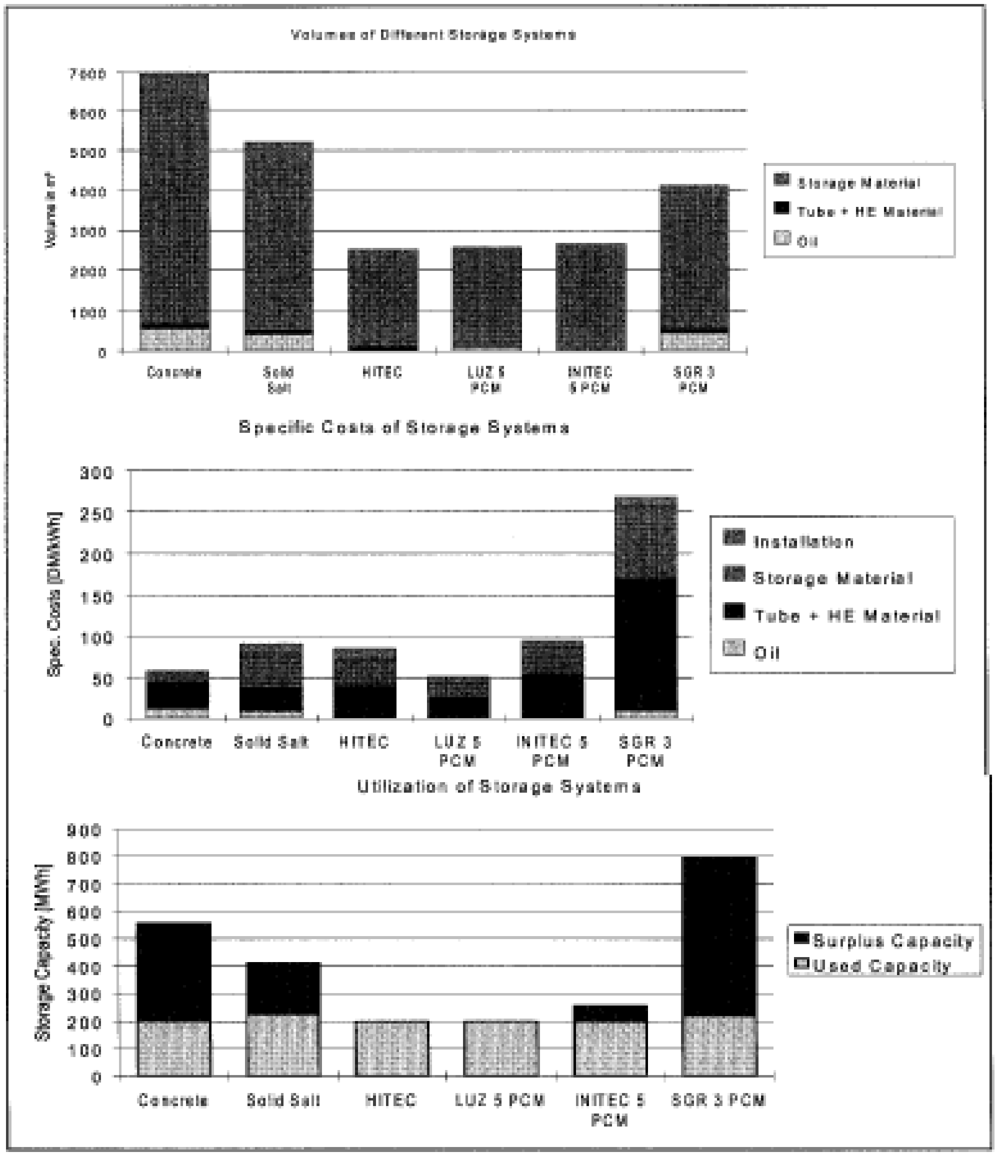

Figure 2. Results of TES evaluations for reference SEGS plant (Dinter et al. 1990)

3.2.2 SEGS TES Workshop

A symposium workshop (SERI 1989) on TES systems for SEGS plants, held in 1989 and sponsored by the Solar Energy Research Institute (SERI—now the National Renewable Energy Laboratory—NREL), discussed several of the options presented above. While the workshop focused on phase-change material concepts, both sensible heat storage and chemical storage were also included in the agenda. The more detailed evaluations reported in Dinter et al. 1990 were completed subsequent to the workshop.

With respect to sensible heat storage, the workshop concluded that this approach could result in a cost-effective system. While no new research would be required, thorough and careful engineering development and small-scale testing would be necessary. Issues such as thermal expansion, potential leakage, heat transfer configuration, and heat exchange optimization require more detailed design within the context of a design concept.

Latent heat (or phase-change) storage was considered to be in a more primitive state of development. While the concept is promising, considerable research, system development, and proof-of-concept testing would be required. Concerns on heat transfer characteristics and heat exchange configuration were expressed. Of several possible configurations, it was concluded that both shell-and-tube heat exchangers and a system of encapsulated particles of phase-change salts were worthy of exploration, with the latter approach having both more potential for cost-effectiveness and a lower probability of success.

3.3 Experience and Research on TES since 1990

To analyze the work that has been done since 1990 on thermal storage for troughs, a thorough literature review was carried out. This review included a computerized literature search in the Energy Technology Data Exchange (ETDE) Energy database.

The ETDE Energy Database contains more than 3.8 million bibliographic records with abstracts for energy research and technology information from around the world. The EDTE, a multilateral information exchange program, was established in 1987 under the auspices of the International Energy Agency (IEA). Member countries share their energy research and technology information through the Energy Database. The database covers journal articles, research reports, conference papers, books, dissertations, computer software, and other miscellaneous types. Of all the records, 7.1% are devoted to energy storage and conservation.

Appendix A gives the report of the database search including the keywords used to identify the records of interest.

Sixty-five references that met the criteria defined through the keywords were identified. After evaluating the 65 abstracts, a lesser number (21) were applicable to TES systems in parabolic trough technology, and this group was added to the reference list given in Chapter 5. The abstracts for this group are included in Appendix B.

Table 7, summarizing the literature analysis, lists all identified works that may help in the selection of a candidate storage concept. The main results for the most promising options are discussed below.

Table 7. Results from Literature Review (after 1999)

Author	Year	Storage Concept	Type of Work*	Temperature Range	Capacity
M. Mitzel et al.	1990	Hydrid/Magnesium Thermochemical Storage	TH	?	-
Brown et al.	1991	Oxide/Hydroxide chemical storage	TH	300°C–400°C	-
D.Steiner, M. Groll	1995	MgH2/Mg Chemical Storage	EX-LS	280°C–480°C	14 kWh
K. Lovegrove A. Luzzi et al.	1999	Ammonia Based Thermochemical Storage	EX-LS	450°C–650°C	?
B.Beine, F. Dinter, R. Ratzesberger et al.	1992	Concrete	EX-LS	290°C–400°C	50 kWh
J. Pacheco, D.B. Kelly et al.	1999	Molten-Salt 2-Tank	EX-FS	290°C–566°C	114 MWh
H. Michels, E. Hahne	1996	Cascaded PCM	EX-LS	250°C–450°C	8.5 kWh

* TH theoretical work
EX-LS experimental work in lab scale
EX-FS experimental work in full scale

In addition to the experimental works listed in Table 7, more theoretical works on TES were performed by Brower 1992, Lund 1994, Meier and Winkler 1993, Steel and Wen 1981, and Steinfeld et al. 1991.

3.3.1 Overview of Progress

3.3.1.1 Experience at Solar Two

The most significant recent work on molten salt storage comes from the experience in the Solar Two Project. This prototype facility, decommissioned in 1999, was a 10-MW power tower system using a nitrate eutectic molten salt as the HTF. A schematic of the system is shown in Figure 3. Molten salt is pumped from the cold storage tank through the tower receiver and then to the hot storage tank. When dictated by the operation, the hot salt is pumped through the steam generation system and then back to the cold tank. Solar Two is capable of producing 10 MWe net electricity. A number of lessons on the equipment design, material selection, and operation of molten salt systems were learned during the 1-1/2 years of testing and evaluation.

Solar Two used an efficient, molten nitrate-salt thermal-storage system (Pacheco and Gilbert 1999). It consisted of an 11.6-m-diameter by 7.8-m-high cold-salt storage tank, a 4.3-m-diameter by 3.4-m-high cold-salt receiver sump, an 11.6-m-diameter by 8.4-m-high hot-salt storage tank, and a 4.3-m-diameter by 2.4-m-high hot-salt steam generator sump. The design thermal storage capacity of the Solar Two molten salt system was 105 MWh_t—enough to run the turbine at full output for 3 hours. The measured gross conversion efficiency of the 12-MWe (10-MWe-net) Solar Two turbine was 33%. Actual thermal storage capacity based on the mass of salt in the tanks, accounting for (subtracting) the 3-foot heels in each tank, and with design temperatures—1050°F hot salt, 550°F cold salt—was 114 MWh_t.

The system contained 1.5 million kilograms of nitrate salt composed of a mixture of 60% $NaNO_3$ and 40% KNO_3, provided by Chilean Nitrate Corporation (New York). This salt melted at 220°C and was thermally stable to about 600°C.

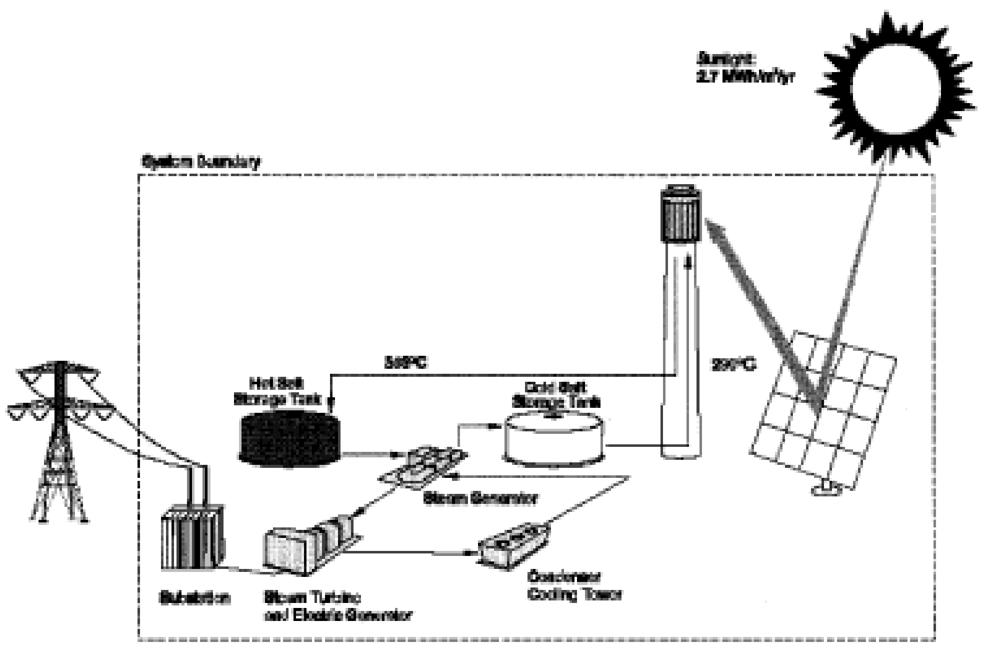

Figure 3. Molten salt power tower system schematic

Heat Losses

Several tests were conducted to quantify the thermal losses of major pieces of equipment throughout the plant and to compare the values to calculated estimates. The major pieces of equipment evaluated were the hot tank, cold tank, steam generator sump, and receiver sump. There were two methods of measuring the thermal losses in the tanks and sumps. One method was to turn off all auxiliary heaters and track the rate of decay of the average tank or sump temperature. By knowing the salt level, and thus the volume of salt in the vessel, an estimate of the heat loss could be made. Another method was to have the heaters energized and regulate the inventory at a set temperature. Once the vessel was at steady state, the power consumption of the heaters was measured over a long period of time. The electrical power consumption was assumed to be equal to the heat loss rate.

A summary of the measured and calculated thermal losses is shown in Table 8. The thermal losses for the tanks and sumps were equal to the calculated values within experimental error, except for the steam generator sump heat loss rate. The losses for the steam generator sump were higher than predicted, possibly because the insulation may have degraded significantly since it was installed. Salt had leaked out of the sump through flanges and into the insulation, which adversely affected its insulating properties. Based on the measured heat loss rates, the total energy lost to the environment over the course of a typical operating year corresponds to a 98% annual thermal efficiency.

Table 8. Measured and Actual Thermal Losses of Major Equipment

Major Equipment	Calculated Thermal Loss, kW	Measured Thermal Loss, kW
Hot Tank	98	102
Cold Tank	45	44
Steam Generator Sump	14	29
Receiver Sump	13	9.5

Operating Experience[1]

The capacity of the system is a function of the hot and cold salt temperatures. Hot salt temperatures at the bottom of the downcomer were typically only 1025°F because some of the isolation ball valves between the riser and downcomer leaked, attemperating the salt coming out of the receiver (which typically exited at 1050°F). The lower salt temperature derated the capacity of the thermal storage system by 5% to 108 MWht.

The fractional amount of the energy sent to thermal storage that was later discharged to the steam generator to make electricity is nearly 1, but is a function of the availability. The thermal losses are basically a fixed loss to the environment. When the plant availability is high, the collected energy increases and the losses are a smaller fraction of the total energy sent to storage. For example, on Dec. 2, 1997, on a sunny winter day, the receiver collected 217 MWh, which was sent to the steam generator system to make electricity. Based on a constant thermal loss of 185 kW from the hot and cold tanks, and the receiver and steam generator sumps, the total energy lost to the environment that day was 185kW x 24 h = 4.43 MWh or 2.0% of the collected energy. In contrast, on a sunny summer day—June 18, 1998—the receiver collected 334 MWht

[1] Comments provided by James Pacheco, Sandia National Laboratories Albuquerque, December 15, 1999.

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and the thermal losses were 1.3% of the collected energy. Even with the very prototypical nature of Solar Two (i.e., poor availability, frequent outages, first year operation, etc.), over several months the fractional amount lost to the environment was only 6% of collected energy. If the plant ran with higher availability, i.e., typical mature operation, the factional amount of stored energy lost to the environment would only be about 2% of collected energy.

There were no major operational problems with the thermal storage system and, in general terms, the system ran satisfactorily. Typically, the plant started using the stored energy within an hour or two after the receiver began collecting energy. Scenarios were also run, however, to demonstrate dispatching energy several times or to demonstrate the production of a constant output of electricity at night and through clouds. A number of practical lessons were learned, and no barriers to future implementation were evident.

3.3.1.2 Concrete

Limited prototype testing has been done on the concrete-steel thermal storage concept. Between 1991 and 1994, two concrete storage modules were tested at the storage test facility at the Center for Solar Energy and Hydrogen Research (ZSW) in Stuttgart, Germany (Ratzesberger et al. 1994). Figure 4 shows the prototype concrete module installed in the center's laboratory.

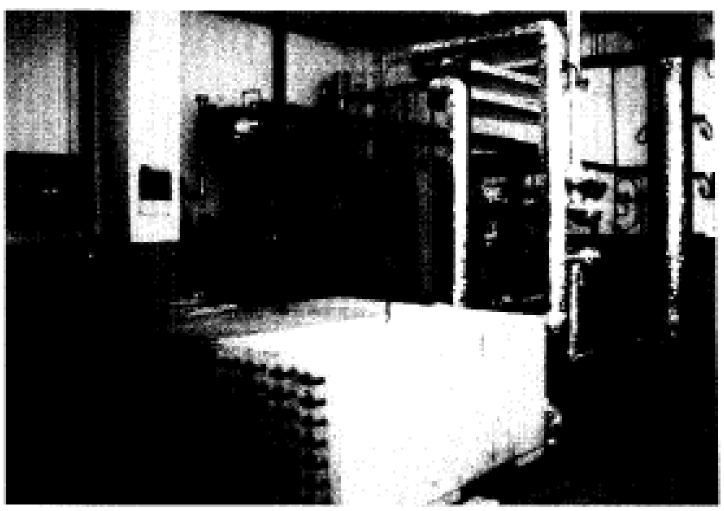

Figure 4. Test Facility for TES with two concrete storage modules at ZSW

The test results gained at ZSW in principle confirm the performance predictions given by Baddruddin, Dinter et al. 1992. Based on these tests, a numerical calculation model for concrete storage was developed by Ratzesberger 1995. He also proposed a slightly different design that results in the same performance but with considerably lower pressure loss in the storage module. According to his results, the pressure loss in a

18

200-MWh module can be reduced from 4.3 to 1.9 bar. The integration of a sensible heat storage system like concrete storage into a SEGS plant is depicted in Figure 5.

Ratzesberger recalculated the cost for storage and obtained a price of $40/kWh in 1994 U.S. dollars. This is slightly higher than the number given by Dinter. As a next step in the development of concrete storage, a project has recently been proposed to the EU (European Union) by a European team (CONTEST 1999). The proposed project consists of a prototype module with a capacity of 1–2 MWh to be erected at the PSA and connected to a parabolic trough solar field. The project, if funded, will be led by the German company Siempelkamp Giesserei GmbH & CO KG. In the company's proposal, it is projected that storage costs of $26/MWh in commercial scale can be realized.

Summarizing the work performed on concrete storage up to now, it can be concluded that this concept presents a relatively cheap option of thermal storage. The feasibility has already been proven in laboratory tests. The highest uncertainty still remains in the long-term stability of the concrete material itself after thousands of charging cycles. Special tests in a climatic chamber dedicated to investigation of this potential problem are included in the aforementioned EU proposal.

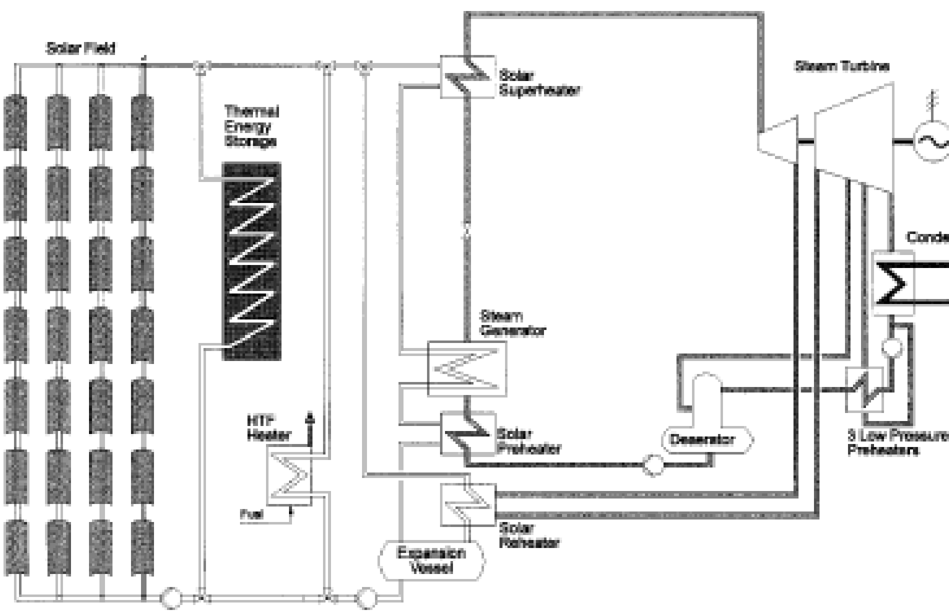

Figure 5. Schematic diagram of a SEGS plant with TES

3.3.1.3 Phase Change Material

Following the recommendations of the SERI workshop held in 1988 (SERI 1989), the ZSW, Germany, started to investigate storage using PCM. It was found by Dinter et al.

1990 that PCM storage has a relatively high heat capacity per volume and offers the lowest cost of all concepts investigated in this study (see also Figure 2).

A storage test facility has been set up in ZSW's laboratory allowing the investigation of various storage concepts independent from the sun. Electrical heating is the heat source, and a cooling tower is the heat sink. Figure 6 shows the flow diagram of the test loop with three PCM modules connected to the system. The modules can be charged by the HTF flow separately or connected to each other in series or in parallel.

A major objective was to investigate the heat transfer mechanism of different PCM salts during phase change and of liquid salts (Hunold et al. 1994, 1992, 1992, and 1994). In the work of Hunold, only one storage module filled with one salt was investigated in each case. Hunold showed that phase change storage is technically feasible and proposed a storage design built out of a shell and tube heat exchanger in a vertical orientation. By adjusting the vertical orientation of the tubes, natural convection and heat transfer can be improved. He selected the nitrate $NaNO_3$, with a melting point at 305°C, as appropriate storage material for the SEGS-type power plants.

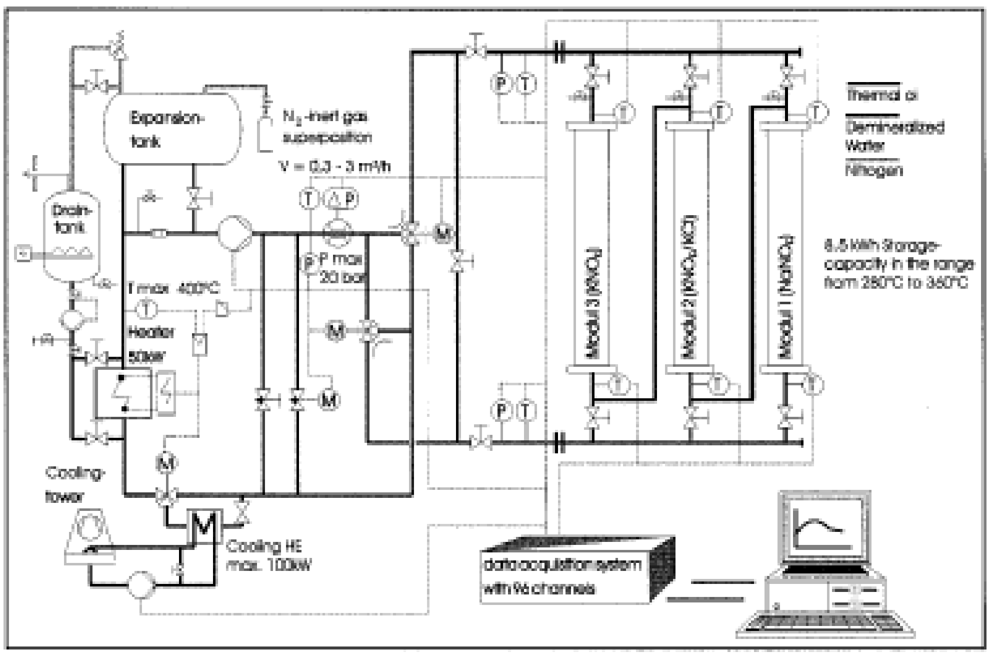

Figure 6. Flow diagram of storage test loop at ZSW (Michels and Hahne 1996)

However, one can only take full advantage of PCM storage by connecting several modules with different salts and different melting points in series as shown in Figure 7. Michels 1996 explained, by means of Figure 8, the reason for this. The left diagram shows the HTF temperature at the end of charging and discharging and the melting temperature of a single-stage salt storage as investigated by Hunold. During discharging the HTF temperature in the biggest part of the storage module is higher than the melting temperature of the salt. This means that a major portion of the salt

20

would not freeze during discharging and the high latent portion of the stored heat can not be extracted from the storage. Consequently, the utilization factor of the system would be relatively low.

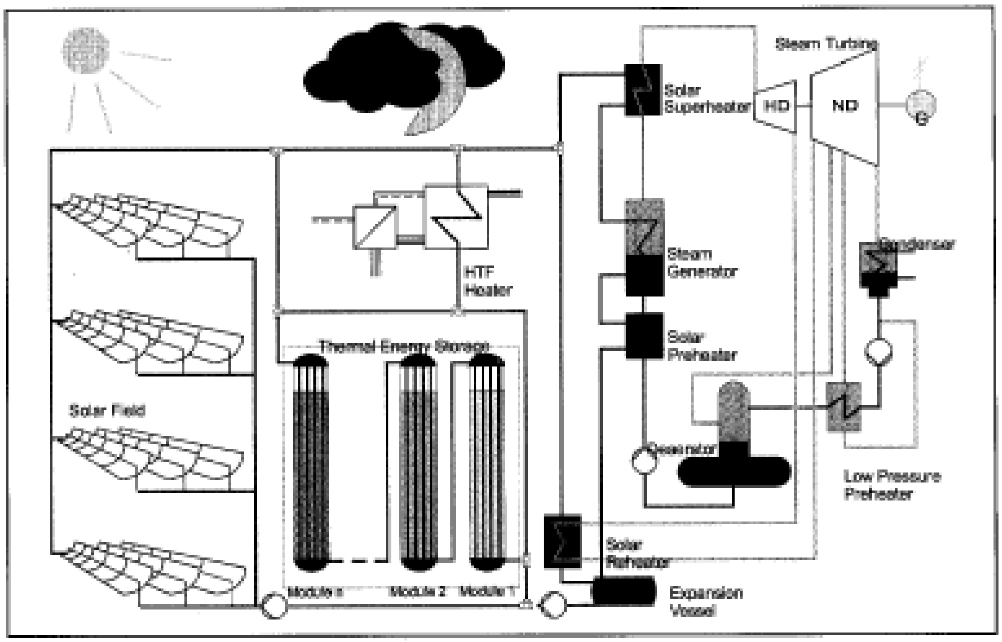

Figure 7. Possible process scheme of a SEGS with integrated PCM-TES (Michels and Hahne 1996)

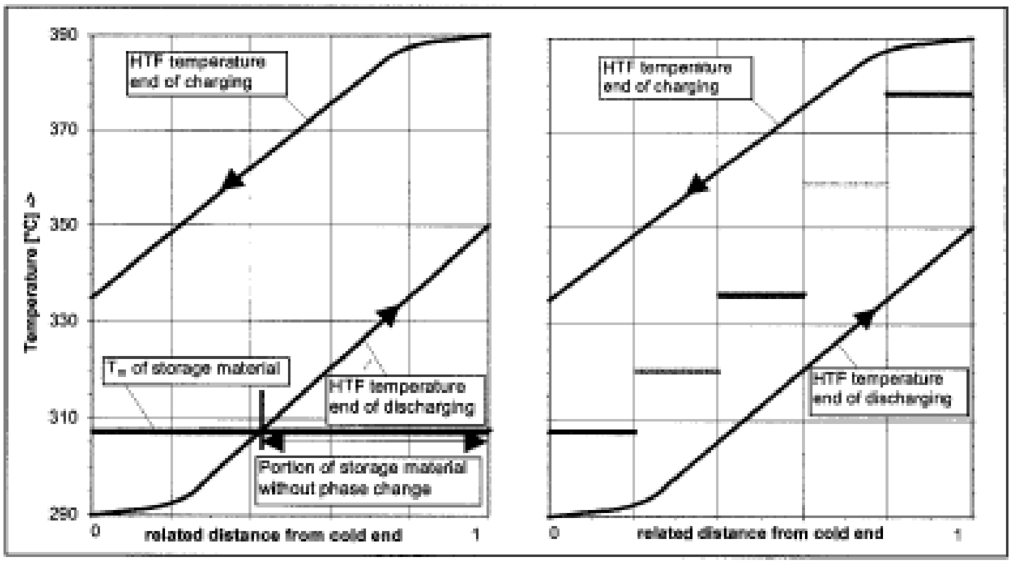

Figure 8. Theoretical temperature distribution in a PCM-TES for SEGS

The latent heat can only be used completely if, during charging, the temperature of the HTF is always higher than the melting point of the storage medium and, during discharging, always lower. This is shown in the right-hand diagram of Figure 8. According to Michels, five different PCMs have to be used for an optimized storage operating in the temperature range of a SEGS plant.

Michels experimentally investigated a configuration of three different modules connected in series (Michels and Hahne 1996). He used the nitrates KNO_3, KNO_3/KCl and $NaNO_3$. Figure 9 shows the measured temperature distribution in the test modules during charging.

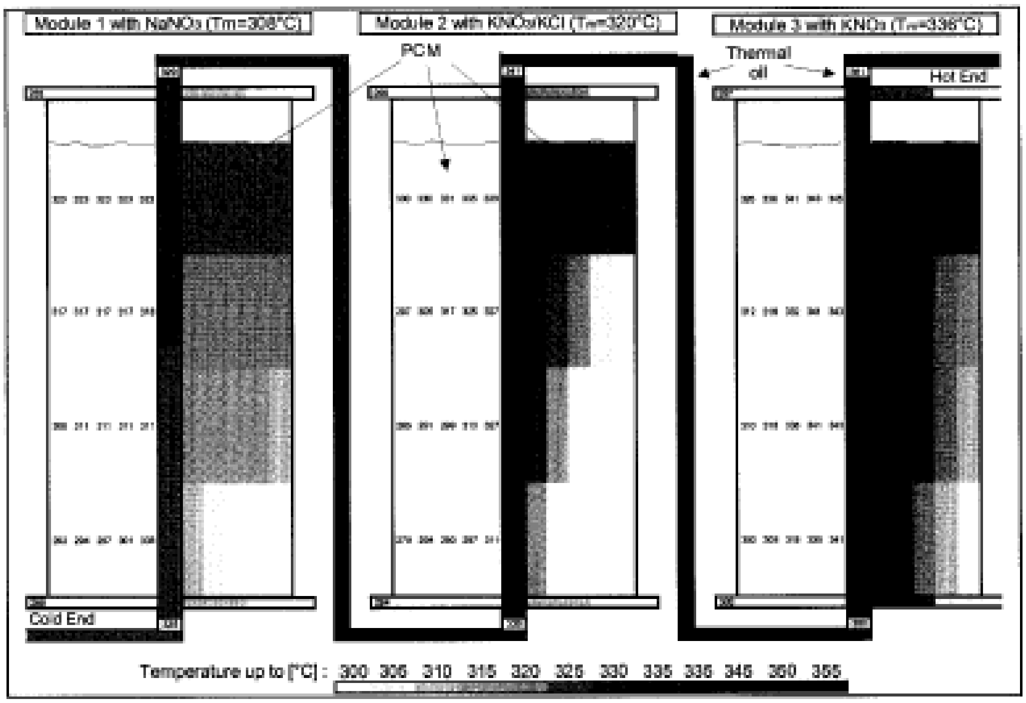

Figure 9. Temperature distribution inside the cascaded PCM test modules during charging

In his experiments, Michels proved the high utilization factor of a cascaded PCM storage. However additional experiments are required to verify the feasibility of a five-stage cascaded storage. Also additional design studies have to be performed to optimize the sizes of each stage, to select the appropriate material for the storage tank for each salt and to evaluate the cost.

Further works are concerned with PCM as storage material for parabolic troughs with Direct Steam Generation (Solomon 1991) and with the development of special measurement devices to observe the phase-change (Jaworske 1991).

A combined configuration of one sensible heat storage module, like concrete, and of two PCM modules at each end as proposed by Ratzesberger et al. (1994) seems to be a reasonable approach as a next step in the development of PCM storage.

3.3.1.4 Chemical Energy Storage

In the SERI workshop it was concluded that chemical energy storage is an attractive option in longer term and may offer relatively low cost. Based on a preliminary cost assessment the hydroxide/oxide reaction between CaO and H_2O was mentioned as one possibility (NASA 1979).

Subsequently, the Pacific Northwest Laboratory (PNL—now the Pacific Northwest National Laboratory—PNNL) conducted a study funded by the U.S. Department of

Energy to investigate the potential feasibility for a chemical energy storage based on this reaction. The report (Brown et al. 1991) concluded that this type of storage is, in principle, applicable under the SEGS temperature conditions. However, the study was based only on theoretical analysis and basic experimental investigations, and information was somewhat limited due to proprietary restrictions. The authors could not determine if the dynamics of the reaction fit to the requirements of storage for solar power plants, and also concluded that the question of proper integration into the solar power system remained unsolved. Costs were roughly estimated to be about $45/kWh. No further development of this type of storage could be identified through the literature review, and it appears that considerable work is required to develop a chemical energy storage system with hydroxide/oxide reaction for commercial application.

Development of another type of chemical storage seems to be much advanced, namely the solar ammonia energy storage developed by the Australian National University (Kreetz and Lovegrove 1999, Lovegrove et al. 1999, and Luzzi et al.). In this system, liquid ammonia is dissociated in a solar reactor into hydrogen and nitrogen. The energy is recovered in an ammonia synthesis reactor. The ammonia system was developed for use with parabolic dishes, but theoretically can also be used in the temperature range of parabolic trough collectors.

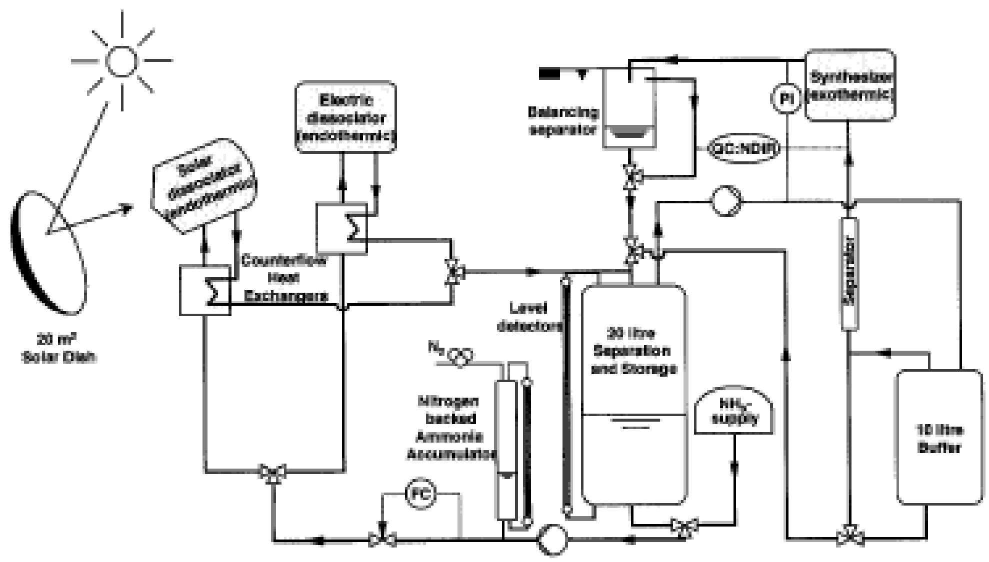

Figure 10. Test loop set up for solar ammonia energy storage (Lovegrove et al. 1999)

The first small-scale solar test facility was set up and has been operating for more than a year. Figure 10 shows the flow diagram of the test installation. The nominal solar input into the system is 1 kW. At this scale, it is clear that potential scale-up to a multi-megawatt system would be a significant undertaking.

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Current estimates are that a 10-MW plant built largely from industry standard or proven components will cost about $100 million (U.S. 1999) (Luzzi et al.).

4.0 Observations and Recommendations

Based on the body of literature examined in this survey, we come to the following observations:

- There have been no *major* bold developments in the field of thermal energy storage systems for trough power plants in the 1990s compared to prior work. However, there have been important contributions furthering work on candidate systems previously identified.
- Within the context of the Solar Two project, a prototype two-tank molten salt system containing a nitrate salt eutectic was successfully tested over a 11/2 year testing period.
- Molten salt systems with lower melting points should be explored for trough applications. The two-tank system as implemented at Solar Two is a relatively low-risk approach. A one-tank thermocline system is riskier with respect to performance, but offers the promise of important cost reductions.
- Useful laboratory-scale testing on several PCM modules was carried out by ZSW. The results substantiate the prior conclusion that these systems offer promise, and further work appears warranted.
- A proposal for prototype construction and testing of 1–2-MWh prototype concrete-steel storage system was submitted to the European Union in the summer of 1999. Present indications at the issuance of this report are that funding for this project will not be granted in the current round of accepted projects, and resubmission in early 2000 is anticipated.
- We found no evidence that the design and development of chemical storage for parabolic trough applications has been *significantly* advanced in the last decade, though some further useful evaluations have been carried out.

These observations lead us to the following recommendations:

1. On the basis of current progress and cost estimates, molten salts and concrete systems merit priority as candidates for near-term deployment. PCM systems are the additional system of choice for longer-term development.
2. The focus of near-term research should be prototype system development and field implementation to refine designs and provide the bases for valid performance and cost estimates.

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APPENDIX A:

Report of Database Search

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ENERGY FILE SEARCH STATISTICS - F337407K 03 DEC 1999 15:03:04 PAGE 2

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29 ANSWERS PRINTED IN FORMAT "ALL"
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L2 4927 SEA FILE=ENERGY 1437/CC
L3 1873 SEA FILE=ENERGY L1 AND L2
L4 18876 SEA FILE=ENERGY ("POWER PLANTS"/CT OR "DUAL-PURPOSE POWER PLANTS"/CT OR "FUEL CELL POWER PLANTS"/CT OR "GAS TURBINE POWER PLANTS"/CT OR "HYDROELECTRIC POWER PLANTS"/CT OR "HIGH-HEAD HYDROELECTRIC POWER PLANTS"/CT OR "LOW-HEAD HYDROELECTRIC POWER PLANTS"/CT OR "MEDIUM-HEAD HYDROELECTRIC POWER PLANTS"/CT OR "MICRO-SCALE HYDROELECTRIC POWER PLANTS"/CT OR "PUMPED STORAGE POWER PLANTS"/CT OR "SMALL-SCALE HYDROELECTRIC POWER PLANTS"/CT OR "MHD POWER PLANTS"/CT OR "MHD GENERATOR ETF"/CT OR "PEAKING POWER PLANTS"/CT OR "COMPRESSED AIR STORAGE POWER PLANTS"/CT OR "PUMPED STORAGE POWER PLANTS"/CT OR "SOLAR POWER PLANTS"/CT OR "OCEAN THERMAL POWER PLANTS"/CT OR "ORBITAL SOLAR POWER PLANTS"/CT OR "PHOTOVOLTAIC POWER PLANTS"/CT OR "SALINITY GRADIENT POWER PLANTS"/CT OR "SOLAR THERMAL POWER PLANTS"/CT OR "DISTRIBUTED COLLECTOR POWER PLANTS"/CT OR "TOWER FOCUS POWER PLANTS"/CT OR "BARSTOW SOLAR PILOT PLANT"/CT OR "THERMAL POWER PLANTS"/CT OR "COMBINED-CYCLE POWER PLANTS"/CT OR "MHD GENERATOR ETF"/CT OR "FOSSIL-FUEL POWER PLANTS"/CT OR "KINGSTON STEAM PLANT"/CT OR "PARADISE STEAM PLANT"/CT OR "SHAWNEE STEAM PLANT"/CT OR "WIDOWS CREEK STEAM PLANT"/CT OR "GEOTHERMAL POWER PLANTS"/CT OR "NUCLEAR POWER PLANTS"/CT OR "RESSAR STANDARD PLANT"/CT OR "EBASCO STANDARD PLANT"/CT OR "GIBSSAR STANDARD PLANT"/CT OR "OFFSHORE NUCLEAR POWER PLANTS"/CT OR "SWESSAR STANDARD PLANT"/CT OR

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SOLAR

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POWER PLANT"/CT OR "WIND POWER PLANTS"/CT OR "EFD WIND GENERATORS"/CT)

L5 245 SEA FILE=ENERGY L3 AND L4

L7 36 SEA FILE=ENERGY L5 AND PY>=[illegible]

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APPENDIX B:

Abstracts of Selected References

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 5

L7 ANSWER 2 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1996(3):15026 ENERGY
TI Development and investigation of thermal energy storage systems for the medium temperature range.
AU Steiner. D.; Groll, M. (Univ. Stuttgart (Germany). Inst. fuer Kernenergetik und Energiesysteme);
Wierse, M. (Forschungsinstitut fuer Kerntechnik und Energiewandlung e.V., Stuttgart (Germany))
NR CONF-950729-
SO Proceedings of the 30. intersociety energy conversion engineering conference. Volume 2.
Editor(s): Goswami, D.Y. (Univ. of Florida, Gainesville, FL (United States)); Kannberg, L.D.; Somasundaram, S. (Pacific Northwest Lab., Richland, WA (United States)); Mancini, T.R. (Sandia National Labs., Albuquerque, NM (United States))
New York, NY: American Society of Mechanical Engineers, 1995. p. 193-198 of 658 p.
American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, NY 10017 (United States).
Conference: 30. Intersociety energy conversion conference, Orlando, FL (United States), 30 Jul - 5 Aug 1995
DT Book Article; Conference
CY United States
LA English
FA AB
AB Within the frame of two projects funded by the German Federal Ministry for Research and Technology (BMFR) a thermochemical energy storage system for solar application and a sensible/latent hybrid storage system for industrial application were investigated. The thermochemical energy storage system utilizes the heat of reaction of the reversible reaction of magnesium and hydrogen. The operation temperature range is between 280 C and 480 C.
The storage capacity amounts to about 54 MJ. The combination of the MgH_2/Mg system with an appropriate low-temperature alloy/hydride offers the option of producing cold below 0 C in the heat retrieval cycle. The hybrid storage system uses a salt/ceramic which consists of a micro-porous MgO matrix, the pores of which are filled with a salt (85 wt% $NaN0_3$, 15 wt% $NaN0_2$). The sensible heat of both the ceramic and the salt and the phase change enthalpy of the salt in the temperature range 250 C to 290 C can be utilized. The experimental storage bed was operated in the temperature range of 150 C to 450 C, the storage capacity was about 400 MJ. Air was used as the heating and cooling heat transfer medium
CC *250600; 142000
CT DESIGN; LATENT HEAT STORAGE; MAGNESIUM HYDRIDES; MAGNESIUM OXIDES; NITRITES;
PERFORMANCE; SENSIBLE HEAT STORAGE; SODIUM COMPOUNDS; SODIUM NITRATES; SOLAR
THERMAL POWER PLANTS; THERMAL ENERGY STORAGE EQUIPMENT; THERMOCHEMICAL HEAT
STORAGE; WASTE HEAT UTILIZATION
*THERMAL ENERGY STORAGE EQUIPMENT: -DESIGN; -THERMAL ENERGY STORAGE EQUIPMENT: -PERFORMANCE; -SOLAR THERMAL POWER PLANTS: -THERMOCHEMICAL HEAT
L7 ANSWER 2 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
STORAGE
BT ALKALI METAL COMPOUNDS; ALKALINE EARTH METAL COMPOUNDS; CHALCOGENIDES; ENERGY STORAGE; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; EQUIPMENT; HEAT
STORAGE; HYDRIDES; HYDROGEN COMPOUNDS; MAGNESIUM COMPOUNDS; NITRATES; NITROGEN
COMPOUNDS; OXIDES; OXYGEN COMPOUNDS; POWER PLANTS; SODIUM COMPOUNDS; SOLAR

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 9

L7 ANSWER 4 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1995(16):102317 ENERGY
TI Storing solar energy in salt.
AU Valenti, M.
SO Mechanical Engineering (United States) (Jun 1995) v. 117(6) p. 72-75.
CODEN: MEENAH ISSN: 0025-6501
DT Journal
CY United States
LA English
FA AB
AB This article describes the world's largest power tower incorporating one of the newest commercial solar energy systems and being build in California's Mojave Desert. The project — sponsored by the Department of Energy (DOE) and a consortium of western utilities, municipalities, and associations — is called Solar Two, and it will use molten salt to absorb solar energy and store that energy until it is needed to generate electricity. Construction will be completed on Solar Two in September. Solar thermal systems convert the sun's rays into electricity by using a thousand or more dual-axis, sun-tracking mirrors, called heliostats, to focus optimum sunlight on the solar receiver of a power tower containing a working fluid. The fluid is heated to a desired temperature and sent to a storage facility. During periods of peak demand, the fluid is circulating through heat exchangers to generate steam used to drive a turbine
CC *142000; 140702
CT CENTRAL RECEIVERS; HYBRID SYSTEMS; MOLTEN SALTS; PHYSICAL PROPERTIES; THERMAL
ENERGY STORAGE EQUIPMENT; TOWER FOCUS POWER PLANTS
*TOWER FOCUS POWER PLANTS: -THERMAL ENERGY STORAGE EQUIPMENT; *MOLTEN SALTS: -PHYSICAL PROPERTIES
BT ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; EQUIPMENT; POWER PLANTS; SALTS; SOLAR
POWER PLANTS; SOLAR RECEIVERS; SOLAR THERMAL POWER PLANTS; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 10

L7 ANSWER 5 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1995(8>:50639 ENERGY
TI Investigation of commercial central receiver thermal storage and steam generator issues.
AU Kelly, B.O.; Lessley, R.L. (Bechtel Corp., San Francisco, CA (United States))
NR CONF-940326-
SO Solar engineering 1994.
Editor(s): Klett, D.E.; Hogan, R.E.; Tanaka, Tadayoshi
New York, NY: American Society of Mechanical Engineers. 1994. p. 611-616 of 670 p.
American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, 10017 (United States).
Conference: ASME/JSME/JSES international solar energy conference, San Francisco, CA (United States), 27-30 Mar 1994
ISBN: 0-7918-1192-1
DT Book Article; Conference
CY United States
LA English
FA AB
AB Conceptual designs, cost estimates, and warranty provisions were developed for nitrate salt steam generators and thermal storage system hot salt tanks in the initial 100 MWe commercial central receiver power plants. All of the steam generator designs, including the U-tube/U-shell, straight tube/straight shell, and U-tube/kettle boiler, offered comparable steady state and transient performance and competitive cost estimates. The hot salt tank designs included <1) a stainless steel tank with external insulation and (2) a carbon steel tank with
internal refractory insulation and a corrugated Incoloy liner to isolate the salt from the refractory. The stainless steel tank designs had both lower heat losses and lower capital costs
CC *140702; 142000; 360104
CT COMMERCIALIZATION; COMPARATIVE EVALUATIONS; FEASIBILITY STUDIES; HEAT LOSSES; MATERIALS TESTING; PERFORMANCE; STEAM GENERATORS; THERMAL ANALYSIS; THERMAL ENERGY STORAGE EQUIPMENT; TOWER FOCUS POWER PLANTS
*TOWER FOCUS POWER PLANTS: COMMERCIALIZATION; *STEAM GENERATORS: •FEASIBILITY STUDIES; -THERMAL ENERGY STORAGE EQUIPMENT: -FEASIBILITY STUDIES
BT BOILERS; ENERGY LOSSES; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; EQUIPMENT; EVALUATION; LOSSES; POWER PLANTS; SOLAR POWER PLANTS; SOLAR THERMAL POWER PLANTS; TESTING; THERMAL POWER PLANTS; VAPOR GENERATORS
ET U

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 11

L7 ANSWER 6 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE

AN 1995(8):50627 ENERGY
TI Attenuation thermal energy storage in sensible-heat solar-dynamic receivers.
AU Lund, K.O. (Univ. of California. La Jolla, CA (United States). Center for Energy and Combustion Research)
NR CONF-940326-
SO Solar engineering 1994.
Editors): Klett, D.E.; Hogan, R.E.; Tanaka, Tadayoshi
New York, NY: American Society of Mechanical Engineers. 1994. p. 273-281 of 670 p.
American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, 10017 (United States).
Conference: ASME/JSME/JSES international solar energy conference, San Francisco, CA (United States), 27-30 Mar 1994
ISBN: 0-7918-1192-1
DT Book Article; Conference
CY United States
LA English
FA AB
AB Solar dynamic receiver designs are investigated and evaluated for possible use with sensible energy storage in single-phase materials. The designs are similar to previous receivers having axial distribution of concentrated solar input flux, but differ in utilizing axial conduction in the storage material for attenuation of the solar flux "signal", and in having convective beat removal at the base of the receiver. One-dimensional, time-dependent heat transfer equations are formulated for the storage material temperature field, including radiative tosses to the environment, and a general heat exchange effectiveness boundary condition at the base. The orbital periodic input solar flux is represented as the sum of steady and oscillating components, with the steady component solved numerically subject to specified receiver thermal efficiency. For the oscillating components the Fast Fourier Transform algorithm (FFT) is applied, and the complex transfer function of the receiver is obtained and evaluated as a filter for the input flux spectrum. Inverse transformation, result in the amplitudes and mode shapes of the oscillating temperatures. By adjustment of design parameters, the amplitude of the oscillating component of the outlet gas temperature is limited to an acceptable magnitude. The overall result of the investigation is the dependence of the receiver M»c product (mass times specific beat) on the conduction transfer units, which leads to lower weight designs than comparable previous single and two phase designs, when all constraints are included. As these designs also offer improvements in cost reduction and reliability they warrant further detailed investigation
CC *140700; 142000
CT DESIGN; MATHEMATICAL MODELS; PERFORMANCE; SENSIBLE HEAT STORAGE; SOLAR RECEIVERS; SOLAR THERMAL POWER PLANTS; SPACECRAFT POWER SUPPLIES; THERMAL ENERGY STORAGE EQUIPMENT
L7 ANSWER 6 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
*SOLAR RECEIVERS: -DESIGN; *SOLAR RECEIVERS: -SENSIBLE HEAT STORAGE; *SOLAR THERMAL POWER PLANTS: -DESIGN; -SPACECRAFT POWER SUPPLIES: -DESIGN
BT ELECTRONIC EQUIPMENT; ENERGY STORAGE; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS;
EQUIPMENT; HEAT STORAGE; POWER PLANTS; POWER SUPPLIES; SOLAR POWER PLANTS; STORAGE; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 13

L7 ANSWER 7 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1995(7):41657 ENERGY
TI Thermal energy storage at medium and high temperatures for solar power plants.
Thermische Energiespeicherung bei mittleren und hohen Temperaturen fuer Solarkraftwerke.
AU Hunold, D. (Geschaeftsbereich Solarthermische Energietechnik des Zentrums fuer Sonnenenergie- und Wasserstoff-Forschung Baden-Wuerttemberg (ZSW), Stuttgart (Germany)); Tamme, R. (Fachgruppe Thermische und Chemische Speicher in der Deutschen Forschungsanstalt fuer Luft-
und Raumfahrt (DLR), Stuttgart (Germany))
SO Forschungsverbund Sonnenenergie. Topics 93/94. Solar thermal power. Thermal uses of solar energy.
Forschungsverbund Sonnenenergie. Themen 93/94. Solarthermie. Thermische Nutzung der Solarenergie.
Compiler: Hertlein, H.P.
Forschungsverbund Sonnenenergie, Koeln (Germany) (9204591)
Feb 1994. p. 75-82 of 96 p. Available from FIZ Karlsruhe.
ISBN: 0939-7582
DT Miscellaneous; Availability Note
CY Germany, Federal Republic of
LA German
FA AB; ABDE
AB The current R and D activities in the field of medium and high temperature storage are presented and the storage test facilities of ZSW and DLR briefly described. The R and D activities include studies on heat transfer processes in alkali metal nitrates used as phase-change storage material for the medium temperature range with different geometries of the heat exchanger, as well as investigations of different salt ceramic hybrid materials for high temperature applications. The state of development of medium and high temperature
storage systems is shown, possible constructions of storage systems are presented, and an outlook on further studies is provided. (orig.)
CC *142000; 140700
CT COMPARATIVE EVALUATIONS; DESIGN; ECONOMICS; ENERGY STORAGE; FLOWSHEETS; FORECASTING; HEAT EXCHANGERS; HEAT TRANSFER; PHASE CHANGE MATERIALS; SOLAR
POWER PLANTS; TECHNOLOGY UTILIZATION; THERMAL ENERGY STORAGE EQUIPMENT; WORKING FLUIDS
-ENERGY STORAGE: -SOLAR POWER PLANTS
BT DIAGRAMS; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; ENERGY TRANSFER; EQUIPMENT;
EVALUATION; FLUIDS; MATERIALS; POWER PLANTS; STORAGE
ET D; Es

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 17

L7 ANSWER 10 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1994(2):12158 ENERGY
TI Storage of solar high temperature heat.
Speicherung solarer Hochtemperaturwaerme.
AU Meier, A.; Winkler, C. (Paul Scherrer Inst. (PSI), Villigen (Switzerland))
CS Paul Scherrer Inst. (PSI), Villigen (Switzerland) (5107100)
NR PSI-93-07
SO Dec 1993. 62 p. OSTI as DE94726403; NTIS.
ISBN: 1019-0643
DT Report; Numerical Data
CY Switzerland
LA German
FA AB
AB Based on a mathematical-physical model for the description of sensible heat storage in packed beds, the simulation program PACKBED has been developed, which is intended to serve as a decision base for the assessment of packed bed storage systems used in solar high temperature applications. For the validation of the theoretical model, the thermodynamic behaviour of packed beds consisting of sensible heat storage material has been investigated in the experimental store ARIANE. using air as heat transfer medium. Different material tests in the temperature range up to 800oC have been carried out. The short-time storage in large scale solar thermal power plants has been simulated under real operating conditions, as they are expected for the planned 30 MWe PHOEBUS solar tower power plant. For the same storage, it has been shown that the pressure drop, and therefore the required pumping power of the fan, can be reduced significantly by introducing an air bypass system. For the characterization of the storage performance, a storage quality factor has been introduced, which allows to compare different sensible heat storage systems and to describe the degradation of such storage systems during consecutive charging/discharging cycles. In the field of latent heat storage, a thorough literature research has been performed. With a new simulation program for large scale latent heat storage systems, parameter studies have been performed in order to clarify the suitability of latent storage material for storing solar high temperature heat in packed beds. (author) 22 figs., 7 tabs., 88 refs.
CC *142000; 140702
CT COMPUTERIZED SIMULATION; EXPERIMENTAL DATA; LATENT HEAT STORAGE; MATHEMATICAL MODELS; P CODES; PACKED BEDS; PARAMETRIC ANALYSIS; SENSIBLE HEAT STORAGE; SOLAR ENERGY; TEMPERATURE RANGE 0273-0400 K; TEMPERATURE RANGE 0400-1000 K; THEORETICAL DATA; THERMAL ENERGY STORAGE EQUIPMENT; TOWER FOCUS POWER PLANTS; VALIDATION
*SOLAR ENERGY: -SENSIBLE HEAT STORAGE; -THERMAL ENERGY STORAGE EQUIPMENT: *PACKED BEDS
BT COMPUTER CODES; DATA; ENERGY; ENERGY SOURCES; ENERGY STORAGE; EQUIPMENT; HEAT STORAGE; INFORMATION; NUMERICAL DATA; POWER PLANTS; RENEWABLE ENERGY SOURCES; SIMULATION; SOLAR POWER PLANTS; SOLAR THERMAL POWER PLANTS; STORAGE; TEMPERATURE RANGE; TESTING; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 21

L7 ANSWER 13 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1992(21):156481 ENERGY
TI A solar energy-based direct steam generation method using latent heat thermal energy storage.
AU Solomon, A.D. (Univ. of Tennessee, Knoxville (United States))
NR CONF-910277—
SO WATTec '91. The technical professional: Staying current/staying competitive.
Anon.
Oak Ridge, TN: Sun Graphics Inc. 1991. p. 67-68 of 80 p. Sun Graphics Inc., 101 East Tyrone Rd., Oak Ridge, TN 37830 (United States).
Conference: 18. annual WATTec interdisciplinary technical conference and exhibition, Knoxville, TN (United States), 19-22 Feb 1991
DT Book Article; Conference
CY United States
LA English
FA AB
AB The heart of a solar-energy based electricity generation approach is a direct steam generation (DSG) unit consisting of tube banks, embedded in a phase changing material (PCM). During times of high solar energy availability steam is pumped through the tubes, releasing heat to the PCM which takes it up as the latent heat of melting and undergoes a phase change to its liquid phase. This period is referred to as the charging period. The discharge period is marked by water being pumped through the tubes; now heat is transferred from the PCM to the water which, under appropriate conditions, will boil and emerge as steam. The process of heat exchange between the water or steam in the tube (during charge and discharge) and the PCM is a complex one governed by a variety of factors including tube size, pressure drops, quality of the two phase flow region, extent of this region, and flow rates. In order to examine the performance of such a DSG unit a computer code simulating two phase flow, heat exchange between tube and PCM, and heat transfer and phase change in the PCM has been prepared. The code permits the user to vary all major geometric and thermophysical parameters; options include variable tube diameter, angle of inclination and different flow directions during charge and discharge. In this paper the author describes the above code, examining its underlying assumptions and algorithms. Among points raised are the role of natural convection in the melt. Results shown include sample runs and simple analytical approximations for key performance factors. In addition he describes preliminary experimental work being done to verify the computer model.
CC *140700; 142000
CT COMPUTERIZED SIMULATION; HEAT TRANSFER; PERFORMANCE; PHASE CHANGE MATERIALS; PHASE TRANSFORMATIONS; SOLAR THERMAL POWER PLANTS; THERMAL ENERGY STORAGE EQUIPMENT
*SOLAR THERMAL POWER PLANTS: -THERMAL ENERGY STORAGE EQUIPMENT; -THERMAL ENERGY STORAGE EQUIPMENT: -COMPUTERIZED SIMULATION
BT ENERGY TRANSFER; EQUIPMENT; MATERIALS; POWER PLANTS; SIMULATION; SOLAR POWER PLANTS; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 23

L7 ANSWER 14 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1992(20):149792 ENERGY
TI Energy storage.
AU Anon.
SO Cool energy. Renewal solutions to environmental problems.
Brower, M.
Cambridge, MA: Massachusetts Inst. of Tech. Press. 1992. p. 155-172 of 225 p. MIT Press, Massachusetts Institute of Technology, Cambridge, MA 02142 (United States).
Book Article
CY United States
LA English
FA AB
AB This chapter discusses the role that energy storage may have on the energy future of the US. The topics discussed in the chapter include historical aspects of energy storage, thermal
energy storage including sensible heat storage, latent heat storage, thermochemical heat storage, and seasonal heat storage, electricity storage including batteries, pumped hydroelectric
storage, compressed air energy storage, and superconducting magnetic energy storage, and production and combustion of hydrogen as an energy storage option.
CC *250000; 142000; 290301; 299000; C5700
CT COMPRESSED AIR ENERGY STORAGE EQUIPMENT; COMPRESSED AIR STORAGE POWER PLANTS; ECONOMICS; ELECTRIC BATTERIES; ELECTRIC-POWERED VEHICLES; ENERGY STORAGE;
ENERGY STORAGE SYSTEMS; ENVIRONMENTAL IMPACTS; HYDROGEN FUEL CELLS; HYDROGEN PRODUCTION; HYDROGEN STORAGE; LEAD-ACID BATTERIES; MAGNETIC ENERGY STORAGE EQUIPMENT; OFF-PEAK ENERGY STORAGE; PEAKING POWER PLANTS; SUPERCONDUCTING COILS; SUPERCONDUCTING MAGNETS; TECHNOLOGY ASSESSMENT; THERMAL ENERGY STORAGE
EQUIPMENT; UNDERGROUND STORAGE
*ENERGY STORAGE SYSTEMS: -ECONOMICS; -ENERGY STORAGE SYSTEMS: -ENVIRONMENTAL IMPACTS; -ENERGY STORAGE SYSTEMS: -TECHNOLOGY ASSESSMENT
BT DIRECT ENERGY CONVERTERS; ELECTRIC BATTERIES; ELECTRICAL EQUIPMENT; ELECTROCHEMICAL CELLS; ELECTROMAGNETS; ENERGY STORAGE; EQUIPMENT; FUEL CELLS; MAGNETS; PEAKING POWER PLANTS; POWER PLANTS; STORAGE; SUPERCONDUCTING DEVICES; VEHICLES

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 27

L7 ANSWER 17 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1992(10):67921 ENERGY
TI Observations of the freeze/thaw performance of lithium fluoride by motion picture photography.
AU Jaworske, D.A. (National Aeronautics and Space Administration, Cleveland, OH (United States). Lewis Research Center); Perry, W.D. (Auburn Univ., AL (United States). Dept. of Chemistry)
NR CONF-910801—
SO Proceedings of the 26th intersociety energy conversion engineering conference. Volume 4. Anon.
La Grange Park, IL: American Nuclear Society. 1991. p. 151-154 of 575 p. American Nuclear Society, 555 North Kensington Ave., La Grange Park, IL 60525 (United States).
Conference: 26. intersociety energy conversion engineering (IECE) conference, Boston, MA (United States), 3-9 Aug 1991
ISBN: 0-89448-163
DT Book Article; Conference
CY United States
LA English
FA AB
AB Molten salts are attractive candidates for thermal energy storage in solar dynamic power systems owing to their high latent heat of fusion. This paper reports that, to gain direct observation of the molten salt phase change, a novel containerless technique was developed where the high surface tension of lithium fluoride was used to suspend a bead of the molten salt inside a specially designed wire cage. By varying the current passing through the wire, the cage also served as a variable heat source. In this way, the freeze/thaw performance of the lithium fluoride could be photographed by motion picture photography without the influence of container walls. The motion picture photography of the lithium fluoride sample revealed several zones during the phase change, a solid zone and a liquid zone, as expected, and a slush zone that was predicted by thermal analysis modeling.
«250600; 142000; 140700; 360204
FUSION HEAT; LATENT HEAT STORAGE; LITHIUM FLUORIDES; MATERIALS TESTING; MOLTEN SALTS; PERFORMANCE TESTING; PHASE CHANGE MATERIALS; SOLAR THERMAL POWER PLANTS; THERMAL ANALYSIS; THERMAL ENERGY STORAGE EQUIPMENT
-LATENT HEAT STORAGE: -THERMAL ENERGY STORAGE EQUIPMENT; -MOLTEN SALTS: -FUSION HEAT; -LITHIUM FLUORIDES: -THERMAL ANALYSIS; -LITHIUM FLUORIDES: -PERFORMANCE TESTING
ALKALI METAL COMPOUNDS; ENERGY STORAGE; ENTHALPY; EQUIPMENT; FLUORIDES; FLUORINE COMPOUNDS; HALIDES; HALOGEN COMPOUNDS; HEAT STORAGE; LITHIUM COMPOUNDS; LITHIUM HALIDES; MATERIALS; PHYSICAL PROPERTIES; POWER PLANTS; SALTS; SOLAR POWER PLANTS; STORAGE; TESTING; THERMAL POWER PLANTS; THERMODYNAMIC PROPERTIES; TRANSITION HEAT

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 30

L7 ANSWER 20 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1992(5):26741 ENERGY
TI C.R.S. receiver and storage systems evaluation.
AU Castro, M.; Presa, J.L.; Diaz, J.; Peire, J. (Univ. Politecnia de Madrid (Spain)); Faas, S.E.; Radosevich, L.G.; Skinrood. A.C. (Sandia National Labs. Livermore, CA (United States))
SO Solar Energy (Journal of Solar Energy Science and Engineering) (United States) (1991) v. 47(3) p. 197-207.
CODEN: SRENA4 ISSN: 0038-092X
DT Journal
CY United States
LA English
FA AB
AB This article describes a comparison and evaluation of the Solar One and CESA-I receiver and thermal storage systems. The evaluation is based on operating data from Solar One, the MWe experimental solar central receiver plant located near Barstow, California, USA and CESA-I, the 1.2 MWe experimental solar central receiver plant located near Almeria, Spain. This study was sponsored by the US-Spain Joint Committee for Scientific and Technological Cooperation. Significant differences exist in the design and operation of the receiver and thermal storage systems for the two experimental plants. An evaluation of their performance has increased our understanding of the plant design variables and provides useful information to improve the designs of future central receiver plants.
*140702; 142000
CALIFORNIA; CENTRAL RECEIVERS; COMPARATIVE EVALUATIONS; DESIGN; EVALUATION; INTERNATIONAL COOPERATION; PERFORMANCE; SPAIN; THERMAL ENERGY STORAGE EQUIPMENT; TOWER FOCUS POWER PLANTS
*TOWER FOCUS POWER PLANTS: *EVALUATION
COOPERATION; DEVELOPED COUNTRIES; DEVELOPING COUNTRIES; EQUIPMENT; EUROPE; EVALUATION; NORTH AMERICA; POWER PLANTS; SOLAR POWER PLANTS; SOLAR RECEIVERS; SOLAR THERMAL POWER PLANTS; THERMAL POWER PLANTS; USA
ET I

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 31

L7 ANSWER 21 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1991(20>:132341 ENERGY
TI Large energy storage facilities (200 mWh th) for medium-temperature-range solar power stations.
Grosse Energiespeicher (200 MWh th) fuer Solarkraftwerke im Mitteltemperaturbereich.
AU Beine, B. (Siempelkamp Giesserei GmbH und Co., Krefeld (Germany, F.R.))
NR CONF-901033—
SO 7th international solar energy forum. Energy-use efficiency and harnessing of renewable energy sources at the regional and municipal levels. What can be their contribution towards averting the threat to the climate? Conference report. Vol. 3.
7. Internationales Sonnenforum. Rationelle Energieverwendung und Nutzung erneuerbarer Energiequellen im regionalen und kommunalen Bereich. Welchen Beitrag koennen sie zur Abwehr der Klimabedrohung leisten? Tagungsbericht. Bd. 3.
Deutsche Gesellschaft fuer Sonnenenergie e.V. (DGS), Muenchen (Germany) (9201294)
Muenchen: DGS-Sonnenenergie Verlags-GmbH. 1990. p. 1680-1685 of 769 p.
Conference: 7. international solar forum: rational use of energy a'd "se of renewable resources of energy in regional and municipal domains. 7. Internationales Sonnenforum: Rationelle Energieverwendung und Nutzung Erneuerbarer Energiequellen im Regionalen und Kommunalen Bereich - Welchen Beitrag Koennen Sie zur Abwehr der Klimabedrohung Leisten, Frankfurt am Main (Germany), 9-12 Oct 1990
DT Book Article; Conference
CY Germany,Federal Republic of
LA German
FA AB; ABDE
AB The objective of the study was to find a thermal energy storage unit for a medium-temperature solar power station in the temperature range between 200deg C and 400deg C requiring investment cost of less than 25 US Dollar/kWh of exploitable thermal energy. The following storage types were compared: Hot-tank and cold-tank liquid salt storage unit with pumps and heat exchangers; thermal oil storage unit; concrete storage unit with cast-in pipes; solid salt slab storage unit with cast-in pipes, and liquid salt storage unit in cascade connection. A concrete storage unit will have to be preferred none the least for reasons of technical risks and fast erectibility. (BWI).
CC *142000; 140700
CT BOILERS; COMPARATIVE EVALUATIONS; CONCRETE BLOCKS; DESIGN; INVESTMENT; MEASURING METHODS; OPERATION; SOLAR THERMAL POWER PLANTS; THERMAL ENERGY STORAGE EQUIPMENT
*SOLAR THERMAL POWER PLANTS: -THERMAL ENERGY STORAGE EQUIPMENT; -THERMAL ENERGY STORAGE EQUIPMENT: -INVESTMENT; -THERMAL ENERGY STORAGE EQUIPMENT: -COMPARATIVE EVALUATIONS
BT BUILDING MATERIALS; EQUIPMENT; EVALUATION; MATERIALS; POWER PLANTS; SOLAR POWER PLANTS; THERMAL POWER PLANTS
ET Es

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ENERGY FILE SEARCH RESULTS - P337407K 03 DEC 1999 15:03:04 PAGE 33

L7 ANSWER 22 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1991(20):132340 ENERGY
TI Solar power plant with thermo-chemical storage - progress in development.
Solarkraftwerk mit thermochemischem Speicher - Fortschritte in der Entwicklung.
AU Mitzel, M. (Bomin-Solar GmbH, Loerrach (Germany, F.R.)); Bogdanovic, B. (Max-Planck-Institut fuer Kohleforschung, Muelheim an der Ruhr (Germany, F.R.). Inst. fuer Kerntechnik und Energiewandlung e.V.); Ritter, A. (Max-Planck-Institut fuer Strahlenchemie, Muelheim an der Ruhr (Germany, F.R.))
NR CONF-901033--
SO 7th international solar energy forum. Energy-use efficiency a"d harnessing of renewable energy sources at the regional and municipal levels. What can be their contribution towards averting the threat to the climate? Conference report. Vol. 3.
7. Internationales Sonnenforum. Rationelle Energieverwendung und Nutzung erneuerbarer Energiequellen im regionalen und kommunalen Bereich. Welchen Beitrag koennen sie zur Abwehr der Klimabedrohung leisten? Tagungsbericht. Bd. 3.
Deutsche Gesellschaft fuer Sonnenenergie e.V. (DGS), Muenchen (Germany) (9201294)
Muenchen: DGS-Sonnenenergie Verlags-GmbH. 1990. p. 1674-1679 of 769 p.
Conference: 7. international solar forum: rational use of energy and use of renewable resources of energy in regional and municipal domains. 7. Internationales Sonnenforum: Rationelle Energieverwendung und Nutzung Erneuerbarer Energiequellen im Regionalen und Kommunalen Bereich - Welchen Beitrag Koennen Sie zur Abwehr der Klimabedrohung Leisten, Frankfurt am Main (Germany). 9-12 Oct 1990
DT Book Article; Conference
CY Germany.Federal Republic of
LA German
FA AB; ABDE
AB This papers describes the functional mode of a solar energy station using thermochemical storage based on magnesium hydride/magnesium which is being developed currently on commission by the Federal Minister for Research and Technology by a study group comprising Bomin Solar GmbH and Co. KG, Loerrach, Max-Planck Institut fuer Kohleforschung,
Muelheim a.d. Ruhr, Institut fuer Kerntechnik u. Energiewandlung e.V., Max-Planck-Institut fuer Strahlenchemie, Muelheim a.d. Ruhr. (orig.).
CC *142000; 140700
CT DESIGN; DIAGRAMS; ELECTRIC POWER; HYBRID SYSTEMS; HYDRIDES; OPERATION; PROCESS
HEAT; SOLAR CONCENTRATORS; SOLAR POWER PLANTS; TEMPERATURE DEPENDENCE;
THERMAL ENERGY STORAGE EQUIPMENT; THERMOCHEMICAL HEAT STORAGE
*SOLAR POWER PLANTS: THERMOCHEMICAL HEAT STORAGE
BT ENERGY; ENERGY STORAGE; EQUIPMENT; HEAT; HEAT STORAGE; HYDROGEN COMPOUNDS;
POWER; POWER PLANTS; SOLAR EQUIPMENT; STORAGE
ET Co

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ANSWER 26 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
1990(14):100530 ENERGY
Thermal stratification in hot storage-tanks.
Kandari, A.M. (Kuwait Inst. for Scientific Research, Safat (KW). Energy Div.)
Applied Energy <UK) (1990) v. 35(4) p. 299-315.
CODEN: APENDX ISSN: 0306-2619
Journal
United Kingdom
English
AB
This experimental investigation was conducted as a support activity for the development at Sulaibiyah, which has a 22 m3 stratified tank to act as a buffer reservoir between the paraboloid-dish solar collector and the toluence turbine energy-conversion device. The results show that the disturbed zone is 1500 mm thick (i.e. nearly 30% of the usable tank height). Based on these results, an experimental model (1/25th scale by volume) was constructed to study the effect of using improved distributor header geometry and a settling mesh for reducing the buffer-zone thickness. Using the new header configuration, extraction efficiencies of 85% could be achieved, (author).
*142000
EFFICIENCY; SCALE MODELS; SOLAR THERMAL POWER PLANTS; STRATIFICATION; THERMAL ENERGY STORAGE EQUIPMENT
-THERMAL ENERGY STORAGE EQUIPMENT: -STRATIFICATION; -THERMAL ENERGY STORAGE EQUIPMENT: -SOLAR THERMAL POWER PLANTS
EQUIPMENT; POWER PLANTS; SOLAR POWER PLANTS; STRUCTURAL MODELS; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 3

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L4 ANSWER 1 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1996(20):141769 ENERGY
TI Regenerators in parabolic dish solar power stations.
Regeneratoren in Parabolrinnen-Solarkraftwerken.
AU Ratzesberger, R.
CS Deutsche Forschungsanstalt fuer Luft- und Raumfahrt e.V. <DLR). Koein (Germany) (2143700)
Funding Organisation: Bundesministerium fuer Forschung und Technologie, Bonn (Germany) (9200321)
SO Thesis. Duesseldorf: VDI-Verl. 1995. 131 p.
Ser. Title: Fortschritt-Berichte VDI. Reihe 6, Energietechnik, v. 330.
ISBN: 3-18-333006-7 ISSN: 0178-9414
DT Book; Dissertation
CY Germany, Federal Republic of
LA German
FA AB; ABDE
AB For the parabolic dish solar powerstations of the solar electric generating system (SEGS) type, regenerators are designed which use the thermal oil used for solar collectors as heat carrier. Alternative concepts with concrete and/or phase change material as storage material are compared. The design for a compound regenerator with a capacity of 200 MWhth is discussed. Using quasi steady state thermodynamic process calculations, the interaction between the regenerator and powerstation operation is measured and the use of the store is thus quantified. From annual energy balances, the effect of solar field size and store capacity on the duration of annual powerstation operation is determined. Finally, from an economy calculation, one can prove that the additional investment in an enlarged solar field and a thermal energy store reduces the electricity generating costs of the plant, (orig.)
CC *140703
CT CALCULATION METHODS; HEAT STORAGE; OPERATION; REGENERATORS; SIMULATION; SOLAR COLLECTORS; SOLAR POWER PLANTS; THERMAL ENERGY STORAGE EQUIPMENT
*SOLAR POWER PLANTS: *SOLAR COLLECTORS
BT ENERGY STORAGE; ENERGY STORAGE SYSTEMS; ENERGY SYSTEMS; EQUIPMENT; POWER PLANTS; SOLAR EQUIPMENT; STORAGE

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 4

L4 ANSWER 2 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1994(0):99103 ENERGY
TI Design of a C02-CH4 reformer for a 100 Kw parabolic dish solar concentrator.
AU Steinfeld, A.; Segal, A.; Levy, M. (Weizmann Inst. of Science, Rehovoth (Israel))
CS Weizmann Inst. of Science, Rehovoth (Israel) (6860000)
NC 90-05 25/90-1-85
NR INIS-mf-13968
SO Jan 1991. 6 p. OSTI as DE94628358; NTIS (US Sales Only); INIS.
DT Report; Progress Report
CY Israel
LA English
FA AB
AB Design of a C02-CH4 reformer. A schematic diagram of the system components is shown. (authors). 1 fig.
CC *140300; F1522
CT CARBON DIOXIDE; CATALYTIC CONVERTERS; CHEMICAL REACTION KINETICS; CHEMICAL REACTION YIELD; COMPUTER CODES; COMPUTERIZED SIMULATION; DESIGN; PARABOLIC DISH COLLECTORS; PROGRESS REPORT; SOLAR ENERGY CONVERSION; SPECIFICATIONS; THERMOCHEMICAL HEAT STORAGE
-PARABOLIC DISH COLLECTORS: *THERMOCHEMICAL HEAT STORAGE; *THERMOCHEMICAL HEAT STORAGE: *CATALYTIC CONVERTERS; *THERMOCHEMICAL HEAT STORAGE: •COMPUTERIZED SIMULATION

CARBON COMPOUNDS; CARBON OXIDES; CHALCOGENIDES; CONCENTRATING COLLECTORS; CONVERSION; DOCUMENT TYPES; ENERGY CONVERSION; ENERGY STORAGE; EQUIPMENT; HEAT
STORAGE; KINETICS; OXIDES; OXYGEN COMPOUNDS; PARABOLIC COLLECTORS; POLLUTION CONTROL EQUIPMENT; REACTION KINETICS; SIMULATION; SOLAR COLLECTORS; SOLAR EQUIPMENT; STORAGE; YIELDS

ET C*H*0; C02; C cp; cp; 0 cp; CH4; H cp; C02-CH4

PLANTS; STORAGE; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 9

L4	ANSWER 7 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN	1986(1):1691 ENERGY
TI	Design of a 13 MW'e parabolic trough plant at Daggett. California.
AU	Kroizer, 1. (Luz Engineering, Encino, CA) [United States]
CS	Solar Energy Research Inst, Golden, CO (USA) (9506687)
NR	SERI/SP—271-2664; CONF-8406111—; DE85002949
SO	Design and performance of large solar thermal collector arrays. Mar 1985. pp. 534-536 Availability: NTIS, PC A24/MF A01; 1. Conference: International Energy Agency workshop on the design and performance of large solar thermal collectors, San Diego, CA. USA, 11 Jun 1984
DT	Report Article; Conference
CY	United States
LA	English
DN	ERA-11:005107
AB	The solar power plant design characteristics and system description at Daggett California are presented. The solar collector assembly (SCA) is the primary building block of this modular system. A single SCA consists of a row of eight parabolic trough collectors, a single drive motor, and a local microprocessor control unit. The basic components of the parabolic trough collector are a mirrored glass reflector, a unique and high-efficiency heat collection element, and a positioning system. The heat collection element includes a stainless steel absorber tube coated with a black chrome selective surface, which is contained within a unique and high-efficiency evacuated cylindrical glass envelope. The SCA is designed to have an operating efficiency of 67% at 265 deg C under a direct normal insolation of 3500 kJ/m2. The operation of the system is discussed.
CC	*140700
CT	*SOLAR THERMAL POWER PLANTS: -OPERATION; *SOLAR THERMAL POWER PLANTS; -PERFORMANCE; PARABOLIC TROUGH COLLECTORS; POWER GENERATION; SENSIBLE HEAT STORAGE
BT	CONCENTRATING COLLECTORS; ENERGY STORAGE; EQUIPMENT; HEAT STORAGE; PARABOLIC COLLECTORS; POWER PLANTS; SOLAR COLLECTORS; SOLAR EQUIPMENT; SOLAR POWER

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SOLAR EQUIPMENT; SOLAR POWER PLANTS; SOLAR REFLECTORS; THERMAL POWER PLANTS

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 12

L4 ANSWER 10 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN 1985(7):44992 ENERGY
TI Performance characteristics of solar thermal power generation system with flat plate mirror and parabolic mirror.
AU Chinen, M.; Anzai, S.; Sasaki, S.; Sato, S.; Sumida, 1.; Taki, T.; Tsukamoto, M. (Energy Research Laboratory, Hitachi Ltd., Hitachi) [Japan]
NR CONF-830839-
SO Solar world congress. Vol. 3.
Szokolay, S.V.
Oxford, England: Pergamon Press. 1963. pp. 1581-1585
Conference: Solar world congress, Perth, Australia, 15 Aug 1983
DT Book Article; Conference
CY United Kingdom
LA English
AB The lMWe solar thermal power generation pilot plant featuring plane-parabolic type concentrators and molten salt heat storages succeeded to generate lMWe power and operated about 2 years. Thermal simulation of the plant predicted the plant operation well and confirmed designed performance of the heat storage system. Optical performance of concentrator was evaluated and led to the following results. 1. The optical performance of the evaporator was satisfactory, and the measured error of parabolic mirror and collecting pipe bending had negligible effect on evaporator concentrator. 2. The bending of collecting pipe produced slight leakage in superheater concentrator, that is about 3%. 3. Adjustment were needed to some sun tracking mechanism due to the friction in sliding parts of it after about 2 years operation.
CC *140700; 141000
CT *SOLAR THERMAL POWER PLANTS: *MIRRORS; *SOLAR THERMAL POWER PLANTS: *PARABOLIC REFLECTORS; *PARABOLIC REFLECTORS: -PERFORMANCE; *SOLAR THERMAL POWER PLANTS: -PERFORMANCE; -MIRRORS: -PERFORMANCE; COMPUTERIZED SIMULATION; OPTICAL PROPERTIES; POWER RANGE 1-10 MW
BT EQUIPMENT; PHYSICAL PROPERTIES; POWER PLANTS; SIMULATION; SOLAR CONCENTRATORS;

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ENERGY FILE SEARCH RESULTS - P330399K 26 NOV 1999 15:02:41 PAGE 17

ANSWER 14 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
1982(17):122788 ENERGY
Comparison of electrochemical and thermal storage for hybrid parabolic dish solar power plants.
Steele, HL.; Wen, L. (JPL, Pasadena, Calif, USA) [United States]
Am. Soc. Mech. Eng., [Pap.] (1981) (81-WA/Sol-27) vp
CODEN: ASMSA4
Journal
United States
English
ERA-07:049782
The cost of storage systems which can compete with the use of fuel in hybrid parabolic dish solar power plants is identified for one set of specific assumptions. The hybrid plants burn fuel to increase the hours of usage each day. The cost and performance characteristics of concentrators, receivers and power conversion units are based on estimates by the contractors developing this hardware under the direction of the Department of Energy and the Jet Propulsion Laboratory (JPL). Thermal storage systems are not yet designed and only the cost goal which would make them competitive is known. 12 refs.
«140703; 142000; 250904; 141000
*DISTRIBUTED COLLECTOR POWER PLANTS: -ENERGY STORAGE; -DISTRIBUTED COLLECTOR POWER PLANTS: *HEAT STORAGE; -DISTRIBUTED COLLECTOR POWER PLANTS: -PARABOLIC DISH COLLECTORS; COST; ELECTRIC BATTERIES; HYBRID SYSTEMS; PERFORMANCE; POWER RANGE 1-10 MW; VERY HIGH TEMPERATURE
CONCENTRATING COLLECTORS; ELECTROCHEMICAL CELLS; ENERGY STORAGE; EQUIPMENT; PARABOLIC COLLECTORS; POWER PLANTS; SOLAR COLLECTORS; SOLAR EQUIPMENT; SOLAR POWER PLANTS; SOLAR THERMAL POWER PLANTS; STORAGE; THERMAL POWER

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ENERGY FILE SEARCH RESULTS - P310399K 26 NOV 1999 15:02:41 PAGE 18

L4	ANSWER 15 OF 26 ENERGY COPYRIGHT 1999 USDOE/IEA-ETDE
AN	1982(17):122775 ENERGY
TI	Parabolic trough development: lessons learned at Willard and Gila Bend.
AU	Dugan, V.L. (Sandia National Labs., Albuquerque, NM) [United States]
NR	CONF-801203-; DE81015033
SO	National conference on renewable energy technologies. 1980. pp. 6.3-6.4 Availability: NTIS, PC A99/MF A01.
DT	Conference: National conference on renewable energy technologies, Honolulu, HI, USA, 7 Dec 1980
CY	Report Article; Conference
LA	United States
DN	English
	ERA-07:049745
AB	Two irrigation projects, one at Willard, New Mexico, and the other at Gila Bend, Arizona, are briefly described, and lessons learned from three years of operating experience relative to collectors, energy transport, engines, and thermocline storage are outlined. (LEW)
CC	*140703
CT	*PARABOLIC TROUGH COLLECTORS: -IRRIGATION; ARIZONA; NEW MEXICO; RANKINE CYCLE ENGINES; SENSIBLE HEAT STORAGE; SOLAR HEAT ENGINES
BT	CONCENTRATING COLLECTORS; ENERGY STORAGE; ENGINES; EQUIPMENT; FEDERAL REGION IX; FEDERAL REGION VI; HEAT ENGINES; HEAT STORAGE; NORTH AMERICA; PARABOLIC COLLECTORS; SOLAR COLLECTORS; SOLAR EQUIPMENT; STORAGE; USA

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ENTEC FILE SEARCH RESULTS - P327382K 24 NOV 1999 01:02:02 PAGE 25

L3 ANSWER 22 OF 39 ENTEC COPYRIGHT 1999 FIZ Karlsruhe
AN 1995:0116924 ENTEC
TI Regeneratoren mit Beton und Phasenwechselmaterial als Speichermasse.
Regenerators with concrete and phase change material as storage mass.
AU Ratzesberger, R.; Hahne, E.; Beine, B.
SO Energiespeicher fuer Strom, Waerme und Kaelte.
Energy storage for electric power, heat and refrigeration.
Verein Deutscher Ingenieure (VDI) - Gesellschaft Energietechnik, Duesseldorf (DE)
Duesseldorf: VDI-Verl. 1994. p. 467-481. of 481 p.
Serientitel: VDI-Berichte. v. 1168.
Konferenz: VDI-GET conference: Electric power and thermal energy storage for electric power, heat and refrigeration, VDI-GET-Tagung: Energiespeicher fuer Strom, Waerme und Kaelte, Leipzig (DE). 6-7 Dec 1994
ISBN: 3-18-091168-9
DT Kapitel der Monographic; Konferenz
CY Deutschland, Bundesrepublik
LA Deutsch
FA AB; ABDE
IP FIZ Karlsruhe
ABDE Die Firma Siempelkamp. Krefeld. hat in einem BmFT-Vorhaben einen Regenerator mit temperaturbestaendigem Beton als Speichermaterial entwickelt. Als Waermetraeger dient das synthetische Thermooel aus dem Solarfeldkreislauf mit 400 C und einem Betriebsdruck von 16 bar. Dieser Beton-Regenerator wurde von Dinter F. (1992) in einer umfassenden technischen und oekonomischen Berechnung als das guenstigste Speicherkonzept fuer die bestehenden Parabolrinnen-Solarkraftwerke ermittelt. Am ZSW wurden im Rahmen des BmFT-Vorhaben zwei Testmodule mit zusammen 50 kWh_Leistungsaufnahme eingehend untersucht. (orig./HW)

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RESPONSES TO COMMENT LETTER #8
(Public Solar Power Coalition - January 30, 2015)

Comment Letter #8 was hand-delivered to SCAQMD staff in the form of a poor image quality photocopy of handwritten materials with reference materials attached. Because this comment letter contains several patches that are either difficult to decipher or are illegible, wherever the difficulty occurs, SCAQMD staff has attempted to either summarize or transcribe the text to assist the reader with understanding the nature of the comment and the context of the responses provided.

8-1 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"Solar Energy is BARCT and should have been submitted as the Best Available Retrofit Technology [illegible] with the backup options cited by staff but solar thermal system with line focus concentrator within 100 miles of the District supplying 354 MW (Megawatts) have been operating for 30 to 20 years. See Power Point printout 9 pages on SEGS solar energy electric generating systems (9 in all – 1x14 MW, 6x30 MW, and 280 MW). These have been the largest operation solar thermal at moderate temperature 500 - 700 °F and higher temps can be operated for use with point double axis solar [illegible] of 1000 °F +++ plus storage. (9 see the 9 page power point print out provided by PSPC/HE."*

SCAQMD staff is aware of the types of solar technologies available and their capabilities. Companies may choose to make use of solar technologies to provide heat and/or power for their facilities. However, for existing and new fuel-fired equipment, the SCAQMD regulates combustion sources through several SCAQMD Regulations (e.g., Regulations IX, X, XI, XIII, and XIV). While solar energy has merits for providing an alternative source of energy on a smaller scale (e.g., residential or commercial applications) or at the utility level, solar energy has not been identified as a feasible replacement source of energy to fulfill the extensive electrical demand and reliability needs of individual, heavy industrial facilities in the NOx RECLAIM program.

In addition, the reference materials linked to this comment as "Attachment A" (e.g., "An Overview of the Kramer Junction SEGS Recent Performance" and the National Renewable Energy Laboratory report "Survey of Thermal Storage for Parabolic Trough Power Plants") do not provide evidence to support the suggestion that solar energy be considered BARCT for any specific source category involved in this rule amendment.

8-2 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"PSPC/HE should be hired as [a] consultant to show the solar options [from] both solar thermal and P.V photovoltaics and hybrids as soon as possible. This can form the center of on, near and further solar thermal SCHP, combines solar combined heating and cooling. District heating and cooling system (absorption vis a vis Dr. Bercum etc. as well as electricity). The repair of sewage and water systems will be*

planned at the same time as well as replacing old nat[ural] gas system a la San Bruno explosion in PG&E territory [illegible].

BARCT is a "technology forcing" control measure cite 2012 California Supreme Court Decision on VOC in American Coatings Association vs. SCAQMD. The law is clear and as pointed out in the current litigation [illegible] the commenter has with the District (with a Draft Amended [illegible] and now federal EPA etc. You can pay now for the construction at a lower costs [sic] or pay more later. A recent study by the [illegible] Economic Advisory says and demonstrated that climate change implementation will cost 40 percent+ each 10 years that we wait."

With regard to the suggestion that the commenter should be hired as a consultant, the commenter is invited to submit a proposal to the SCAQMD Technology Advancement Office with a description of the proposed project, budget and proposed deliverables. In addition, the commenter should periodically review the requests for proposals from the SCAQMD that may be of interest and submit proposals accordingly.

With regard to the remark that BARCT is a technology forcing control measure, see Response 8-1 for why the SCAQMD believes that solar energy, while a very beneficial alternative energy source that we support, does not qualify as BARCT.

8-3 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

"The SEGS plants were brought to the SCP decades by the [illegible]/consultant. This information was [illegible] between early 1991 AQMP Draft and the final adopted in mid year July 1991. Our litigation followed but without a follow through – the time to act is now if not yesterday."

The commenter has not provided a correlation that explains how the SEGS plants and the 1991 AQMP are linked to the currently proposed amendments to the NOx RECLAIM program. As such, SCAQMD staff is unable and not required to prepare a response to this comment.

8-4 This comment requests a full Environmental Impact Report (EIR) to be prepared for the proposed project.

The SCAQMD is not required to prepare an EIR for the proposed project, but is required to prepare a full environmental analysis and has done so. Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written documents in lieu of an EIR once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD operates pursuant to a regulatory program that was certified by the Secretary of the Resources Agency on March 1, 1989 in accordance with CEQA Guidelines §15251 (l) and as codified in SCAQMD Rule 110 - Rule Adoption Procedures to Assure Protection and Enhancement of the Environment. Thus, in accordance with the SCAQMD's certified regulatory program, a Program Environmental Assessment (PEA) has been prepared for the proposed project. The PEA is a substitute CEQA document that has been prepared in lieu of an EIR as allowed by

CEQA Guidelines §15252. Nonetheless, the PEA provides the same quality of analysis and will afford the public the same amount of time for comment and review on the Draft PEA as would be provided for under a Draft EIR (e.g., 45 days).

8-5 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"In reference to the December 5, 2014 document, at least solar energy must be studied as an alternative. The areas covered are energy, GHG green house [sic] gases, transportation and traffic as well as water (even the fact that over 20 percent of the District's state energy is used to move water.)"*

As explained in Response 8-1, SCAQMD does not believe that solar energy qualifies as BARCT for sources involved in this rule amendment. (Utilities are already required to source 33 percent of their power from renewable sources, including solar energy, by 2020.) While solar energy has merits for providing an alternative source of energy on a smaller scale (e.g., residential or commercial applications) or at the utility level, solar energy has not been identified as a feasible replacement source of energy to fulfill the extensive electrical demand and reliability needs of individual, heavy industrial facilities in the NOx RECLAIM program. Further, in accordance with CEQA Guidelines §15126.6, the Draft PEA shall describe a range of reasonable alternatives to the project which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives. However, the Draft PEA is not required to consider alternatives which are infeasible. For these reasons, solar energy as "BARCT" for all sources was not considered as an alternative in the Draft PEA.

8-6 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"Immediate total solar conversion means now or yester year. Climate change etc. was addressed in the 1992 BC cases that are in the record in the Superior and Appeals Courts in the state as well as the Federal 9th Circuit Appeal Court. This time with a plethora of environmental and community groups joining us HE/PSPC in litigation. The drought continues."*

There are no substantive remarks on the currently proposed amendments to the NOx RECLAIM program or the associated CEQA document in the legible portions of this comment. As such, SCAQMD staff is unable and not required to prepare a response to this comment.

8-7 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

> *"The fact that almost two years ago the District had all of the information in hand prior litigation with us from the sunshot initial draft incorporated by reference herein as well as the complete sections of solar thermal and solar photovoltaic technology. Sunshot is a play on words for Kennedy's moon shot in the 1960's. Over 60 percent*

on it [sic] was for air grip parity as of last year with only 40 percent of this passing. This is for everywhere in the U.S.A. All other [illegible] in SC119641 Eder vs. SCAQMD as well as B251627 [illegible] as the Federal Record and Federal Register September 3, 2014 and all information submitted to date as well as in the future are incorporated here into the record."

Of the legible words, the sentences and phrasing structure do not raise, in the context presented, any substantive remarks on CEQA or on the NOP/IS. In addition, the attachments to Comment Letter #8, "An Overview of the Kramer Junction SEGS Recent Performance" and the National Renewable Energy Laboratory report "Survey of Thermal Storage for Parabolic Trough Power Plants" also do not correlate to the text in this comment. As such, SCAQMD staff is unable and not required to prepare a response to this comment.

8-8 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

"At the January 7 GB meeting, Eder/PSIC stated that (as is part of the record [sic]) no consultant was hired to study solar energy as BARCT which has been before the District and CARB for decades!"

Because the comment does not specify the year when the January 7th Governing Board (GB) meeting occurred, it is unclear if the commentator meant to say the January 9, 2015 GB meeting, or the January 7, 2011 GB meeting. These are the only two recent GB meetings that fell on January 7. In any event, for both of these GB meetings, the minutes do not mention the topic of solar energy or BARCT. The following is the link to the minutes for the January 9, 2015 GB meeting: http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2015/2015-feb6-001.pdf?sfvrsn=2. The following is the link to the minutes for the January 9, 2015 GB meeting: http://www.aqmd.gov/docs/default-source/Agendas/Governing-Board/2011/2011-feb4-001.pdf?sfvrsn=2. In addition, the comment does not mention any source category for which solar energy would be BARCT.

With regard to the suggestion that the SCAQMD should hire a solar energy consultant, see Response 8-2.

8-9 Because this comment may appear difficult to decipher, SCAQMD staff has attempted to transcribe the text, as follows:

"As the cover article in this week's Economist says carpe diem of sieze [sic] the day. Gov. Brown set 50 percent solar renewables by 2030 of [illegible] but his off by 100 percent in February and 100 percent/50 percent [illegible] by EPA for 2023!"

Of the legible words, the sentences and phrasing structure do not raise, in the context presented, any substantive remarks on CEQA or on the NOP/IS. As such, SCAQMD staff is unable and not required to prepare a response to this "CEQA" comment.

APPENDIX H (OF THE DRAFT PEA)

CEQA SCOPING MEETING COMMENTS AND RESPONSES TO COMMENTS

INTRODUCTION

The NOP/IS for the proposed project was circulated for a 57-day public review and comment period, which started on December 5, 2014, and ended on January 30, 2015. During this public comment and review period, the SCAQMD held a CEQA Scoping Meeting at the SCAQMD's headquarters on January 8, 2015. The CEQA Scoping Meeting was held in accordance with the requirements in Public Resources Code §21083.9 (a)(2) for any project that may have statewide, regional or areawide significance.

CEQA SCOPING MEETING COMMENTS AND RESPONSES TO COMMENTS

At the CEQA Scoping Meeting, oral public testimony was received relative to the rule development process and the CEQA process. The following is a summary of the CEQA-specific comments that were made at this meeting and the responses to the comments.

1. Comment: Since SCR technology is being considered for BARCT, there could be an increase in the need to transport, store and use ammonia as part of operating SCR equipment. The Draft PEA should contain an analysis of ammonia.

   Response: As explained in the NOP/IS, both SCR and SNCR technologies utilize ammonia, a toxic air contaminant (TAC) and acutely hazardous material. Because hazard and hazardous materials impacts could occur as a result of the increased use, transport and storage of ammonia as well as the potential for an accidental release of ammonia into the environment, the NOP/IS identified ammonia as a source of potentially significant hazards and hazardous materials impacts and these impacts were analyzed in the Draft PEA.

2. Comment: A different approach to tackling the NOx RECLAIM RTC shave via an "incremental BARCT analysis shave" is currently being developed by industry groups and will be submitted to SCAQMD as a recommendation for consideration as part of the rule development process. As such, the Draft PEA should include and analyze the potential environmental impacts of the "incremental BARCT analysis shave" as one of the alternatives.

   Response: A Draft PEA is being prepared for the proposed project and several alternatives to the proposed project will be analyzed in accordance with the requirements in CEQA Guidelines §15126.6. The purpose of analyzing alternatives is to find project components that minimize impacts while still attaining the project's objectives. Alternatives were developed by altering specific components of the proposed project. One of the alternatives analyzed in the Draft PEA is an alternative based on the industry proposal.

3. Comment: The CEQA Scoping presentation states that all equipment subject to the proposed BARCT will install the most cost-effective control technology to meet proposed reductions. Does this mean that the CEQA document will analyze the environmental impacts of installing SCR technology now, even if SCR technology was not installed as a result of the NOx RTC shave in 2005?

Response: The Draft PEA analyzes a wide assortment of cost-effective BARCT options, including SCR technology. The analysis in the Draft PEA examines the potential environmental impacts of installing SCR technology in response to the currently proposed project, regardless of whether SCRs were installed in response to the previous NOx RTC shave that was implemented in 2005.

4. Comment: In addition to analyzing an alternative comprised of the industry's proposed "incremental BARCT analysis shave," the Draft PEA should also analyze an alternative that focuses on meeting the minimum NOx emission reduction goals in the 2012 AQMP per Control Measure #CMB-01 (e.g., at least three to five tons per day of NOx reductions by 2023).

Response: As required per CEQA Guidelines §15126.6 (e), the Draft PEA contains a "No Project" alternative that analyzes what would reasonably be expected to occur in the foreseeable future in the event the proposed project is not approved. A specific alternative limited to three to five tons per day of NOx RTC reductions was not analyzed because its impacts would likely fall between those resulting from the industry proposal (Alternative 3) and the No Project alternative (Alternative 4). The Draft PEA thus provides a range of potential impacts for these alternatives.

5. Comment: While the proposed revisions to the semi-annual assessment procedures in protocols for Rule 2011 and Rule 2012 will cause affected facilities difficulties to implement, it is not clear whether these proposed revisions would cause an adverse environmental effect.

Response: SCAQMD staff invites the commentator to provide more specific information regarding the implementation difficulties. Even if there are implementation difficulties, SCAQMD believes that the proposed revisions to the semi-annual assessment procedures are administrative in nature and as such, no physical environmental effects requiring a CEQA evaluation would be expected from implementing this portion of the proposed project.