APPENDIX A

BARCT Determinations

BARCT – Boilers and Heaters (other than refinery or utility)

SCAQMD Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
Rule 1146	Boilers/heaters ≥ 5 mmBtu/hr	30 ppm 0.036 lb/mmBtu	Electric utility boilers, Boilers > 40 mmBtu/hr used at refineries, Sulfur plant reaction boilers, Limited exemption for low fuel usage	
Rule 1146.1	Boilers/heaters > 2 and < 5 mmBtu/hr	30 ppm 0.037 lb/mmBtu	Limited exemption for low fuel usage	
Rule 1146.2	Boilers/heaters ≤ 2 mmBtu/hr	30 ppm 0.037 lb/mmBtu	Units at RECLAIM facilities	
Other District's Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
Bay Area Air Quality Management District (BAAQMD) 9-7	Boilers/heaters > 1 mmBtu/hr	30 ppm .037 lb/mmBtu	Natural gas/LPG-fired ≤ 10,000 mmBtu/hr, Electric utility boilers, Refinery boilers/heaters, Waste heat recovery boilers, Kilns, ovens, furnaces, Limited exemption for low fuel usage	Non-gaseous fuel 40 ppm
Kern County APCD 425.2	Boilers/heaters ≥ 5 mmBtu/hr			Less stringent than SCAQMD
Sacramento Metropolitan AQMD (SMAQMD) 411	Boilers/heaters ≥ 5 mmBtu/hr	30 ppm		Similar to SCAQMD
San Diego Co APCD 69-2	≥ 5 mmBtu/hr	30 ppm		Similar to SCAQMD
San Joaquin Valley Unified APCD (SJVUAPCD) 4305	≥ 5 mmBtu/hr	30 ppm gaseous fueled 40 ppm liquid fueled		Similar to SCAQMD
SJVUAPCD 4306	≤ 20 mmBtu/hr > 20 mmBtu Refinery boilers/heaters	15 ppm gaseous fuel 40 ppm liquid fuel 9 ppm gaseous fuel 40 ppm liquid fuel see next category	Solid fuel units, Dryers & glass melting furnaces, Kilns & smelters, Waste heat recovery boilers	More stringent than SCAQMD
Ventura Co APCD 74-15	≥ 5 mmBtu/hr	40 ppm		Less stringent than SCAQMD
Ventura Co APCD 74-15-1	≥ 1 and < 5 mmBtu/hr	30 ppm		Similar to SCAQMD

Control Technologies

Technology	Emission Limit Achievable	Retrofit Feasibility	Cost Issues	Notes
Ultra-low NOx Burner	12 ppm for < 20 mmBtu/hr for natural gas 9 ppm for > 20 mmBtu/hr for natural gas	Achieved in practice	Cost effective	Manufacturer guarantee

Recommended New BARCT

≤ 20 mmBtu/hr	12 ppm (0.015 lb/mmBtu)
> 20 mmBtu/hr	9 ppm (0.010 lb/mmBtu)

Basis

Other District's rule (SJVUAPCD)
Achieved in practice (SCAQMD units at or below proposed BARCT)
Manufacturer guarantee
Existing technology for retrofits (ultra low NOx burners)
Cost effective

BARCT – Refinery Boilers/Heaters

SCAQMD Rule	Applies To	Emission Factors	Exceptions/Exemptions	Notes
R1109	Boilers and process heaters at petroleum refineries > 40 mmBtu/hr	0.030 lb/mmBtu (25 ppm)	≤ 40 mmBtu/hr, Sulfur plant reaction boilers, Units operated < 10% capacity for 12 months	12/31/92 compliance date
Other Districts' Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
BAAQMD 9-10		.20 lb/mmBtu input NOx facility-wide or 300 ppm NOx daily avg	CO Boilers, Various other exemptions	Less stringent
Kern Co. APCD				No separate rule
SMAQMD				No separate rule
San Diego Co. APCD				No separate rule
SJVUAPCD 4306	5 – 65 mmBtu/hr > 65 – 110 mmBtu/hr >110 mmBtu/hr	30 ppm gaseous fuel 40 ppm liquid fuel 25 ppm gaseous fuel 40 pm liquid fuel 5 ppm gaseous fuel 40 pm liquid fuel	Solid fuel units, Dryers and glass melting furnaces, Kilns an smelters where products of combustion directly contact material being heated, Waste heat recovery boilers on turbines or internal combustion engines	Less stringent than SCAQMD for 5 – 110 mmBtu/hr More stringent for > 110 mmBtu/h
Ventura Co APCD				No separate rule

Control Technologies

Technology	Emission Limit Achievable	Retrofit Feasibility	Cost Issues	Notes
SCR	5 ppm	Achieved in practice	Cost effective	
Ultra-low NOx Burner	25 ppm	Achieved in practice	Cost effective	Manufacturer guarantee

Recommended New BARCT

5 ppm (0.006 lb/mmBtu) for > 110 mmBtu/hr
(no new BARCT for 40 – 110 mmBtu/hr units because current allocations are based on Rule 1109 limit of 25 ppm which is the limit achievable with ultra low NOx burners and SCR is not cost effective)

Basis

Other District's rule (SJVUAPCD)
Achieved in practice
Existing technology for retrofits (SCR)
Cost effective

BARCT – Utility Boilers

SCAQMD Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
1135	Electric power generating systems (SCE, LADWP, City of Burbank, City of Glendale, City of Pasadena, or any of their successors)	Annual limits per facility (based on limits ~ 21 ppm)	Smaller utilities	
2009	Same as above	BARCT (not defined in specific limits)		
Other Districts' Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
BAAQMD 9-11	New power plants only			Not a BARCT rule
Kern Co APCD				No rule
SMAQMD				No rule
San Diego APCD 68 & 69	All units 3 specific utilities Other utility boilers	125 ppm Aggregate annual emissions cap: 1/1/97: 2100 tons 1/1/01: 800 tons 1/1/05: 650 tons 0.15 lbs NOx/MW-Hr	Units < 100 mmBtu/hr, Units used for heat and not electric generation	 Less stringent More stringent
SJVUAPCD 4306 Phase 3	≤ 20 mmBtu/hr > 20 mmBtu/hr PO limit of 9 to 30 billion Btu/yr annual heat input	15 ppm or 0.018 lb/mmBtu 9 ppm or 0.011 lb/mmBtu 30 ppm or 0.036 lb/mmBtu		Compliance by 100% of units by June 1, 2007 Equivalent to Rule 2009 limits for > 20 mmBtu/hr, less stringent for smaller units

Other Districts' Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
SJVUAPCD 4306 Phase 3 (continued)	Units with multiple burners ≤ 5 mmBtu/hr, but total rated heat input is > 5 mmBtu/hr	30 ppm or 0.036 lb/mmBtu		
Ventura Co APCD				No rule

Control Technologies

Technology	Emission Limit Achievable	Retrofit Feasibility	Cost Issues	Notes
SCR	5 ppm for retrofit 7 ppm is the weighted average emission concentration for utility boilers subject to Rule 2009 after retrofits	Achieved in practice	Cost effective	Retrofits already completed

Recommended New BARCT for Utility Boilers and Turbines

7 ppm

Basis

Achieved in practice (average post-Rule 2009 emission concentration for utility boilers)
Existing technology for retrofits (SCR)
Cost effective for retrofits and peak year usage

BARCT – Gas Turbines

SCAQMD Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
1134	> 0.3 MW	Reference limits: 0.3 - < 2.9 MW 25 ppm 2.9 - < 10 MW 9 ppm 2.9 - < 10 MW with no SCR 15 ppm ≥ 10 MW 9 ppm ≥ 10 MW with no SCR 12 ppm ≥ 60 MW, combined cycle, no SCR 15 ppm ≥ 60 MW, combined cycle, no SCR 15 ppm ≥ 60 MW, combined cycle 15 ppm Sewage digester gas units 25 ppm	Laboratory units, Fire fighting and flood control units, Chemical processing gas turbines, Pipeline gas turbines located in Southeast Desert Air Basin (SEDAB), Emergency standby and peaking units operating < 200 hours per year, Existing gas turbines rated < 4 MW, operated < 877 hours per year and located in SEDAB or San Clemente Island	
2009	Electric power generating systems (SCE, LADWP, City of Burbank, City of Glendale, City of Pasadena, or any of their successors)	5 – 17 ppm		
Other Districts' Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
BAAQMD 9-9	> 0.3 MW	Reference limits: 0.3 – 10 MW gaseous fueled 42 ppm refinery gas fueled 55 ppm non-gaseous fueled 65 ppm ≥ 10 MW gaseous fueled w/o SCR 15 ppm non-gaseous fueled w/o SCR 42 ppm gaseous fueled with SCR 9 ppm non-gaseous fueled with SCR 25 ppm	Testing of aircraft turbine engines for certification, Flood & fire control, Emergency standby	Less stringent for most categories, equivalent to SCAQMD for ≥ 10 MW with SCR
Kern Co APCD 425	Cogeneration turbines ≥ 10 MW	Reference limits: Gas-fired with SCR 9 ppm Oil-fired with SCR 25 ppm Gas-fired w/low-NOx combustors 20 ppm Oil-fired with low-NOx combustors 42 ppm		Equivalent to SCAQMD for units with SCR

Other Districts' Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
SMAQMD 413	≥0.3 MW output or 3 mmBtu/hr input	RACT (reference limits) gaseous fuels 42 ppm liquid fuels 65 ppm BARCT (reference limits) ≥ 0.3 MW to < 2.9 MW or ≥ 2.9 MW operating < 877 hr/yr gaseous fuels 42 ppm liquid fuels 65 ppm ≥ 2.9 MW and <10 MW operating ≥877 hr/yr gaseous fuels 25 ppm liquid fuels 65 ppm ≥ 10 MW w/o SCR operating ≥ 877 hrs/yr gaseous fuels 15 ppm liquid fuels 42 ppm ≥ 10 MW w/ SCR operating ≥ 877 hrs/yr gaseous fuels 9 ppm liquid fuels 25 ppm	Emergency stand-by units, laboratory units, startup/shutdown	Less stringent or equivalent to SCAQMD
San Diego APCD 69-3	≥ 0.3 MW Applies to any unit	Reference limits gaseous fuels 42 ppm liquid fuels 65 ppm	Research, portable engines, engines rated ≤ 0.4 MW used in conjunction w/ military tactical equipment provided ≤ 1000 hours/year, emergencies, startup/shutdown	RACT Rule Less stringent than SCAQMD
San Diego APCD 69-3-1	Existing unit ≥ 1.0 MW and New units ≥ 0.3	Reference limits new units ≥ 0.3 and < 2.9 and existing units ≥ 1.0 and < 2.9 MW gaseous fuels 42 ppm liquid fuels 65 ppm ≥ 2.9 and < 10 MW gaseous fuels 25 ppm liquid fuels 65 ppm ≥ 10 MW w/o controls gaseous fuels 15 ppm liquid fuels 42 ppm	Research, portable engines, engines rated ≤ 0.4 MW used in conjunction w/ military tactical equipment provided ≤ 1000 hours/year, emergencies, startup/shutdown	BARCT Rule
San Diego APCD 69-3-1		≥ 10 MW w/ controls gaseous fuels 9 ppm liquid fuels 25 ppm		

Other Districts' Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
San Diego APCD 69-3-1 (continued)		Peaking Units ≥ 4 MW operating < 877 hr/yr and < 4 MW operating < 877 hr/yr gaseous fuels 42 ppm liquid fuels 65 ppm		
SJVUAPCD 4703	≥0.3 MW output and/or 3 mmBtu/hr input	Tier I Reference limits: ≥ 4 MW operating < 877 hr/yr and > 0.3 MW, but < 10 MW operating ≥ 877 hr/yr gaseous fuels 42 ppm oil 65 ppm ≥ 10 MW w/o SCR operating ≥ 877 hr/yr gaseous fuels 15 ppm oil 42 ppm ≥ 10 MW w/ SCR operating ≥ 877 hr/yr gaseous fuels 9 ppm oil 25 ppm General Electric Frame 7 with Quiet Combustors gaseous fuels 18 ppm oil 42 ppm Solar Saturn 1100 horsepower gas turbine powering centrifugal compressor gaseous fuels or oil 50 ppm Tier II Solar Saturn < 2 MW driving a centrifugal compressor gaseous and liquid fuels 50 ppm ≤ 10 MW if dry low-NOx (DLN) system is commercially available gaseous fuel 25 ppm liquid fuel 65 ppm	Research and testing, Firefighting or flood control, Emergency standby operating < 200 hours per year, 4 MW units operating < 877 hours/year	Tier 1 requirements less stringent or equivalent to SCAQMD. Tier II Less stringent for most, but more stringent for specific categories
SJVUAPCD 4703		> 10 MW combined cycle or >10 MW simple cycle operating > 877 hr/yr gaseous fuels 5 ppm (standard) 3 ppm (enhanced) liquid fuel 25 ppm		

Other Districts' Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
SJVUAPCD 4703 (continued)		> 10 MW simple cycle operating ≤ 877 hr/yr gaseous fuels 25 ppm (standard) 5 ppm (enhanced) liquid fuels 42 ppm (standard) 25 ppm (enhanced)		
Ventura Co APCD 74-23	≥ 0.3 MW	Reference limits: ≥ 0.3 and < 2. gaseous fuels 42 ppm liquid fuels 65 ppm ≥ 2.9 and < 10 MW gaseous fuels 25 ppm liquid fuels 65 ppm ≥ 10 MW without controls gaseous fuels 15 ppm liquid fuels 42 ppm ≥ 10 MW w/ control gaseous fuels 9 ppm liquid fuels 25 ppm Units ≥ 4 MW operating < 877 hours/year gaseous fuels 42 ppm liquid fuels 65 ppm	Research and testing, Firefighting or flood control, Emergency standby units, Units operating < 200 hours per year, Start-up, planned shut-down, or unplanned load changes	Emission factor at ppmv on a dry basis, corrected to 15% O_2 when firing on gaseous fuels

Control Technologies

Technology	Emission Limit Achievable	Retrofit Feasibility	Cost Issues	Notes
SCR	5 ppm or less for retrofit	Achieved in practice	Not Cost Effective	

Recommended New BARCT

None proposed

Basis

Further control beyond Rule 1134 emission levels is not cost effective based on peak year usage factors

BARCT – Petroleum Refinery Fluid Catalytic Cracking Units (FCCU)

SCAQMD Rules

No Rule for FCCU NOx
Control Measure 90P-B-2 (70% reduction) subsumed for year 2000 allocation calculations

Other Districts' Rules

None for FCCU NOx

Control Technologies

Technology	Emission Limit Achievable	Retrofit Feasibility	Cost Issues	Notes
SCR	≥ 85% control efficiency	Achieved in practice at 13 refineries worldwide	Cost Effective	

Recommended New BARCT

85% control efficiency

Basis

Achieved in practice
Retrofit technology available (SCR)
Cost effective

BARCT – Cement Kilns

SCAQMD Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
1112	Gray cement kilns	11.6 lbs/ton of clinker (24 hr avg) and 6.4 lb/ton of clinker (30 consecutive day avg)		CEMS required
Other Districts' Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
BAAQMD				**No rule**
Kern Co APCD 425-3	Portland cement kilns	11.6 lbs/ton of clinker (24 hr avg) and 6.4 lbs/ton of clinker (30 consecutive day avg)	Startup and shutdown, Breakdowns	CEMs required Equivalent to SCAQMD
Mojave Desert AQMD	Portland cement kilns	Preheater-precalciner kilns & long dry kilns 6.4 lb/ton (30 consecutive day avg) Short dry kilns 7.2 lb/ton of clinker (30 consecutive day avg)		Startup and shutdown requirements and emission limits
SCMAQMD				No rule
San Diego APCD				No rule
SJVUAPCD				No rule

Recommended New BARCT

None proposed

Basis

SCAQMD is most stringent
Rule 2002 end factor based on SCAQMD Rule 1112
SCR may be feasible, but has not been achieved in practice
Further reductions not yet technically or economically feasible

BARCT – Internal Combustion Engines

SCAQMD Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
1110.2	Stationary and portable engines > 50 bhp	Portable compression ignition 50 and < 117 bhp 10.0 g/bhp-hr 117 - < 400 bhp 7.2 g/bhp-hr ≥ 400 bhp 7.0 g/bhp-hr Stationary engines 0.15 g/bhp-hr or Reference limits: 50 to < 500 bhp 36 ppm ≥ 500 bhp 45 ppm	Emergency engines (< 200 hr/yr) Auxiliary engines used to power other engines or gas turbines during startup Test cells Ski lift & snow mfg Nov 1 – Apr 15 Portable engines under state registration Non-road engines Engines on san Clemente Island	Some categories with higher limits
Other Districts' Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
BAAQMD 9-8	Stationary engines > 50 bhp	Gaseous fueled: Rich burn 56 ppm @ 15% O_2 Lean burn 140 ppm @ 15% O_2 Waste gas fueled: Lean burn 140 ppm 15% O_2 Rich burn 210 ppm 15% O_2	No emission limits: < 250 bhp liquid fueled engines agricultural emergency standby (< 100 hr/yr) ≤ 1000 bhp & operate < 200 hr/yr > 1000 bhp & operate < 100 hr/yr	Less stringent
Kern Co APCD 427	Stationary engines > 50 bhp	> 50 bhp maintenance ≥ 250 bhp rich burn 50 ppm ≥ 250 bhp lean burn 125 ppm diesel 600 ppm	Agricultural engines Emergency (< 200 hr/yr) Portable (< 1 yr at same site) Test cells	Less stringent
SCMAQMD 412	Stationary engines > 50 bhp at major source	Spark ignited Rich burn 25 ppm Lean burn 65 ppm Compression ignited 80 ppm	Emergency, Agricultural, Nonroad, Flight line support engines, Test cells Less stringent limits for lower usage engines	Less stringent
San Diego APCD 69-4	Stationary engines > 50 bhp at major source	Rich burn fossil fuel 0.9 g/bhp-hr (50 ppm) Lean burn 2.3 g/bhp-hr (125 ppm) Waste gas fueled 2.3 g/bhp-hr (125 ppm) Diesel or kerosene 9.0 g/bhp-hr (700 ppm)	Agricultural, Test cells, Emergency (< 200 hr/yr), Military tactical support	Less stringent

Other Districts' Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
San Diego APCD 69-4-1	Stationary engines > 50 bhp	Rich burn 25 ppm Waste gas 50 ppm Lean burn 65 ppm	Agricultural, Test cells, Emergency (< 200 hr/yr), Military tactical support	Less stringent
San Diego APCD 69-4-1 (continued)		Diesel or kerosene Low use 9.0 g/bhp-hr (700 ppm) High use 6.9 g/bhp-hr (535 ppm) New 6.9 g/bhp-hr (535 ppm)		
SJVUAPCD 4701	Stationary engines > 50 bhp	Waste gas 125 ppm Water districts Rich burn 90 ppm Lean burn 150 ppm Diesel or dual fuel 600 ppm Other Rich burn 50 ppm Lean burn 75 ppm Diesel or dual fuel 600 ppm	Standby, Emergency, Test cells. Portable engine under Statewide Registration, Use of other fuels during natural gas curtailment, Military tactical equipment, Transportable engines (< 1 yr at same site)	Less stringent
SJVUAPCD 4702	Spark ignited > 50 bhp	Rich burn Waste gas 50 ppm Cyclic, filed gas 50 ppm Other 25 ppm Lean burn 2-stroke, gaseous fuel and < 100 bhp 75 ppm Other 65 ppm	Emergency standby, Low usage, Statewide Registration, Military tactical equipment, Transportable engines (< 1y at same site)	Less stringent
Other Districts				Several other Districts have NOx BARCT rules for ICEs but all are Less stringent than SCAQMD

Recommended New BARCT

None proposed

Basis

SCAQMD is most stringent, most RECLAIM engines either exempt or already controlled
Further reductions not economically feasible

BARCT – Glass Melting Furnaces

SCAQMD Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
1117	Glass melting furnaces	4.0 lb NOx per ton of glass pulled	Furnaces limited to ≤ 15 lbs NOx/hr by permit, Glass remelt facilities using exclusively glass cullet, marbles, chips or similar feedstock, Furnaces producing glass tableware exclusively, Flat glass melting furnaces, Furnaces melting glass for production of fiberglass exclusively, Idling furnaces	
Other Districts' Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
BAAQMD 9-12	Glass melting furnaces	2.75 grams of NO_x per kilogram (5.5 lbs of NO_x per short ton) of glass pulled (3 consecutive hour avg excluding start-up, shutdown, and idling)	Uses electricity except when furnace contains no molten glass, Capacity < 5 short tons/day	Less stringent than SCAQMD
Kern County APCD				No rule
SMAQMD				No rule
San Diego Co APCD				No rule
SJVUAPCD 4354	Glass melting furnaces at major NOx sources	Container Glass or Fiberglass 4.0 lb NOx per ton of glass pulled (24 hr avg) Flat Glass 9.2 lb NOx per ton of glass pulled (block 24 hr avg) and 7.0 lb NOx per ton of glass pulled (rolling 30 day avg) Oxygen-assisted combustion 9.2 lb NOx per ton of glass pulled (block 24 hr avg) and 7.0 lb NOx per ton of glass pulled (rolling 30 day avg)	Uses electricity except when furnace contains no molten glass, Startup, shutdown, and idling	Equivalent to SCAQMD for container glass, also contains requirements for processes exempt under SCAQMD Rule 1117
Ventura Co APCD				No rule

Recommended New BARCT

None proposed

Basis

SCAQMD Rule 1117 and Rule 2002 end factors for NOx RECLAIM sources are most stringent limits
Rule 2002 end factors for glass melting furnaces

Glass Fiber Furnace and Flat Glass Melting Furnace	4 lb NOx per ton of product (Rule 1117 Rule 2002)
Tableware Glass	5.68 lb NOx per ton of product (Rule 2002)
Container Glass	1.2 lb NOx per ton of product (Rule 2002)

BARCT – Curing and drying ovens

SCAQMD Rules

No SCAQMD rule for NOx BARCT for this category

Other Districts' Rules

No rules

Recommended New BARCT

None proposed

Basis

No BARCT rules
Rule 2002 end factor (0.031 lb/mmBtu) is more stringent than new BARCT recommended for other miscellaneous combustion equipment
Further reductions not technically feasible

BARCT – Metal Melting Furnaces and Heat Treating Furnaces

SCAQMD Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
				No NOx rules for these sources
Other District's Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
BAAQMD				No rule
Kern County APCD				No rule
SMAQMD				No rule
San Diego Co APCD				No rule
SJVUAPCD				No rule
Ventura Co APCD				No rule

Control Technologies

Technology	Emission Limit Achievable	Retrofit Feasibility	Cost Issues	Notes
Low NOx & Ultra Low NOx Burners	Varies depending on equipment	Achieved in practice	Cost effective	

Recommended New BARCT

45 ppm (0.055 lb/mmBtu)

Basis

Achieved in practice
Retrofit technology available (ultra low NOx burners)
Cost effective

BARCT – Miscellaneous Combustion (ovens, kilns, claimers, dryers, furnaces)

SCAQMD Rules	Applies To	Emission Factors	Exceptions/Exemptions	Notes
				No NOx rules for these sources
Other District's Rules	**Applies To**	**Emission Factors**	**Exceptions/Exemptions**	**Notes**
BAAQMD				No rule
Kern County APCD				No rule
SMAQMD				No rule
San Diego Co APCD				No rule
SJVUAPCD				No rule
Ventura Co APCD				No rule

Control Technologies

Technology	Emission Limit Achievable	Retrofit Feasibility	Cost Issues	Notes
Low NOx & Ultra Low NOx Burners	30 ppm for retrofit	Achieved in practice	Cost effective	

Recommended New BARCT

30 ppm (0.036 lb/mmBtu)

Basis

Achieved in practice
Retrofit technology available (ultra low NOx burners)
Cost effective

APPENDIX B

Comparison of Cost-Effectiveness Methodologies

Comparison of Cost-Effectiveness Methodologies

This appendix has been prepared in response to comments regarding the methodology by which the AQMD conducts cost-effective analyses for regulatory development purposes. Included in this appendix is a brief summary of the AQMD's history of conducing cost evaluations; a comparison between two key cost-effectiveness methodologies, which includes examples of cost outputs; rationale for the AQMD's selected approach; and a series of tables demonstrating the difference between the methodologies for the varying equipment identified as having new BARCT levels.

Background

The AQMD routinely conducts cost-effective analyses regarding proposed rules and regulations that result in the reduction of criteria pollutants (NOx, SOx, VOC, PM, and CO). The analysis is used as a measure of relative effectiveness of a proposal. It is generally used to compare and rank rules, control measures, or alternative means of emissions control relating to the cost of purchasing, installing, and operating control equipment in order to achieve the projected emission reductions. The major parameters in cost-effectiveness include capital and installation costs, operating and maintenance costs, interest rates, and project life.

There are two primary methods for evaluating cost-effectiveness: Discounted Cash Flow (DCF); and Levelized Cash Flow (LCF). DCF is the AQMD's chosen method of analyzing costs and is based on a conversion of future expenditures (including annual costs) to a present value basis using a present value factor. LCF is different in that fixed capital expenditures are converted into an equivalent annual amount using a capital recovery factor. Under the same interest rate and project life, the present value factor is a reciprocal of the capital recovery factor. LCF generally yields higher numbers. Following is a more detailed discussion of the DCF and LCF methodologies.

AQMD Cost-Effectiveness History

The AQMD has been using DCF for the assessment of control measures in the AQMP. In 1995, the AQMD began to use DCF in determining compliance of the best available control technology for minor sources. DCF has become the cost effectiveness methodology for rulemaking since 1996.

Furthermore, in 1998, the California Air Pollution Control Officer's Association Board approved *Incremental Cost-Effectiveness Calculation Procedures for Rule Adoption* that recognized the importance of using a single cost effectiveness assessment methodology to maintain consistency when comparing different projects. This guidance document was a collaborative effort among all the air pollution districts in California. Both the Western States Petroleum Association and the California Council for Environmental and Economic Balance participated in the process.

The AQMD has utilized the DCF method for nearly a decade. The rationale for DCF is based on several factors. DCF provides a better mechanism for dealing with non-constant annual operating and maintenance costs. This method can handle capital costs beyond the first year and

is neutral on how the project is financed. In addition, it allows for non-uniform emission reductions over time.

Control Costs

In conducting its analysis of the costs of purchasing, installing, and operating emissions control equipment, staff utilizes, to the extent feasible, data and information provided by equipment manufacturers and also uses actual installation data, where available. In order to derive the control costs by which to examine cost-effectiveness, staff utilizes the capital and annual costs associated with implementing emission reductions. Typically, staff relies on the guidance provided in the Cost Control Manual developed by US EPA's Office of Air Quality and Planning Standards (OAQPS). The EPA developed the factors used in the Cost Control Manual from vendor quotes. This guidance provides a means by which to estimate direct and indirect capital and annual costs as a ratio of the equipment costs. Indirect costs include other associated costs into the analysis, such as the cost of overhead, property taxes, insurance, shipping, and labor. These costs are all included in the cost effectiveness equations and can generally be broken out as follows: total equipment cost includes cost of control device, ancillary equipment, and taxes and freight; the retrofit factor includes installation, and indirect costs including engineering, field expenses, start-up, performance tests, and contingencies; total annual costs include materials, utilities, labor, maintenance, overhead and administration, taxes and insurance.

Below are the equations used for calculating cost effectiveness:

Total Capital Investment = Total Equipment Cost + Retrofit

Cost Effectiveness = (Total Capital Investment + (Total Annual Costs x Present Value Factor)) ÷ Emission Reductions

Cost of Control Assumptions

For the RECLAIM analysis, equipment cost, fuel, emission limit achievable, and instrumentation information provided by manufacturers were used, to the extent feasible. When necessary, the following assumptions, based on the OAQPS Cost Control Manual, were used to analyze the control costs for the various equipment categories:

- Instrumentation is assumed at 10% of equipment cost;
- Sales tax based on Los Angeles County, at 8.25%;
- Freight is assumed at 5% of equipment cost;
- Retrofit is assumed to be 50% of equipment cost;
- Maintenance and material costs are assumed to be 100% of the maintenance labor costs;
- Overhead is assumed to be 60% of all labor and maintenance materials; and
- Property taxes, insurance, and administrative costs are assumed to be 4% of the Total Capital Investment (TCI).

RECLAIM Cost Effectiveness Calculations

Cost effectiveness for RECLAIM 2004 amendments was completed using equipment inventory in the AQMD database and emission reductions that were determined by the allocation method. Device level data is unavailable; therefore the cost effectiveness analysis is conservative. For

example, there are 75 Rule 1109 boilers/heaters that have ratings of greater than 110 mmBtu/hr at the six large refineries. Of these, 24 were identified as having SCR already installed. Since the emission reductions were determined on an equipment category basis, it is not possible to determine which emissions are associated with which boiler therefore this analysis does not take into account that 24 boilers/heater are already controlled. It is assumed that all 75 will add SCR and the emission reductions are based on all 75 as well. This is true for all the equipment categories that have a new proposed BARCT.

Equation for determining emission reductions for cost effectiveness:

(Peak year activity x Tier I end factor) – (Peak year activity x lower of proposed new BARCT or Tier I end factor)

DCF and LCF Cost Effectiveness Comparison

Cost effectiveness is defined as dollars per ton of pollutant reduced. Criteria pollutants and their precursors subject to the cost effectiveness assessment include volatile organic compounds (VOC), oxides of nitrogen (NOx), oxides of sulfur (SOx), particulate matter (PM), and oxides of carbon (CO). Cost effectiveness calculations have been performed for control measures in the Air Quality Management Plan (AQMP) and proposed rules. The cost effectiveness assessment is often used in a relative sense, i.e., to compare the effectiveness of control measures, rules, and their alternatives. For example, proposed rules with an average cost effectiveness exceeding $13,500 per ton will trigger a more vigorous analysis of control alternatives. A Governing Board resolution in 1994 requires that rules being proposed for adoption be considered in the order of cost effectiveness. Cost effectiveness is not required for toxic rules because they are risk based and the magnitude of cost-effectiveness for controlling air toxic emissions is not comparable to that of controlling criteria pollutants. For example, air toxic rules can result in significant health risk reductions by the reduction of a few pounds, such as nickel or hexavalent chromium. Whereas rules for criteria pollutants would generally seek to reduce tons of emissions.

<u>Cost Parameters</u>
The major parameters used in the cost effectiveness assessment are one-time and recurring costs, interest rate, and the economic life of a project. The one-time cost occurs in the beginning of a project and includes costs of equipment, installation, construction, freight, and instrumentation. Recurring costs repeat year after year and include costs of utility, maintenance, and operation. Because of time preference for money (i.e., a dollar today is worth more than a dollar tomorrow), both interest rate and project life are used to convert one-time and recurring expenditures on an equal basis.

<u>Methodology</u>
The two most commonly used approaches to cost effectiveness are the discounted cash flow (DCF) methodology and the levelized cash flow (LCF) methodology. DCF converts all the expenditures during the project life to today's dollars via a present value factor (PVF), which is a function of interest rate and project life. On the other hand, LCF converts the one-time expenditure into an equivalent annual flow throughout the project life via a capital recovery factor (CRF), which is also a function of interest rate and project life. Given the same interest

rate and project life, PVF is a reciprocal of CRF. Mathematically, the DCF and LCF formulae are:

$$DCF = \frac{\text{One-time Cost + (Recurring Cost x PVF)}}{\text{Emission Reductions over Project Life}}$$

$$LCF = \frac{\text{One-time Cost x CRF + Recurring Cost}}{\text{Annual Emission Reductions}}$$

The difference between DCF and LCF can be best summarized in the following table:

Table 1
DCF vs. LCF

Item	DCF	LCF
Time Horizon	Treats all costs as if they were paid in the initial year	Looks at the capital costs as if they were paid like a home mortgage.
Payment Method	Provides the cost today to pay for a steady stream of expenditures.	Paying overtime with interest.
Methodology	Discounts the future costs back into the amount that would be needed to set aside now (based on the rate of interest) to fund the future costs as they occur.	Provides the amount needed in each future year if the up-front capital costs are paid for in equal annual installments?

<u>Example</u>

As an illustration, based on the same parameters shown below, DCF will always yield a lower estimate than LCF:

- One-time Cost: $200,000
- Annual Operating & Maintenance Cost: $20,000
- Annual Emission Reductions: 16 tons/year
- Equipment (Project) Life: 10 Years
- Real Interest Rate: 4%
- CRF = 0.123, or PVF = 8.11

DCF = [$200,000 + (8.11 x 20,000)] / (16 x 10) = $2,264/ton

LCF = [($200,000 x 0.123) + $20,000] / 16 = $2,788/ton

It can also be shown below that DCF and LCF are conceptually equivalent:

Total Annual Payments in 10 Years under LCF

= Annualized One-time Cost + Recurring Cost

= $200,000 x 0.123 + $20,000

= $24,658 + $20,000

Present Value of 10-year Payment under DCF

= Total Annual Payments in 10 Years x PVF

= ($24,658 + $20,000) x 8.11

= $24,658 x 8.11 + $20,000 * 8.11

= $200,000 + 20,000 x 8.11

Differences in the DCF and LCF estimates will become wider if the interest rate is higher or the project life is longer. Table 1 shows the DCF and LCF estimates at the 4-percent interest rate under various project lives and Table 2 has the two separate estimates for a project life of 10 years and at four and 10 percent interest rates, respectively.

Table 2
DCF vs. LCF Estimates at Four Percent Interest Rate

Method	Project Life (in years)			
	10	15	20	25
DCF	$2,264	$1,760	$1,474	$1,281
LCF	$2,791	$2,374	$2,170	$2,050
DCF/LCF	0.81	0.74	0.68	0.62

Table 3
DCF vs. LCF Estimates for 10-Year Project Life

Method	Real Interest Rate	
	4%	10%
DCF	$2,264	$2,018
LCF	$2,791	$3,284
DCF/LCF	0.81	0.61

Rationale for DCF

DCF is more versatile than LCF in that DCF can easily deal with non-constant annual operating and maintenance costs and those costs occurring longer than the standard one-year interval (e.g., catalyst replacement every five years). Second, DCF allows non-uniform emission reductions over the project life. Finally, DCF is neutral on how a project is financed by individual businesses, which is very much tied to the well-being of these businesses.

In addition, as pointed out in the previously mentioned CAPCOA document, the most important criteria in applying a cost-effectiveness methodology is to maintain consistency. That is, if past rulemaking projects are based on DCF, then it would be prudent to continue using DCF for future projects.

Results

The following table represents the cost-effectiveness for each equipment category using the DCF method. For comparison purposes, the costs using the LCF method are also shown.

Table 4
Cost-Effectiveness by Equipment Category

Equipment Category	DCF $/ton	LCF $/ton
Miscellaneous Combustion	11,000	13,700
FCCUs*	12,200	19,400
Metal Melting	8,500	10,000
Heat Treating	4,000	5,000
Rule 1109 Boilers/Heaters > 110 mmBtu*	11,200 - 17,000	18,000 – 27,270
Rules 1146 & 1146.1 Boilers/Heaters	9,000 - 17,500	11,000 – 20,500
Rule 2009 Utility Boilers	3,000	3,700

* 25-year equipment life used for cost effectiveness, all other categories based on 10-year equipment life.

As stated earlier, staff conducted its analysis of the costs of purchasing, installing, and operating emissions control equipment. In addition staff utilized, to the extent feasible, data and information provided by equipment manufacturers and also uses actual installation data (e.g., FCCUs and refineries boilers/heaters), where available. However, during the rule development process, some representatives of the petroleum refining industry provided total capital

investment cost data (i.e., SCR control equipment and installation costs) that was, in most cases, higher than the staff's estimates. Many of these facilities experienced atypical costs that were unique to their facility. For example, remediation needs or construction challenges that would not be a common occurrence for retrofitting an emission source with control equipment. Such unforeseen costs are covered by industry in very high contingencies, which can dramatically increase control costs. However, as a matter of reference, staff has utilized the total capital investment information and potential emission reduction information (either 80 or 85 percent NOx reduction) from these projects to conduct a cost-effective assessment (see Tables 5A and 5B) below. Staff utilized the same assumption for annual costs that were used for the staff's analysis and included, for comparison, total capital cost data provided by manufacturers, the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD), as well as included cost data provided during the development of Rule 1105.1 rule development. This type of cost-effectiveness analysis was used in prior rule development and AQMP control measure analysis. Adding these atypical costs would not justify a comparison to previous rules or control measure derived cost-effectiveness. It should be noted that due to the confidentiality of the information provided, a breakdown of the cost data cannot be presented. As such, specific refineries cannot be identified.

Table 5A
Cost-Effectiveness Based on Facility-Specific Data
(SCR Control and 80 Percent)

Source	Total Cost (Million $)	Cost Effectiveness ($/ton) @ 80% NOx reduction, 25 year equipment life
Refinery B	$6 – $15	$40,900
Refinery D	$4.0 – $6.7	$23,600
Manufacturer	$1.5 - $3.15	$9,600
SJVUAPCD	$0.24 – $1.96	$3,100

Table 5B
Cost-Effectiveness Based on Facility-Specific Data
(SCR Control and 85 Percent)

Source	Total Cost (Million $)	Cost Effectiveness ($/ton) @ 85% NOx reduction, 25 year equipment life
Refinery A	$9	$11,800
Refinery B1	$33.6	$22,560
Refinery B2	$33.8	$22,650
Refinery C	$20	$16,600
Refinery D	$18.5	$16,000
Manufacturer	$4.1 - $8.5	$9,600 - $11,600
Industry Contractor (R1105.1)		
Refinery D	$10 (for 2)	$10,000
Refinery E	$6	$10,500
Refinery F	$10	$12,200

DCF Cost Effectiveness

Cost Data for FCCUs

Basic Equipment	Control Equipment	Equipment Cost (EC)	Instrumentation[1] (0.10 x EC)	Equipment Cost + Instrumentation	Sales Tax [2] (.0825 x EC)	Freight [3] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [4] (.50 x TEC)	Total Capital investment (TCI)
FCCU	SCR	$5,258,200	$525,800	$5,784,000	$477,200	$289,200	$6,550,400	$3,275,200	$9,825,600

Equipment	Total Annual Costs[5] (TAC)	Number of equipment
SCR	$1,150,000	4

Notes:

1. Instrumentation = 10% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
2. Sales Tax = 8.25% for Los Angeles
3. Freight = 5% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
4. Retrofit = 50% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-28 to 2-30, paragraph 2.5.4.2) This cost includes engineering.
5. Annual Costs include cost of catalyst (5 year life), aqueous NH_3, power and routine maintenance.

Equipment Cost = the average for 2 FCCUs. Costs for the following equipment are included: SCR reactor, ammonia control skids, ammonia injection grids, catalyst, ESP purge blowers, switchgear, motor control, ammonia tanks and pumps, ducting and duct valves, hardware and CEMs system.

Cost Effectiveness Calculation for FCCU

Present Value Factor (25 yr life, 4% real interest rate)	Present value of annual cost per FCCU	Total present value of the Capital investment per FCCU	Cost of control for 4 units	Total NOx reduction for 4 units (ton/25yr)	Cost Effectiveness ($/ton)
15.6	$17,940,000	$27,765,600	$111,062,400	9139	**$12,200**

Note:
Above calculations are based on total cost of control and emission reductions for 4 units

Cost Data for Rule 1109 Boilers/Heaters > 110 mmBtu (34.5 ppm to 5ppm)

Equipment Size mmBtu/hr	Equipment Cost[1]	Instrumentation[2] (0.10 x EC)	Equipment Cost + Instrumentation	Emission Limit [1]	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
100 - 170	$1,673,836	$167,384	$1,841,220	5 ppmv	$151,901	$92,061	$2,085,181	$1,042,591	$3,127,772
427	$2,288,649	$228,865	$2,517,514	5 ppmv	$207,695	$125,876	$2,851,084	$1,425,542	$4,276,627

Equipment Size mmBtu/hr	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor (TL)	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
100 - 170	$46,916.58	$46,916.58	$93,833.15	$181,410.76	$275,243.92
427	$64,149.40	$64,149.40	$128,298.80	$248,044.35	$376,343.15

Cost Effectiveness Calculation for Rule 1109 Boilers/Heaters > 110 mmBtu

Equipment Size mmBtu/hr	% of equipment in size range	Number of equipment	Present Value Factor (25 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	Cost of control for all equipment
100 - 170	79%	59	15.6	$4,293,805	$7,421,577	$437,873,038
427	21%	16	15.6	$5,870,953	$10,147,580	$162,361,279

Total number of boilers[1]	75	Total cost of control for all pieces of equipment	$600,234,317
Total NOx reduction (ton/25yr)[2]	53442	Average cost of control/ton emission reduced	**$11,200**

Cost Data for Rule 1109 Boilers/Heaters > 110 mmBtu (25 ppm to 5 ppm)

Equipment Size mmBtu/hr	Equipment Cost[1]	Instrumentation[2] (0.10 x EC)	Equipment Cost + Instrumentation	Emission Limit [1]	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
100 - 170	$1,673,836	$167,384	$1,841,220	5 ppmv	$151,901	$92,061	$2,085,181	$1,042,591	$3,127,772
427	$2,288,649	$228,865	$2,517,514	5 ppmv	$207,695	$125,876	$2,851,084	$1,425,542	$4,276,627

Equipment Size mmBtu/hr	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor (TL)	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
100 - 170	$46,916.58	$46,916.58	$93,833.15	$181,410.76	$275,243.92
427	$64,149.40	$64,149.40	$128,298.80	$248,044.35	$376,343.15

Cost Effectiveness Calculation for Rule 1109 Boilers/Heaters > 110 mmBtu

Equipment Size mmBtu/hr	% of equipment in size range	Number of equipment	Present Value Factor (25 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	Cost of control for all equipment
100 - 170	79%	59	15.6	$4,293,805	$7,421,577	$437,873,038
427	21%	16	15.6	$5,870,953	$10,147,580	$162,361,279

Total number of boilers[1]	75	Total cost of control for all pieces of equipment	$600,234,317
Total NOx reduction (ton/25yr)[2]	35241	Average cost of control/ton emission reduced	**$17,032**

Cost Data for Rule 1146 & 1146.1 Boilers/Heaters from Vendor A

Boilers Size Range (mmBtu)	Lox NOx Burner (mmBtu)	Equipment Cost[1]	Instrumentation[2] (0.10 x EC)	Equipment Cost + Instrumentation	Emission Limit[1] (ppmv)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
2 to 5	4.2	$25,000	$2,500	$27,500	12	$2,269	$1,375	$31,144	$15,572	$46,716
6 to 10	8.4	$30,000	$3,000	$33,000	12	$2,723	$1,650	$37,373	$18,686	$56,059
11 to 14	12.6	$40,000	$4,000	$44,000	12	$3,630	$2,200	$49,830	$24,915	$74,745
15 to 17	16	$50,000	$5,000	$55,000	12	$4,538	$2,750	$62,288	$31,144	$93,431
18 to 20	20	$55,000	$5,500	$60,500	12	$4,991	$3,025	$68,516	$34,258	$102,774
21 to 24	21	$60,000	$6,000	$66,000	9	$5,445	$3,300	$74,745	$37,373	$112,118
24 to 27	25.2	$65,000	$6,500	$71,500	9	$5,899	$3,575	$80,974	$40,487	$121,461
28 to 30	29.2	$70,000	$7,000	$77,000	9	$6,353	$3,850	$87,203	$43,601	$130,804
31 to 34	33.6	$72,000	$7,200	$79,200	9	$6,534	$3,960	$89,694	$44,847	$134,541
35 to 40	37.8	$80,000	$8,000	$88,000	9	$7,260	$4,400	$99,660	$49,830	$149,490
> 40	42	$90,000	$9,000	$99,000	9	$8,168	$4,950	$112,118	$56,059	$168,176

Low NOx Burner (mmBtu)	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor (TL)	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
4.2	$701	$701	$1,401	$2,710	$4,111
8.4	$841	$841	$1,682	$3,251	$4,933
12.6	$1,121	$1,121	$2,242	$4,335	$6,578
16	$1,401	$1,401	$2,803	$5,419	$8,222
20	$1,542	$1,542	$3,083	$5,961	$9,044
21	$1,682	$1,682	$3,364	$6,503	$9,866
25.2	$1,822	$1,822	$3,644	$7,045	$10,689
29.2	$1,962	$1,962	$3,924	$7,587	$11,511
33.6	$2,018	$2,018	$4,036	$7,803	$11,840
37.8	$2,242	$2,242	$4,485	$8,670	$13,155
42	$2,523	$2,523	$5,045	$9,754	$14,800

Cost Effectiveness Calculation for Rule 1146 and 1146.1 Boilers/Heaters

Boiler size range (mmBtu)	Low NOx burner (mmBtu)	% of boilers in size range	Number of boilers	Present Value Factor (10 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	Cost of control
2 to 5	4.2	24%	162	8.11	$33,340	$80,056	$12,969,012
6 to 10	8.4	21%	141	8.11	$40,008	$96,067	$13,545,413
11 to 14	12.6	12%	82	8.11	$53,344	$146,775	$12,035,571
15 to 17	16	9%	63	8.11	$66,680	$169,454	$10,675,627
18 to 20	20	4%	27	8.11	$73,348	$185,466	$5,007,569
21 to 24	21	5%	36	8.11	$80,016	$201,477	$7,253,159
24 to 27	25.2	4%	28	8.11	$86,684	$217,488	$6,089,658
28 to 30	29.2	4%	25	8.11	$93,352	$227,893	$5,697,326
31 to 34	33.6	3%	23	8.11	$96,019	$245,509	$5,646,712
35 to 40	37.8	8%	55	8.11	$106,688	$274,864	$15,117,535
> 40	42	7%	45	8.11	$120,024	$120,024	$5,401,081

Total number of boilers	687	Total cost of control for all pieces of equipment	$99,438,663
Total NOx Reduction (ton/10yr)	11203	Average cost of control/ton emission reduced	**$8,876/ton**

Notes:

1. Equipment cost, FGR cost ($8,250) filter cost ($800 - $900), fuel, and emission limit info provided by manufacturer/vendor
2. Instrumentation = 10% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
3. Sales Tax = 8.25% for Los Angeles
4. Freight = 5% of Equipment cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
5. Retrofit = 50% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-28, paragraph 2.5.4.2)
6. Maintenance and Material: Maintenance material costs are 100% of the Maintenance Labor costs (OAQPS Section 1, Chapter 2, page 2-32, paragraph 2.5.5.3)
7. Overhead = 60% of all labor and maintenance materials; Property taxes, Insurance and Administrative = 4% of TCI (OAQPS Section 1, Chapter 2, Page 2-34, paragraphs 2.5.5.7 and 2.5.5.8)

Emission reductions from Tier I End Factor to a weighted average of 9 ppm for boilers > 20 mmBtu and 12 ppm for boilers ≤ 20 mmBtu

Cost Data for Rule 1146 & 1146.1 Boilers/Heaters from Vendor B

Boilers (mmBtu)	Low NOx Burner (mmBtu)	Equipment Cost[1]	Instrumentation[2] (0.10 x EC)	Equipment Cost + Instrumentation	Emission Limit[1] (ppmv)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
≤ 5	5	$25,000	$2,500	$27,500	12	$2,269	$1,375	$31,144	$15,572	$46,716
>5 – 20	14.7	$37,750	$3,775	$41,525	12	$3,426	$2,076	$47,027	$23,514	$70,541
>20 – 50	21	$70,600	$7,060	$77,660	9	$6,407	$3,883	$87,950	$43,975	$131,925
	33.6	$94,700	$9,470	$104,170	9	$8,594	$5,209	$117,973	$58,986	$176,959
> 50	63	$127,200	$12,720	$139,920	9	$11,543	$6,996	$158,459	$79,230	$237,689

Low NOx Burner (mmBtu)	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor (TL)	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
5	$701	$701	$1,401	$2,710	$4,111
14.7	$1,058	$1,058	$2,116	$4,091	$6,208
21	$1,979	$1,979	$3,958	$7,652	$11,609
33.6	$2,654	$2,654	$5,309	$10,264	$15,572
63	$3,565	$3,565	$7,131	$13,786	$20,917

Cost Effectiveness Calculation for Rule 1146 & 1146.1 Boilers/Heaters

Boiler size range (mmBtu)	Low NOx burner (mmBtu)	% of boilers in size range	Number of boilers in size range	Present Value Factor (10 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	Cost of control
≤ 5	5	17%	117	8.11	$33,340	$80,056	$9,366,509
>5 – 20	14.7	53%	362	8.11	$50,343	$120,884	$43,760,010
>20 – 50	33.6	26%	177	8.11	$94,152	$271,111	$47,986,641
>50	63	5%	31	8.11	$126,292	$363,981	$11,283,412

Total number of boilers	687	Total cost of control for all pieces of equipment	$112,396,572
Total NOx Reduction (ton/10yr)	11203	Average cost of control/ton emission reduced	**$10,033/ton**

Notes:

1. Equipment cost, FGR cost ($8,250) filter cost ($800 - $900), fuel, and emission limit info provided by manufacturer/vendor
2. Instrumentation = 10% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
3. Sales Tax = 8.25% for Los Angeles
4. Freight = 5% of Equipment cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
5. Retrofit = 50% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-28, paragraph 2.5.4.2)
7. Overhead = 60% of all labor and maintenance materials; Property taxes, Insurance and Administrative = 4% of TCI (OAQPS Section 1, Chapter 2, Page 2-34, paragraphs 2.5.5.7 and 2.5.5.8)

Emission reductions from Tier I End Factor to a weighted average of 9 ppm for boilers > 20 mmBtu and 12 ppm for boilers ≤ 20 mmBtu

Cost Data for Misc. Heat Treating, and Metal Melting Categories
High Temperature Burners
Processes requiring pre-heated air

Burner (mm Btu/Hr)	Equipment Cost	Instrumentation[1]	Equipment Cost + Instrumentation	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
0.5	$2,162	$4,000	$6,162	$508	$308	$6,978	$3,489	$10,467
2.5	$2,711	$4,000	$6,711	$554	$336	$7,600	$3,800	$11,401
5	$3,162	$4,000	$7,162	$591	$358	$8,111	$4,056	$12,167
9	$6,383	$4,000	$10,383	$857	$519	$11,759	$5,880	$17,639
18	$10,182	$4,000	$14,182	$1,170	$709	$16,061	$8,030	$24,091
27	$15,495	$4,000	$19,495	$1,608	$975	$22,078	$11,039	$33,117
40	$25,925	$4,000	$29,925	$2,469	$1,496	$33,890	$16,945	$50,836

Burner (mm Btu/Hr)	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
0.5	$157	$157	$314	$607	$921
2.5	$171	$171	$342	$661	$1,003
5	$183	$183	$365	$706	$1,071
9	$265	$265	$529	$1,023	$1,552
18	$361	$361	$723	$1,397	$2,120
27	$497	$497	$994	$1,921	$2,914
40	$763	$763	$1,525	$2,948	$4,474

Low to Moderate Temperatures

Burner (mmBtu/Hr)	Equipment Cost[8]	Instrumentation[1]	Equipment Cost + Instrumentation	Emission Limit [1] (ppmv)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
0.4	$3,592	$4,000	$7,592	< 25	$626	$380	$8,597	$4,299	$12,896
0.8	$3,592	$4,000	$7,592	< 25	$626	$380	$8,597	$4,299	$12,896
1.6	$3,724	$4,000	$7,724	< 25	$637	$386	$8,748	$4,374	$13,122
2.7	$5,124	$4,000	$9,124	< 25	$753	$456	$10,333	$5,166	$15,499
3.7	$5,183	$4,000	$9,183	< 25	$758	$459	$10,399	$5,200	$15,599
5.4	$3,255	$4,000	$7,255	< 25	$599	$363	$8,216	$4,108	$12,324
7.4	$3,407	$4,000	$7,407	< 25	$611	$370	$8,389	$4,194	$12,583

Burner (mmBtu/Hr)	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
0.4	$193	$193	$387	$748	$1,135
0.8	$193	$193	$387	$748	$1,135
1.6	$197	$197	$394	$761	$1,155
2.7	$232	$232	$465	$899	$1,364
3.7	$234	$234	$468	$905	$1,373
5.4	$185	$185	$370	$715	$1,085
7.4	$189	$189	$377	$730	$1,107

Burner mmBtu	Equipment Cost	Instrumentation[2] (.10 x EC)	Equipment Cost + Instrumentation	Emission Limit[1] (ppm)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
70	$68,712	$6,871	$75,584	< 25	$6,236	$3,779	$85,598	$42,799	$128,397

Burner mmBtu	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
70	$1,926	$1,926	$3,852	$7,447	$11,299

Notes:

1. Equipment cost, fuel, emission limit, and instrumentation info provided by Manufacturer.
2. Instrumentation = 10% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
3. Sales Tax = 8.25% for Los Angeles
4. Freight = 5% of Equipment cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
5. Retrofit = 50% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-28, paragraph 2.5.4.2)
6. Maintenance and Material: Maintenance material costs are 100% of the Maintenance Labor costs (OAQPS Section 1, Chapter 2, page 2-32, paragraph 2.5.5.3)
7. Overhead = 60% of all labor and maintenance materials; Property taxes, Insurance and Administrative = 4% of TCI
(OAQPS Section 1, Chapter 2, Page 2-34, paragraphs 2.5.5.7 and 2.5.5.8)

Cost Effectiveness Calculation for Metal Melting

Equipment Size (mmBtu)	Burner Size (mmBtu)	% of equipment in size range	Number of equipment	Present Value Factor (10 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	Cost of control
≤2	0.5	2%	2	8.11	$7,470	$17,938	$35,875
>2 ≤ 3	2.5	10%	9	8.11	$8,136.42	$19,537.07	$175,834
>3 ≤ 6	5	30%	26	8.11	$8,683.19	$20,849.98	$542,099
>6 ≤ 10	9	9%	8	8.11	$12,588.46	$30,227.26	$241,818
>10 ≤ 20	18	27%	23	8.11	$17,193.26	$41,284.25	$949,538
>20 ≤ 40	27	21%	18	8.11	$23,634.79	$56,751.58	$1,021,528

Total number of metal melting equipment 86 Total cost of control for all pieces of equipment $2,966,693
Total NOx reduction (ton/10yr) 354 Average cost of control/ton emission reduced **$8,380/ton**

Cost Effectiveness for Miscellaneous Combustion

Equipment Size	Burner Size mmBtu	% of equipment in size range	Number of equipment	Present Value Factor (10 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	Cost of control
≤1	0.4/0.8	21%	109	8.11	$9,204	$22,100	$2,408,870
>1 ≤ 2	1.6	9%	49	8.11	$9,365	$22,486	$1,101,830
>2 ≤ 3	2.7	13%	68	8.11	$11,061	$26,560	$1,806,109
>3 ≤ 5	3.7	18%	92	8.11	$11,133	$26,731	$2,459,280
>5 ≤ 7	5.4	10%	56	8.11	$8,795	$21,120	$1,182,695
>7 ≤ 10	7.4	9%	57	8.11	$8,980	$21,563	$1,229,103
>10 ≤ 20	18	9%	46	8.11	$17,193	$41,284	$1,899,076
>20 ≤ 30	27	2%	11	8.11	$23,635	$56,752	$624,267
>30 ≤ 60	40	2%	11	8.11	$36,280	$87,115	$958,276
>60*	70	4%	23	8.11	$91,635	$220,032	$5,060,741

Total number of misc equipment 522 Total cost of control for all pieces of equipment $18,730,244
Total NOx reduction (ton/10yr) 1679 Average cost of control/ton emission reduced: **$11,100/ton**

Cost Effectiveness Calculation for Heat Treating

Equipment Size (mmBtu)	Burner size (mmBtu)	% of equipment in size range	Number of equipment in size category	Present Value Factor (10 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	Cost of control
≤2	0.5	3%	8	8.11	$7,470	$17,938	$143,502
>2 ≤ 3	2.5	25%	73	8.11	$8,136	$19,537	$1,426,206
>3 ≤ 6	5	47%	138	8.11	$8,683	$20,850	$2,877,297
>6 ≤ 10	9	12%	36	8.11	$12,588	$30,227	$1,088,181
>10 ≤ 20	18	11%	31	8.11	$17,193	$41,284	$1,279,812
>20 ≤ 40	27	1%	4	8.11	$23,635	$56,752	$227,006
>40 *	40	1%	2	8.11	$36,280	$87,116	$174,232

Total number of heat treating equipment	292	Total cost of control for all pieces of equipment	$7,216,236
Total NOx reduction (ton/10yr)	1762	Average cost of control/ton emission reduced	**$4,095/ton**

Cost Data for Rule 2009 Utility Boilers

Boiler Size (MW)	55	230
straight ratio	0.26	1.07
straight ratio to the .6 power	0.44	1.04
Capital Cost (equipment)	$1,323,963	$3,123,884
Installation Cost	$441,321	$1,041,295
Annualized Catalyst Cost (4 yr life)	$59,909	$141,356
O&M (includes ammonia)	$35,306	$83,304
Total Capital Investment	$1,765,284	$4,165,178
Total Annual Costs	$95,215	$224,659

Ref: Nelson, W.L., Petroleum Refinery Engineering, 1969, p. 879

Boiler Size (MW)	175	320
	95% eff	85% eff
Capital Cost (equipment)	$4,305,000	$3,750,000
Installation Cost		$1,250,000
Annualized Catalyst Cost (4 yr life)	$250,000	$127,500
O&M (includes ammonia)		$80,000
Total Capital Investment		$5,000,000
Total Annual Costs		$207,500

Cost Effectiveness Calculation for Rule 2009 Utility Boilers using 10 Year Equipment Life

Equipment Size MW	SCR Price Category	% of equipment in size range	Number of equipment	Present Value Factor (10 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	cost of control
55	55	27%	13	8.11	$772,194	$2,537,477	$32,987,206
175	175	29%	14	8.11	$2,027,500	$6,332,500	$88,655,000
230	230	17%	8	8.11	$1,821,987	$5,987,166	$47,897,324
320	320	27%	13	8.11	$1,682,825	$6,682,825	$86,876,725

Total number of Boilers	48	Total cost of control for all pieces of equipment	$223,429,049
Total NOx reduction (ton/10yr)	74944	Average cost of control/ton emission reduced	**$3,000ton**

Cost Data for Rule 2009 Utility Boilers

Boiler Size (MW)	55	230
straight ratio	0.26	1.07
straight ratio to the .6 power*	0.44	1.04
Capital Cost (equipment)	$1,323,963	$3,123,884
Installation Cost	$441,321	$ 1,041,295
Annualized Catalyst Cost (4 yr life)	$59,909	$ 141,356
O&M (includes ammonia)	$35,306	$83,304
Total Capital Investment	$1,765,284	$4,165,178
Total Annual Costs	$95,215	$224,659

*Ref: Nelson, W.L., Petroleum Refinery Engineering, 1969, p. 879

Boiler Size (MW)	175	320
	95% eff	85% eff
Capital Cost (equipment)	$4,305,000	$3,750,000
Installation Cost		$1,250,000
Annualized Catalyst Cost (4 yr life)	$250,000	$127,500
O&M (includes ammonia)		$80,000
Total Capital Investment		$5,000,000
Total Annual Costs		$207,500

Cost Effectiveness Calculation for Rule 2009 Utility Boilers Using 15 Year Equipment Life

Equipment Size MW	SCR Price Category	% of equipment in size range	Number of equipment	Present Value Factor (15 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	Cost of control
55	55	27%	13	11.11	$1,057,839	$2,823,122	$36,700,591
175	175	29%	14	11.11	$2,777,500	$7,082,500	$99,155,000
230	230	17%	8	11.11	$2,495,965	$6,661,143	$53,289,148
320	320	27%	13	11.11	$2,305,325	$7,305,325	$94,969,225

Total number of Boilers	48	Total cost of control for all pieces of equipment	$247,413,373
Total NOx reduction (ton/15yr)	112416	Average cost of control/ton emission reduced	**$2,201/ton**

Cost Data for Rule 2009 Utility Boilers

Boiler Size (MW)	55	230
straight ratio	0.26	1.07
straight ratio to the .6 power*	0.44	1.04
Capital Cost (equipment)	$1,323,963	$3,123,884
Installation Cost	$441,321	$ 1,041,295
Annualized Catalyst Cost (4 yr life)	$59,909	$ 141,356
O&M (includes ammonia)	$35,306	$83,304
Total Capital Investment	$1,765,284	$4,165,178
Total Annual Costs	$95,215	$224,659

*Ref: Nelson, W.L., Petroleum Refinery Engineering, 1969, p. 879

Boiler Size (MW)	175	320
	95% eff	85% eff
Capital Cost (equipment)	$4,305,000	$3,750,000
Installation Cost		$1,250,000
Annualized Catalyst Cost (4 yr life)	$250,000	$127,500
O&M (includes ammonia)		$80,000
Total Capital Investment		$5,000,000
Total Annual Costs		$207,500

Cost Effectiveness Calculation for Rule 2009 Utility Boilers Using 25 Year Equipment Life

Equipment Size MW	SCR Price Category	% of equipment in size range	Number of equipment	Present Value Factor (15 yr life, 4% real interest rate)	Present value of annual cost per boiler	Total present value of the Capital investment per boiler	Cost of control
55	55	27%	13	15.6	$1,485,354	$3,250,638	$42,258,290
175	175	29%	14	15.6	$3,900,000	$8,205,000	$114,870,000
230	230	17%	8	15.6	$3,504,685	$7,669,864	$61,358,910
320	320	27%	13	15.6	$3,237,000	$8,237,000	$107,081,000

Total number of Boilers	48	Total cost of control for all pieces of equipment	$283,309,910
Total NOx reduction (ton/25yr)	187360	Average cost of control/ton emission reduced	**$1,512/ton**

LCF Cost Effectiveness

Cost Data for FCCUs

Basic Equipment	Control Equipment	Equipment Cost (EC)	Instrumentation[1] (0.10 x EC)	Equipment Cost + Instrumentation	Sales Tax [2] (.0825 x EC)	Freight [3] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [4] (.50 x TEC)	Total Capital investment (TCI)
FCCU	SCR	$5,258,200	$525,800	$5,784,000	$477,200	$289,200	$6,550,400	$3,275,200	$9,825,600

Equipment	Total Annual Costs[5] (TAC)	Number of equipment
SCR	$1,150,000	4

Notes:
1. Instrumentation = 10% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
2. Sales Tax = 8.25% for Los Angeles
3. Freight = 5% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
4. Retrofit = 50% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-28 to 2-30, paragraph 2.5.4.2) This cost includes engineering.
5. Annual Costs include cost of catalyst (5 year life), aqueous NH3, power and routine maintenance.

Equipment Cost = the average for 2 FCCUs. Costs for the following equipment are included: SCR reactor, ammonia control skids, ammonia injection grids, catalyst, ESP purge blowers, switchgear, motor control, ammonia tanks and pumps, ducting and duct valves, hardware and CEMs system.

Cost Effectiveness Calculation for FCCUs

Capital Recovery Factor (25 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control for 4 units	Total NOx reduction for 4 units (ton/yr)	Cost Effectiveness ($/ton)
0.064	$628,838	$1,778,838	$7,115,354	366	$19,440

Note:
Above calculations are based on total cost of control and emission reductions for 4 units

Cost Data for Rule 1109 Boilers/Heaters > 110 mmBtu (34.5 ppm to 5 ppm)

Equipment Size mmBtu/hr	Equipment Cost[1]	Instrumentation[2] (0.10 x EC)	Equipment Cost + Instrumentation	Emission Limit [1] (ppmv)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
100 - 170	$1,673,836	$167,384	$1,841,220	5	$151,901	$92,061	$2,085,181	$1,042,591	$3,127,772
427	$2,288,649	$228,865	$2,517,514	5	$207,695	$125,876	$2,851,084	$1,425,542	$4,276,627

Equipment Size mmBtu/hr	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor (TL)	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
100 - 170	$46,917	$46,917	$93,833	$181,411	$275,244
427	$64,149	$64,149	$128,299	$248,044	$376,343

Cost Effectiveness Calculation for Rule 1109 Boilers/Heaters

Equipment Size mmBtu/hr	% of equipment in size range	Number of equipment	Capital Recovery Factor (25 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control for all equipment
100 - 170	79%	59	0.064	$200,177	$475,421	$28,049,857
427	21%	16	0.064	$273,704	$650,047	$10,400,756

Total number of boilers[1]	75	Total cost of control for all pieces of equipment	$38,450,614
Total NOx reduction (ton/yr)[2]	2137.7	Average cost of control/ton emission reduced	**$17,987/ton**

Cost Data for Rule 1109 Boilers/Heaters > 110 mmBtu (25 ppm to 5 ppm)

Equipment Size mmBtu/hr	Equipment Cost[1]	Instrumentation[2] (0.10 x EC)	Equipment Cost + Instrumentation	Emission Limit [1] (ppmv)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
100 - 170	$1,673,836	$167,384	$1,841,220	5	$151,901	$92,061	$2,085,181	$1,042,591	$3,127,772
427	$2,288,649	$228,865	$2,517,514	5	$207,695	$125,876	$2,851,084	$1,425,542	$4,276,627

Equipment Size mmBtu/hr	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor (TL)	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
100 - 170	$46,917	$46,917	$93,833	$181,411	$275,244
427	$64,149	$64,149	$128,299	$248,044	$376,343

Cost Effectiveness Calculation for Rule 1109 Boilers/Heaters

Equipment Size mmBtu/hr	% of equipment in size range	Number of equipment	Capital Recovery Factor (25 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control for all equipment
100 - 170	79%	59	0.064	$200,177	$475,421	$28,049,857
427	21%	16	0.064	$273,704	$650,047	$10,400,756

Total number of boilers[1]	75	Total cost of control for all pieces of equipment	$38,450,614
Total NOx reduction (ton/yr)[2]	1410	Average cost of control/ton emission reduced	**$27,270/ton**

Cost Data for Rule 1146 & 1146.1 Boilers/Heaters from Vendor A

Boilers Size Range (mmBtu)	Lox NOx Burner (mmBtu)	Equipment Cost[1]	Instrumentation[2] (0.10 x EC)	Equipment Cost + Instrumentation	Emission Limit[1] (ppmv)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
2 to 5	4.2	$25,000	$2,500	$27,500	12	$2,269	$1,375	$31,144	$15,572	$46,716
6 to 10	8.4	$30,000	$3,000	$33,000	12	$2,723	$1,650	$37,373	$18,686	$56,059
11 to 14	12.6	$40,000	$4,000	$44,000	12	$3,630	$2,200	$49,830	$24,915	$74,745
15 to 17	16	$50,000	$5,000	$55,000	12	$4,538	$2,750	$62,288	$31,144	$93,431
18 to 20	20	$55,000	$5,500	$60,500	12	$4,991	$3,025	$68,516	$34,258	$102,774
21 to 24	21	$60,000	$6,000	$66,000	9	$5,445	$3,300	$74,745	$37,373	$112,118
24 to 27	25.2	$65,000	$6,500	$71,500	9	$5,899	$3,575	$80,974	$40,487	$121,461
28 to 30	29.2	$70,000	$7,000	$77,000	9	$6,353	$3,850	$87,203	$43,601	$130,804
31 to 34	33.6	$72,000	$7,200	$79,200	9	$6,534	$3,960	$89,694	$44,847	$134,541
35 to 40	37.8	$80,000	$8,000	$88,000	9	$7,260	$4,400	$99,660	$49,830	$149,490
> 40	42	$90,000	$9,000	$99,000	9	$8,168	$4,950	$112,118	$56,059	$168,176

Low NOx Burner (mmBtu)	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor (TL)	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
4.2	$701	$701	$1,401	$2,710	$4,111
8.4	$841	$841	$1,682	$3,251	$4,933
12.6	$1,121	$1,121	$2,242	$4,335	$6,578
16	$1,401	$1,401	$2,803	$5,419	$8,222
20	$1,542	$1,542	$3,083	$5,961	$9,044
21	$1,682	$1,682	$3,364	$6,503	$9,866
25.2	$1,822	$1,822	$3,644	$7,045	$10,689
29.2	$1,962	$1,962	$3,924	$7,587	$11,511
33.6	$2,018	$2,018	$4,036	$7,803	$11,840
37.8	$2,242	$2,242	$4,485	$8,670	$13,155
42	$2,523	$2,523	$5,045	$9,754	$14,800

Cost Effectiveness Calculation for Rule 1146 & 1146.1 Boilers/Heaters

Boiler size range (mmBtu)	Low NOx burner (mmBtu)	% of boilers in size range	Number of boilers	Capital Recovery Factor (10 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control
2 to 5	4.2	24%	162	0.123	$5,746	$9,857	$1,596,833
6 to 10	8.4	21%	141	0.123	$6,895	$11,828	$1,667,804
11 to 14	12.6	12%	82	0.123	$9,194	$15,771	$1,293,238
15 to 17	16	9%	63	0.123	$11,492	$19,714	$1,241,982
18 to 20	20	4%	27	0.123	$12,641	$21,685	$585,506
21 to 24	21	5%	36	0.123	$13,790	$23,657	$851,645
24 to 27	25.2	4%	28	0.123	$14,940	$25,628	$717,589
28 to 30	29.2	4%	25	0.123	$16,089	$27,600	$689,990
31 to 34	33.6	3%	23	0.123	$16,549	$28,388	$652,927
35 to 40	37.8	8%	55	0.123	$18,387	$31,542	$1,734,831
> 40	42	7%	45	0.123	$20,686	$35,485	$1,596,833

Total number of boilers	687	Total cost of control for all pieces of equipment	$12,629,179
Total NOx Reduction (ton/yr)	1120	Average cost of control/ton emission reduced	**$11,276/ton**

Notes:

1. Equipment cost, FGR cost ($8,250) filter cost ($800 - $900), fuel, and emission limit info provided by manufacturer
2. Instrumentation = 10% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
3. Sales Tax = 8.25% for Los Angeles
4. Freight = 5% of Equipment cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
5. Retrofit = 50% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-28, paragraph 2.5.4.2)
6. Maintenance and Material: Maintenance material costs are 100% of the Maintenance Labor costs (OAQPS Section 1, Chapter 2, page 2-32, paragraph 2.5.5.3)
7. Overhead = 60% of all labor and maintenance materials; Property taxes, Insurance and Administrative = 4% of TCI
(OAQPS Section 1, Chapter 2, Page 2-34, paragraphs 2.5.5.7 and 2.5.5.8)

Emission reductions from Tier I End Factor to a weighted average of 9 ppm for boilers > 20 mmBtu and 12 ppm for boilers ≤ 20 mmBtu

Cost Data for Rule 1146 & 1146.1 Boilers/Heaters from Vendor B

Boilers (mmBtu)	Low NOx Burner (mmBtu)	Equipment Cost[1]	Instrumentation[2] (0.10 x EC)	Equipment Cost + Instrumentation	Emission Limit[1] (ppmv)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total C invest (TC
≤ 5	5	$25,000	$2,500	$27,500	12	$2,269	$1,375	$31,144	$15,572	$46,
>5 – 20	14.7	$37,750	$3,775	$41,525	12	$3,426	$2,076	$47,027	$23,514	$70,
>20 – 50	21	$70,600	$7,060	$77,660	9	$6,407	$3,883	$87,950	$43,975	$131,
	33.6	$94,700	$9,470	$104,170	9	$8,594	$5,209	$117,973	$58,986	$176,
> 50	63	$127,200	$12,720	$139,920	9	$11,543	$6,996	$158,459	$79,230	$237,

Low NOx Burner (mmBtu)	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor (TL)	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
5	$701	$701	$1,401	$2,710	$4,111
14.7	$1,058	$1,058	$2,116	$4,091	$6,208
21	$1,979	$1,979	$3,958	$7,652	$11,609
33.6	$2,654	$2,654	$5,309	$10,264	$15,572
63	$3,565	$3,565	$7,131	$13,786	$20,917

Cost Effectiveness Calculation for Rule 1146 & 1146.1 Boilers/Heaters

Boiler size range (mmBtu)	Low NOx Burner Size (mmBtu)	% of boilers in size range	Number of boilers	Capital Recovery Factor (10 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control
≤ 5	5	17%	117	0.123	$5,746	$9,857.00	$1,153,269
>5 – 20	14.7	53%	362	0.123	$8,676	$14,884.07	$5,388,032
>20 – 50	33.6	26%	177	0.123	$21,766	$37,338.30	$6,608,880
>50	63	5%	31	0.123	$29,236	$50,152.40	$1,554,724

Total number of boilers	687	Total cost of control for all pieces of equipment	$14,704,905
Total NOx Reduction (ton/yr)	1120	Average cost of control/ton emission reduced	**$13,129/ton**

Notes:

1. Equipment cost, FGR cost ($8,250) filter cost ($800 - $900), fuel, and emission limit info provided by manufacturer A.
2. Instrumentation = 10% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
3. Sales Tax = 8.25% for Los Angeles
4. Freight = 5% of Equipment cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
5. Retrofit = 50% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-28, paragraph 2.5.4.2)
6. Maintenance and Material: Maintenance material costs are 100% of the Maintenance Labor costs (OAQPS Section 1, Chapter 2, page 2-32, paragraph 2.5.5.3)
7. Overhead = 60% of all labor and maintenance materials; Property taxes, Insurance and Administrative = 4% of TCI
(OAQPS Section 1, Chapter 2, Page 2-34, paragraphs 2.5.5.7 and 2.5.5.8)

Cost Data for Misc, Heat Treating, and Metal Melting Categories
High Temperature Burners
Processes requiring pre-heated air

Burner (mm Btu/Hr)	Equipment Cost	Instrumentation[1]	Equipment Cost + Instrumentation	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
0.5	$2,162	$4,000	$6,162	$508	$308	$6,978	$3,489	$10,467
2.5	$2,711	$4,000	$6,711	$554	$336	$7,600	$3,800	$11,401
5	$3,162	$4,000	$7,162	$591	$358	$8,111	$4,056	$12,167
9	$6,383	$4,000	$10,383	$857	$519	$11,759	$5,880	$17,639
18	$10,182	$4,000	$14,182	$1,170	$709	$16,061	$8,030	$24,091
27	$15,495	$4,000	$19,495	$1,608	$975	$22,078	$11,039	$33,117
40	$25,925	$4,000	$29,925	$2,469	$1,496	$33,890	$16,945	$50,836

Burner (mm Btu/Hr)	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
0.5	$157	$157	$314	$607	$921
2.5	$171	$171	$342	$661	$1,003
5	$183	$183	$365	$706	$1,071
9	$265	$265	$529	$1,023	$1,552
18	$361	$361	$723	$1,397	$2,120
27	$497	$497	$994	$1,921	$2,914
40	$763	$763	$1,525	$2,948	$4,474

Low to Moderate Temperatures

Burner (mmBtu/Hr)	Equipment Cost[8]	Instrumentation[1]	Equipment Cost + Instrumentation	Emission Limit [1] (ppmv)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investmer (TCI)
0.4	$3,592	$4,000	$7,592	< 25	$626	$380	$8,597	$4,299	$12,896
0.8	$3,592	$4,000	$7,592	< 25	$626	$380	$8,597	$4,299	$12,896
1.6	$3,724	$4,000	$7,724	< 25	$637	$386	$8,748	$4,374	$13,122
2.7	$5,124	$4,000	$9,124	< 25	$753	$456	$10,333	$5,166	$15,499
3.7	$5,183	$4,000	$9,183	< 25	$758	$459	$10,399	$5,200	$15,599
5.4	$3,255	$4,000	$7,255	< 25	$599	$363	$8,216	$4,108	$12,324
7.4	$3,407	$4,000	$7,407	< 25	$611	$370	$8,389	$4,194	$12,583

Burner (mmBtu/Hr)	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
0.4	$193	$193	$387	$748	$1,135
0.8	$193	$193	$387	$748	$1,135
1.6	$197	$197	$394	$761	$1,155
2.7	$232	$232	$465	$899	$1,364
3.7	$234	$234	$468	$905	$1,373
5.4	$185	$185	$370	$715	$1,085
7.4	$189	$189	$377	$730	$1,107

Burner mmBtu	Equipment Cost	Instrumentation[2] (.10 x EC)	Equipment Cost + Instrumentation	Emission Limit[1] (ppm)	Sales Tax [3] (.0825 x EC)	Freight [4] (.05 x EC)	Total Equipment Cost (TEC)	Retrofit [5] (.50 x TEC)	Total Capital investment (TCI)
70	$68,712	$6,871	$75,584	< 25	$6,236	$3,779	$85,598	$42,799	$128,397

Burner mmBtu	Maintenance Labor[6] (0.015 X TCI)	Maintenance Material[6] (0.015 X TCI)	Total Labor	Overhead Administrative Property Tax Insurance[7] (.6 X TL + .04 X TCI)	Total Annual Costs
70	$1,926	$1,926	$3,852	$7,447	$11,299

Notes:

1. Equipment cost, fuel, emission limit, and instrumentation info provided by Manufacturer.
2. Instrumentation = 10% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
3. Sales Tax = 8.25% for Los Angeles
4. Freight = 5% of Equipment cost (OAQPS Section 1, Chapter 2, page 2-27, table 2.4)
5. Retrofit = 50% of Equipment Cost (OAQPS Section 1, Chapter 2, page 2-28, paragraph 2.5.4.2)
6. Maintenance and Material: Maintenance material costs are 100% of the Maintenance Labor costs (OAQPS Section 1, Chapter 2, page 2-32, paragraph 2.5.5.3)
7. Overhead = 60% of all labor and maintenance materials; Property taxes, Insurance and Administrative = 4% of TCI
(OAQPS Section 1, Chapter 2, Page 2-34, paragraphs 2.5.5.7 and 2.5.5.8)

Cost Effectiveness for Metal Melting

Equipment Size (mmBtu)	Burner Size (mmBtu)	% of equipment in size range	Number of equipment	Capital Recovery Factor (10 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control
≤2	0.5	2%	2	0.123	$1,287	$2,209	$4,417
>2 ≤ 3	2.5	10%	9	0.123	$1,402	$2,406	$21,650
>3 ≤ 6	5	30%	26	0.123	$1,497	$2,567	$66,747
>6 ≤ 10	9	9%	8	0.123	$2,170	$3,722	$29,774
>10 ≤ 20	18	27%	23	0.123	$2,963	$5,083	$116,914
>20 ≤ 40	27	21%	18	0.123	$4,073	$6,988	$125,778

Total number of equipment 86 Total cost of control for all pieces of equipment $365,280
Total NOx reduction (ton/10yr) 36 Average cost of control/ton emission reduced **$10,147/ton**

Cost Effectiveness Calculation for Miscellaneous Combustion

Equipment Size (mmBtu)	Burner Size (mmBtu)	% of equipment in size range	Number of equipment	Capital Recovery Factor (10 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control
≤1	0.4/0.8	21%	109	0.123	$1,586	$2,721	$296,596
>1 ≤ 2	1.6	9%	49	0.123	$1,614	$2,769	$135,665
>2 ≤ 3	2.7	13%	68	0.123	$1,906	$3,270	$222,380
>3 ≤ 5	3.7	18%	92	0.123	$1,919	$3,291	$302,803
>5 ≤ 7	5.4	10%	56	0.123	$1,516	$2,600	$145,621
>7 ≤ 10	7.4	9%	57	0.123	$1,548	$2,655	$151,336
>10 ≤ 20	18	9%	46	0.123	$2,963	$5,083	$233,827
>20 ≤ 30	27	2%	11	0.123	$4,073	$6,988	$76,864
>30 ≤ 60	40	2%	11	0.123	$6,253	$10,726	$117,989
>60*	70	4%	23	0.123	$15,793	$27,092	$623,113

Total number of equipment 522 Total cost of control for all pieces of equipment $2,306,196
Total NOx reduction (ton/yr) 168 Average cost of control/ton emission reduced **$13,727/ton**

Cost Effectiveness Calculation for Heat Treating

Equipment Size (mmBtu)	Burner Size (mmBtu)	% of equipment in size range	Number of equipment	Capital Recovery Factor (10 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control
≤2	0.5	3%	8	0.123	$1,287	$2,209	$17,669
>2 ≤ 3	2.5	25%	73	0.123	$1,402	$2,406	$175,604
>3 ≤ 6	5	47%	138	0.123	$1,497	$2,567	$354,273
>6 ≤ 10	9	12%	36	0.123	$2,170	$3,722	$133,984
>10 ≤ 20	18	11%	31	0.123	$2,963	$5,083	$157,579
>20 ≤ 40	27	1%	4	0.123	$4,073	$6,988	$27,951
>40 *	40	1%	2	0.123	$6,253	$10,726	$21,453

Total number of equipment	292	Total cost of control for all pieces of equipment	$888,512
Total NOx reduction (ton/yr)	176	Average cost of control/ton emission reduced	**$5,048/ton**

Cost Data for Rule 2009 Utility Boilers

Boiler Size (MW)	55	230
straight ratio	0.26	1.07
straight ratio to the .6 power*	0.44	1.04
Capital Cost (equipment)	$1,323,963	$3,123,884
Installation Cost	$441,321	$ 1,041,295
Annualized Catalyst Cost (4 yr life)	$59,909	$ 141,356
O&M (includes ammonia)	$35,306	$83,304
Total Capital Investment	$1,765,284	$4,165,178
Total Annual Costs	$95,215	$224,659

*Ref: Nelson, W.L., Petroleum Refinery Engineering, 1969, p. 879

Boiler Size (MW)	175	320
	95% eff	85% eff
Capital Cost (equipment)	$4,305,000	$3,750,000
Installation Cost		$1,250,000
Annualized Catalyst Cost (4 yr life)	$250,000	$127,500
O&M (includes ammonia)		$80,000
Total Capital Investment		$5,000,000
Total Annual Costs		$207,500

Cost Effectiveness Calculation for Rule 2009 Utility Boilers Using 10 Year Equipment Life

Equipment Size MW	SCR Price Category	% of equipment in size range	Number of equipment	Capital Recovery Factor (10 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control
55	55	27%	13	0.123	$217,130	$312,345	$4,060,484
175	175	29%	14	0.123	$529,515	$779,515	$10,913,210
230	230	17%	8	0.123	$512,317	$736,976	$5,895,810
320	320	27%	13	0.123	$615,000	$822,500	$10,692,500

Total number of equipment	48	Total cost of control for all pieces of equipment	$27,501,520
Total NOx reduction (ton/yr)	7494	Average cost of control/ton emission reduced	**$3,670/ton**

Cost Data for Rule 2009 Utility Boilers

Boiler Size (MW)	55	230
straight ratio	0.26	1.07
straight ratio to the .6 power*	0.44	1.04
Capital Cost (equipment)	$1,323,963	$3,123,884
Installation Cost	$441,321	$ 1,041,295
Annualized Catalyst Cost (4 yr life)	$59,909	$ 141,356
O&M (includes ammonia)	$35,306	$83,304
Total Capital Investment	$1,765,284	$4,165,178
Total Annual Costs	$95,215	$224,659

*Ref: Nelson, W.L., Petroleum Refinery Engineering, 1969, p. 879

Boiler Size (MW)	175	320
	95% eff	85% eff
Capital Cost (equipment)	$4,305,000	$3,750,000
Installation Cost		$1,250,000
Annualized Catalyst Cost (4 yr life)	$250,000	$127,500
O&M (includes ammonia)		$80,000
Total Capital Investment		$5,000,000
Total Annual Costs		$207,500

Cost Effectiveness Calculation for Rule 2009 Utility Boilers Using 15 Year Equipment Life

Equipment Size MW	SCR Price Category	% of equipment in size range	Number of equipment	Capital Recovery Factor (15 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control
55	55	27%	13	0.09	$158,875	$254,090	$3,303,177
175	175	29%	14	0.09	$387,450	$637,450	$8,924,300
230	230	17%	8	0.09	$374,866	$599,525	$4,796,203
320	320	27%	13	0.09	$450,000	$657,500	$8,547,500

Total number of equipment	48	Total cost of control for all pieces of equipment	$22,268,003
Total NOx reduction (ton/yr)	7494	Average cost of control/ton emission reduced	**$2,971/ton**

Cost Data for Rule 2009 Utility Boilers

Boiler Size (MW)	55	230
straight ratio	0.26	1.07
straight ratio to the .6 power*	0.44	1.04
Capital Cost (equipment)	$1,323,963	$3,123,884
Installation Cost	$441,321	$ 1,041,295
Annualized Catalyst Cost (4 yr life)	$59,909	$ 141,356
O&M (includes ammonia)	$35,306	$83,304
Total Capital Investment	$1,765,284	$4,165,178
Total Annual Costs	$95,215	$224,659

*Ref: Nelson, W.L., Petroleum Refinery Engineering, 1969, p. 879

Boiler Size (MW)	175	320
	95% eff	85% eff
Capital Cost (equipment)	$4,305,000	$3,750,000
Installation Cost		$1,250,000
Annualized Catalyst Cost (4 yr life)	$250,000	$127,500
O&M (includes ammonia)		$80,000
Total Capital Investment		$5,000,000
Total Annual Costs		$207,500

Cost Effectiveness Calculation for Rule 2009 Utility Boilers Using 25 Year Equipment Life

Equipment Size MW	SCR Price Category	% of equipment in size range	Number of equipment	Capital Recovery Factor (25 yr life, 4% real interest rate)	Annualized Capital Cost	Annualized Cash Flow	Cost of control
55	55	27%	13	0.064	$112,978	$208,193	$2,706,511
175	175	29%	14	0.064	$275,520	$525,520	$7,357,280
230	230	17%	8	0.064	$266,571	$491,231	$3,929,846
320	320	27%	13	0.064	$320,000	$527,500	$6,857,500

Total number of equipment	48	Total cost of control for all pieces of equipment	$18,144,626
Total NOx reduction (ton/yr)	7494	Average cost of control/ton emission reduced	**$2,421/ton**

APPENDIX C

Summary of Various Proposals for RECLAIM

Element	Industry 1	Industry 2	Environmental Groups	AQMD Staff
BARCT Determination	Industry supports a two-phased initial reduction of 4 tons per day based on our analysis of appropriate levels of further control. Further reductions, if appropriate, should be implemented incrementally, with careful consideration of cost-effectiveness and projected levels of economic activity. There are different ways to demonstrate equivalency to command & control, including a proposed market-based approach (see attached) but also the staff's approach if key policy issues are addressed and calculation errors corrected.		Technology-Based & Source-Specific (AQMD is legally required to achieve emission reductions equivalent to that which would be achieved through command & control; this is the only method that will achieve such equivalence.	Technology-Based & Source-Specific
Cost Effectiveness Analysis				
Equipment Life	Per ARB Cost Effectiveness Method, Use 10 years as default.		Variable 10-25 years (The useful life of RECLAIM equipment varies. Recent AQMD rules have reflected the longer useful life of equipment, such as the 25-year life of non-refinery boilers and process heaters, in order to derive a more realistic view of cost-effectiveness. To depart from this would set a bad precedent, make it difficult to compare cost-effectiveness of various AQMD rules, and unnecessarily limit emission reductions achieved from the RECLAIM program.)	Varies 10 - 25 years

Element	Industry 1	Industry 2	Environmental Groups	AQMD Staff
Cost Threshold	The Board should consider the cost estimate set in the 2003 AQMP ($7k/ton) in determining the threshold for the average of the cost of controls for all source categories. The cost of controls should not exceed $15,000 per ton for any single source category.		Variable past actions (RECLAIM is designed on a market system of trading. It is anticipated that some retrofit technologies will be more cost-effective than others, and where it is not cost-effective for a participant to install controls, that participant will instead purchase credits. To arbitrarily place a cap on cost-effectiveness would undermine this market system and artificially limit emission reductions achieved from the RECLAIM program.)	Varies past actions
Method	Method used by EPA and all of Cal/EPA, including ARB (Equipment life, interest rate and LCF)		DCF (AQMD has chosen to use the DCF method since the late 80's. Switching to LCF for RECLAIM alone would make it very difficult to compare RECLAIM cost-effectiveness with past AQMD rules.)	DCF

Element	Industry 1	Industry 2	Environmental Groups	AQMD Staff
Method to Derive Reductions	Industry supports a two-phased initial reduction of 4 tons per day based on our analysis of appropriate levels of further control. Further reductions, if appropriate, should be implemented incrementally, with careful consideration of cost-effectiveness and projected levels of economic activity. There are different ways to demonstrate equivalency to command & control, including a proposed market-based approach (see attached) but also the staff's approach if key policy issues are addressed and calculation errors corrected.		Neutral on the method employed, *as long as* the RECLAIM program achieves emissions reductions equivalent to those that would be achieved through command & control.	AQMP growth assumptions and new BARCT control
RTC Reduction				
Amount	4 tpd, additional based on future analysis cycles		10.2 tpd (This figure is based on staff's BARCT evaluations, but without the 10% RTC withholding as discussed below. Given the fact that the most recent AQMP projects a shortfall of greater than 100 tpd of NOx by 2010 and that all of the major stationary sources of NOx pollution are participants in RECLAIM, AQMD needs to achieve the greatest emission reductions possible from this program.)	7.8 tpd

Element	Industry 1	Industry 2	Environmental Groups	AQMD Staff
Schedule	2007 = 2 tpd 2008 = 2 tpd		Reductions beginning in 2006. 2006, 2007, 2008, and 2009 = 2 tpd each year. 2010 = 2.2 tpd. (After years of improvement, air quality is on the decline. AQMD needs to achieve emission reductions from RECLAIM as soon as possible.)	2007 = 4 tpd 2008 - 2010: 3.8 tpd
Method for Reducing RTCs	across-the-board	see Facilities at BARCT and Other, below	Across-the-board, *as long as* the RECLAIM program achieves emissions reductions equivalent to those that would be achieved through command & control.	across-the-board
Power Plant Trading Restrictions	All trading restrictions should be lifted.		Power providers should not be allowed back into RECLAIM, as they will have excess credits that will flood the market and result in reduced effectiveness of the program. If they are allowed back into the program, then we agree with staff that they should not be allowed back in until the RTC shave occurs and the holdings of power providers are shaved as well.	until 2007

Element	Industry 1	Industry 2	Environmental Groups	AQMD Staff
Mechanisms for Market Stability				
10% Market Adjustment	Yes - It should be understood that companies need a compliance margin in their allocations to prevent curtailment of operations due to normal variations in emissions.		No 10% withholding (Given the fact that the most recent AQMP projects a shortfall of greater than 100 tpd of NOx by 2010 and that all of the major stationary sources of NOx pollution are participants in RECLAIM, AQMD needs to achieve the greatest emission reductions possible from this program. A 10% withholding of credits will unnecessarily reduce the program's effectiveness. The RECLAIM program already has a mechanism in place to deal with emergency market fluctuations.)	Yes
Price Trigger	The same as the current rule.		No price trigger (The proposed arbitrary cap on the price of RECLAIM credits would create an incentive for participants to purchase credits, rather than install BARCT. This would unnecessarily limit emission reductions achieved from the program.)	$15,000/ton for 2010 reductions
Other	Extend and expand mobile source credit availability.			

Element	Industry 1	Industry 2	Environmental Groups	AQMD Staff
Facilities Already at BARCT	The same as the current rule.	Facilities at BARCT with current allocations <90% of emissions needed to operate without curtailment exempt from shave; two other alternatives under Other below	No exemptions for facilities already at BARCT (RECLAIM is a cap and trade program. Taking facilities out of the program as they achieve BARCT would result in a command & control program, but with emission reductions being achieved over a much longer time frame.)	Exemption from shave for structure buyers since 1994
Future Evaluation	Commencing mid-2009 (i.e., after both RECLAIM cycles have implemented the second-phase shave), if the RTC credit price, based on the preceding 18 months remained significantly below $15,000 per ton (or such other cost benchmark as the Board may establish), considering of the full range of factors relevant to the overall performance of the RECLAIM program, staff may propose further reductions. No further reductions would be proposed if the RTC price had reached or was projected soon to reach the established benchmark. This evaluation would occur during the following AQMP revision following implementation of the 2008 reduction and subsequent revisions thereafter.		As part of future AQMP based on BARCT evaluation (BARCT changes with time as new technology develops. Since AQMD is legally required to achieve equivalent reductions to command & control through the RECLAIM program, it should continue to evaluate BARCT as part of future AQMPs.)	As part of future AQMP based on BARCT evaluation

Element	Industry 1	Industry 2	Environmental Groups	AQMD Staff
Other	Industry is concerned with the SCAG Utility sector growth assumptions. If growth in this sector exceeds current projections, then a shortage of credits could result in power generation curtailment and an adverse effect on facility modernization and economic growth of the region.	Facilities at BARCT can opt out of RECLAIM with cap equal to BARCT emission rate x baseline activity level, or Shave done on per facility basis reflecting BARCT reductions available at facility		

APPENDIX D

Economist Reports on Potential Impacts of the RECLAIM Amendments