

**TESORO REFINING AND MARKETING COMPANY
ANACORTES REFINERY**



TESORO

**BEST AVAILABLE
RETROFIT TECHNOLOGIES (BART)
ASSESSMENT ASSISTANCE**

**FINAL
ENGINEERING ANALYSIS REPORT**

**TESORO NW PO NO. 4500821974
ANVIL NO. BE9411**

FEBRUARY 2008



EXECUTIVE SUMMARY

Anvil has completed a Best Available Retrofit Technology (BART) study of BART-eligible emission sources at the Tesoro Refinery located at Anacortes, Washington. Anvil investigated technologies that could reduce emissions of nitrogen oxides (NO_x) from 14 combustion sources: 12 heaters and 1 boiler ranging in capacity from 16.5 to 322 million Btu/hr (gross) and 1 flare.

The study included the assessment of 8 technologies for their suitability in reducing visibility impairments in Class I areas caused by NO_x emissions. Anvil used U.S. Environmental Protection Agency cost factors and vendor quotations to prepare 2 sets of top-down BART analyses. The U.S. Environmental Protection Agency cost factors were used as a method to screen the economic feasibility of the control technologies. Subsequently, the vendor quotations were used to develop a -50/+100% total installed cost (TIC) estimate for the control technologies. The TIC estimates cover the installation of the new emissions control equipment only and do not include any existing utility infrastructure improvements required to support the new equipment.

The study found that 4 of the BART-eligible sources contribute approximately 93% of the NO_x emissions from the 14 combustion sources: F-103, F-304, F-6650, and F-6651.

Based on the vendor-supplied NO_x reductions, vendor equipment costs, calculations, and analyses of the data, it is recommended that Tesoro Anacortes make the following cost-effective modifications to achieve a BART-eligible, plant-wide NO_x reduction of 605 tons per year at an annualized cost of \$2,532,169 or an average cost of \$4,185 per ton¹:

- Install low NO_x burners on F-103. A NO_x removal of 80 tons per year would cost an estimated \$4,648 per ton.
- Install low-NO_x burners and Selective Non-Catalytic Reduction technology on F-304. A NO_x removal of 323 tons per year would cost an estimated \$4,592 per ton at an incremental cost of \$5,160 per ton over and above SNCR retrofit alone.
- Install low-NO_x burners at units F-6650 and F-6651 and install ultra-low-NO_x burners at units F-6652 and F-6653. A NO_x removal of 202 tons per year would cost an estimated \$3,349 per ton.

¹ Note that the conclusions are based only on determinations of cost effectiveness and do not consider the degree of visibility improvement associated with installing the technologies as allowed for under the BART rules.

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INTRODUCTION

Anvil has completed a Best Available Retrofit Technology (BART) study on BART-eligible emission sources at the Tesoro Refinery located at Anacortes, Washington. Anvil investigated technologies that would reduce nitrogen oxides (NO_x) from 14 sources: 12 heaters and 1 boiler ranging in capacity from 16.5 to 322 million British thermal units per hour (MMBtu/hr) (gross) and 1 flare.

The study included the assessment of 8 technologies for their suitability in reducing visibility impairments in Class I areas caused by NO_x emissions. This report recommends the best current technology for NO_x reduction based on the following information:

- A review of the proven technologies available
- The energy, air, and non-air quality environmental impacts of compliance
- Pollution control equipment in use at the source
- The cost of compliance.

Background

In conformance with Washington State Department of Ecology (DOE) BART protocol, Tesoro Anacortes conducted an air modeling study which showed a computed visibility impairment in excess of 0.5 deciviews (dv) caused by the refinery. This determination was based upon maximum 24-hour emission rates from BART-eligible sources over the BART assessment years of 2003 through 2005.

Regulatory Background

Sections 169A and 169B of the Clean Air Act (CAA) contain requirements for visibility protection in scenic areas across the United States. To meet the CAA requirements, the EPA published regulations to protect against a particular type of visibility impairment known as “regional haze.” The regional haze rule is found at 40 CFR 51.200 through 51.309. These regulations require, in 40 CFR 51.308(e), that certain types of existing stationary sources of air pollutants install BART.

The 1999 EPA Regional Haze Rule addresses regional haze visibility impairment for 156 federally-protected, Class 1 parks and wilderness areas. The rule fulfills a long-standing EPA commitment to address regional haze under the authority and requirements of the CAA. The Washington Department of Ecology has requested that sources with stationary BART-eligible sources investigate their contribution to visibility impact. Sources with impacts greater than 0.5 dv must next carry out BART technology assessments to establish reasonable retroactive controls to reduce emissions.

BART Definition

Best Available Retrofit Technology (BART) is an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a stationary source that was in existence on August 7, 1977 and began operation after August 7, 1962. *In existence* means that the owner or operator

obtained all necessary preconstruction approvals or permits and had either (1) begun, or caused to begin, a continuous program of physical on-site construction, or, (2) entered into binding agreements or contractual obligations, which could not be canceled or modified without substantial loss.

The emission limitation must be established, on a case-by-case basis, taking the following into consideration:

- Technology available
- Costs of compliance
- Energy and non-air quality environmental impacts of compliance
- Any pollution control equipment in use or in existence at the source
- The remaining useful life of the source
- Degree of improvement in visibility that may reasonably be expected from the use of such technology.

Information Sources

To calculate the pre-project related emissions, Anvil used source test data where available and EPA AP-42 emission factors.

To evaluate costs, Anvil used U.S. Environmental Protection Agency (EPA) cost factors and vendor quotations. The EPA cost factors provided estimates of total installed costs and an estimate of annual maintenance and operation costs. The EPA cost factors were used as a method to screen the economic feasibility of the control technologies. Subsequently, vendors provided capital costs, design specifications, and levels of anticipated NO_x emission reductions. From the vendor-supplied capital costs, in-house total installed cost estimates were developed for feasibility purposes (-50/+100%).

Costs for the EPA analysis were escalated from 1991 to 2007 U.S. dollars using the Chemical Engineering Plant Cost Index (Equipment Factors).

Basis and Study Limitations

Installation costs are based on a preliminary -50/+100% basis. Anvil prepared total installed costs (-50/+100%) for sources F-103, F-304, F-6600, F-6601, F-6650, F-6651, F-6652, and F-6653 based on a combination of previous experience, vendor cost estimates, and installation factors. Sources F-6650, F-6651, F-6652, and F-6653 share two common stacks. Due to this common stack configuration, these sources were evaluated on a combined basis for the vendor cost analyses. Anvil used only a factored approach for sources F-654, F-6602, F-6654, and F-6655.

The TIC estimates cover the installation of the new emissions control equipment only and do not include any existing utility infrastructure improvements that may be required to support the new equipment.

Prolonged use of sulfurous fuels commonly results in the corrosion of some components essential to the heater's structural integrity. Where the fuel's sulfur compounds have precipitated

out behind damaged refractory layers, the refractory anchors have commonly been severely corroded. This allows the refractory to move away from the heater walls and the acidic deposits to attack the steel casing plate and main supporting columns. Frequently, this results in hot spots on the heater's outer casing, as evidenced by peeling casing paint.¹

Consideration must be given to matters such as the strength and integrity of corroded structures, asbestos presence, and the procedures for its safe removal. Anvil did not provide a structural engineering review, conduct a structural inspection of the heaters and boilers, or establish an asbestos inventory. Anvil included only a preliminary estimate for handling and disposal of refractories containing asbestos.

APPROACH

The present study's approach is outlined in Appendix Y to Part 51, (EPA 40 CFR Part 51 – Regional Haze Regulations) and Guidelines for Best Available Retrofit Technology (BART) Determination:

1. Identify all available retrofit control technologies
2. Eliminate technically infeasible options
3. Evaluate control effectiveness of remaining control technologies
4. Evaluate impacts and document the results
5. Determine remaining useful life
6. Select BART

Step 1 – Identify All Available Retrofit Control Technologies

Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions source and the regulated pollutant under evaluation. Technologies required as Best Available Control Technologies (BACT) and Lowest Achievable Emission Rate (LAER) must be included as control alternatives. In addition, a level of control equivalent to the New Source Performance Standards (NSPS) was included; however, the NSPS level of control does not automatically represent the best that can be installed on sources.

Potentially applicable retrofit control alternatives can be categorized in three ways:

- Pollution prevention using inherently lower-emitting processes/practices including the use of control techniques and work practices that prevent emissions and result in lower “production-specific” emissions
- The use of, and improvement of, add-on controls
- The combination of inherently lower-emitting processes and add-on controls.

Step 2 – Eliminate Technically Infeasible Options

For each emission source under review, physical, chemical, or engineering principles were used to eliminate technically infeasible control options. Control options are generally technically feasible if one of the following applies:

- They have been installed and operated successfully for the source type under similar conditions.

¹ (Tindal, 2004)

- The technology could be applied to the specific source under review.
- The technology does not cause a significant reduction in the operation of the source.

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

An evaluation of the control effectiveness for each pollutant and emission source was conducted using a similar metric “apples-to-apples” between emission sources. The ability of the control techniques to operate over a wide range of emission performance levels was considered. The control technologies were matched to the source’s range of operability.

Step 4 – Evaluate Impacts and Document Results

The following impacts were considered:

- Costs of compliance
- Energy impacts
- Air quality and non-air quality environmental impacts.

Step 5 – Determine Remaining Useful Life

Remaining useful life and visibility impacts analysis are not part of the present study.

Step 6 – Select BART

A summary of the impacts was prepared and the best available retrofit technology was selected. The BART analysis identified the best system of continuous emission reduction taking into account:

- Available retrofit control options
- Any pollution control equipment in use at the source (which affects the availability of options and their impacts)
- Costs of compliance with control options
- Energy and non-air quality environmental impacts of the control options.

The minimum requirements considered in this analysis encompass those technologies included in the EPA’s RACT/BACT/LAER¹ guidelines. For NO_x emission limits, see Appendix C, Summary of BACT Determinations of Refinery Heaters and Boilers.

REFINERY BACKGROUND

BART-Eligible Sources

Table 1 lists the BART-eligible sources at the Tesoro Anacortes Refinery. Gross heater capacities are provided. Gross heating values are 1.1 times the net heating values.

¹ Reasonably Available Control Technology/Best Available Control Technology/Lowest Achievable Emission Rate

Source	Service	Year of Construction	Gross Capacity (MMBtu/hr) ²	Ave. Gross Heat Release (MMBtu/hr) ³
F-103 ¹	Crude Oil Distillation	1963	145	103.5
F-104	Gasoline Splitter	1972	53	15.5
F-304	CO Boiler No. 2	1964	322	184.5
F-654	Clean Fuels Hydrotreater	1964	16.5	7.6
F-6600	Naphtha Hydrotreater	1971	71.5	46.3
F-6601	Naphtha Hydrotreater	1971	75	48.3
F-6602	Naphtha Hydrotreater	1971	75	28.0
F-6650	Catalytic Reformer	1971	157	124.7
F-6651 A/B	Catalytic Reformer	1971	157	90.4
F-6652	Catalytic Reformer	1971	74	41.7
F-6653	Catalytic Reformer	1971	42	31.4
F-6654	Catalytic Reformer	1971	35	24.6
F-6655	Catalytic Reformer	1971	30	11.9
X-819	Flare	1971	244	-

Notes:

1 Capable of combusting both gaseous and liquid fuels. In the present study, however, only gaseous fuels were considered.

2 Million British thermal units per hour

3 Average of 2003 through 2005 operating data, corrected for days that sources were shut down during 2003 through 2005.

Source Descriptions

Table 2 provides a description of the BART-eligible sources at Tesoro Anacortes Refinery.

Source	Manufacturer	Type	Firing	Burners	Notes
F-103	Foster Wheeler	Crude oil distillation furnace - box-type heater	Horizontal	2 cells each with 12 burners for a total of 24 burners	Capable of combusting both gaseous and liquid fuels. Present study, however, only considered gaseous fuels as fuel source.
F-104	Petro-Chem Dev.	Vertical cylindrical gasoline splitter heater	Up-fired	6 floor-mounted ultra-low-NO _x burners	
F-304	Alcorn Combustion	Box	Horizontal	4 wall-mounted burners	Designed to combust regen flue gas from the FCC (using refinery fuel gas for supplemental heat). Operated at a consistently high temperature to provide favorable conditions for CO combustion. When not combusting regen flue gas, operation as a conventional boiler can be maintained using refinery fuel gas.
F-654	Petro-Chem Dev.	Vertical cylindrical catalytic feed hydrotreater	Up-fired	3 floor-mounted burners	
F-6600	Born Engineering Company	Vertical cylindrical naphtha hydrotreater feed preheater	Up-fired	4 floor-mounted burners	

Source	Manufacturer	Type	Firing	Burners	Notes
F-6601	Born Engineering Company	Vertical cylindrical naphtha hydrotreater stabilizer column reboiler	up-fired	4 burners	
F-6602	Born Engineering Company	Naphtha hydrotreater splitter column reboiler	Up-fired	4 burners	The reboiler is operated on an as needed basis, and is otherwise shutdown.
F-6650	Foster Wheeler	Box catalytic reformer feed preheat heater	Up-fired	10 floor-mounted burners	Two common stacks for sources F-6650, F-6651, F-6652, and F-6653
F-6651 A/B	Foster Wheeler	Box catalytic reformer inter-reactor heater	Up-fired	16 floor-mounted burners	Consists of 2 contiguous rectangular fire boxes. Shares two common stacks with sources F-6650, F-6651, F-6652, and F-6653.
F-6652	Foster Wheeler	Box catalytic reformer inter-reactor heater	Up-fired	7 floor-mounted burners	Shares two common stacks with sources F-6650, F-6651, F-6652, and F-6653.
F-6653	Foster Wheeler	Box catalytic reformer inter-reactor heater	Up-fired	3 floor-mounted burners	Shares two common stacks with sources F-6650, F-6651, F-6652 and F-6653.
F-6654	Born Engineering	Vertical cylindrical catalytic reformer stabilizer column reboiler	Up-fired	3 floor-mounted burners	
F-6655	Born Engineering	Vertical cylindrical catalytic reformer regeneration gas heater	Up-fired	3 floor-mounted burners	
X-819 Flare	Based on Esso Research Design	Vertical smokeless	2-stage	7, 4-inch refractory covered headers with 41 stainless, 1-inch nozzles.	15-foot diameter and 32 feet high. 2.6 MMscfd capacity. Relief capacities of 0.5 and 2.1 MMscfd for first and second stage, respectively.

Current Emissions

Anvil calculated the baseline NO_x emissions using source test data where available and EPA AP-42 emission factors. See Appendix A for a more detailed list of the baseline emission estimates and for emissions calculations. Table 3 summarizes the calculated emissions.

Source		NO _x ¹ (tpy) ²	BART-Eligible NO _x Percentage
F-103	Gas Crude Oil Distillation	121.4	9.3
F-104	Gasoline Splitter	4.7	0.4
F-304	CO Boiler No. 2	836.0 ³	64.0
F-654	Cat Feed Hydrotreater	2.6	0.2
F-6600	Naphtha Hydrotreater	18.9	1.4
F-6601	Naphtha Hydrotreater	19.8	1.5

Table 3. Emissions Summary			
Source		NO _x ¹ (tpy) ²	BART-Eligible NO _x Percentage
F-6602	Naphtha Hydrotreater	1.3	0.1
F-6650	Catalytic Reformer	144.7	11.1
F-6651A/B	Catalytic Reformers	104.7	8.0
F-6652	Catalytic Reformer	17.1	1.3
F-6653	Catalytic Reformer	13.0	1.0
F-6654	Catalytic Reformer	10.2	0.8
F-6655	Catalytic Reformer	3.3	0.3
X-819	Flare	8.8	0.7

Notes:

1 EPA-AP42, 2003 to 2005 average

2 Tons per year

3 NO_x emissions based on source testing, 2003-2005 average

BART PROCESS

Step 1 – Identify NO_x Control Technologies

NO_x emissions control from refinery fuel gas and flue gas combustion can be achieved with 8 technologies or combinations of technologies:

- Flue gas recirculation (FGR)
- Low-NO_x burners
 - Staged-air, low-NO_x burners (LNBS)
 - Staged-fuel, low-NO_x burners (LNBS)
- Ultra-low-NO_x burners (ULNBS)
- NO_x tempering
- Selective non-catalytic reduction (SNCR)
 - SNCR (SNCR + NO_x tempering - Peerless vendor quotation)
 - LNBS + SNCR
 - ULNBS + SNCR
- Selective catalytic reduction (SCR)
 - SCR
 - LNBS + SCR
 - ULNBS + SCR
- Non-thermal plasma LoTO_xTM process (Cat. Cracker CO Boiler, F-304 only)
- Sulfur Recovery Unit/Tail Gas Unit (Cat. Cracker CO Boiler, F-304 only).

Flue Gas Recirculation

Flue Gas Recirculation (FGR) generally involves forced flue gas return to the burners and introduces the air/flue gas mixture into the combustion zone. This technique is usually referred to as an external FGR system. FGR is a NO_x emission reduction technique based on recycling 15 to 30% of the essentially inert combustion products (flue gas) to the primary combustion

zone. Flue gas recirculation dilutes the combustion reactants, reduces the peak flame temperature, and reduces the local oxygen concentrations, thereby inhibiting thermal NO_x formation. However, FGR is believed to have only a small effect on fuel NO_x formation.

FGR has been successfully used with boilers, but FGR has been used on only a few fired heaters. Retrofit operations require extensive modification to the firebox floor and re-orientation of burners if they are currently in close proximity to each other. Tesoro regards flue gas recirculation of flue gases at process heaters as an unacceptable safety risk due to the potential of formation of explosive gas mixtures in the event of a heater tube failure. Few applications have been made to refinery process heaters due to this risk. Therefore, this technology was not explored.

Low-NO_x and Ultra-Low-NO_x Burners

There are two main types of LNBs, the staged-air and the staged-fuel burners. Manufacturers have developed a number of LNBs and ULNBs that combine elements of FGR, air staging, and fuel staging to achieve NO_x reductions. Emission factors from EPA's RACT/BACT/LAER Clearinghouse range from 0.08 to 0.1 lb/MMBtu (NO_x) for LNBs and ULNBs. See Appendix C, Summary of BACT Determination for Refinery Heaters and Boilers.

Staged-Air, Low-NO_x Burners

Staged-air, low-NO_x burners limit NO_x production by reducing flame oxygen concentrations. The initial fuel combustion takes place in a fuel-rich, reducing atmosphere in which N₂ is preferentially formed rather than NO_x. The initial combustion zone's flame temperature is high due to the low combustion air/fuel ratio, but the low O₂ concentration limits thermal NO_x formation. The reducing conditions prevailing in certain makes of staged-air burners (particularly those with longer primary zone residence times) are thought to have a greater impact on fuel NO_x reduction than the staged-fuel burner.

Design considerations affecting flame characteristics include burner tip placement, burner tip hole sizes and angles, flue gas recycle duct placement, and burner tile shape. Retrofit operations may require extensive heater modifications. In general, retrofitting heaters with spacing of less than 3 feet may not be practical due to potential flame impingement. Emission reductions achieved by staged-air LNBs range from 30 to 40% below emissions from conventional burners.¹ This study used a 40% NO_x reduction for the EPA cost factor portion.

Staged-Fuel, Low-NO_x Burners

Staged-fuel LNBs were more recently developed than staged-air LNBs. Staged-fuel LNBs separate the combustion zone into two regions. The first is a lean primary region in which the total combustion air quantity is supplied with a fraction of the fuel. In the second region, the remaining fuel is injected and the oxygen left over from the primary region combusts it. This technique inhibits thermal NO_x formation, but has little effect on fuel NO_x formation.

¹ (CPPI, 1990), (Campbell, 1991), (Martin, 1993), (Shareef, 1988)

Staged-fuel LNBS have several advantages over staged-air LNBS. First, the improved fuel/air mixing due to the pressurized injection of the secondary fuel region reduces the excess air operating level necessary to ensure complete combustion. The lower excess air both reduces NO_x formation and improves heater efficiency. Second, for a given peak flame temperature, staged-fuel LNBS have a more compact flame than staged-air LNBS. Up to 72% NO_x emissions reductions for staged-fuel LNBS have been reported over conventional burners based on vendor test data. This study used a 60% average NO_x reduction in the EPA cost factor portion.

Reported vendor NO_x reductions for low-NO_x burners ranged from 28 to 66%. The NO_x reduction factor was found by using the EPA-AP 42 estimated emission factor, fuel composition, and turndown ratios. Therefore, actual NO_x reductions may differ from those that have been estimated.

Ultra-Low-NO_x Burners

Ultra-low-NO_x burners (ULNBs) recirculate hot, oxygen-depleted flue gas from the flame or firebox back into the combustion zone. This reduces the average O₂ concentration within the flame without reducing the flame temperature below the temperatures necessary for optimal combustion efficiency. Reduced O₂ concentrations in the flame have a strong impact on fuel NO_x, so these burners are an effective NO_x control technique for heaters firing nitrogen-bearing fuels.

ULNBs are larger in size and may require larger mechanical draft air plenums than do conventional burners that use natural draft air plenums. Burner mount modifications may be required because ULNBs usually do not fit into conventional burner mounts. ULNBs now have the following features available:

- Compact sizes
- Shorter flame paths
- High turndown ratios.

A 75% average NO_x reduction was used in the EPA cost factor portion.

A 73% (vendor guaranteed) average NO_x reduction was used in the vendor cost factor portion. The 73% NO_x reduction was found by using the EPA-AP 42 estimated emission factor, fuel composition and turndown ratio. Therefore, actual NO_x reductions may differ from the estimated reductions.

NO_x Tempering (Steam or Water Injection)

Peerless Manufacturing Company has proposed that SNCR technology could be combined with NO_x tempering technology on sources F-103 and F-304. NO_x tempering is a patented process in which water is injected into the burner flame. For each 190°F of flame temperature reduction, the NO_x is reduced by 50%.

First, the NO_x production zone within the flame is found using computational fluid dynamics. Then, a defined spray droplet size and velocity is developed to target the NO_x production zone. The very high adiabatic flame temperatures of the fuel gas and absence of fuel-bound nitrogen

has a high potential for NO_x reduction with very little water use. The vendor estimated that NO_x tempering would reduce NO_x formation by 30 to 35%.

Flame temperature cooling would relate to reduced bridgewall temperatures and increased fuel gas use. In addition, water vaporization would result in an increased volume of flue gas that could potentially over-pressurize the fire box. Steam or water injection to control NO_x is usually a part of a new design and not a retrofit design. Finally, NO_x tempering has only been used on large utility boilers.

Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction (SNCR) is a post-combustion technology that involves directly injecting a NO_x-reducing chemical into the hot flue gas. At suitably high temperatures, the injected chemical can convert the NO_x to N₂ without a catalyst. Currently, three chemical reactants are available for the SNCR process:

- Anhydrous ammonia
- Aqueous ammonia
- Aqueous urea solution.

The reaction temperatures required range from 1,600 to 1,750°F for ammonia and from 1,000 to 1,900°F for urea-based reagents. Other chemicals such as hydrogen, hydrogen peroxide, fuel gas, and methanol may be added to improve performance and lower the minimum threshold temperatures.

SNCR reduces both thermal and fuel-derived NO_x. The SNCR systems require rapid chemical diffusion in the flue gas. The injection point must be selected to ensure adequate flue gas residence time. Furthermore, the injection point is determined by the allowable temperature required to carry out the reaction. Computer modeling is often used to select the optimum injection points.

Unreacted ammonia in the emissions is known as slip, and is potentially higher in SNCR systems than in those fitted with a catalyst (see SCR below) due to higher reactant injection ratios (2:1). Ammonia slip also poses safety and environmental concerns. In the present study, vendors projected potential NO_x reductions with not more than 25 ppm ammonia slip. Ammonia in the waste gas stream may impact plume visibility. Furthermore, SNCR systems may increase refinery fuel gas consumption by approximately 0.3% in addition to the power required to vaporize aqueous ammonia. Ammonia emissions are also contributors to regional haze. In addition, nitrous oxide (N₂O), a by-product formed during SNCR, is a greenhouse gas. Nitrous oxide does not contribute to ground level ozone or acid formation.¹

Thermal DeNO_x[™], developed by Exxon Mobil, uses anhydrous or aqueous ammonia while the Nalco Fuel Tech NO_xOUT[®] system uses a urea-based reactant.² Anhydrous ammonia requires permitting and personnel trained in its safe use. Anhydrous ammonia is stored as a liquid under

¹ (EPA, 2003)

² (EPA, 1993)

pressure, and upon uncontrolled release, will freeze exposed skin and chemically burn tissue. On the other hand, 19% aqueous ammonia does not require permits, nor does it pose anhydrous ammonia's safety hazards.

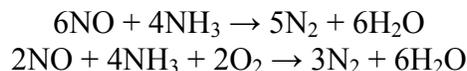
Alternatively, dry urea can be converted on-site to ammonia using Hamon Research – Cottrell's U₂A™ patented system (U.S. Patent No. 6,077,491) that generates ammonia on-site for various processes, such as SCR or SNCR. Benign dry urea is transported to the site and mixed with water to form an aqueous solution. The solution is then fed to an in-line hydrolysis reactor where steam or electricity heats the reactants to 280 to 310°F. The product gas is a mixture of ammonia (NH₃), carbon dioxide (CO₂), and water vapor (H₂O), and may be used in any application where ammonia is required (such as SCRs or SNCRs.) Dry urea is an expensive proposition for smaller scale systems and may increase CO₂ emissions.

SNCR may be used as the sole NO_x control technique or in combination with LNBs or ULNBs. At optimum temperatures, NO_x destruction efficiencies range from 30 to 50%.¹ The present study uses a 50% NO_x reduction in the EPA cost factor portion.

Vendor NO_x reductions ranged from 35 to 40%. These reductions were found by using the EPA AP-42 estimated emission factor, fuel gas compositions, and flue firebox temperatures. Therefore, actual NO_x reductions may differ from the estimated reduction. An emission limit from EPA's RACT/BACT/LAER Clearinghouse of 127 ppmv NO_x at 7% oxygen was listed for an FCC and a CO Boiler. See Appendix C, Summary of BACT Determinations for Refinery Heaters and Boilers.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR), a post-combustion gas treatment technique, reduces NO_x in the exhaust stream. Ammonia (NH₃), the reducing agent, is injected in the flue gas upstream of a catalyst bed. As the exhaust gas mixture passes through the catalyst bed, the reducing agent selectively reduces the nitrogen oxide compounds in the exhaust to produce elemental nitrogen (N₂) and water (H₂O). The major reactions that occur in the presence of the catalyst are the following:



Adequate ammonia mixing in the exhaust gas and controlling the injected ammonia amount (based on inlet NO_x concentration) are critical to obtaining the required reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum O₂ concentrations and remain within a specified temperature range with the catalyst type dictating the range. SCR requires catalyst bed temperatures of 600 to 750°F for conventional vanadium or titanium-based catalyst and from 470 to 510°F for platinum catalysts. Exhaust gas temperatures greater than the upper limit (850°F) will pass NO_x and unreacted ammonia through the catalyst.

¹ (EPA, 2003)

The catalyst is usually a mixture of titanium dioxide, vanadium pentoxide, and tungsten trioxide. The catalyst lowers the activation energy of the NO_x decomposition reaction. The catalyst life expectancy is typically 3 to 6 years at which time the vendor can recycle the catalyst to minimize waste. Note that back pressure created by the catalyst bed may impact firebox combustion conditions.

Other than the catalyst bed reactor, major components of an SCR system are ammonia storage sources, vaporizer, and an ammonia injection grid. Catalyst deactivation and residual ammonia slip in the flue gas are the two key drawbacks in an SCR system. Catalyst activity decreases with operating time and with catalyst fouling. The catalyst must then be disposed of, presenting another environmental concern.

Ammonia slip poses a safety and environmental concern. In the present study, vendors projected potential NO_x reductions with not more than 25 ppm ammonia slip. Ammonia in the waste gas stream may impact plume visibility. Another concern when using the SCR catalyst is the oxidation of flue gas SO₂ to SO₃. The SO₃ will then combine with water vapor to form sulfuric acid mist. Sulfuric acid mist could cause downstream component corrosion and is an aerosol particle that also impacts visibility. SCR systems may increase refinery fuel gas consumption by approximately 1.5% in addition to that required to vaporize aqueous NH₃.

Anhydrous ammonia requires permitting and personnel trained in its safe use. Anhydrous ammonia is stored as a liquid under pressure and upon uncontrolled release, will freeze exposed skin and chemically burn tissue. On the other hand, 19% aqueous ammonia does not require permits, nor does it pose anhydrous ammonia's safety hazards.

Dry urea can be converted on-site to ammonia using Hamon Research – Cottrell's U₂A™ patented system (U.S. Patent No. 6,077,491) which generates ammonia on-site for various processes, such as SCR or SNCR. Benign dry urea is transported to the site and mixed with water to form an aqueous solution. The solution is then fed to an in-line hydrolysis reactor where steam or electricity heats the reactants to 280° to 310°F. The product gas is a mixture of ammonia (NH₃), carbon dioxide (CO₂) and water vapor (H₂O) and may be used in any application where ammonia is required (such as SCRs or SNCRs.) Dry urea is an expensive proposition for smaller scale systems and may increase CO₂ emissions.

Typical SCR NO_x removal efficiencies range from 70 to 90% removal.¹ The present study uses 90% NO_x removals in the EPA cost portion. A 90% average estimated NO_x reduction was used in the vendor cost factor portion. These reductions were found by using the EPA-AP 42 estimated emission factor, fuel gas compositions, and flue gas temperatures. Therefore, actual NO_x reductions may differ from the estimated reduction.

Non-Thermal Plasma

The LoTOx™ process is available from BELCO under license from BOC. It uses ozone to convert NO_x to a higher oxidation state that is subsequently hydrolyzed and removed with a

¹ (EPA, 1993)

caustic scrubber. Specifically, injected ozone (O_3) preferentially oxidizes the NO_x to N_2O_5 . With the flue gas fully saturated, the N_2O_5 combines with water vapor in the flue gas to form nitric acid mist (HNO_3). Following the reaction zone, multiple spray levels scrub the flue gas to absorb nitric acid mist and un-reacted ozone in the final step. The reported LoTOxTM NO_x removal efficiency is 80%.¹

Ozone is generated using industrial-grade oxygen and “corona discharge” (non-thermal plasma). Temperature differences in the flue gas do not affect LoTOxTM. Refinery Operations can optimize the combustion process to achieve the most cost-efficient burner conditions without considering NO_x generation; continuous NO_x monitors within the system provide the ozone flow rates necessary to achieve a set stack NO_x level.

LoTOxTM systems require a downstream caustic scrubber. The scrubber must handle the pressure drops induced by the upstream LoTOxTM system. The LoTOxTM system would create pressure differences that would interfere with the operation of the pressure-sensitive venturis on the existing ExxonMobil scrubber. The area following the existing demisters in the existing scrubber is the first zone where it is practical to inject ozone without making major changes to the current scrubber design that might affect the current operation and performance. However, due to the creation of nitric acid mist, different metallurgy may be required. Nitric acid mist, if not removed with a caustic scrubber, could act to increase particulate matter since it is an aerosol particle. Therefore, a caustic scrubber would have to be added downstream of the existing ExxonMobil scrubber.

LoTOxTM is only being considered for control of NO_x emissions from F-304. If installed, the existing ExxonMobil scrubber would be left intact to a point just after the tower diameter transitions down to the stack diameter. At this point, ozone could be injected and the flue gas would travel down through a new alloy duct to a new upflow EDV[®]-1000 scrubber. This scrubber should be located adjacent to the existing scrubber to minimize the cost of the duct work. The new duct and upflow scrubber would provide the necessary retention time for the oxidation reactions.

The upflow scrubber would also require liquid to gas contact for scrubbing the nitric acid mist, removal of excess water, and an integral stack to discharge flue gas to the atmosphere. Caustic scrubbers are reportedly prone to operational issues, such as plugging nozzles and shifts in pH, and could lead to the inadvertent release of a nitric acid mist. Un-reacted nitric acid mist not removed in the caustic scrubber would form aerosol particles and impact visibility. Proper reagent selection and operational controls on the caustic scrubber are paramount.

Currently, EDV[®] Wet Scrubbing systems with the LoTOxTM process for NO_x control are being installed on five FCCUs. One of these is already in operation and the remainder will be commissioned throughout 2007.

¹ (EPA, 2005)

Sulfur Recovery Unit with Tail Gas Treatment

A method for reducing NO_x emissions from the Cat Cracker CO Boiler F-304 is to discontinue burning ammonia-rich vent gas from the sour water stripper's (SWS) second stage. This can be achieved by routing the vent stream instead to a Sulfur Recovery Unit (SRU) where the ammonia would be converted to nitrogen gas, rather than nitrogen oxides. The Tesoro Refinery currently routes its H₂S acid gas stream to the SRU and to the sulfuric acid plants at the neighboring General Chemical facility.

In addition to the fact that General Chemical's SRU has no spare capacity, General Chemical cannot handle the ammonia-rich second stage gases because of nitric acid generation at the acid plants. Therefore, the ability to remove this ammonia-rich SWS vent gas stream from F-304 and treat it elsewhere could only be achieved by constructing a new and independent SRU.

Tesoro has evaluated the cost of a new 50-ton per day SRU and associated equipment needed to permit, construct, and operate the facility including the following equipment and modifications:

- Tail Gas Treatment Unit (TGU)
- Sulfur loading rack
- Storage tank
- Sour water stripper manifold revisions
- Flare.

The total installed capital cost is estimated (-50/100%) at \$58 million. A NO_x reduction on the order of 30% would be expected at F-304 after implementing the SRU/TGU system.

Retrofit Technology Summary

Table 4 presents a summary of the retrofit technologies considered in the present study.

Table 4. Retrofit Technology				
Technology	Manufacturer	Description	NO _x Reduction	
			EPA	Vendor
Flue Gas Recirculation	NA	Recycles 15 to 30% of inert flue gas to the primary combustion zone.	30%	-
Low-NO _x Burner	John Zink (SFG/PSFG Retrofit Kit) & Todd Combustion	Burner upgrade kit includes tile, cone extension, primary riser, four fuel gas tips.	40% staged air 60% staged fuel	28-66%
Ultra-Low-NO _x Burner	John Zink (Coolstar Burner)	Compact size, short flame, high turndown capabilities	75%	73%
NO _x Tempering	Peerless Manufacturing Group	Patented process of targeted water injection into the flame of a burner to reduce NO _x formation. Cons: increased fuel use, over-pressurized fire box, limited installations.	-	30-35%
SNCR (Selective Non-Catalytic Reduction)	Peerless Manufacturing Group	19% aqueous ammonia injection into radiant and convective regions of firebox. (1,600 – 2,200°F) Cons: Ammonia slip, increased fuel use.	50%	35-40%

Table 4. Retrofit Technology				
Technology	Manufacturer	Description	NO _x Reduction	
			EPA	Vendor
SCR (Selective Catalytic Reduction)	CRI Catalyst	19% aqueous ammonia injection and catalyst. (470-510°F and 600-750°F), low temperature pelletized extrudate catalyst. Cons: Ammonia slip, increased fuel use, pressure drop, catalyst disposal.	90%	90%
LoTOx (Non-Thermal Plasma)	Available through BELCO under License from BOC	Uses ozone to convert NO _x to higher oxidation state which is subsequently hydrolyzed and removed with a caustic scrubber. Cons: High power consumption, creates pressure drops and incompatible when located upstream of ExxonMobil WGS due to pressure sensitive venturis. Potential for nitric acid mist.	-	80%
Sulfur Recovery Unit with Tail Gas Treatment	Not Identified	NO _x emissions from CO Boiler F-304 can be reduced by discontinuing the burning of ammonia-rich sour water stripper vent gas. Routing the vent gas to an SRU, where ammonia is converted to nitrogen gas, is an identified option.	-	30%

Step 2 – Eliminate Technically Infeasible Options

Flue Gas Recirculation

Flue gas recirculation (FGR) is not an appropriate retrofit technology for F-304, CO Boiler No. 2, because consistent and high fire box temperatures are required to achieve the conditions necessary for CO-containing regen flue gas combustion. In addition, field experience has shown that flame outs have occurred in boilers with 30% flue gas recirculation.

Given that FGR has been used on only a few fired heaters, it has not been considered for use on the process heaters in the present study.¹ Heaters with burners closer than three feet cannot physically install FGR and associated piping. Tesoro regards FGR at process heaters an unacceptable safety risk due to the potential for the formation of explosive gas mixtures if a heater tube should fail. Few applications have been made to refinery process heaters due to this risk. Therefore, this technology was not explored.

FGR is not applicable to flares. For these reasons, FGR has been rejected for all of the sources.

Low-NO_x and Ultra-Low-NO_x

Due to low furnace temperatures, John Zink recommends installing Reed walls in conjunction with ULNB in sources F-6601, F-6653, and F-6654. In sources F-6600, F-6601, and F-6602, John Zink recommends increasing the number of burners from 4 to 5, with lower heat release per burner due to flame lengths versus heater height.

¹ (EPA, 1993)

Installing Reed walls and increasing the number of burners requires structural modifications to the firebox and heater floor. While these modifications are technically feasible, they are costly. The cost analysis provided with vendor quotations has been adjusted accordingly.

On Cat Cracker CO Boiler F-304, ultra-low-NO_x burners are technically infeasible because high firebox temperatures are required to combust the regen flue gas rich in carbon monoxide. Furthermore, Tesoro Operations has stressed the importance of consistent fire box temperatures. Ultra-low-NO_x burners would not provide the flexibility required to achieve a consistent fire box temperature given that varying proportions of regen flue gas and refinery fuel gas are combusted in F-304.

F-104 already has ultra-low-NO_x burners installed.

LNBS and ULNBS are not applicable to flares.

NO_x Tempering

Steam or water injection into the fire box would increase the flue gas volume contained within the firebox. This could lead to firebox over-pressurization and heater failure. In addition, lowering the flame temperature would affect the efficiency of both the heater and boilers. NO_x tempering would also interfere with the operation of F-304 in which high and consistent fire box temperatures are necessary for the combustion of CO regen flue gas. The vendor admits that NO_x tempering systems have not been installed on CO Boilers, such as F-304. For these reasons, NO_x tempering is not considered technically feasible on any of the sources.

SNCR

SNCR requires flue gas temperatures in the range of 1,600 to 2,200°F to produce NO_x reductions. With H₂ injection, the temperature range can be lowered to 1,400°F.¹ John Zink measured each source's bridgwall temperature during a burner inspection in August 2006. The bridgwall is the region where flue gases leave the heater's radiant section and enter the convection section.

Insufficient firebox temperatures lead to decreased NO_x removal and increased ammonia slip. The following heaters have insufficient firebox temperatures or economizers that significantly lower flue gas temperatures and therefore SNCR is not technically feasible:

- F-104
- F-654
- F-6601
- F-6650
- F-6651
- F-6652
- F-6653
- F-6654
- F-6655

¹ (EPA,1993)

High sulfur contents in the flue gas combined with low flue gas temperatures could lead to ammonium bisulfate formation, precipitation, and plugging of downstream components such as air preheaters or economizers where small spaces preferentially collect ammonium bisulfate. Flue gas temperatures below 450°F favor ammonium bisulfate precipitation. In the case of the F-304 CO boiler, a downstream Wet Gas Scrubber lowers the flue gas temperature to 150°F. At these temperatures, ammonium bisulfate will precipitate. However, if ammonium bisulfate precipitated, it is highly soluble in water and the scrubber water could potentially dissolve it. In solution, the ammonium bisulfate could reach a crystallization concentration if allowed to concentrate in the scrubber water system.

While flue gases may be hotter in the radiant section, bridgewall temperatures are the only data points available other than original design specifications. For the present study, the SNCR retrofit was assumed technically feasible on the F-103, F-6600, and F-6602 heaters and on the F-304 CO boiler. Source F-304 would require the use of a hydrogen gas assisted combustion system to raise the firebox temperature. SNCR is unaffected by particulate matter encountered in the F-304 CO boiler.

SNCR is not applicable to flares.

SCR

SCR requires catalyst bed temperatures of 600 to 750°F for conventional vanadium or titanium-based catalyst and from 470 to 510°F for platinum catalysts. For a given catalyst, optimum performance is achieved within 50°F of its design temperature in which flue gas O₂ concentrations are greater than 1%. Below this temperature, catalyst activity is greatly reduced and unreacted ammonia will slip through. Furthermore, temperatures above 850°F may damage the catalyst. Therefore, retrofit applications are limited by the location of a suitable temperature window. Sources F-6650/51/52/53 were investigated with the use of the low temperature catalyst and with the use of the higher temperature catalyst combined with a duct heater.

Due to catalyst temperature requirements, SCR is not technically feasible for heaters F-6600, F-6602, and F-6655.

An ExxonMobil Wet Gas Scrubber (WGS) is situated downstream of CO Boiler No. 2, F-304. Flue gas from the FCCU contains FCCU catalyst fines. These catalyst fines would foul a catalyst bed, causing enough backpressure on the firebox to cause a boiler shutdown. Furthermore, insufficient vertical stack height precludes the placement of an SCR catalyst bed upstream of the Wet Gas Scrubber. An SCR catalyst bed cannot be placed in the WGS or downstream of the WGS due to water and water vapor presence. For these reasons, SCR is technically infeasible on CO Boiler No. 2, F-304.

SCR is not applicable to flares.

LoTOx™

The LoTOx™ system (BELCO) requires a downstream caustic scrubber that is not pressure sensitive. The LoTOx™ system cannot be placed upstream of the existing ExxonMobil WGS

because the WGS uses pressure-sensitive venturitis to remove particulates. Therefore, the LoTOx™ system would have to be located downstream of the ExxonMobil scrubber requiring a non-pressure-sensitive EDV®-1000 scrubber addition. Given the large capital cost of a scrubber, the LoTOx™ system is only being considered for installation on CO Boiler No. 2, F-304.

Sulfur Recovery Unit with Tail Gas Treatment

Sulfur Recovery Unit with Tail Gas Treatment was only considered for source F-304 to evaluate the NO_x reduction option of removing the SWS vent gas stream currently combusted in this boiler.

Table 5 presents a summary of the technically feasible options for reducing NO_x for each source.

Source F-	NO _x Reduction Technology							
	FGR	Low-NO _x Burners	Ultra-Low-NO _x Burners	NO _x Tempering	SNCR	SCR	LoTOx Non-Thermal Plasma	SRU/TGU
103	No	Yes	Yes	No	Yes	Yes	No	No
104	No	-	Already equipped	No	No	Yes	No	No
304	No	Yes	No High firebox temps. required	No	Yes	No High particulate matter, excessive press. drop	Yes	Yes
654	No	Yes	Yes	No	No	Yes	No	No
6600	No	Yes	Yes	No	Yes	No	No	No
6601	No	Yes	Yes	No	No	Yes	No	No
6602	No	Yes	Yes	No	Yes	No	No	No
6650/51/52/53	No	Yes	Yes	No	No	Yes	No	No
6654	No	Yes	Yes	No	No	Yes	No	No
6655	No	Yes	Yes	No	No	No	No	No
Flare X-819	No	No	No	No	No	No	No	No

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Emissions data used in the present study and subsequent cost analysis were compiled from heater/boiler use for the years 2003, 2004, and 2005. Refinery fuel gas use, heating value, and EPA AP-42 emission factors established baseline NO_x emissions. Source testing data established NO_x emissions on F-304 (CO Boiler No. 2).

Table 6 contains a list of the control technology maximum NO_x reductions used in EPA cost calculations.

Source F-	NO _x Percent Reductions											
	LNB Staged Air	LNB Staged Fuel	ULNB	SNCR	LNB Staged Air + SNCR	LNB Staged Fuel + SNCR	ULNB + SNCR	SCR	LNB Staged Air + SCR	LNB Staged Fuel + SCR	ULNB + SCR	LoTOx
103	40	60	75	50	70	80	87.5	90	94	96	97.5	NA
104	NA	NA	NA	No	NA	NA	NA	90	NA	NA	97.5	NA
304	No	NA ¹	No	50	NA	NA ²	NA	No	NA	NA	NA	80
654	40	60	75	No	NA	NA	NA	90	94	96	97.5	NA
6600	40	60	75	50	70	80	87.5	No	NA	NA	NA	NA
6601	40	60	75	No	NA	NA	NA	90	94	96	97.5	NA
6602	40	60	75	50	70	80	87.5	No	NA	NA	NA	NA
6650	40	60	75	No	NA	NA	NA	90	94	96	97.5	NA
6651	40	60	75	No	NA	NA	NA	90	94	96	97.5	NA
6652	40	60	75	No	NA	NA	NA	90	94	96	97.5	NA
6653	40	60	75	No	NA	NA	NA	90	94	96	97.5	NA
6654	40	60	75	No	NA	NA	NA	90	94	96	97.5	NA
6655	40	60	75	No	NA	NA	NA	No	NA	NA	NA	NA
Flare	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Source: *Alternative Control Techniques Document – NO_x Emissions from Process Heaters* EPA, 1993. EPA-453/R-93-034.

Source: *Using Non-Thermal Plasma to Control Air Pollutants*. EPA and the Clean Air Technology Center (CATC). EPA-456/R-05-001. February 2005.

Notes:

- 1 During the short and infrequent periods when F-304 is used as a conventional boiler (i.e., no burning of Cat Cracker CO gas), burner NO_x reduction based on refinery fuel gas combustion only would be 34.5% per EPA guidance.
- 2 EPA guidance suggests a reduction of 67% for this combination of technologies. However, review shows that this is a value associated with operation as a conventional boiler.

Table 7 contains vendor-estimated NO_x reductions. Vendor estimates were solicited for those sources that emitted NO_x at a high enough rate to make the control technologies potentially feasible on a dollar per ton NO_x removal basis. EPA cost estimates were used as a preliminary and conservative screening tool to determine initial cost effectiveness.

Source F-	NO _x Percent Reductions						
	Burners	SNCR	Burners + SNCR	SCR	Burners + SCR	LoTOx	SRU/TGU
103	66.2	40	77	90	96	-	-
104	-	-	-	-	-	-	-
304 ¹	5.5	35	39	-	-	80	30
654	73.5	-	-	-	-	-	-
6600	73.5	-	-	-	-	-	-
6601	73.5	-	-	-	-	-	-
6602	73.5	-	-	-	-	-	-
6650/51/ 52/53	72.4	-	-	90	97	-	-
6654	73.5	-	-	-	-	-	-
6655	28.6	-	-	-	-	-	-
Flare	-	-	-	-	-	-	--

Notes: 1 F-304 burner NO_x reduction based on combustion of refinery fuel gas and CO gas combustion.

Step 4 – Evaluate Impacts and Document Results

Compliance Costs

Anvil conducted a source-by-source cost effectiveness analysis for each technically feasible retrofit technology where operating data and cost estimates were available from EPA sources and from vendors. To conduct the cost analyses, Anvil first identified design parameters and assumptions for each control technology, as summarized in Table 8.

Table 8. Design Parameters and Assumptions for Each Control Technology			
Control Device	Design Parameters	Assumptions	
		(EPA Cost Analysis)	Vendor
Low-NO _x Burners		<ul style="list-style-type: none"> - Number of burners after retrofit is the same as before. - Costs do not include fire box modifications. - Maintenance costs are 2.75% of installed costs - Includes conversion from natural to mechanical draft 	<ul style="list-style-type: none"> - Low-NO_x burners on sources F-103, F-304, F-6650, F-6651, F-6655. - Low-NO_x burners on F-304 would reduce NO_x from refinery fuel gas combustion only and not from CO regen flue gas.
Ultra-Low-NO _x Burners		<ul style="list-style-type: none"> - Number of burners after retrofit is the same as before. - Costs do not include fire box modifications. - Maintenance costs are 2.75% of installed costs - Conversion from natural draft to mechanical draft is included 	<ul style="list-style-type: none"> - ULNB on F-654, F-6600, F-6601, F-6602, F-6652, F-6653, F-6654 - Reed walls required in sources F-6601, F-6653, & F-6654. - Increase no. of burners from 4 to 5 in sources F-6600, F-6601, & F-6602. - Burner weights need to be evaluated.
Selective Non-Catalytic Reduction	<ul style="list-style-type: none"> - Ammonia to NO_x molar ratio of 2:1 - Maximum NO_x reduction with 25 ppm NH₃ slip 	<ul style="list-style-type: none"> - Loss of thermal efficiency estimated to require a 0.3% increase in fuel firing - NH₃ cost (\$0.125/lb) - Refinery fuel cost \$3.63/MMBtu - Additional energy consumption from NH₃ vaporizer - Conversion from natural draft to mechanical draft is included 	<ul style="list-style-type: none"> -19% aqueous ammonia - Stand alone SNCR heater control system ~\$80,000. - Less than 25 ppm NH₃ slip.
Selective Catalytic Reduction	<ul style="list-style-type: none"> - Ammonia to NO_x molar ratio of 1:1 - Maximum NO_x reduction with 25 ppm NH₃ slip 	<ul style="list-style-type: none"> - Loss of thermal efficiency requires an estimated 1.5% increase in fuel firing - NH₃ cost (\$0.125/lb) - Refinery fuel cost \$3.63/MMBtu - Additional energy consumption from NH₃ vaporizer - Conversion from natural draft to mechanical draft is included 	<ul style="list-style-type: none"> -19% aqueous ammonia with vaporizer (6kW/GPH) -Induced draft fan 32/72 kW - Stand-alone SCR heater control system ~\$80,000. - Less than 25 ppm NH₃ slip.
LoTOx	<ul style="list-style-type: none"> - 20 ppm stack NO_x 		<ul style="list-style-type: none"> - O₃ generation (80 STPD O₂, \$180/ton O₂) - 3450 kW power consumption - Reagent consumption (247 lb/hr, \$480/dry-short-ton NaOH)

Table 8. Design Parameters and Assumptions for Each Control Technology			
Control Device	Design Parameters	Assumptions	
		(EPA Cost Analysis)	Vendor
SRU/TGU	<ul style="list-style-type: none"> - Discontinue burning ammonia-rich sour water stripper vent gas. - Route the vent gas to an SRU, where ammonia is converted to nitrogen gas. 	- No information available at this time	- Not Identified

Anvil used EPA cost factors and vendor quotations to analyze costs. In the EPA cost analysis, published EPA NO_x removal efficiencies were used. Dollars were escalated from 1991 to 2007 U.S. dollars. In the second cost analysis, Anvil estimated total installed costs using equipment vendors' design specifications and vendor quotations. These estimates included site-specific factors that may significantly affect the retrofit costs. Site-specific factors included new stacks, stack access platforms, and continuous emissions monitoring equipment. Annualized costs were estimated using a capital recovery factor calculated using an interest rate of 7%, a 10-year retrofit equipment life for burners, and a 15-year retrofit equipment life for all other technologies. See Appendix B for EPA Capital and Maintenance Cost Calculations for LNB, ULNB, SNCR, and SCR. See Appendix C for Economic Analysis Assumptions.

The most stringent emission control level that the technology is capable of achieving was used for the EPA case, per the requirements set out in conducting a BART analysis. NO_x removal rates (tpy), NO_x stack concentrations (ppm-v), and emission factors (lb/MMBtu) were calculated for each retrofit technology. See Appendix C for EPA removal rates, stack concentrations, and emission factors. See Appendix D for Vendor Economic Analysis and Assumptions including removal rates, stack NO_x concentrations, and emission factors. See Appendix E for Vendor Design Quotations.

Next, Anvil prepared a dominant controls diagram for each source. The dominant set of control options is represented on a least cost envelope diagram where you get increasing NO_x reduction for the least annualized cost. Increasing total annualized costs (dollars per year) were plotted against increasing emissions reduction (tons per year). These diagrams show the most cost effective NO_x reduction technologies on the right side of the chart when they are fitted with a smooth curve. See Appendix C for EPA Dominant Control Diagrams. See Appendix D for Vendor Dominant Control Diagrams.

EPA

Dominant NO_x reduction costs for sources F-103, F-304, F-6650, and F-6651 that contribute most of the BART-eligible NO_x emissions ranged from \$2,400 to \$13,300 per ton in 2007 U.S. dollars. NO_x reduction costs for the remaining sources (excluding X-819) range from \$13,650 to \$480,000 per ton. See Appendix C, Tables C.1 through to C.13, for the following information:

- Cost estimates
- Dominant control diagrams
- Individual source emission factors

- NO_x stack concentrations
- NO_x removal rates
- Total annualized costs
- Total cost effectiveness (dollars per ton)
- Incremental cost effectiveness (dollars per ton).

Please note that source X-819 is not included in the cost analysis due to the absence of technically feasible retrofit technologies.

For a summary comparing all the selection factors for the dominant control technologies, including cost effectiveness, see Table 9 in the *Step 6 - Select BART* section.

Vendor

Vendor quotations were received for the following NO_x control technologies:

- Burners
- SNCR
- SCR
- LoTO_xTM.

Vendor quotations were requested for those sources that potentially represent a viable retrofit application based on pre-retrofit NO_x emissions and retrofit costs on a dollars per ton basis (estimated using EPA cost factors):

- Burner quotations were received for all sources; however, since F-104 is already fitted with ultra-low-NO_x burners, burner retrofit on this source was not considered appropriate. Burners were considered on sources F-6650/51/52/53 combined because the four sources share two common stacks.
- SNCR Technology was considered on sources F-103 and F-304.
- SCR Technology was considered on sources F-6650/51/52/53 combined and on F-103. Sources F-6650/51/52/53 share two common stacks, potentially allowing all of the emission sources to be treated using one SCR catalyst housing. This scenario is reported in the vendor-specific cost factor portion detailed in Appendix D (F-6650/51/52/53 combined SCR). Due to the common stack on sources F-6650/51/52/53, burners plus SCR were considered on a combined basis.
- LoTO_xTM and SRU/TGU technologies were considered for source F-304 only.

Dominant NO_x reduction technologies for sources F-103, F-304, F-6650/51/52/53, which contribute most of the BART-eligible NO_x emissions, ranged from \$3,349 to \$8,107 per ton in 2007 U.S. dollars. NO_x reduction costs for the remaining sources (excluding F-104 and X-819) range from \$11,069 to \$92,695 per ton. See Appendix D, Tables D.1 through to D.9, for the following information:

- Cost estimates
- Dominant control diagrams
- Individual source emission factors

- NO_x stack concentrations
- NO_x removal rates
- Total annualized costs
- Total cost effectiveness (dollars per ton)
- Incremental cost effectiveness (dollars per ton).

Note that source F-104 is not included in the vendor cost analysis due to the ultra-low-NO_x burners already equipped on F-104 and the expensive cost (\$/ton) for SCR technology estimated with the US-EPA cost factors.

There were no technically feasible retrofit technologies for X-819.

For a summary comparing all the selection factors for the dominant control technologies, including cost effectiveness, see Table 10 in the *Step 6 - BART* section.

Air Impacts

LNBs and ULNBs

LNBs and ULNBs are not expected to increase CO emissions. EPA-42 Emission Factors for the relevant sources are 0.082 lb/MMBtu. The vendor-guaranteed CO emission factor of 0.006 lb/MMBtu was received for the sources. The vendor-guaranteed CO emission factor is valid for temperatures above 1,200°F.

NO_x emissions can be reduced by optimizing the level of excess air. Improper control can cause incomplete combustion and result in increased CO and unreacted hydrocarbon emissions.¹

SNCR

Unreacted ammonia in the emissions is known as slip, and is potentially higher in SNCR systems than in those fitted with a catalyst (see SCR below) due to higher reactant injection ratios (2:1). Ammonia slip poses a safety and environmental concern. Ammonia in the waste gas stream may impact plume visibility.

Unreacted ammonia in the emissions can combine with available SO₃ to form ammonium bisulfate PM. Typically, 100% of slipped ammonia will react with the available SO₃ to form ammonium bisulfate particulate matter.²

Approximately 5% of the untreated nitrogen oxides will form HNO₃. HNO₃ will react with slipped ammonia and may form NH₄NO₃ particulate matter. However, formation of HNO₃ rather than NH₄NO₃ is more likely below the dew point.

Nitrous oxide (N₂O) is a by-product formed during SNCR. Nitrous oxide, a greenhouse gas, does not contribute to ground level ozone or acid formation.³

¹ (EPA, 1993)

² (Murphy, 2007)

³ (EPA, 2003)

SCR

Ammonia slip poses a safety and environmental concern. In the present study, vendors projected potential NO_x reductions with not more than 25 ppm ammonia slip. Ammonia in the waste gas stream may impact plume visibility. The SCR catalyst will oxidize a portion of the flue gas SO₂ to SO₃, with conversion ranging from 3 to 10%. The SO₃ will then combine with available ammonia slip to form ammonium bisulfate PM. Typically, 100% of slipped ammonia will react with the available SO₃ to form ammonium bisulfate particulate matter.¹

Approximately 5% of the untreated nitrogen oxides will form HNO₃. HNO₃ will react with slipped ammonia and may form NH₄NO₃ particulate matter. However, formation of HNO₃ rather than NH₄NO₃ is more likely below the dew point.

In the absence of slipped ammonia, the SO₃ will combine with water vapor to form sulfuric acid mist. Sulfuric acid mist could cause downstream component corrosion and is an aerosol particle that also impacts visibility.

LoTOx™

Nitric acid is generated as a byproduct of the LoTOx™ process. A caustic scrubber would be required to remove the nitric acid from the flue gas. Caustic scrubbers are reportedly prone to operational issues, such as plugging nozzles and shifts in pH, and could lead to the inadvertent release of a nitric acid mist. Unreacted nitric acid mist not removed in the caustic scrubber would form aerosol particles and impact visibility.

Energy Impacts

LNBS and ULNBS

Low-NO_x and ultra-low-NO_x burners are not expected to increase energy consumption.

SNCR

Selective Non-Catalytic Reduction is noted to increase refinery fuel gas consumption by 0.3%.² An ammonia vaporizer will increase energy consumption by 0.44 kW/MMBtu/hr³ (approximate), which was used in the EPA cost estimates. Vendor quotations suggest that an ammonia vaporizer for SNCR was not necessary.

To reach appropriate firebox temperatures, hydrogen fuel gas assisted combustion is required for source F-304.

SCR

SCR requires forced draft fans to overcome the pressure drops across the catalyst beds. The fans range in size from 32.4 to 72 kW. An ammonia vaporizer will increase energy consumption by approximately 0.44 kW/MMBtu/hr,³³ which was used for the EPA cost estimates. The increase in energy consumption from the ammonia vaporizer that was used in the vendor cost estimate

¹ (Murphy, 2007)

² (EPA, 2005)

³ (EPA, 1994)

was 6 kW/gal/hr of ammonia. The vaporized ammonia injection system requires a dilution air fan that would consume approximately 6.7 kW of power. All vendor power consumptions were estimated based on continuous normal operating duty.

To reach appropriate catalyst face temperatures for a conventional catalyst, a duct burner would be required in the case of sources F-6650/51/52/53. These heaters share a common economizer; therefore, any consideration of SCR involves combining the flue gases from all four. The duct burner would fire approximately 14 MMBtu/hr of refinery fuel gas in this situation. If a low temperature catalyst (i.e., Pt instead of V/Ti) were selected for sources F-6650/51/52/53, a duct burner would not be required. Low temperature catalyst is well suited to the flue gas temperatures found at F-6650/51/52/53 and serves as the basis for the SCR feasibility analysis.

LoTOx™

LoTOx™ generates ozone from a corona discharge in the presence of oxygen. The electrical power requirements for the LoTOx™ system would be close to 3,450 kW. The system would consume approximately 80 STPD (short tons per day) of oxygen. The caustic scrubber would consume 247 lb/hr of sodium hydroxide. The 50% sodium hydroxide/water solution would be delivered by truck approximately 92 times per year.

SRU/TGU

In Claus Sulfur Recovery Units, hydrogen sulfide gas is converted to elemental sulfur. In this process, some of the hydrogen sulfide gas is burned in a reducing atmosphere. The refinery uses the heat released from this combustion to generate steam used within the refinery.

Non-Air Quality Environmental Impacts

SNCR and SCR

The handling of 19% aqueous ammonia including transport could have a detrimental environmental impact if a spill should occur. Aqueous ammonia would be used in both the SNCR and SCR systems. However, the consequences of a spill associated with aqueous ammonia are far less than those associated with anhydrous ammonia. Aqueous ammonia storage tanks and piping components all have potential ammonia emissions. An ammonia spill and release is an EPA toxic release and potential impacts must be reported to the EPA.

Both the SNCR and SCR systems proposed in the present study are designed to achieve maximum NO_x reductions while limiting ammonia slip to 25 ppm. As removal rate increases, so does potential ammonia slip. Ammonia slip may impact plume opacity.

The SCR systems would use a low-temperature catalyst. This catalyst is a pellet extrudate and not a honeycomb design. The pressure drop across the catalyst bed would be approximately 1 to 2 inches water column. The catalyst is guaranteed for 5 years, but field experience suggests that with refinery fuel gas, a catalyst life of 6 years is possible. The catalyst would have to be disposed of in an appropriate manner.

LoTOx™

The LoTOx™ system will consume approximately 80 STPD of oxygen, 2,800 gpm of cooling water, 247 lb/hr of reagent (NaOH) and will add approximately 525 lb/hr of NaNO₃ to the water discharged from the EDV®-1000 scrubber. Approximately 92 times a year, a truck would deliver a 50% solution of NaOH/water to the site. The flow rate of scrubber discharge water is estimated at 20 to 50 gpm (from vendor quotation). The process creates a nitric acid mist as an intermediary chemical. The mist would be subsequently removed in the caustic scrubber; however, if the caustic scrubber should fail, then nitric acid mist would escape to the atmosphere. Improper pH control or plugged nozzles are common modes of caustic scrubber failure.

Step 5 - Remaining Useful Life

Tesoro has no long range or short term plans to replace any of the sources. Table 1 lists the year of construction for each BART-eligible source.

Step 6 - Select BART

EPA Top-Down BART Selection

Table 9 contains a comparison matrix for the dominant control technologies (data extracted from tables in Appendix C).

Table 9. EPA Dominant Control Technologies Comparison

Source F-	Dominant Control Alternatives	EPA Reported Reduction (%)	Annual NO _x Emission Rate ¹ (tpy)	Emissions Factor (lb/MMBtu) Gross	NO _x Concentration ² (ppm-v)	NO _x Removal Rate ³ (tpy)	Total Capital Cost	Total Annualized Cost ⁴ (\$)	Total Cost Effectiveness ⁵ (\$/ton)	Incremental Cost Effectiveness ⁶ (\$/ton)	Adverse Environmental Impact ⁷ (yes/no)	Energy Consumption (MW-hr/yr)
103	No Controls (baseline)		121	0.275	193	NA		NA	NA	NA	-	-
	ULNB - (75%)	75	30	0.069	48	91	\$1,474,000	\$309,443	\$3,398	-	No	NA
	SNCR (50%) ⁸	50	61	0.138	96	61	\$1,699,000	\$387,143	\$6,376	-	Yes	368
	ULNB + SNCR (87.5%)	87.5	15	0.034	24	106	-	\$696,586	\$6,556	\$25,504	Yes	368
	SCR (90%) ⁸	90	12	0.028	19	109	\$4,840,000	\$1,032,141	\$9,444	-	Yes	368
	ULNB + SCR (97.5%)	97.5	3	0.007	5	118	-	\$1,341,584	\$11,331	\$53,114	Yes	368
104	Existing ULNB		4.7	0.013	48	NA	-	NA	NA	NA	-	NA
	SCR (90%)	90	0.5	0.001	5	4	\$2,634,000	\$499,850	\$117,044	-	Yes	51
304	No Controls (baseline)		836	1.71	-	NA		NA	NA	NA	-	NA
	SNCR - (50%)	50	418	0.86	-	418	\$2,741,000	\$1,004,437	\$2,403	-	Yes	700
654	No Controls (baseline)		2.6	0.098	52	NA		NA	NA	NA	-	-
	ULNB (75%)	75	0.7	0.025	13	2	\$336,000	\$70,456	\$36,131	-	No	Minimal
	SCR (90%) ⁸	90	0.3	0.010	5	2	\$1,309,000	\$244,184	\$104,352	-	Yes	26
	ULNB + SCR (97.5%)	97.5	0.1	0.002	1	3	-	\$314,641	\$124,119	\$417,409	Yes	26
6600	No Controls (baseline)		18.9	0.098	61	NA		NA	NA	NA	-	-
	SNCR - (50%)	50	9	0.049	30	9	\$1,111,000	\$224,712	\$23,779	-	Yes	157
	ULNB - (75%)	75	5	0.025	15	14	\$1,451,000	\$304,630	\$21,491	\$16,914	No	NA
	ULNB + SNCR (87.5%)	87.5	2	0.012	8	17	-	\$529,342	\$32,009	\$95,116	Yes	157
6601	No Controls (baseline)		19.8	0.098	61	NA		NA	NA	NA	-	NA
	ULNB - (75%)	75	5	0.025	15	15	\$1,627,000	\$341,483	\$22,995	-	No	NA
	SCR (90%)	90	2	0.010	6	18	\$3,247,000	\$652,890	\$36,638	\$104,851	Yes	164
	ULNB + SCR (97.5%)	97.5	0.5	0.002	2	19	-	\$994,373	\$51,509	\$229,955	Yes	164
6602	No Controls (baseline)		1.3	0.098	12	NA		NA	NA	NA	-	-
	SNCR - (50%)	50	0.7	0.049	6	0.7	\$1,141,000	\$204,213	\$314,174	-	Yes	14
	ULNB - (75%)	75	0.3	0.025	3	1.0	\$1,627,000	\$341,483	\$350,238	\$422,367	No	NA
	ULNB + SNCR (87.5%)	87.5	0.2	0.012	2	1.1	-	\$545,696	\$479,732	\$1,256,696	Yes	14

Table 9. EPA Dominant Control Technologies Comparison

Source F-	Dominant Control Alternatives	EPA Reported Reduction (%)	Annual NO _x Emission Rate ¹ (tpy)	Emissions Factor (lb/MMBtu) Gross	NO _x Concentration ² (ppm-v)	NO _x Removal Rate ³ (tpy)	Total Capital Cost	Total Annualized Cost ⁴ (\$)	Total Cost Effectiveness ⁵ (\$/ton)	Incremental Cost Effectiveness ⁶ (\$/ton)	Adverse Environmental Impact ⁷ (yes/no)	Energy Consumption (MW-hr/yr)
6650	No Controls (baseline)		144.7	0.28	172	NA		NA	NA	NA	-	-
	ULNB - (75%)	75	36.2	0.07	43	109	\$2,054,000	\$431,162	\$3,973	-	No	NA
	SCR - (90%)	90	14.5	0.03	17	130	\$5,079,000	\$1,103,498	\$8,473	\$30,976	Yes	368
	ULNB + SCR (97.5%)	97.5	3.6	0.01	4	141	-	\$1,534,660	\$10,878	\$39,729	Yes	368
6651	No Controls (baseline)		104.7	0.28	171	NA		NA	NA	NA	-	-
	ULNB - (75%)	75	26.2	0.07	43	79	\$1,393,000	\$292,300	\$3,722	-	No	NA
	SCR - (90%) ⁸	90	10.5	0.03	17	94	\$5,079,000	\$1,061,053	\$11,260	-	Yes	307
	ULNB + SCR (97.5%)	97.5	2.6	0.01	4	102	-	\$1,353,353	\$13,257	\$45,041	Yes	307
6652	No Controls (baseline)		17.1	0.098	61	NA		NA	NA	NA	-	-
	ULNB - (75%)	75	4.3	0.025	15	13	\$834,000	\$175,007	\$13,646	-	No	NA
	SCR (90%) ⁸	90	1.7	0.010	6	15	\$3,219,000	\$640,203	\$41,599	-	Yes	140
	ULNB + SCR (97.5%)	97.5	0.4	0.002	2	17	-	\$815,210	\$48,895	\$166,394	Yes	140
6653	No Controls (baseline)		13.0	0.098	61	NA		NA	NA	NA	-	-
	ULNB - (75%)	75	3.3	0.025	15	10	\$725,000	\$152,141	\$15,604	-	No	NA
	SCR - (90%)	90	1.3	0.010	6	12	\$2,289,000	\$454,296	\$38,829	\$154,951	Yes	105
	ULNB + SCR (97.5%)	97.5	0.3	0.002	2	13	-	\$606,438	\$47,845	\$156,042	Yes	105
6654	No Controls (baseline)		10.2	0.098	59	NA		NA	NA	NA	-	-
	ULNB - (75%)	75	2.6	0.025	15	8	\$564,000	\$118,444	\$15,483	-	No	NA
	SCR - (90%) ⁸	90	1.0	0.010	6	9	\$2,064,000	\$404,692	\$44,084	-	Yes	83
	ULNB + SCR (97.5%)	97.5	0.3	0.002	1	10	-	\$523,135	\$52,603	\$176,336	Yes	83
6655	No Controls (baseline)		3.3	0.098	55	NA		NA	NA	NA	-	-
	LNB - Staged fuel (60%)	60	1.3	0.039	22	2.0	\$461,000	\$96,661	\$48,818	-	No	NA
	ULNB - (75%)	75	0.8	0.025	14	2.5	\$472,000	\$99,116	\$40,047	\$4,961	No	NA

- Notes: 1 Calculated from literature emission factors.
2 Concentration at 3% O₂.
3 Calculated by subtracting the controlled NO_x emission rate for each option from the baseline emission rate.
4 From associated control option spreadsheet.

- 5 Calculated by dividing the total annualized cost by the NO_x removal rate.
6 Calculated by dividing the difference in annualized cost for the control option and the preceding most effective control option by the difference in emissions reduction resulting from the respective alternatives.
7 There is a chance of ammonia slip, typically 25 ppmv.
8 Non-dominant control technology is included in Table 9 for information only.

The EPA economic analyses revealed that on a source-to-source comparison, similar technology had widely different costs (\$/ton of NO_x removed) because of the different BART-eligible plant-wide NO_x contributions from each source.

For example, the CO Boiler, F-304, contributes approximately 66% of total NO_x emissions from the BART-eligible sources, and sources F-103, F-6650, and F-6651 collectively contribute approximately 27%. NO_x reduction costs for these sources range from \$2,400 (F-304 SNCR) to \$13,250 per ton (F-6651 ULNB + SCR), in 2007 U.S. dollars. These four sources contribute most of the BART-eligible, plant-wide NO_x emissions and have the lowest NO_x removal costs.

Finally, the remaining 10 sources contribute only 7% of the total refinery NO_x emissions. NO_x reduction costs (excluding X-819) for these sources are prohibitively expensive and range from \$13,650 (F-6652 ULNB) to \$480,000 per ton (F-6602 ULNB + SNCR), in 2007 U.S. dollars.

Vendor Top-Down BART Selection

Table 10 contains a comparison matrix for the dominant control technologies (data extracted from tables in Appendix D).

Table 10. Vendor Dominant Control Technologies Comparison

Source F-	Dominant Control Alternatives	Vendor Estimated Reduction (%)	Annual NO _x Emission Rate ¹ (tpy)	Emissions Factor (lb/MMBtu) Gross	NO _x Concentration ² (ppm-v)	NO _x Removal Rate ³ (tpy)	Total Capital Cost	Total Annualized Cost ⁴ (\$)	Total Cost Effectiveness ⁵ (\$/ton)	Incremental Cost Effectiveness ⁶ (\$/ton)	Adverse Environmental Impact ⁷ (yes/no)	Energy Consumption (MW-hr/yr)
103	No Controls (baseline)		121	0.275	193	NA		NA	NA	NA	-	NA
	LNB ⁸	66.2	41	0.093	65	80	\$1,980,000	\$373,477	\$4,648	-	No	NA
	SCR	90.0	12	0.028	19	109	\$4,380,500	\$736,754	\$6,743	\$12,564	Yes	458
	LNB ⁸ + SCR	97	4	0.008	6	118	\$5,471,299	\$954,678	\$8,107	\$25,644	Yes	394
304	No Controls (baseline)		836	1.71	-	NA		NA	NA	NA	-	NA
	LNB ⁸	5.5	790	1.62	-	46	\$1,468,700	\$280,458	\$6,045	-	No	NA
	SNCR	35	543	1.11	-	293	\$6,260,000	\$1,326,682	\$4,534	\$4,249	Yes	5 MMBtu/hr H ₂
	LNB ⁸ + SNCR	39	514	1.05	-	323	\$7,007,000	\$1,480,954	\$4,592	\$5,160	Yes	5 MMBtu/hr H ₂
654	No Controls (baseline)		2.6	0.098	52	NA		NA	NA	NA	-	-
	ULNB ⁸	73.5	0.7	0.026	14	2	\$441,934	\$82,317	\$43,093	-	No	NA
6600	No Controls (baseline)		18.9	0.098	61	NA		NA	NA	NA	-	-
	ULNB ⁸	73.5	5.0	0.026	16	14	\$1,324,401	\$244,118	\$17,581	-	No	NA
6601	No Controls (baseline)		20	0.098	61	NA		NA	NA	NA	-	NA
	ULNB ⁸	73.5	5	0.026	16	15	\$1,353,801	\$249,480	\$17,150	NA	No	NA
6602	No Controls (baseline)		1.3	0.098	12	NA		NA	NA	NA	-	-
	ULNB ⁸	73.5	0.3	0.026	3	1.0	\$471,308	\$88,533	\$92,695	NA	No	NA
6650/ 51/52/ 53	No Controls (baseline)		279.5	0.227	152	NA		NA	NA	NA	-	NA
	LNB & ULNB ⁸	72.4	77.1	0.063	42	202	\$3,620,001	\$677,738	\$3,349	-	No	NA
	SCR ⁹	90	28	0.02	15	252	\$7,162,599	\$1,406,090	\$5,590	\$14,806	Yes	2,085
	LNB & ULNB ⁸ + SCR ⁹	97	7.7	0.01	4	272	\$8,819,798	\$1,623,962	\$5,975	\$10,767	Yes	1,402
6654	No Controls (baseline)		10.2	0.098	59	NA		NA	NA	NA	-	-
	ULNB ⁸	73.5	2.7	0.026	16	7	\$445,417	\$82,952	\$11,069	NA	No	No
6655	Controls (baseline)		3.3	0.098	55	NA		NA	NA	NA	-	-
	LNB ⁸	28.6	2.4	0.070	39	0.9	\$437,866	\$81,575	\$86,519	NA	No	No

Notes: 1 Calculated from vendor emission factors.
2 Concentration at 3% O₂.
3 Calculated by subtracting the controlled NO_x emission rate for each option from the baseline emission rate.
4 From associated control option spreadsheet.

5 Calculated by dividing the total annualized cost by the NO_x removal rate.
6 Calculated by dividing the difference in annualized cost for the control option and next most effective control option by the difference in emissions reduction resulting from the respective alternatives.
7 There is a chance of ammonia slip, typically 25 ppmv.
8 Low NO_x (LNB) or ultra-low-NO_x (ULNB) burners represent John Zink's best product offerings for NO_x reduction.
9 Estimated without the use of a duct heater (Uses low-temperature catalyst Appendix D.6.1)

Note: TIC Estimates (-50/+100%) were prepared for the following sources:

F-103	F-6601
F-304	F-6650/51/52/53
F-6600	F-6652

The following sources were estimated using installation cost factors:

F-654	F-6654
F-6602	F-6655

Source F-104 was not estimated given that EPA cost estimates were prohibitively expensive.

New stacks and stack access platforms were budgeted for each source with the exception of F-304 which only requires a stack access platform. Anvil deemed this necessary so that a continuous emission monitoring system could be outfitted within each stack. Stack modifications include the cost of fitting the new stack with an access platform. In the case of combined sources F-6650/51/52/53 with burner retrofit, two new stacks with stack access platforms were budgeted. In the case of combined sources F-6650/51/52/53 with SCR retrofit, a duct tower and single new stack with foundation were included in the budget.

Continuous emission monitoring system (CEMS) costs were estimated at \$250,000 for each source. These costs included a CEMS NO_x analyzer with sample probe and a small shelter at grade. The analyzer would be fully automated to perform required daily calibrations. The NO_x measurement and calibration results would be connected to, and recorded on, Tesoro's DCS system. An additional cost was included for an ammonia probe and analyzer for use with either the SCR or SNCR systems. In the case of combined sources F-6650/51/52/53 with burner retrofit, an additional cost was included for a flow measurement system located in the two common stacks.

Burners

A refinery fuel gas coalescer and filter was included for each source that would undergo burner retrofit. The coalescer will be mounted at grade on a concrete foundation. Piping would include a pressure safety valve and tie-in to an existing flare header.

John Zink Company provided retrofit burner specifications and budget costs. They proposed burners representing their best product offerings for the following sources:

- Low-NO_x burners for sources F-103, F-6650, F-6651, and F-6655.
- Ultra-low-NO_x burners for the following sources:

F-654	F-6652
F-6600	F-6653
F-6601	F-6654
F-6602	

See Appendix E.1 for the retrofit burner specifications and budget.

Todd Combustion provided retrofit burner specifications and budget costs for CO Boiler F-304. Four Dynaswirl Low-NO_x burners have been proposed. These burners would reduce NO_x emissions from refinery fuel gas combustion only and not from CO gas combustion.

Burner retrofit requires extensive modifications to the fireboxes, refractory, plenums, and dampers. A structural analysis would be needed to ensure that the existing source can support the retrofit burners, associated installation hardware, and Reed walls where required. The refractory would need modification to accommodate different burner diameters and would potentially need appropriate removal for potential asbestos-containing compounds. Furthermore, some sources would require the Reed wall installations due to low furnace temperatures (F-104, F-6601, F-6653, and F-6654). The Reed wall installations require modification to the sight ports and to the floor access hatch. In addition, the refractory will need modification to accommodate the Reed walls.

Prolonged use of sulfurous fuels can result in the corrosion of some components essential to the heater's structural integrity. Where the sulfur compounds in the fuel have precipitated out behind damaged refractory layers, the refractory anchors are commonly severely corroded. This allows the refractory to move away from the heater walls and the acidic deposits to attack the steel casing plate and main supporting columns. Frequently, this results in hot spots on the heater's outer casing, which can be evidenced by peeling casing paint. Anvil did not investigate the structural integrity of the heaters/boilers, nor did it investigate the condition of the refractory.

LoTOxTM

The LoTOxTM system installation would require additional costs for foundations, footings, permits, licenses, and power lines. Utility consumption includes oxygen at 80 STPD (\$180 per ton), power at 3,450 kW (\$0.06/kW-hr), NaOH at 247 lb/hr (\$480 per dry ton delivered).

The vendor estimate is budgetary (+/-30%) and is near lump sum turnkey quality. The installation estimate includes the mechanical and structural work and excludes the civil work (foundations and other underground work), electrical work (including instrument and controls wiring), and the cost of modifying the existing scrubber.

Additional installation costs (for those items not included in the vendor quotation) to fully support the LoTOxTM system installation are typically factor estimated at 40% of the capital cost. This percentage represents information provided to BELCO by customers who have installed systems on existing FCCUs. Since the LoTOxTM system's proposed location at Tesoro is downstream of the existing Wet Gas Scrubber, a direct installation cost factor of 33% plus an additional 20% for civil, structural, and power was used in the present study. This includes installation costs related to existing scrubber modifications, foundations, footings, power, and control systems. See the vendor estimate in Appendix E.2.

SNCR

Peerless Manufacturing Ltd. provided an estimate for SNCR on sources F-103 and F-304. See Appendix E.2 for the vendor estimate.

A control system at a cost of \$80,000 was included in the total installed cost estimate. This control system would monitor heater parameters to adjust reagent feed rates. A 10,000-gallon stainless steel tank, ammonia pump skid, and truck unloading station were also included in the total installed cost estimate.

Effective NO_x reduction using the SNCR method requires an understanding of the heat distribution within the fire box and flue gas stream, gained by using computational fluid dynamics and modeling. An analysis including computational fluid dynamics was not conducted for this study. Therefore, vendor-reported NO_x reduction rates are estimates. In addition, considering that source F-103 has 24 burners, SNCR may not be an applicable technology for the heat distribution within the firebox. Without conducting a complete analysis including computational fluid dynamics, the suitability of SNCR technology for source F-103 can only be estimated.

SCR

Estimates for SCR technology were received from Peerless Manufacturing and from CRI Catalyst. CRI has a proprietary low-temperature, pelletized, extrudate catalyst applicable to the sources in the present study. The catalyst is expected to have a life of 5 years. See Appendix E.4 for vendor estimates.

In addition to the SCR capital cost provided by the vendor, the TIC estimate includes the following necessary components:

- Control system
- A 10,000-gallon stainless steel ammonia tank, ammonia pump skid, and truck unloading station
- Overhead crane for catalyst replacement
- Expansion joints
- Flow distribution correction vane
- In-line forced draft fan
- F-6650/51/52/53 estimate prepared with and without a duct heater (see Appendix D.6 and D.6.1). Where duct burners are required for conventional catalyst use, a fuel gas coalescer was also included as an additional cost.

An \$80,000 control system would monitor heater parameters to adjust reagent feed rates. A forced draft fan would assist the flue gas through the flow distribution correction vanes and on through the SCR catalyst. Subsequently, the treated flue gas would be passed into the stack.

The vendor estimate is included as Appendix E.5.

RECOMMENDATIONS

Vendor Cost Factor Analysis

Based on the vendor-supplied NO_x reductions, vendor equipment costs, calculations, and data analyses, it is recommended that Tesoro Anacortes make the following cost-effective

modifications to achieve a BART-eligible, plant-wide NO_x reduction of 605 tons per year at an annualized cost of \$2,532,169 or an average cost of \$4,185 per ton¹:

- Install low-NO_x burners on F-103. A NO_x removal of 80 tons per year would cost an estimated \$4,648 per ton.
- Install low-NO_x burners and SNCR technology on F-304. A NO_x removal of 323 tons per year would cost an estimated \$4,592 per ton at an incremental cost of \$5,160 per ton over and above SNCR retrofit alone.
- Install low-NO_x burners at units F-6650 and F-6651 and install ultra-low-NO_x burners at units F-6652 and F-6653. A combined NO_x removal of 202 tons per year would cost an estimated \$3,349 per ton.

¹ Note that the conclusions are based only on determinations of cost effectiveness and do not consider the degree of visibility improvement associated with installing the technologies as allowed for under the BART rules.

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APPENDICES

Appendix A Pre-Project Emission Estimates & Calculations

Appendix B EPA Capital and Maintenance Cost Calculations

B.1 Calculations for LNB

B.2 Calculations for ULNB

B.3 Calculations for SNCR

B.4 Calculations for SCR

Appendix C EPA Cost Effectiveness

Sources F-103 through F-6655, Excluding X-819

- Summary of BACT Determinations for Refinery Heaters and Boilers
- Economic Analysis Assumptions
 - C.1 Source F-103
Control Options
Dominant Controls Diagram
Control Cost Effectiveness
 - C.2 Source F-104
 - C.3 Source F-654
 - C.4 Source F-6600
 - C.5 Source F-6601
 - C.6 Source F-6602
 - C.7 Source F-6650
 - C.8 Source F-6651
 - C.9 Source F-6652
 - C.10 Source F-6653
 - C.11 Source F-6654
 - C.12 Source F-6655
 - C.13 Source F-304

Appendix D Vendor Cost Effectiveness

Sources F-103 through F-6655

- Economic Analysis and Assumptions
 - D.1 Source F-103
Control Options
Dominant Controls Diagram
Control Cost Effectiveness
 - D.2 Source F-654
 - D.3 Source F-6600
 - D.4 Source F-6601
 - D.5 Source F-6602
 - D.6 Sources F-6650/51/52/53 with Duct Heater
 - D.6.1 Sources F-6650/51/52/53 w/o Duct Heater

- D.7 Source F-6654
- D.8 Source F-6655
- D.9 Source F-304

Appendix E Vendor Quotations and Design Specifications

- E.1 Burners
- E.2 LoTOx™
- E.3 NOx Tempering and SNCR
- E.4 SCR