Exhibit A

Salt River Project
Santan Generating Station

Santan Emissions Assessment Report

June 3, 2011

SALT RIVER PROJECT
SANTAN GENERATING STATION

SANTAN EMISSIONS ASSESSMENT REPORT

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Rev. 0

FINAL

Prepared By:

Sargent & Lundy LLC

Project No. 12046-018

June 3, 2011

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FOR

SALT RIVER PROJECT

SANTAN GENERATING STATION

SANTAN EMISSIONS ASSESSMENT REPORT

I CERTIFY THAT THIS REPORT WAS PREPARED BY ME OR UNDER MY SUPERVISION AND THAT I AM A REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARIZONA.

Electronic copy of final document;

Sealed original is with Arvind A. Patel

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APPROVAL PAGE

FOR

SALT RIVER PROJECT
SANTAN GENERATING STATION
SANTAN EMISSIONS ASSESSMENT REPORT

Rev.	Date/ Purpose	Discipline	Prepared	Reviewed	Approved	Pages Affected
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ABBREVIATIONS AND ACRONYMS

Abbreviation or Acronym	Explanation
ACC	Arizona Corporation Commission
BACT	Best Available Control Technology
Btu	British thermal unit
CEC	Certificate of Environmental Compatibility
CEMS	continuous emission monitoring system
CO	carbon monoxide
CT	combustion turbine
DLN	dry low NO_x
EPA	U.S. Environmental Protection Agency
EGU	electric generating unit
GE	General Electric
GHG	greenhouse gas
g/kW-hr	grams per kilowatt-hour
gpm	gallons per minute
gr/ft^3	grains per cubic feet
HC	hydrocarbon
H_2SO_4	sulfuric acid
hp	horsepower
hr	hour
HRSG	heat recovery steam generator
in	inches
kW	kilowatt
kWh	kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	pound
mmBtu	million British thermal unit
MCAQD	Maricopa County Air Quality Department
MW	megawatt
NGCC	natural gas combined cycle
NH_3	ammonia
NO_X	nitrogen oxide
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	operations and maintenance
O_2	oxygen

Abbreviation or Acronym	Explanation
OEM	original equipment manufacturer
^{o}F	degrees Fahrenheit
PM	particulate matter
PM_{10}	particulate matter (10 micrometers and smaller)
$PM_{2.5}$	particulate matter (2.5 micrometers and smaller)
ppm	parts per million
PSD	Prevention of Significant Deterioration
S&L	Sargent & Lundy, LLC
SCR	selective catalytic reduction
SGS	Santan Generating Station
SO_2	sulfur dioxide
SRP	Salt River Project
ST	steam turbine
TDS	total dissolved solids
tpy	tons per year
VOC	volatile organic compound

EXECUTIVE SUMMARY

Sargent & Lundy, LLC (S&L) has been retained by Salt River Project (SRP) to perform an emissions assessment for the Santan Generating Station (SGS). SGS includes seven (7) gas-fired combined cycle units capable of generating a total of nominally 1,193 MW with seasonal variations.

Units 1 through 4 (S-1, S-2, S-3, S-4) each include a GE 7EA combustion turbine (CT), heat recovery steam generator (HRSG), and steam turbine. Units 1 through 4 are capable of generating approximately 368 MW. Units 1, 2, and 3 were commissioned in 1974 while Unit 4 was commissioned in 1975. Emissions control improvements consisting of installation of DLN1 combustors and CO oxidation catalyst to reduce NO_x and CO emissions were implemented between 2000 and 2004. These emissions control improvements were implemented per Conditions 32 and 37 of the Arizona Corporation Commission's (ACC) Certificate of Environmental Compatibility (CEC) for the Santan Expansion Project issued on May 1, 2001.

The Santan Expansion Project is comprised of Units 5 and 6. Unit 5 (S-5A, S-5B) includes two GE 7FA CTs with low NO_x combustors, two supplementary fired HRSGs with CO and SCR catalyst for CO and NO_X control, and one steam turbine (S-5S). Unit 5 was commissioned in 2005. Unit 6 (S-6A) consists of one GE 7FA CT with low NO_x combustors, one HRSG with CO and SCR catalyst for CO and NO_X control, and one steam turbine (S-6S). Unit 6 was commissioned in 2006. Units 5 and 6 are capable of generating nominally 825 MW.

In addition to the electric generating units, the following emission sources are installed at the facility: cooling tower, emergency engines, abrasive blasting equipment, and fuel storage tanks.

This assessment has been prepared in accordance with Condition 38 of the ACC CEC for the Santan Expansion Project. Condition 38 states:

> *"Beginning upon commercial operation of the new units, SRP shall conduct a review of the Santan Generating facility operations and equipment every five years and shall, within 120 days of completing such review, file with the Commission and all parties in this docket, a report listing all improvements which would reduce plant emissions and the costs associated with each potential improvement.*
>
> *Commission staff shall review the report and issue its findings on the report, which will include an economic feasibility study, to the Commission within 60 days of receipt. SRP shall install said improvements within 24 months of filing the review with the Commission, absent an order from the Commission directing otherwise."*

This evaluation includes information necessary to meet the objectives set forth in Condition 38 of the CEC. S&L performed the emissions assessment in two phases; Phase 1 - "Data Collection / Evaluation & Initial Assessments" and Phase 2 – "Development of Emissions Reduction Options." Based on the results of Phases 1 and 2, S&L developed a list of potential emissions improvements for SGS.

The first phase of the evaluation included data collection and initial emissions assessments. S&L conducted an assessment of the current emissions at SGS in order to determine which pollution control technologies should be evaluated in detail. In addition to evaluating emissions from the seven natural gas fired combined cycle generating units (Units S-1, S-2, S-3, S-4, S-5A, S-5B, S-6A), S&L evaluated emissions from the diesel engines, cooling towers, and abrasive blasting equipment. S&L also visited SGS to meet with plant personnel to understand how various equipment and systems are operated and maintained. During the site visit, S&L performed a constructability walk down to identify site and space constraints that could affect the implementation of potential environmental upgrades.

Based on the results of the "Phase 1" emissions assessment, there is potential for reducing CO and NO_x emissions from Units 1-4. Therefore, emissions improvements for Units 1-4 were further evaluated in the "Phase 2" evaluation. For other SGS emissions sources, improvements were not further evaluated based on the following: (1) Units 5-6 are currently operating at or below levels generally required for similar, recently permitted facilities, they are equipped with the same state-of-the-art technology that would be used if they were permitted and constructed today, and, based on S&L's engineering judgement, any physical changes to the units would cost well in excess of normal thresholds for cost effectiveness, (2) cooling towers currently include mist eliminators designed to achieve 0.0005% drift, (3) diesel engine improvements are not practical due to limited annual operation, (4) a new dust collector has been installed on the abrasive blasting equipment, (5) the gasoline storage tank vapor losses are minimized due to proper tank design, fuel handling procedures, and limited annual gasoline throughput, and, based on S&L's engineering judgement, modifications to reduce emissions any further, such as employing vapor recovery systems used at high throughput commercial gas stations, would not be cost effective, and (6) the key elements of a comprehensive O&M program are utilized at SGS. The results of the "Phase 1" emissions assessment are discussed in detail in Section 4 of the report. A summary of the results of the "Phase 1" emissions assessment is provided in Table ES-1.

Table ES-1. Summary of Phase 1 Emissions Assessment

Emission Source		Pollutant					Emissions Improvements Further Evaluated?
		NOx	CO	VOC	PM_{10} / $PM_{2.5}$	SO_2	
Units 1-4	SGS (Actual)	< 40 ppm (across full operating range) < 20 ppm (80-100% load)	< 40 ppm (across full operating range) < 10 ppm (80-100% load)	~1.7 ppm (reported) 1.4 ppm (guarantee – 80-100% load)	0.0066 lb/mmBtu (reported) 5 lb/hr (guarantee)	Fuel S Content < 0.00363 gr/ft^3	Yes - NO_x/CO No – $VOC/PM/SO_2$ *(Emissions reductions will not be evaluated due to (1) DLN1 combustors/CO catalyst for VOC, and (2) firing low sulfur fuel and good combustion practices for* PM/SO_2*)*
	Recent Permit Limits (AZ, CA)	*2-2.5 ppm (50% to 100% load)*	*2-4 ppm (50% to 100% load)*	*1-4 ppm (50% to 100% load)*	*< 0.015 lb/mmBtu*	*Fuel S Content < 0.005 gr/ ft^3*	
Units 5-6	SGS (Actual)	< 2 ppm	< 2 ppm	< 2 ppm	0.01lb/mmBtu	Fuel S Content < 0.00363 gr/ft^3	No *(Emissions reductions will not be evaluated because Units 5-6 are already equipped with state-of-the-art emissions controls and based on S&L's engineering judgment, any changes would cost well in excess of the typical cost thresholds)*
	Recent Permit Limits (AZ, CA)	*2-2.5 ppm (50% to 100% load)*	*2-4 ppm (50% to 100% load)*	*1-4 ppm (50% to 100% load)*	*< 0.015 lb/mmBtu*	*Fuel S Content < 0.005 gr/ ft^3*	
Cooling Towers	SGS (Actual)	NA	NA	NA	Drift < 0.0005%	NA	No *(Emissions reductions will not be evaluated because SGS cooling tower mist eliminator drift efficiency is less than 0.0005%)*
	Recent Permit Limits (AZ, CA)	*NA*	*NA*	*NA*	*Drift < 0.0005-0.001%*	*NA*	

Table ES-1. Summary of Phase 1 Emissions Assessment (cont.)

Emission Source		Pollutant					Emissions Improvements Further Evaluated?
		NOx	CO	VOC	PM_{10} / $PM_{2.5}$	SO_2	
Emergency Diesel Engines	**SGS (Actual)**	**9.2 g/kW-hr (310 hp fire pump, 830 hp generator) NOx + HC: 4.0 g/kW-hr (577 hp generator)**	**11.4 g/kW-hr (310 hp fire pump, 830 hp generator) 3.5 g/kW-hr (577 hp generator)**	**1.3 g/kW-hr (310 hp fire pump, 830 hp generator) NOx + HC: 4.0 g/kW-hr (577 hp generator)**	**0.54 g/kW-hr (310 hp fire pump, 830 hp generator) 0.20 g/kW-hr (577 hp generator)**	**Fuel S Content < 0.0015 wt%**	**No** ***(Additional emissions control technology is not practical for limited use engines such as emergency generators, and the emissions reductions generated by such controls would be < 0.1 tpy, so improvements are not further evaluated because, based on S&L's engineering judgement, the cost effectiveness of such controls would be well in excess of typical cost thresholds)***
	Recent Permit Limits (AZ, CA)	***NOx + HC: 4.0 g/kW-hr (310 hp fire pump, 577 hp generator) NOx + HC: 6.4 g/kW-hr (830 hp generator)***	***3.5 g/kW-hr (310 hp fire pump, 577/830 hp generators)***	***NOx + HC: 4.0 g/kW-hr (310 hp fire pump, 577 hp generator) NOx + HC: 6.4 g/kW-hr (830 hp generator)***	***0.20 g/kW-hr (310 hp fire pump, 577/830 hp generators)***	***Fuel S Content < 0.0015 wt%***	
Abrasive Blasting Equipment	**SGS (Actual)**	**NA**	**NA**	**NA**	**Opacity < 20%**	**NA**	**No** ***(SRP recently installed new dust collector that achieves 99.9% PM control)***
	Recent Permit Limits (AZ, CA)	***NA***	***NA***	***NA***	***Opacity < 20%***	***NA***	
Gasoline Storage Tank	**SGS (Actual)**	**NA**	**NA**	**NA(1)**	**NA**	**NA**	**No** ***(Emissions reductions will not be evaluated because tank design and fuel handling procedures generally meet requirements for similar tanks, and based on S&L's engineering judgement, making any physical changes would be cost prohibitive compared to typical thresholds)***
	Recent Permit Limits for similarly sized tanks (AZ, CA)	***NA***	***NA***	***NA(1)***	***NA***	***NA***	

(1) VOC emissions from gasoline storage tanks are controlled by utilizing proper tank design (e.g., submerged fill pipe) and fuel handling procedures to minimize vapor losses, and limiting annual fuel throughput.

The "Phase 2" analysis performed for Units 1-4 generally follows a "top-down" approach that is used in permitting new major sources of air emissions or modifications to existing major source. A similar process has been used by state and county agencies in evaluating NO_x emission controls at existing stationary sources as part of a regional ozone attainment strategy. The "top-down" approach used in this evaluation includes the following steps for each emission source and pollutant that is being evaluated:

1. Identify potential control technologies;
2. Eliminate technically infeasible control options;
3. Rank the remaining control technologies by control effectiveness;
4. Evaluate the control technologies, starting with the most effective for:
    - economic impacts,
    - environmental impacts, and
    - energy impacts.
5. Summary of potential emissions improvements.

The NO_x control technology assessment identified three options that are considered technically feasible and commercially available for control of NO_x emissions from Units 1-4: (1) combustor upgrades, (2) selective catalytic reduction (SCR) systems, and (3) SCR systems and combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness ranges from approximately $22,104 per ton (combustor upgrades) to $74,369 per ton (SCR + combustor upgrades).

EPA has not defined a cost threshold at which NO_x control technologies for existing power plants are considered "cost effective." Cost effectiveness thresholds are typically set at the discretion of regulating agencies on a project-specific basis. However, based on a review of publicly available documents, it is common for agencies to consider NO_x control options "cost prohibitive" at levels exceeding $10,000 per ton NO_x removed (see Attachment 8 for a table of reference documents). Therefore, based on the range of costs identified for SGS Units 1-4 NO_x control options, and an assumed cost effectiveness threshold of $10,000 per ton NO_x removed, NO_x emissions improvements for SGS Units 1-4 would be considered cost prohibitive. A summary of the "Phase 2" NO_x emissions assessment for Units 1-4 is presented in Table ES-2.

Table ES-2. Summary of NO_x Control Evaluation for Units 1-4[(1)]

Control Technology	Total Emissions Reduction (tpy)	Total Capital Cost ($)	Total Annual O&M Cost ($/year)	Total Annual Costs ($/year)	Average Cost Effectiveness ($/ton)
SCR + Combustor Upgrades	**154.5**	**$69,560,000**	**$3,802,000**	**$11,490,000**	**$74,369**
SCR	**154.5**	**$49,612,000**	**$3,751,000**	**$9,235,000**	**$59,773**
Combustor Upgrades	**103.1**	**$19,948,000**	**$75,000**	**$2,279,000**	**$22,104**
Baseline Combustion Controls (DLN1 Combustors)	**NA**	**NA**	**NA**	**NA**	**NA**

(1) Values presented in table are combined totals for SGS Units 1-4.

The CO control technology assessment identified three options that are considered technically feasible and commercially available for control of CO emissions from Units 1-4: (1) combustor upgrades, (2) upgraded oxidation catalyst system, and (3) upgraded oxidation catalyst system and combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness ranges from approximately $63,895 per ton (CO catalyst upgrades) to $464,694 per ton (CO catalyst + combustor upgrades).

EPA has not defined a cost threshold at which CO control technologies for existing power plants are considered “cost effective.” Cost effectiveness thresholds are typically set at the discretion of regulating agencies on a project-specific basis. However, based on a review of publicly available documents, it is common for agencies to consider CO control options “cost prohibitive” at levels exceeding $4,000 per ton CO removed (see Attachment 8 for a table of reference documents). Therefore, based on the range of costs identified for SGS Units 1-4 CO control options, and an assumed cost effectiveness threshold of $4,000 per ton CO removed, CO emissions improvements for SGS Units 1-4 would be considered cost prohibitive. A summary of the “Phase 2” CO emissions assessment for Units 1-4 is presented in Table ES-3.

Based on the average cost effectiveness of technically feasible control options and assumed cost effectiveness thresholds, we recommend that SRP not add any additional NO_x or CO emission controls to SGS Units 1-4 at this time.

Table ES-3. Summary of CO Control Evaluation for Units 1-4[(1)]

Control Technology	Total Emissions Reduction (tpy)	Total Capital Cost ($)	Total Annual O&M Costs ($/year)	Total Annual Costs ($/year)	Average Cost Effectiveness ($/ton)
CO Catalyst System Upgrades	24.9	$7,784,000	$731,000	$1,591,000	$63,895
CO Catalyst System Upgrades and Combustor Upgrades	24.9	$27,732,000	$804,000	$3,868,000	$155,341
Combustor Upgrades and Existing CO Catalyst System	4.9	$19,948,000	$73,000	$2,277,000	$464,694
Baseline Combustion Controls (DLN1 Combustors) and Existing CO Catalyst System	NA	NA	NA	NA	NA

(1) Values presented in table are combined totals for SGS Units 1-4.

Summary Level project schedules for development, design, construction, and startup of the options were also developed. The schedules suggest that permitting timelines (including uncertainty associated with greenhouse gas permitting requirements), and constructability issues that could preclude activities being completed on multiple units simultaneously, would in most circumstances prevent the work from being completed in accordance with the 24 month time frame established in Condition 38 of the Santan CEC.

1 INTRODUCTION

Sargent & Lundy, LLC (S&L) has been retained by Salt River Project (SRP) to perform an emissions assessment for the Santan Generating Station (SGS). This assessment has been prepared in accordance with Condition 38 of the Arizona Corporation Commission's (ACC) Certificate of Environmental Compatibility (CEC) for the Santan Expansion Project issued on May 1, 2001 (see Attachment 1). Condition 38 states:

> *Beginning upon commercial operation of the new units, SRP shall conduct a review of the Santan Generating facility operations and equipment every five years and shall, within 120 days of completing such review, file with the Commission and all parties in this docket, a report listing all improvements which would reduce plant emissions and the costs associated with each potential improvement.*
>
> *Commission staff shall review the report and issue its findings on the report, which will include an economic feasibility study, to the Commission within 60 days of receipt. SRP shall install said improvements within 24 months of filing the review with the Commission, absent an order from the Commission directing otherwise.*

This evaluation includes information necessary to meet the objectives set forth in Condition 38 of the CEC. Information is presented in the following sections:

Section 2 – Facility Description contains information describing SGS and emissions sources considered in the evaluation.

Section 3 – The Evaluation Process provides a description of the steps that were included in the review of the facility's operations and equipment with respect to identifying potential improvements that would reduce plant emissions.

Section 4 – Phase 1 Evaluation: Current Emissions provides a description of current plant wide emissions and identifies potential emissions improvements.

Section 5 – Phase 2 Evaluation: Emissions Reduction Options presents an evaluation of potential control options and associated costs with options that are deemed technically feasible.

Section 6 – Conclusion identifies potential emissions improvements for SGS.

2 FACILITY DESCRIPTION

The Santan Generating Station is located at 1005 South Val Vista Drive, Gilbert, Arizona. The Facility operates under the Title V Air Quality Permit V95-008, and has a total of seven (7) electric generating units (EGU).

Units 1 through 4 (S-1, S-2, S-3, S-4) each include a GE 7EA combustion turbine (CT) with DLN1 combustors for NO_X control, heat recovery steam generator (HRSG), and CO oxidation catalyst for CO control. Units 1 through 4 are capable of generating approximately 368 MW. Units 1, 2, and 3 were commissioned in 1974 while Unit 4 was commissioned in 1975. Emissions control improvements consisting of installation of DLN1 combustors and CO oxidation catalyst to reduce NO_x and CO emissions were implemented between 2000 and 2004. These emissions control improvements were implemented per Conditions 32 and 37 of the ACC's CEC for the Santan Expansion Project issued on May 1, 2001.

The Santan Expansion Project is comprised of Units 5 and 6. Unit 5 (S-5A, S-5B) consists of two GE 7FA CTs with low-NO_x combustors, two HRSGs with CO and SCR catalyst for CO and NO_X control, and one steam turbine (S-5S). Unit 5 was commissioned in 2005. Unit 6 (S-6A) consists of one GE 7FA CT with low-NO_x combustors, one HRSG with CO and SCR catalyst for CO and NO_X control, and one steam turbine (S-6S). Unit 6 was commissioned in 2006. Units 5 and 6 are capable of generating nominally 825 MW.

In addition to the electric generating units, the following emission sources are installed at the facility:

- Cooling Towers
    - CT1: One 101,500 gpm mechanical draft, cross flow cooling tower, in operation since 1973
    - CT5: One 172,923 gpm mechanical draft, counter flow cooling tower, in operation since 2004
    - CT6: One 80,755 gpm mechanical draft, counter flow cooling tower, in operation since 2005
- Emergency Engines
    - One 310 hp diesel-fired emergency fire water pump certified to meet EPA Tier 1 emissions standards, in operation since 2004
    - One 830 hp diesel-fired emergency generator certified to meet EPA Tier 1 emissions standards, in operation since 2004
    - One 577 hp diesel-fired emergency generator certified to meet Tier 3 emissions standards, in operation since 2008
    - One 122 hp propane-fired emergency generator, in operation since 2008
- Abrasive Blasting Equipment
    - Abrasive blasting building, in operation since 1978

- Fuel Storage Tanks
  - One 500 gallon gasoline storage tank
  - Three diesel fuel storage tanks (two 500 gallon, one 350 gallon)

3 THE EVALUATION PROCESS

S&L performed the emissions assessment in two phases; Phase 1 - "Data Collection / Evaluation & Initial Assessments" and Phase 2 – "Development of Emissions Reduction Options." Based on the results of Phases 1 and 2, S&L developed a list of potential emissions improvements for SGS. A brief description of each phase of this assessment is provided below.

Phase 1 – Data Collection / Evaluation & Initial Assessments

The first phase included data collection and an initial emissions assessment. S&L reviewed both current and historical emissions information from plant data collection systems (e.g., DCS, PI, CEMS). In addition, the Title V Permit for SGS ("the permit") dated December 23, 2010 was reviewed to identify regulated emission units and respective emission limits. The information provided for the "Phase 1" assessment was processed and compared with emissions limits that have been included in recently issued permits for similar new sources. This comparison identified emissions sources that were further evaluated in "Phase 2."

In conjunction, S&L also evaluated how the plant has been operated and maintained to determine if changes to O&M practices could affect emissions as well. S&L visited SGS to meet with plant personnel to understand how various equipment and systems are operated and maintained. During the site visit, S&L also performed a constructability walk down to identify site and space constraints that could affect the implementation of potential environmental upgrades.

Phase 2 – Development of Emissions Reduction Options

The second phase included an evaluation of potential emissions improvements for sources identified in "Phase 1." This assessment included a discussion of potential emissions control options and an estimate of costs associated with such options.

Potential Emissions Improvements

Based on the results of the Phase 1 and Phase 2 evaluations, S&L identified potential emissions improvements that could be implemented at SGS.

4 PHASE 1 EVALUATION: CURRENT EMISSIONS

S&L conducted an assessment of the emissions at SGS in order to determine which pollution control technologies should be evaluated in detail. In addition to the seven EGUs, S&L evaluated emissions from the diesel engines, cooling towers, and abrasive blasting equipment. The pollutants that were evaluated were NO_X, CO, VOC, $PM_{10}/PM_{2.5}$, and SO_2.

4.1 UNITS 1, 2, 3 & 4

Units 1-4 (S-1, S-2, S-3, S-4) each include a GE 7EA combustion turbine (CT) and heat recovery steam generator (HRSG). Units 1, 2, and 3 began operation in 1974 while Unit 4 began operating in 1975. In 2001 and 2003, combustor modifications and installation of oxidation catalyst on Units 1 through 4 resulted in NO_x, CO, and VOC emissions reductions.

The SGS Title V Operating Permit No. V95-008 includes annual emission limits for Units 1-4. Based on review of the facility's 2008 and 2009 annual emissions inventories submitted to the Maricopa County Air Quality Department (MCAQD), emissions from Units 1-4 have been significantly less than the respective annual permit limits (see Table 4-1).

Table 4-1. Units 1-4 Annual Emissions Limits and Reported Emission Rates

Pollutant	Permit Limit (tons per year)	Reported Emissions for 2008 and 2009 (tons per year)
NO_X	1056.0	171.7 (2008) 118.2 (2009)
CO	174.0	48.0 (2008) 41.1 (2009)
SO_2	22.48	1.4 (2008) 0.9 (2009)
VOC	33.68	4.7 (2008) 3.2 (2009)
$PM_{10}/PM_{2.5}$	105.88	14.9 (2008) 10.0 (2009)

Note: The emission limits and reported emissions are combined for Units 1, 2, 3, and 4.

In addition to evaluating annual emissions, S&L also performed an evaluation of short-term emissions from Units 1-4. The following sections provide a pollutant-by-pollutant evaluation of current short-term emissions.

4.1.1 NO_x Emissions

The SGS Title V Operating Permit Condition 18.C.3.a states that Units 1-4 shall not emit NO_x in excess of 155 ppmvd@15%O_2 on a 30-day rolling average basis while firing natural gas. S&L's review of emissions inventories and compliance test reports submitted to MCAQD, along with discussions with SRP personnel, indicate that Units 1-4 are operating in accordance with permit requirements.

In 2001, SRP replaced the original Units 1-4 combustors with GE's Dry Low NO_X 1 (DLN1) combustors. The DLN1 combustors were guaranteed to achieve NO_x values of 20 ppmvd@15%

O_2 while operating from 80 to 100% load. Based on review of NO_x CEMS data, Units 1-4 are generally achieving less than 20 ppm NO_x at full load, and less than 40 ppm while operating at part loads.

Recent NO_x control technology developments have enabled units to achieve NO_x levels below those currently achieved by Units 1-4. For example, DLN combustor technology has matured and DLN systems installed on new combustion turbines have demonstrated the ability to achieve NO_x levels below 10 ppmvd@15%O_2 during "normal" operation (i.e., loads above 50% load). In addition, post-combustion control technologies, namely selective catalytic reduction (SCR), could be used to further reduce NO_x emissions. Based on a review of potentially available NO_x control systems, improvements may be available to reduce NO_x emissions from Units 1-4. Therefore, potential NO_x reduction methods are evaluated in Section 5 of this report.

4.1.2 CO Emissions

The SGS Title V Operating Permit Condition 18.C.2 states that Units 1-4 shall not emit CO in excess of 400 ppmvd@15%O_2 at any time. S&L's review of emissions inventories and compliance test reports submitted to MCAQD, along with discussions with SRP personnel, indicate that Units 1-4 are operating in accordance with permit requirements.

The DLN1 combustors installed in 2001 were guaranteed to meet a CO level of 10 ppmvd while operating from 80 to 100% load. In 2003, SRP further reduced CO emissions from Units 1-4 with the installation of CO catalyst at the CT plenum outlet. The CO catalyst was designed to achieve a stack emission rate of 4 ppm while operating from 80 to 100% load. Based on review of CO CEMS data, Units 1-4 are generally achieving less than 4 ppm CO at full and mid loads.

Although oxidation catalyst is currently installed on Units 1-4 for CO reduction, further reductions could potentially be achieved with the installation of additional catalyst. Based on a review of potentially available CO control systems, improvements may be available to reduce CO emissions from Units 1-4. Therefore, potential CO emissions improvements for Units 1-4 are evaluated in Section 5 of this report.

4.1.3 VOC Emissions

The DLN1 combustors installed in 2001 were guaranteed to achieve a VOC level of 1.4 ppmv while operating from 80 to 100% load. SRP is currently reporting VOC emissions that are based on EPA's AP42 Section 3.1 emission factor for gas fired combustion turbines; 0.0021 lb/mmBtu (~1.7 ppm). This emission factor is in the general range of reported values for similar gas fired units that are based on results of EPA's Test Methods 18/25A.

As discussed in Section 4.1.2, SRP installed oxidation catalyst at the CT plenum outlet for Units 1-4 in 2003. Even though the CO catalyst vendor did not provide VOC reduction guarantees, it is likely that the oxidation catalyst systems currently installed on Units 1-4 are reducing VOC emissions below the guaranteed levels of 1.4 ppmv while operating from 80 to 100% load.

Based on a review of recent permits that have been issued for new combined cycle units in Arizona and California, most units are subject to VOC emissions limits ranging from 1 to 4 ppmvd@15%O_2. For Units 1-4, it is likely that VOC emissions are already within this range due to the combination of DLN1 combustors that are guaranteed to meet 1.4 ppmv and oxidation catalyst systems that are expected to further reduce VOC emissions. Although improvements to the existing oxidation catalyst systems may be available to provide additional CO emissions reductions, it is unlikely that these improvements would provide any significant reduction in VOC emissions. Therefore, VOC emissions improvements for Units 1-4 will not be evaluated at this time.

4.1.4 SO_2 Emissions

Emissions of SO_2 from combustion turbines are a result of oxidation of fuel sulfur. SGS Units 1-4 are designed to fire natural gas. Table 4-2 shows the applicable fuel sulfur content permit limits and actual values obtained from fuel sample data and fuel contracts.

Table 4-2. Units 1-4 Fuel Sulfur Content Permit Limits and Actual Values

Fuel	Permit Limit	Actual Fuel Sulfur Content[1]
Natural Gas	**0.005 gr S/ft^3**	**< 0.00363 gr S/ft^3**

Note 1: Information obtained from 2008 and 2009 monthly natural gas fuel analyses.

Post combustion SO_2 control systems would have no practical application to combined cycle units. The only practical method for controlling SO_2 emissions from combined cycle units is the use of low sulfur fuels. Due to the inherently low sulfur content in natural gas, gas firing is the most practical method for minimizing SO_2 emissions.

Based on a review of recent permits that have been issued for new combined cycle units in Arizona and California, SO_2 emissions have been minimized with the use of natural gas. Furthermore, there are no post-combustion SO_2 control technologies, or other improvements, available to further reduce SO_2 emissions from Units 1-4. Because Units 1-4 only fire natural gas, SO_2 emissions improvements for Units 1-4 will not be evaluated at this time.

4.1.5 $PM_{10}/PM_{2.5}$ Emissions

The DLN1 combustors installed in 2001 were guaranteed to achieve a PM emission rate of 5 lb/hr. SRP is currently reporting PM_{10} emissions that are based on EPA's AP42 Section 3.1 emission factor for gas fired combustion turbines: 0.0066 lb/mmBtu. This emission factor is in the general range of reported values for similar gas fired units that are based on results of EPA's Test Methods 5/202.

SGS Units 1-4 are designed to fire natural gas, which is an inherently clean fuel. $PM_{10}/PM_{2.5}$ emissions from natural gas combustion are significantly less than emissions associated with liquid or solid fuel firing. OEMs generally contend that the reported $PM_{10}/PM_{2.5}$ emissions levels are not due to the combustion of natural gas, but instead, reported $PM_{10}/PM_{2.5}$ can be attributed to sampling error, construction debris, suspended $PM_{10}/PM_{2.5}$ in ambient air that passes through CT inlet air filters, and metallic rust or oxidation products.

Post combustion $PM_{10}/PM_{2.5}$ control systems would have no practical application to combined cycle units. The only practical methods for controlling PM emissions from combined cycle units are: (1) use of natural gas, (2) good combustion practices, and (3) follow recommended O&M procedures.

S&L evaluated the SGS operations and maintenance (O&M) records and determined that SRP is following recommended procedures to adequately reduce non-combustion related $PM_{10}/PM_{2.5}$ emissions from Units 1-4 (see Section 4.6).

Based on a review of recent permits that have been issued for new combined cycle units in Arizona and California, PM_{10} emissions limits have been based on firing clean fuels and good combustion practices. Furthermore, there are no post-combustion $PM_{10}/PM_{2.5}$ control technologies, or other improvements, available to further reduce PM_{10} emissions. For Units 1-4, $PM_{10}/PM_{2.5}$ emissions are minimized due to the combustion of natural gas and following recommended unit operation and maintenance practices. Therefore, $PM_{10}/PM_{2.5}$ emissions improvements for Units 1-4 will not be evaluated at this time.

4.2 UNITS 5A, 5B & 6A

The CEC for the Santan Expansion Project includes the ACC's conditions for approval of the construction of Units 5 and 6 (S-5A, S-5B, S-6A). Included in the CEC is the following Condition 35:

> *The Santan Expansion Project shall be required to meet the lowest achievable emission rate (LAER) for carbon monoxide (CO), nitrogen oxides (NO_x), volatile organic carbons (VOCs), and particulate matter (PM) less than 10 micron in aerodynamic diameter (PM_{10}). The Santan Expansion Project shall be required to submit an air quality permit application requesting this LAER to the Maricopa County Environmental Services Department.*

Units 5-6 each include a GE 7FA CT and a HRSG. Units 5A and 5B were commissioned in 2005 while Unit 6A was commissioned in 2006. The Units 5A and 5B HRSGs are each equipped with 530 mmBtu/hr (LHV) supplemental duct burners. The Unit 6 HRSG is equipped with a 490 mmBtu/hr (LHV) supplemental duct burner. In order to meet Lowest Achievable Emission Rate "LAER" requirements for NO_x, CO and VOC, the units are equipped with SCR for NO_x control and oxidation catalyst for CO and VOC control. LAER for PM_{10} is achieved by firing natural gas exclusively.

The SGS Title V Operating Permit includes annual emission limits for Units 5-6. Based on review of the facility's 2008 and 2009 annual emissions inventories submitted to the MCAQD, actual emissions from Units 5-6 have been below the respective annual permit limits (see Table 4-3).

Table 4-3. Units 5-6 Annual Emissions Limits and Reported Emission Rates

Pollutant	Permit Limit (tons per year)	Reported Emissions for 2008 and 2009 (tons per year)
NO_X	212.8	142.1 (2008) 103.4 (2009)
CO	304.1	82.7 (2008) 29.4 (2009)
SO_2	34.8	9.3 (2008) 8.3 (2009)
VOC	59.8	40.9 (2008) 21.1 (2009)
$PM_{10}/PM_{2.5}$	170.3	33.3 (2008) 27.7 (2009)

Note: The emission limits and reported emissions are combined for Units 5A, 5B, and 6A.

In addition to evaluating annual emissions, S&L also performed an evaluation of short-term emissions from Units 5-6. The following sections provide a pollutant-by-pollutant evaluation of current short-term emissions.

4.2.1 NO_x Emissions

The SGS Title V Operating Permit includes a NO_X concentration limit of 2 ppmvd@15%O_2 on a 1-hour averaging basis for Units 5A, 5B, and 6A. In addition, Units 5-6 are subject to EPA's New Source Performance Standards (NSPS) Subparts GG and Da. NSPS Subpart GG states that the combustion turbine NO_x emissions shall not exceed approximately 110 ppmvd@15%O_2.[1] NSPS Subpart Da states that the Units 5-6 duct burners NO_x emissions shall not exceed 1.6 lb/MWh on a 30-day rolling average basis.

To meet the applicable NO_x emissions limits, each unit is equipped with low NO_x combustors and an SCR system. S&L's review of emissions inventories and compliance certifications, along with discussions with SRP personnel, indicate that Units 5A, 5B, and 6A are operating in accordance with permit requirements. Based on a review of recent permits that have been issued for new combined cycle units in Arizona and California, most units are subject to NO_x emissions limits ranging from 2 to 2.5 ppmvd@15%O_2 (see Attachment 2). Units 5A, 5B, and 6A include combustors and duct burners that are designed to achieve low NO_x emissions and SCR that enables the units to meet and exceed the most stringent NO_x levels required for new units. While there are equipment changes that could reduce emissions slightly, based on S&L's engineering

[1] The NSPS Subpart GG NOx emissions limit is estimated based on the equation identified in the SGS Title V Permit Condition 18.B.2.a.

judgement, those changes would cost well in excess of cost effectiveness thresholds discussed later in this report. Therefore, NO_x emissions improvements for Units 5-6 will not be evaluated at this time.

4.2.2 CO Emissions

Units 5A, 5B, and 6A are required to meet a CO concentration limit of 2.0 ppmvd@15%O_2 on a 3-hour rolling average basis. To meet this limit, each unit is equipped with an oxidation catalyst system. S&L's review of emissions inventories and compliance certifications, along with discussions with SRP personnel, indicate that Units 5A, 5B, and 6A are operating in accordance with permit requirements.

Based on a review of recent permits that have been issued for new combined cycle units in Arizona and California, most units are subject to CO emissions limits ranging from 2 to 4 ppmvd@15%O_2 (see Attachment 2). Units 5A, 5B, and 6A include combustors and duct burners designed to achieve low CO emissions and oxidation catalyst that enables the units to meet and exceed CO levels required for new units. While modifications to further reduce CO are possible, based on S&L's engineering judgement, the costs associated with those modifications would outweigh the reductions that would be achieved. Therefore, CO emissions improvements for Units 5-6 will not be evaluated at this time.

4.2.3 VOC Emissions

Units 5A, 5B, and 6A are required to meet a VOC concentration limits of 1.0 ppmvd@15%O_2 (without duct firing) and 2.0 ppmvd@15%O_2 (with duct firing), on a 3-hour rolling average basis. The oxidation catalyst systems that are installed for CO reduction also reduce VOC emissions. S&L's review of stack test data and compliance certifications, along with discussions with SRP personnel, indicate that Units 5A, 5B, and 6A are operating in accordance with permit requirements. For example, 2010 stack test results for Unit 6A show that VOC emissions range from 0.38 ppm to 0.54 ppm.

Based on a review of recent permits that have been issued for new combined cycle units in Arizona and California, several units are subject to VOC emissions limits ranging from 1 to 4 ppmvd@15%O_2 (see Attachment 2). Units 5A, 5B, and 6A include combustors and duct burners designed to achieve low VOC emissions and oxidation catalyst that enable the units to meet VOC levels required for new units. While modifications to reduce VOC emissions exist, based on S&L's engineering judgement, the costs associated with those modifications would outweigh the reductions that would be achieved. Therefore, VOC emissions improvements for Units 5-6 will not be evaluated at this time.

4.2.4 SO_2 Emissions

Emissions of SO_2 from combustion turbines are a result of oxidation of fuel sulfur. SGS Units 5A, 5B, and 6A are designed to fire natural gas exclusively. Table 4-4 shows the applicable fuel sulfur content permit limits and actual values obtained from fuel sample data and fuel contracts. In addition, Units 5-6 are subject to SO_2 standards found in NSPS Subparts GG and Da. NSPS Subpart GG states that combustion turbine SO_2 emissions shall not exceed 0.015% by volume at 15% O_2 on a dry basis, and the fuel S content shall not exceed 0.8% by weight. NSPS Subpart

Da states that SO_2 emissions from the duct burners shall not exceed 100% of the potential combustion concentration.

Table 4-4. Units 5-6 Fuel Sulfur Content Permit Limits and Actual Values

Fuel	Permit Limit	Actual Fuel Sulfur Content
Natural Gas	**0.005 gr S/ft^3**	**< 0.00363 gr S/ft^3**

The only practical method for controlling SO_2 emissions from combined cycle units is the use of low sulfur fuels. Due to the inherently low sulfur content in natural gas, gas firing is the most practical method for minimizing SO_2 emissions. Based on a review of recent permits that have been issued for new combined cycle units in Arizona and California, SO_2 emissions have been minimized with the use of natural gas. Furthermore, there are no post-combustion SO_2 control technologies, or other improvements, available to further reduce SO_2 emissions from Units 5A, 5B, or 6A. Because Units 5A, 5B, and 6A only fire natural gas, SO_2 emissions improvements for Units 5-6 will not be evaluated at this time.

4.2.5 $PM_{10}/PM_{2.5}$ Emissions

Units 5A, 5B, and 6A are required to meet a $PM_{10}/PM_{2.5}$ emission limit of 0.01 lb/mmBtu (with and without duct firing). In addition, the Units 5-6 duct burners are subject to PM standards found in NSPS Subparts Da, which states that PM emissions shall not exceed 0.03 lb/mmBtu.

S&L's review of stack test data and compliance certifications, along with discussions with SRP personnel, indicate that Units 5A, 5B, and 6A are operating in accordance with permit requirements. For example, 2010 stack test results for Units 5A, 5B, and 6A show that PM_{10} emissions range from 0.0039 to 0.0053 lb/mmBtu.

SGS Units 5-6 are designed to fire natural gas, which is an inherently clean fuel. $PM_{10}/PM_{2.5}$ emissions from natural gas combustion are significantly less than emissions associated with liquid or solid fuel firing. OEMs generally contend that the reported $PM_{10}/PM_{2.5}$ emissions levels are not due to the combustion of natural gas, but instead, reported $PM_{10}/PM_{2.5}$ can be attributed to sampling error, construction debris, suspended $PM_{10}/PM_{2.5}$ in ambient air that passes through CT inlet air filters, and metallic rust or oxidation products.

Post combustion $PM_{10}/PM_{2.5}$ control systems would have no practical application to combined cycle units. SGS Units 5-6 are designed to fire natural gas exclusively, which is an inherently clean fuel. The only practical methods for controlling PM emissions from combined cycle units are: (1) use of natural gas, (2) good combustion practices, and (3) follow recommended O&M procedures.

S&L evaluated the SGS operations and maintenance (O&M) records and determined that SRP is following recommended procedures to adequately reduce non-combustion related PM_{10} emissions from Units 5-6 (see Section 4.6).

Based on a review of recent permits that have been issued for new combined cycle units in Arizona and California, PM_{10} emissions limits have ranged from 0.005 to 0.015 lb/mmBtu based on firing clean fuels and good combustion practices. Furthermore, there are no post-combustion PM_{10} control technologies, or other improvements, available to further reduce $PM_{10}/PM_{2.5}$ emissions. For Units 5-6, $PM_{10}/PM_{2.5}$ emissions are minimized due to the combustion of natural gas and following recommended unit operation and maintenance practices. Therefore, $PM_{10}/PM_{2.5}$ emissions improvements for Units 5-6 will not be evaluated at this time.

4.3 COOLING TOWERS

The Santan facility has three cooling towers that dissipate heat from the condensing water for each of the three steam turbines. Cooling Tower CT1 serves the Units 1-4 steam turbine, and Cooling Tower CT5 and CT6 serve the Units 5 and 6 steam turbines, respectively. Table 4-5 provides information for each cooling tower.

Table 4-5. Cooling Tower Design Parameters

Emission Unit	Units Served	Year in Service	Circulating Water Flow Rate (gpm)	Design Mist Eliminator Drift Efficiency*
Cooling Tower CT1	S-1, S-2, S-3, S-4	1973	101,500	< 0.0005%
Cooling Tower CT5	S-5A, S-5B	2005	175,000	< 0.0005%
Cooling Tower CT6	S-6A	2006	80,000	< 0.0005%

* Mist eliminator efficiency is measured as a percentage of the circulating water flow rate.

$PM_{10}/PM_{2.5}$ from cooling towers is generated by the presence of solids in the cooling tower circulating water, which is potentially emitted as "drift" or moisture droplets that are suspended in the air that is blown through the cooling tower. A portion of the water droplets emitted from the tower exhausts will evaporate, thereby resulting in $PM_{10}/PM_{2.5}$ emissions.

PM_{10} emissions from cooling towers are controlled by the use of high efficiency drift eliminators, reduced number of cycles of concentration, or a combination of both. The cycles of concentration are limited by water availability; lower circulating water concentrations require increased blowdown frequency and thus more makeup water.

The SGS Title V permit includes limits for circulating water TDS values, mist eliminator drift efficiency, and $PM_{10}/PM_{2.5}$ emissions. As part of the initial emissions assessment, S&L reviewed cooling tower design parameters, reported emission rates, and operating data and compared this information with the respective permit limits. As indicated in Table 4-5 and Attachment 3, the cooling tower mist eliminators are designed to achieve less than 0.0005% drift. Tables 4-6 and 4-

7 show that the SGS cooling tower emissions and TDS values are less than the respective permit limits.

Table 4-6. Cooling Tower Annual PM_{10}/$PM_{2.5}$ Emissions Limits and Reported Values

Emission Unit	Permit Limit	Reported Values for 2008 and 2009
Cooling Tower CT1	3.34 tpy	0.82 tpy (2008) 0.76 tpy (2009)
Cooling Tower CT5	3.45 tpy	1.91 tpy (2008) 2.56 tpy (2009)
Cooling Tower CT6	1.59 tpy	0.89 tpy (2008) 0.86 tpy (2009)

Table 4-7. Cooling Tower TDS Content Limits and Actual Values

Emission Unit	Permit Limit	Maximum Values for 2008 and 2009
Cooling Tower CT1	9,500 mg/L	3,100 mg/L
Cooling Tower CT5	5,700 mg/L	3,450 mg/L
Cooling Tower CT6	5,700 mg/L	3,100 mg/L

In addition to review of operating and emissions data, S&L also reviewed SGS O&M procedures and inspection reports pertaining to the cooling towers. S&L concludes that SRP's O&M records are complete and that an adequate inspection program is in place (see Section 4.7 and Attachment 9).

Based on a review of recent permits that have been issued for new cooling towers, PM_{10}/$PM_{2.5}$ emissions have generally been controlled by utilizing mist eliminators designed to achieve 0.0005% drift efficiency. Furthermore, there are no additional PM_{10} controls, or other improvements, capable of providing further $PM_{10}/PM_{2.5}$ emissions reductions from the existing cooling towers. Because SRP utilizes mist eliminators that are designed to achieve 0.0005% drift, $PM_{10}/PM_{2.5}$ emissions improvements for CT1, CT5, and CT6 will not be evaluated at this time.

4.4 DIESEL ENGINES

The following emergency engines are installed at Santan Generating Station:

- One 310 hp diesel-fired emergency fire water pump
- Two diesel-fired emergency generators, rated at 830 hp and 577 hp
- One 122 hp propane-fired emergency generator

Per Permit Condition 19.B.33, an emergency for the engines is defined as "when normal power line or natural gas service fails, for the emergency pumping of water, for when low water pressure in the fire suppression system is triggered, for unforeseen flood or fire or life threatening situation, or for similar situations accepted as an emergency by the Control Officer and Administrator."

As required by the facility's Title V operating permit, the diesel engines are designed to meet the applicable US EPA emissions standards. Permit limits pertaining to the diesel engines are shown in Table 4-8.

Table 4-8. Diesel Engine Permit Limits

Parameter	310 hp and 830 hp Engines		577 hp Engine	
	Current Title V Permit Limit	**Compliance Method**	**Current Title V Permit Limit**	**Compliance Method**
Hours of Operation	<= 37.5 hr/yr for engine testing, each <= 500 hr/yr for testing/emergencies	Engines operate less than 37.5 hr/yr	<= 37.5 hr/yr for engine testing, each <= 500 hr/yr for testing/emergencies	Engines operate less than 37.5 hr/yr
NO_X	9.2 g/kW-hr 4,000 lb/yr, each	Engines meet EPA Tier 1 standard	4.0 g/kW-hr ($NMHC+NO_x$) 4,000 lb/yr, each	Engines meet EPA Tier 3 standard
CO	11.4 g/kW-hr 4,000 lb/yr, each	Engines meet EPA Tier 1 standard	3.5 g/kW-hr 4,000 lb/yr, each	Engines meet EPA Tier 3 standard
SO_2	Fuel S content = 0.0015 wt%	Engines fire ultra low-S diesel fuel (fuel S content $\leq$ 0.0015 wt%)	Fuel S content = 0.0015 wt%	Engines fire ultra low-S diesel fuel (fuel S content $\leq$ 0.0015 wt%)
VOC	1.3 g/kW-hr	Engines meet EPA Tier 1 standard	4.0 g/kW-hr ($NMHC+NO_x$)	Engines meet EPA Tier 3 standard
$PM_{10}/PM_{2.5}$	0.54 g/kW-hr	Engines meet EPA Tier 1 standard	0.20 g/kW-hr	Engines meet EPA Tier 3 standard

EPA is requiring new, recently permitted emergency diesel engines to meet more stringent NSPS Subpart IIII emissions limits. The NSPS Subpart IIII standards that would apply to new emergency diesel generators and stationary fire pump engines are provided in Table 4-9.

Table 4-9. Comparison of Emergency Diesel Engine Standards

Pollutant	Permit Limits for 310 and 830 hp Engines (1)	Permit Limits for 577 hp Engines (3)	NSPS Subpart IIII Standards for New Emergency Generators and Fire Pumps (4,5)
NO_X + HC	10.5 g/kW-hr(2)	4.0 g/kW-hr	4.0 g/kW-hr (for 310 hp fire pump and 577 hp engine) 6.4 g/kW-hr (for 830 hp engine)
CO	11.4 g/kW-hr	3.5 g/kW-hr	3.5 g/kW-hr
$PM_{10}/PM_{2.5}$	0.54 g/kW-hr	0.20 g/kW-hr	0.20 g/kW-hr

(1) Based on Tier 1 standards for 830 hp emergency generator and 310 hp fire pump per 40 CFR 89.112, Table 1
(2) Sum of NOx and CO limits; 9.2 g/kW-h and 1.3 g/kW-h
(3) Based on Tier 3 standards for 577 hp emergency generator per 40 CFR 89.112, Table 1
(4) Standards for new 577 hp and 830 hp emergency generators per 40 CFR 89.112, Table 1
(5) Standards for new 310 hp fire pump per 40 CFR Part 60 Subpart IIII, Table 4

The current NSPS Subpart IIII emissions standards for NO_x+HC, CO, and PM_{10} are the same or more stringent than the limits that apply to the SGS emergency engines. Although control technologies exist that can reduce NO_x, VOC, CO and PM_{10} (e.g., water or urea injection for NO_x control, catalyst for CO and VOC), it is not practical to install such controls on existing Tier 1 diesel engines, especially engines that are limited to less than 37.5 hours per year operation for required testing and routine maintenance. Using 37.5 hours per year as a basis, the potential NO_x, VOC, CO or PM_{10} emissions reductions associated with meeting current NSPS Subpart IIII emissions limits would be less than 0.1 ton per year each. Because there are no available control technologies, or other improvements, with a practical application on the existing diesel engines, emissions improvements for the SGS diesel engines will not be evaluated at this time.

In addition to the diesel engines, a propane-fired emergency generator is installed at SGS. S&L's review of emissions data sheets along with discussions with SRP personnel indicate that the propane generator is operating in accordance with permit requirements. Based on limited annual operation and low emissions associated with firing propane, emissions improvements for the SGS propane generator will not be evaluated.

4.5 ABRASIVE BLASTING EQUIPMENT

SGS is equipped with an abrasive blast shed where parts and equipment are cleaned and blasted with abrasive media. The current permit for SGS states that the station shall not "discharge into the atmosphere from any abrasive blasting any air contaminant for a period or periods aggregating more than three minutes in any one-hour period which is a shade or density darker than 20 percent opacity." Abrasive blasting equipment exhaust must be vented through a baghouse if the exhaust is sent to the outside of the building.

A new baghouse was installed in late 2010 for the SGS abrasive blasting equipment. The new baghouse is designed to achieve a control efficiency of 99.9%. With the installation of the new baghouse, there are no additional controls, or other improvements capable of providing further PM_{10} control from this source. Therefore, emissions improvements for the abrasive blasting equipment will not be evaluated at this time.

4.6 FUEL STORAGE TANKS

SGS is equipped with three diesel storage tanks and one gasoline storage tank. The facility's Title V operating permit lists the diesel storage tanks as "insignificant activities." Because of the low vapor pressure of diesel fuel, it is commonly accepted that VOC emissions associated with diesel fuel storage and handling are minimal. Therefore, emissions improvements for the diesel storage tanks will not be evaluated.

With regard to the gasoline storage tank, the SGS Title V Operating Permit Condition 19.J requires the following design considerations:

- "basic tank integrity" such that "no vapor or liquid escapes are allowed through a dispensing tank's outer surfaces, nor from any of the joints where the tank is connected to the pipe(s), wires, or other systems"
- "each fill-line into a stationary dispensing pipe shall be equipped with a permanent submerged fill-pipe"
- "fill pipe caps" having a "securely attached, intact gasket"
- "overfill protection equipment" that is "vapor tight to the atmosphere"

In addition to the gasoline storage tank design requirements, the facility's permit restricts annual gasoline throughput to less than 120,000 gallons. VOC emissions are minimized with required gasoline handling procedures identified in Permit Condition 19.J.6.a. Per discussion with SRP personnel, the gasoline storage tank design and fuel handling procedures are in compliance with the requirements of Permit Condition 19.J.

Based on review of environmental regulations for other states and air quality districts, the MCAQD requirements generally coincide with regard to gasoline storage tank design and fuel handling requirements for new gasoline storage tanks of similar size and annual throughput. Modifications to reduce emissions any further, such as employing vapor recovery systems used at high throughput commercial gas stations, could be installed. However, based on S&L's engineering judgement, such modifications would be cost prohibitive. Therefore, emissions improvements for the gasoline storage tank will not be evaluated at this time.

4.7 FACILITY O&M EVALUATION

As part of the CEC Condition 38 assessment required by the ACC for SGS, S&L evaluated the Operations and Maintenance practices to investigate the possibility of reducing emissions from current operating levels by either: a) changing operating and maintenance (O&M) practices or b) implementing new emissions reduction technologies.

The SGS O&M Program encompasses the following activities:

i. A documented Preventive Maintenance and Inspection program for the emission control equipment,

ii. A Preventive / Predictive Maintenance program to maintain equipment reliability and performance,

iii. A Work Management Process to complete station activities efficiently,

iv. Several Performance Monitoring Systems to provide technical information for plant staff, and

v. Reliable modern control systems that automate system operations.

S&L reviewed operation and maintenance procedures, inspection schedules, and O&M manuals for each of the combined cycle units, the cooling towers, and the diesel engines. For the combined cycle units, S&L evaluated the Preventative Maintenance and Inspection program for the dry low-NO_x burners, CO catalyst, SCR system, and the baghouse for abrasive blasting equipment.

S&L prepared Santan Emissions Operating and Maintenance Practices Assessment Report SL-10419, which has been provided in Attachment 9. The assessment did not find opportunities where a change in operations and maintenance practices would help reduce air emissions.

4.8 SUMMARY OF PHASE 1 EMISSIONS ASSESSMENT

The Phase 1 emissions assessment included a review of plant data that reflects current SGS emissions. This information was then processed so it could be utilized for an initial comparison to the emissions rates that are considered to be achievable. In conjunction, a review of equipment operating practices was performed to determine if O&M improvements could be implemented to reduce emissions. The results of this initial assessment were discussed in Sections 4.1 through 4.6, and are summarized in Table 4-10.

Table 4-10. Summary of Phase 1 Emissions Assessment

Emission Source		Pollutant					Emissions Improvements Further Evaluated?
		NOx	CO	VOC	PM_{10}	SO_2	
Units 1-4	SGS (Actual)	< 40 ppm (across full operating range) < 20 ppm (80-100% load)	< 40 ppm (across full operating range) < 10 ppm (80-100% load)	~1.7 ppm (reported) 1.4 ppm (guarantee – 80-100% load)	0.0066 lb/mmBtu (reported) 5 lb/hr (guarantee)	Fuel S Content < 0.00363 gr/ft^3	Yes - NO_x/CO No – VOC/PM_{10}/SO_2 *(Emissions reductions will not be evaluated due to (1) DLN1 combustors/CO catalyst for VOC, and (2) firing low sulfur fuel and good combustion practices for* PM_{10}/SO_2*)*
	Recent Permit Limits (AZ, CA)	*2-2.5 ppm (50% to 100% load)*	*2-4 ppm (50% to 100% load)*	*1-4 ppm (50% to 100% load)*	*< 0.015 lb/mmBtu*	*Fuel S Content < 0.005 gr/ ft^3*	
Units 5-6	SGS (Actual)	< 2 ppm	< 2 ppm	< 2 ppm	0.01lb/mmBtu	Fuel S Content < 0.00363 gr/ft^3	No *(Emissions reductions will not be evaluated because Units 5-6 are already equipped with state-of-the-art emissions controls and, based on S&L's engineering judgement, any changes would cost well in excess of typical cost thresholds)*
	Recent Permit Limits (AZ, CA)	*2-2.5 ppm (50% to 100% load)*	*2-4 ppm (50% to 100% load)*	*1-4 ppm (50% to 100% load)*	*< 0.015 lb/mmBtu*	*Fuel S Content < 0.005 gr/ ft^3*	
Cooling Towers	SGS (Actual)	NA	NA	NA	Drift < 0.0005%	NA	No *(Emissions reductions will not be evaluated because SGS cooling tower mist eliminator drift efficiency is less than 0.0005%)*
	Recent Permit Limits (AZ, CA)	*NA*	*NA*	*NA*	*Drift < 0.0005-0.001%*	*NA*	

Table 4-10. Summary of Phase 1 Emissions Assessment (cont.)

Emission Source		Pollutant: NOx	Pollutant: CO	Pollutant: VOC	Pollutant: PM_{10}	Pollutant: SO_2	Emissions Improvements Further Evaluated?
Emergency Diesel Engines	**SGS (Actual)**	**9.2 g/kW-hr (310 hp fire pump, 830 hp generator)** **NOx + HC:** **4.0 g/kW-hr (577 hp generator)**	**11.4 g/kW-hr (310 hp fire pump, 830 hp generator)** **3.5 g/kW-hr (577 hp generator)**	**1.3 g/kW-hr (310 hp fire pump, 830 hp generator)** **NOx + HC:** **4.0 g/kW-hr (577 hp generator)**	**0.54 g/kW-hr (310 hp fire pump, 830 hp generator)** **0.20 g/kW-hr (577 hp generator)**	**Fuel S Content < 0.0015 wt%**	**No *(Additional emissions control technology is not practical on limited use engines such as emergency generators, and the emissions reductions generated by such controls would be < 0.1 tpy, so improvements are not further evaluated because, based on S&L's engineering judgment, the cost effectiveness of such controls would be well in excess of typical cost thresholds)***
	Recent Permit Limits (AZ, CA)	***NOx + HC:*** ***4.0 g/kW-hr (310 hp fire pump, 577 hp generator)*** ***NOx + HC:*** ***6.4 g/kW-hr (830 hp generator)***	***3.5 g/kW-hr (310 hp fire pump, 577/830 hp generators)***	***NOx + HC:*** ***4.0 g/kW-hr (310 hp fire pump, 577 hp generator)*** ***NOx + HC:*** ***6.4 g/kW-hr (830 hp generator)***	***0.20 g/kW-hr (310 hp fire pump, 577/830 hp generators)***	***Fuel S Content < 0.0015 wt%***	
Abrasive Blasting Equipment	**SGS (Actual)**	**NA**	**NA**	**NA**	**Opacity < 20%**	**NA**	**No *(SRP recently installed new dust collector that achieves 99.9% PM control)***
	Recent Permit Limits (AZ, CA)	***NA***	***NA***	***NA***	***Opacity < 20%***	***NA***	
Gasoline Storage Tank	**SGS (Actual)**	**NA**	**NA**	**NA[(1)]**	**NA**	**NA**	**No *(Emissions reductions will not be evaluated because tank design and fuel handling procedures generally meet requirements for similar tanks and, based on S&L's engineering judgment, making any physical changes to small, low throughput tanks would likely be cost ineffective compared to typical thresholds)***
	Recent Permit Limits for similarly sized tanks (AZ, CA)	***NA***	***NA***	***NA[(1)]***	***NA***	***NA***	

(1) VOC emissions from gasoline storage tanks are controlled by utilizing proper tank design (e.g., submerged fill pipe) and fuel handling procedures to minimize vapor losses, and limiting annual fuel throughput.

5 PHASE 2 EVALUATION: EMISSIONS REDUCTION OPTIONS

Based on the results of the "Phase 1 Evaluation," this "Phase 2 Evaluation" explores potential NO_x and CO emissions improvements for Units 1-4. This analysis generally follows a "top-down" approach that is used in permitting new major sources of air emissions or modifications to existing major source. A similar process has been used by state and county agencies in evaluating NO_x emission controls at existing stationary sources as part of a regional ozone attainment strategy. The "top-down" approach utilized in this evaluation includes the following steps for each emission source and pollutant that is being evaluated:

1. Identify potential control technologies;
2. Eliminate technically infeasible control options;
3. Rank the remaining control technologies by control effectiveness;
4. Evaluate the control technologies, starting with the most effective for:
   - economic impacts,
   - environmental impacts, and
   - energy impacts;
5. Summary of potential emissions improvements.

A more detailed description of each step in the "top-down" control technology analysis is provided below.

5.1 "TOP DOWN" CONTROL TECHNOLOGY EVALUATION PROCESS

Step 1 - Identify All Control Options

The first step in this "top-down" control technology analysis is to identify, for the emission unit in question, available control options. Available control options are those air pollution control technologies with a practical potential for application to the emission unit and the regulated pollutant under evaluation. For this evaluation, the emission units that are being evaluated is the existing SGS Units 1-4 combined cycle units.

In an effort to identify potentially applicable emission control technologies for Units 1-4, S&L conducted a comprehensive review of available sources of technical information, including but not necessarily limited to:

- EPA's RACT/BACT/LAER Clearinghouse;
- Information from control technology vendors and engineering/environmental consultants;
- Federal and State new source review permits;
- Technical journals, reports, newsletters and air pollution control seminars.

Step 2 - Eliminate Technically Infeasible Control Options

The second step in this "top-down" control technology analysis is to review the technical feasibility of the control options identified in Step 1 with respect to source-specific and unit-specific factors. A demonstration of technical unfeasibility must be based on physical, chemical and engineering principals, and must show that technical difficulties would preclude the successful use of the control option on the emission unit under consideration. The economics of an option are not considered in the determination of technical feasibility/unfeasibility. Options that are technically infeasible for the intended application are eliminated from further review.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All technically feasible options are ranked in order of overall control effectiveness. Control effectiveness is generally expressed as the rate that a pollutant is emitted after the control system. The most effective control option is the system that achieves the lowest emissions level.

Step 4 - Evaluate Most Effective Controls

After identifying the technically feasible control options, each option, beginning with the most effective, is evaluated for associated economic, energy and environmental impacts. Both beneficial and adverse impacts may be assessed and, where possible, quantified. In the event that the most effective control alternative is shown to be inappropriate due to economic, environmental or energy impacts, the basis for this finding is documented and the next most stringent alternative evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific economic, environmental or energy impacts.

Economic Analysis

The economic analysis performed as part of this “top-down” control technology analysis examines the cost-effectiveness of each control technology, on a dollar per ton of pollutant removed basis. Annual emissions using a particular control device are subtracted from base case emissions to calculate tons of pollutant controlled per year. The base case generally represents uncontrolled emissions or the inherent emission rate from the proposed source. Annual costs are calculated by adding annual operation and maintenance costs to the annualized capital cost of an option. Cost effectiveness ($/ton) of an option is simply the annual cost ($/yr) divided by the annual pollution controlled (ton/yr).

In addition to the cost effectiveness relative to the base case, the incremental cost-effectiveness to go from one level of control to the next more stringent level of control may also be calculated to evaluate the cost effectiveness of the more stringent control.

Environmental Impact Analysis

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal. The environmental impact analysis should be made on a consideration of site-specific circumstances.

Energy Impact Analysis

The energy requirements of a control technology can be examined to determine whether the use of that technology results in any significant or unusual energy penalties or benefits. Two forms of energy impacts associated with a control option can normally be quantified. First, increases in energy consumption resulting from increased heat rate may be shown as total Btu’s or fuel consumed per year or as Btu’s per ton of pollutant controlled. Second, the installation of a particular control option may reduce the output and/or reliability of equipment. This reduction would result in loss of revenue from power sales and/or increased fuel consumption due to use of less efficient electrical and steam generation methods.

Step 5 – Summary of Potential Emissions Improvements

Based on the results of Steps 1 through 4, Step 5 provides a summary of potential emissions improvements for the generating units that are being evaluated.

The methodology described above will be applied to the SGS Units 1-4 combined cycle units. Based on the results of the "Phase 1 Evaluation" included in Section 4, potential emissions improvements were evaluated for the following pollutants:

- Nitrogen Oxides (NO_x)
- Carbon Monoxide (CO)

5.2 NO_X CONTROL OPTIONS FOR UNITS 1-4

5.2.1 Step 1: Identify Feasible NO_x Control Options

Potentially available control options were identified based on a comprehensive review of available information. NOx control technologies with potential application to Units 1-4 are listed in Table 5-1.

Table 5-1. List of Potential NO_x Control Options (Units 1-4)

Control Technology
Combustion Controls
Baseline Combustion Controls (DLN1 Combustors)
Combustor Upgrades
Post-Combustion Controls
Selective Catalytic Reduction (SCR)
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)
Urea Injection Systems (Selective Non-Catalytic Reduction and NOxOut™)
Ammonia Injection Systems (Thermal DeNOx™)
Catalytic Combustion (Xonon™)

5.2.2 Step 2: Technical Feasibility of NO_x Control Options

NO_x control technologies can be divided into two general categories: combustion controls and post-combustion controls. Combustion controls reduce the amount of NO_x that is generated in the combustors. Post-combustion controls remove NO_x from the CT exhaust gas.

5.2.2.1 Combustion Controls

NO_x formation in a natural gas-fired combustion turbine (CT) occurs by three fundamentally different mechanisms; thermal NO_x, prompt NO_x, and fuel NO_x. Essentially all NO_x formed from natural gas combustion is thermal NO_x. Thermal NO_x is created by the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. The amount of thermal NO_x formed is a function of the combustion chamber design and the CT operating parameters, including flame temperature, residence time at flame temperature, combustion pressure, and fuel/air ratios at the primary combustion zone. The maximum thermal NO_x formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The rate of thermal NO_x formation is also an exponential function of the flame temperature. Uncontrolled NO_x emissions from a natural gas-fired combustion turbine will be in the range of 0.32 lb/mmBtu (or approximately 90 ppmvd @ 15% O_2).[2]

Prompt NO_x is formed from reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x forms within the flame and is usually negligible when compared to thermal NO_x.

Fuel NO_x is formed by the gas-phase oxidation of fuel-bound nitrogen compounds with oxygen. Its formation is dependent on fuel nitrogen content and the combustion oxygen levels. Natural gas contains negligible chemically-bound fuel nitrogen; thus, the formation of fuel NO_x is also negligible when compared to thermal NO_x.

Excess air in lean combustion cools the flame and reduces the formation of thermal NO_x. Dry low- NO_x (DLN) combustion systems reduce the amount of thermal NO_x formed by lowering the overall flame temperature within the CT combustor. The lower flame temperature is accomplished by premixing the fuel and air at controlled stoichiometric ratios prior to combustion.

Prior to the development of premix-based DLN combustors, fuel and air were injected separately into the CT's combustor section. Oxygen in the combustion air, needed to support the combustion process, would diffuse into the flame front located at the combustor's fuel burner, and combustion occurred in a diffusion flame. The result of this approach was a range of fuel-to-air ratios over which combustion occurred and a corresponding range of flame temperatures.

For DLN combustor designs, air/fuel mixing is accomplished prior to the burner where the actual combustion occurs. This design provides better control of the air-to-fuel stoichiometric ratio, lower flame temperature, reduced excess oxygen, and minimizes the potential for localized high-temperature fuel-rich pockets.

Baseline Combustion Controls (DLN-1 Combustors)

The original combustors for Units 1 through 4 were replaced with GE's DLN-1 combustors in 2001. The DLN-1 combustors are two-stage premix combustors designed to fire both natural gas and fuel oil. Although the DLN-1 combustors are typically designed to achieve NO_x levels of 9 ppmvd @ 15% O_2 and CO levels of 25 ppmvd @ 15% O_2 while firing natural gas, the DLN-1 combustors for Units 1-4 were required to achieve CO levels of 10 ppmvd @ 15% O_2. Therefore,

[2] See, AP-42 Table 3.1-1; NO_x Emission Factor for Uncontrolled Natural Gas-Fired Turbines.

the Units 1-4 DLN-1 combustors were designed to meet NO_x levels of 20 ppmvd @ 15% O_2 while firing natural gas so that the reduced CO levels could be achieved.

Combustor Upgrades

Since 2001, DLN combustor technology has matured and DLN systems installed on new combustion turbines have demonstrated the ability to achieve NO_x levels below 10 ppmvd @ 15% O_2. For example, GE's DLN-1+ combustors include redesigned secondary fuel nozzles, optimized air-fuel mixing, and updated control systems that enable the combustors to achieve NO_x levels as low as 4 ppmvd @ 15% O_2, with CO levels in the range of 25 ppmvd @ 15% O_2. However, to achieve CO levels equal to or less than current levels of 10 ppmvd @ 15% O_2, the design NO_x levels would be in the range of 7 to 9 ppmvd @ 15% O_2,

Combustor upgrades are a technically feasible and commercially available option for reducing NO_x emissions. Based on information from combustor vendors, combustor upgrades on Units 1-4 will be evaluated at a controlled NO_x level of 8 ppmvd @ 15% O_2 while firing natural gas and operating from 50% to 100% load, which represents a NO_x reduction of approximately 60% from the baseline level. A combustor design NO_x level of 8 ppm was selected such that combustor upgrades will result in a slight reduction in CO emissions (see Section 5.3.2).

5.2.2.2 Post-Combustion Controls

A second strategy to minimize NO_x emissions from a natural gas-fired combined cycle unit is to reduce NO_x formed in the CT/HRSG using a post-combustion control system. Potentially available post-combustion NO_x control systems are evaluated below.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion NO_x control technology. SCR reduces NO_x by injecting ammonia (NH_3) in the presence of a catalyst. Ammonia reacts with NO_x in the presence of active catalyst and excess oxygen to form water vapor and nitrogen, as shown in the following equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The performance of an SCR system is influenced by several factors including flue gas temperature, SCR inlet NO_x level, the catalyst surface area, volume and age of the catalyst, and the amount of ammonia slip that is acceptable.

SCR catalysts used in combined cycle application generally consist of vanadium pentoxide as an active ingredient mixed with titanium dioxide as a substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the gas turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit.

Flue gas temperature and residence time must be taken into consideration when designing a SCR control system. The temperature range for base metal catalyst is in the range of 400°F and 800°F. On a combined-cycle combustion turbine, this temperature window occurs within the heat recovery steam generator (HRSG), downstream of the gas turbine.

Controlled NO_x emission rates achievable with a SCR control system are a function of the catalyst volume, ammonia-to-NO_x (NH_3:NO_x) ratio, reaction temperature, and catalyst activity. For a given catalyst volume, higher NH_3:NO_x ratios can be used to achieve higher NO_x emission reductions, but this control strategy can result in an unacceptable increase in emissions of unreacted NH_3 (ammonia slip).

Catalyst activity is a function of catalyst age and deactivation. SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation (catalyst sintering) if the catalyst is exposed to excessive temperatures (typically > 800°F) over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include compounds containing arsenic, and salts of potassium, sodium, and calcium. On a natural-gas combined cycle unit, where only natural gas is fired, potential catalyst poisons should be minimal, and a catalyst life of approximately 5 years can be expected.

Ammonia slip should be minimized due to the potential for salt formation from the reaction of ammonia with sulfur compounds in the flue gas. The combustion of sulfur-bearing fuels produces SO_2, and to a lesser degree, SO_3. Some conversion of SO_2 to SO_3 also occurs across the SCR catalyst bed. SO_3 in the flue gas can react with ammonia to form ammonium sulfate and/or ammonium bisulfate. Ammonium bisulfate is a sticky compound, which can deposit in the low-temperature region of the HRSG, resulting in increased back-pressure on the CT and reduced heat transfer efficiency in the HRSG. A unit shutdown is generally required to remove ammonium bisulfate deposits from heat transfer surfaces.

The rate of ammonium salt formation increases with increasing levels of SO_3 and NH_3, and decreasing stack gas temperature. Ammonium sulfate and bisulfate are also classified as filterable particulates; thus, the formation of ammonium salts results in an increase in PM_{10} emissions. Because the Santan Units 1-4 fire natural gas exclusively, these issues should be minimal; however, to minimize potential operating issues and to minimize ammonia and filterable particulate emissions, ammonia slip should still be maintained below a level of approximately 5 ppmvd.

Based on a review of Units 1-4 HRSG drawings, three SCR placement options were considered: (1) CT plenum outlet, (2) stack, and (3) superheater section. This first placement option, CT plenum outlet, would require installation of a high temperature catalyst that could withstand exhaust temperatures in excess of 1000°F. At this time, there is limited experience with high temperature SCR operation and therefore SCR placement at the CT plenum outlet will not be considered at this time.

The second SCR placement option is at the HRSG stacks for Units 1-4. This option would potentially require expanding the stack ductwork to reduce the exhaust velocity and raising the stack height by approximately 30 feet. Unlike the option to place the SCR in the superheater / evaporator section (see description below), locating the SCR at the stack would reduce costs since piping, tubes, and drums would not have to be raised. However, a primary concern lies with exhaust temperature of approximately 320°F. Although OEMs typically require a minimum SCR operating temperature of 500°F, it is generally feasible to operate an SCR system at temperatures as low as 350°F. However, at temperatures in the range of 300°F to 350°F, there is potential that ammonium bisulfate will be formed thus resulting in a loss in unit performance. Therefore, based on a typical stack temperature of 320°F, SCR installation at the Units 1-4 HRSG stacks will not be considered at this time.

The third SCR placement option for Units 1-4 is in the superheater / evaporator section to take advantage of an optimal exhaust gas temperature ranging from 500°F to 700°F. The superheater / evaporator sections of the Units 1-4 HRSGs are vertical and confined which means that SCR installation would require expanding the ductwork and raising the piping, tubes, drum and stack approximately 30 feet to accommodate the SCR reactor and ammonia injection grid assembly.

SCR is considered a technically feasible and commercially available NO_X control technology for Santan Units 1- 4 if the SCR reactor and ammonia injection grid is located in the HRSG superheater / evaporator section. Based on a review of emission rates achieved in practice at similar sources and emission limits included in recently issued Prevention of Significant Deterioration (PSD) permits for natural gas-fired combined cycle facilities, S&L concludes that an SCR control system could be designed to achieve a controlled NO_X emission rate of 2.0 ppmvd @ 15% O_2 at loads ranging from 50 to 100%, thus representing a NO_x reduction of approximately 90% from the baseline level.

<u>Oxidation Catalyst w/ Potassium Carbonate Absorption</u>

EMx™ (SCONOx™) is a post-combustion, multi-pollutant control technology, originally developed by Goal Line Environmental Technologies (now EmeraChem LLC). The EMx™ technology uses a coated oxidation catalyst to remove NO_x, CO, and VOC emissions in the turbine exhaust gas by oxidizing CO to CO_2, NO to NO_2, and hydrocarbons to CO_2 and water. The CO_2 is then emitted to the atmosphere, and the NO_2 is absorbed onto the potassium carbonate coating on the EMx™ catalyst to form potassium nitrate/nitrite. These reactions are referred to as the "oxidation/absorption cycle."

Because the potassium carbonate coating is consumed as part of the absorption step, it must be regenerated periodically. This is accomplished by passing a regeneration gas containing hydrogen and carbon dioxide across the surface of the catalyst in the absence of oxygen. The hydrogen in this gas reacts with nitrites and nitrates to form water vapor and elemental nitrogen. The carbon dioxide in the gas reacts with the liberated potassium oxide to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began. These reactions are called the "regeneration cycle." Water vapor and elemental nitrogen are exhausted, and potassium carbonate is once again present on the surface of the catalyst, allowing the oxidation/absorption cycle to repeat.

Because the regeneration cycle must take place in an oxygen-free environment, the catalyst undergoing regeneration must be isolated from the CT-HRSG exhaust gas. This is accomplished by dividing the catalyst bed into discreet sections, and placing dampers upstream and downstream of each section. During regeneration, some of the dampers close, isolating a section of the catalyst bed. While this is going on, exhaust gas continues to flow through the remaining open sections of the catalyst bed. After the isolated section of catalyst has been regenerated, another set of dampers closes so that the next section of catalyst can be isolated for regeneration. This cycle is repeated for each catalyst section approximately once every 5 minutes.

The EMx™ catalyst is very sensitive to fouling, because the potassium coating is irreversibly deactivated by sulfur in the exhaust gas. For large-scale applications, however, EmeraChem recommends using a sulfur oxidation/absorption catalyst, called ESx™ (formerly SCOSOx), to remove sulfur from the exhaust gas. The ESx™ catalyst would be located upstream of the EMx™ catalyst, and would be regenerated at the same time as the EMx™ catalyst. Regeneration of the ESx™ catalyst would result in an off-gas consisting of H_2S and/or SO_2. The H_2S/SO_2 off-gas would be discharged to the HRSG stack and emitted into the atmosphere.

The EMx™ multi-pollutant control system has operated successfully on several smaller natural gas-fired units. Potential advantages of the EMx™ control system include the concurrent control of CO and VOC emissions and the fact that the control system does not use a reactant. However, there are a number of engineering challenges associated with applying this technology to larger plants with full scale operations such as the SGS Units 1-4. Potential issues include the following:

- For large-scale natural gas combined cycle (NGCC) applications, the EMx™ catalyst would have to be placed in the HRSG where the exhaust gas temperatures will be in the range of 500 to 700°F. Performance of the EMx™ catalyst in a high-temperature application has not been demonstrated in practice.
- The dampers and damper bearings, which are moving parts exposed to the hot exhaust gas, could present long-term maintenance and reliability problems. This is particularly true as the damper size and number of dampers increase, as would be necessary in order to use this technology for Units 1-4.
- Regeneration of the EMx™ catalyst would require hydrogen gas to be continuously generated (from natural gas) and introduced into the high-temperature zone of the HRSG. Because hydrogen gas is explosive, any leaks in the dampers used to isolate the catalyst for regeneration could create a serious hazard.
- In addition to periodic regeneration, the EMx™ catalyst would have to be cleaned at least once per year by removing the catalyst beds from the HRSG and dipping them in a potassium carbonate solution.
- The EMx™ and ESx™ processes have the potential to create additional air pollutants, such as hydrogen sulfide (H_2S). Emissions of these additional pollutants have not been completely quantified.

To date, the EMx™ (SCONOx) multi-pollutant control system has not been installed and operated on a large gas-fired combined cycle application. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system for Units 1-4. Therefore, at this time the EMx™ control system is not considered an available NOx control system, and will not be further evaluated.

<u>Urea Injection Systems (Selective Non-Catalytic Reduction and NO_xOut™)</u>

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) at flue gas temperatures of approximately 1600 - 1900 ºF. The ammonia or urea reacts with NO_x in the flue gas to produce N_2 and water. The NO_x reduction reactions in an SNCR are driven by the thermal decomposition of ammonia or urea and the subsequent reduction of NO_x. SNCR systems do not employ a catalyst to promote these reactions.

Flue gas temperature at the point of reagent injection can greatly affect NO_x removal efficiencies and the quantity of reactant that will pass through the SNCR unreacted (e.g., slip). At temperatures below the desired operating range, the NO_x reduction reactions diminish and unreacted reactant emissions increase. Above the desired temperature range, the reactant may be oxidized to NO_x resulting in low NO_x reduction efficiencies. The NO_xOut™ process is a post-combustion NOx reduction method in which aqueous urea is injected into the flue gas stream. The urea reacts with NOx in the flue gas to produce N_2 and water as shown below:

$(NH_2)_2CO + 2NO + ½O_2 \rightarrow 2H_2O + CO_2 + 2N_2$

The use of urea to control NO_x emissions was developed under the sponsorship of the Electric Power Research Institute (EPRI). The urea-NO_x reaction takes place over a narrow temperature range, below which ammonia is formed and above which NO_x emission levels may actually increase. Fuel Tech's NOxOut™ process is a urea-based SNCR process that uses mechanical modifications and chemical injection hardware to widen the effective temperature range of the reaction to between 1,600 and 1,950°F. To date, commercial application of this system on large natural gas-fired combined cycle units has been limited. Based on a review of available literature, and engineering judgment, the NO_xOut™ process is not considered a technically feasible NO_x control option for the Units 1-4. NO_x reduction reactions require flue gas temperatures in the range of 1,600 to 1,950°F; however, exhaust gas temperatures from Units 1-4 will be in the range of 1,100°F. Increasing the exhaust gas temperature would significantly reduce the efficiency of the combustion turbine or require additional fuel consumption and installation of a flue gas heater. Neither option is considered practical for a gas-fired combined cycle unit. Therefore, at this time, NOxOut™ is not considered a technically feasible NO_x control option for Units 1-4, and will not be considered further.

Ammonia Injection Systems (Thermal DeNO_x™)

Exxon Research and Engineering Company's Thermal DeNO_x™ process utilizes an ammonia/NO_x SNCR reaction to reduce NO_x to nitrogen and water as shown in the following equation:

$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$

Hamon Research Cottrell is licensed by Exxon-Mobil for the application of the ammonia based Thermal DeNO_x™ process. The process consists of a high-temperature selective non-catalytic reduction of NO_x using ammonia as the reducing agent. This process does not use a catalyst to aid the reaction, rather temperature control is used to direct the reactions. Optimum reaction temperatures for NO_x reduction are between 1,600°F and 1,800°F. Below the optimum temperature range, ammonia does not fully react and can be released in the flue gas. Above the optimum temperature, the following competing reaction will begin to take place, which can result in increased NO_x emissions:

$4H_3 + 5O_2 \rightarrow 4O + 6H_2O$

To date, commercial applications of the Thermal DeNO_x™ process have been limited to furnaces, heavy industrial boilers, and incinerators that consistently produce exhaust gas temperatures in the range of 1,800°F. Because exhaust gas volumes increase significantly with increased temperatures, application of the Thermal DeNO_x™ process would require that flue gas handling systems be designed to handle larger high temperature flows. Similar to the NO_xOut™ process, high capital and O&M costs are expected due to material requirements, additional equipment, and fuel consumption. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system on Units 1-4. Therefore, at this time the Thermal DeNO$_x$™ control system is not considered an available NO$_x$ control system, and will not be further evaluated.

Catalytic Combustion (Xonon™)

Catalytic combustion uses a catalyst within the combustor to oxidize a lean air-to-fuel mixture rather than burning with a flame. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO$_x$. One technical challenge associated with catalytic combustion has been achieving catalyst life long enough to make the combustor commercially viable.

The Xonon™ ("no NO$_x$" spelled backwards) combustion system was originally developed by Catalytica Combustion Systems (now Catalytica Energy Systems). The Xonon™ control system works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is lower temperature partial combustion followed by flameless catalytic combustion to reduce NO$_x$ formation. To date, the system has successfully completed pilot- and full-scale testing, and has been demonstrated on a 1.5 MW Kawasaki gas turbine. However, the Xonon™ combustion system has not been demonstrated for extended periods of time on a large natural gas-fired combustion turbine. Applications of this technology have been in the 1 to 15 MW range. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system on Units 1-4. Therefore, at this time, catalytic combustion systems (including Xonon™) are not considered available NO$_x$ control systems, and will not be further evaluated.

Table 5-2. Technical Feasibility of NO_x Control Technologies (Units 1-4)

Control Technology	Approximate Controlled NO_x Emission Rate (ppmvd@15%O_2)	In Service on Existing Gas-Fired Combined Cycle Units?	Technically Feasible on the SGS Units 1-4?
Baseline Combustion Controls (DLN1 Combustors)	20	Yes	Yes – currently installed
Combustor Upgrades	8	Yes	Yes
SCR	2	Yes	Yes
SCR + Combustor Upgrades	2	Yes	Yes
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)	NA	limited application	This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for the Units 1-4
Urea Injection Systems (Selective Non-Catalytic Reduction and NOxOut™)	NA	limited application	This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for the Units 1-4
Ammonia Injection Systems (Thermal DeNOx™)	NA	limited application	This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for the Units 1-4
Catalytic Combustion (Xonon™)	NA	limited application	This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for the Units 1-4

5.2.3 Step 3: Rank the Technically Feasible NO_x Control Options by Effectiveness

The technically feasible and commercially available NO_x control technologies are listed in Table 5-3 in descending order of control efficiency.

Table 5-3. Ranking of Technically Feasible NO_x Control Technologies (Units 1-4)

Control Technology	Controlled NO_x Emission Rate (80-100% Load) (ppmvd@15%O_2)	% Reduction (from base case)
SCR + Combustor Upgrades	2	90%
SCR	2	90%
Combustor Upgrades	8	60%
Baseline Combustion Controls (DLN1 Combustors)	20	NA

The most effective NO_x control system, in terms of reduced emissions, that is considered to be technically feasible for the SGS Units 1-4 includes post-combustion SCR. The effectiveness of the SCR system is dependent on several site-specific system variables including inlet NO_x concentrations, the type and size of the SCR catalyst system, flue gas temperatures, ammonia injection system design, and catalyst deactivation rate. This control option should be capable of achieving the most stringent controlled NO_x emission rate on an on-going long-term basis. The other effective NO_x control system that is considered technically feasible and commercially available is combustor upgrades.

5.2.4 Step 4: Evaluation of Technically Feasible NO_x Controls

An evaluation of the economic, environmental and energy impacts of each technically feasible and commercially available NO_x emissions control option is provided below.

NO_x Control Technologies – Economic Evaluation

Economic impacts associated with the potentially feasible NO_x control systems were evaluated using an approach that is similar to the methodology specified in the EPA's New Source Review Workshop Manual (Draft, 1990). For the economic impact analysis, projected annual emissions (tpy) were used to evaluate average cost effectiveness (i.e., dollar per ton removed). Annual emissions (tpy) were calculated assuming: (1) baseline control option emissions are equal to the actual, maximum reported level from years 2008 and 2009; (2) post-control emissions are equal to the baseline control option emissions times the assumed percent reduction associated with each control option.[3]

Cost estimates were compiled from a number of data sources. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual.[4] Major equipment costs were developed based on information available from equipment vendors and equipment costs recently developed for similar projects. Capital costs include the equipment, material, labor, and all other direct costs needed to install the control technologies. Fixed and variable O&M costs were developed for each control system.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (if applicable), byproduct management, and power requirements. The annual O&M Costs include both of these fixed and variable O&M components. O&M costs account for actual unit capacity factors provided by SRP.

Maximum annual NO_x emission rates associated with each NO_x control technology are summarized in Table 5-4. Table 5-5 presents the capital costs and annual operating costs associated with building and operating each control system. Table 5-6 shows the average annual and incremental cost effectiveness for each control system. Detailed cost estimates are provided in Attachment 4.

[3] The baseline emission rates are currently based on actual reported emissions for 2008 and 2009. The emissions estimates that would be required to be used in a permitting action may be different depending on the timeline associated with the project.

[4] U.S. Environmental Protection Agency, *EPA Air Pollution Cost Control Manual*, 6th Ed., Publication Number EPA 452/B-02-001, January 2002.

Table 5-4. Annual NO_x Emissions (Units 1-4)

Control Technology	Annual Emissions Rate(1) (tpy)	Annual Reduction in Emissions (2) (tpy from base case)
SCR + Combustor Upgrades	17.2	154.5
SCR	17.2	154.5
Combustor Upgrades	68.7	103.1
Baseline Combustion Controls (DLN1 Combustors)	171.7	

(1) Baseline combustion control annual emissions based on maximum, actual emission rates for years 2008 and 2009.
(2) Annual emissions reductions for SCR catalyst upgrade and combustor upgrade options are based on control efficiencies identified in Table 5-3

Table 5-5. NO_x Emissions Control System Cost Summary (Units 1-4)

Control Technology	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Annual Operating Cost ($/year)	Total Annual Costs ($/year)
SCR + Combustor Upgrades	$69,560,000	$7,688,000	$3,802,000	$11,490,000
SCR	$49,612,000	$5,484,000	$3,751,000	$9,235,000
Combustor Upgrades	$19,948,000	$2,204,000	$75,000	$2,279,000
Baseline Combustion Controls (DLN1 Combustors)	NA	NA	NA	NA

Table 5-6. NO_x Emissions Control System Cost Effectiveness (Units 1-4)

Control Technology	Total Annual Costs ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness ($/ton)
SCR + Combustor Upgrades	$11,490,000	154,5	$74,369	$179,202(1)
SCR	$9,235,000	154,5	$59,773	$135,595
Combustor Upgrades	$2,279,000	103.1	$22,104	NA
Baseline Combustion Controls (DLN1 Combustors)	NA	NA	NA	NA

(1) Incremental cost effectiveness based on comparison with combustion upgrade option.

Table 5-6 indicates that the average cost effectiveness of the NO_x control systems for Units 1-4 range from approximately $22,104 per ton (combustor upgrades) to $74,369 per ton (SCR + combustor upgrades). Equipment costs, energy costs, and annual operating costs (e.g., routine catalyst replacement) all have a significant impact on the cost of the SCR system.

Total capital costs associated with the SCR systems for Units 1-4 (estimated at $49,612,000), as well as O&M costs (including power costs and catalyst replacement costs) are both significant. The total power costs associated with increased backpressure on the turbine resulting from the SCR system installations are estimated to be $40,000 per year. The total annual costs associated with reagent use, catalyst replacement, and catalyst disposal are estimated to be $307,000 per year. Total annual costs associated with the SCR system installation, including capital recovery are estimated to be $9,235,000 per year.

The significant increase in total annual costs coupled with the relatively small decrease in annual emissions (approximately 155 tpy) results in a very high average cost effectiveness for SCR systems. The average cost effectiveness of the SCR systems (estimated to be $59,773 per ton NO_x removed) is higher than the costs associated with the combustor upgrade option. The incremental cost associated with SCR is estimated to be $135,595 per ton. Both capital costs and annual O&M costs are significantly higher with SCR and contribute to the high cost effectiveness numbers.

Total capital costs associated with the combustor upgrade option for Units 1-4 are estimated to be $19,948,000. The combustor upgrades are expected to result in an increased heat rate, thereby increasing the annual fuel costs by approximately $75,000 per year. Total annual costs associated with the combustor upgrades are estimated to be $2,279,000 per year. The increase in total annual costs coupled with the relatively small decrease in annual emissions (approximately 103.1 tpy) results in a relatively high average cost effectiveness for combustor upgrades. The average cost effectiveness of the combustor upgrades option is estimated to be $22,104 per ton NO_x removed.

The option to install an SCR system along with upgrades to the CT combustors is the least cost effective control option. Installing SCR (without combustor upgrades) will achieve the same emissions reduction at a lesser cost than SCR with combustor upgrades.

NO_x Control Technologies – Environmental Impacts

Combustion modifications designed to decrease NO_x formation (lower temperature and less oxygen availability) also tend to increase the formation and emission of CO and VOC. Therefore, the combustion controls must be designed to reduce the formation of NO_x while maintaining CO and VOC formation at an acceptable level.

Operation of an SCR system has certain collateral environmental consequences. First, in order to maintain a stringent NO_x emission rate some excess ammonia will pass through the SCR. Ammonia slip will increase with lower NO_x emission limits, and will also tend to increase as the catalyst becomes deactivated. Ammonia slip from an SCR designed to control NO_x emissions from a natural gas fired combined cycle unit is expected to be approximately 10 ppm or less, however, ammonia emissions are of concern because ammonia is a potential contributor to regional secondary particulate formation and visibility degradation.

Second, undesirable reactions can potentially occur in an SCR system, including the oxidation of NH_3 and SO_2 and the formation of sulfate salts. A fraction of the SO_2 in the flue gas (approximately 1 - 1.5%) will oxidize to SO_3 in the presence of the SCR catalyst. SO_3 can react with water to form sulfuric acid mist (H_2SO_4) or with the ammonia slip to form ammonium sulfate ($(NH_4)_2SO_4$). Sulfuric acid mist and ammonium sulfate could increase total PM_{10} emissions from the unit.

Another environmental impact associated with SCR is disposal of the spent catalyst. Some of the catalyst used in SCR systems must be replaced every three to five years. These catalysts typically contain heavy metals including vanadium pentoxide. Vanadium pentoxide is an acute hazardous waste under the Resource Conservation and Recovery Act (RCRA), Part 261, Subpart D – Lists of Hazardous Materials. The annual cost associated with proper material handling controls must be initiated when handling and disposing of the spent catalyst.

NO_x Control Technologies – Energy Impacts

Compared with the existing DLN1 combustors, new DLN1+ combustors may reduce the efficiency of Units 1-4. Based on vendor information for the DLN1+ combustor, the power output for Units 1-4 could be reduced by approximately 1.2 MW and the heat rate could increase by 4 Btu/kWh. Assuming a 1.2 MW power output reduction, a power cost of $50/MWh, and a capacity factor of approximately 14%, reduced power costs for combustor modifications will be$75,000 per year. This cost was included in the economic impact evaluation of the combustor modification option, and contributes to the relatively high cost effectiveness value of the system for the control of NO_x emissions.

Post-combustion NO_x control with an SCR system increases the pressure drop of the combustion turbine exhaust thereby reducing the combustion turbine power output. Based on engineering calculations and information provided by catalyst vendors, upgrading the existing oxidation catalyst system to achieve greater than 80% reduction in NO_x emissions will result in an increased pressure drop of approximately 2.0 in. w.c. per unit. Assuming 80 kW/inch power output reduction, a power cost of $50/MWh, and a capacity factor of approximately 14%, total reduced power costs for the SCR control systems will be $40,000 per year. This cost was included in the economic impact evaluation of the SCR systems option, and contributes to the relatively high cost effectiveness value of the system for the control of NO_x emissions.

A summary of the Step 4 economic and environmental impact analysis is provided in Table 5-7.

Table 5-7. Summary of NO_x Controls Evaluation (Units 1-4)

Control Technology	Emissions (tpy)	Emissions Reduction (tpy)	Total Annual Costs ($/year)	Average Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness ($/ton)	Environmental Impact
SCR + Combustor Upgrades	17.2	154.5	$11,490,000	$74,369	$179,202(1)	Ammonia emissions, increased PM/CO/VOC emissions, and catalyst disposal
SCR	17.2	154.5	$9,235,000	$59,773	$135,595	Ammonia emissions, increased PM emissions, and catalyst disposal.
Combustor Upgrades	68.7	103.1	$2,279,000	$22,104	NA	Potential to increase CO/VOC emissions.
Baseline Combustion Controls (DLN1 Combustors)	171.7	NA	NA	NA	NA	NA

(1) Incremental cost effectiveness is based on comparison with combustion upgrade option.

5.2.5 Step 5: Summary of Potential NO_x Improvements for Units 1-4

The NO_x control technology evaluation for Units 1-4 has shown that the combustor upgrade and SCR control options are technically feasible and effective control systems in terms of reduced emissions. An economic evaluation performed for each option indicates that, based on the use of actual baseline emissions and capacity factors, expected emissions reductions, and estimated control costs, the average annual cost effectiveness of the NO_x control systems for Units 1-4 range from $22,104 per ton (combustor upgrades) to $74,369 per ton (SCR + combustor upgrades) NO_x removed.

EPA has not defined a cost threshold at which NO_x control technologies for existing power plants are considered "cost effective." Cost effectiveness thresholds are typically set at the discretion of regulating agencies on a project-specific basis. However, based on a review of publicly available documents, it is common for agencies to consider NO_x control options "cost prohibitive" at levels exceeding $10,000 per ton NO_x removed (see Attachment 8 for a table of reference documents). Therefore, based on the range of costs identified for SGS Units 1-4 NO_x control options, and an assumed cost effectiveness threshold of $10,000 per ton NO_x removed, NO_x emissions improvements for SGS Units 1-4 would be considered cost prohibitive.

Because the cost effectiveness values are dependent upon the assumed utilization of each unit, figures showing NO_x control cost sensitivities versus capacity factors have been prepared and can be found in Attachment 5.

5.3 CO CONTROL OPTIONS FOR UNITS 1-4

Emissions of carbon monoxide (CO) result from incomplete fuel combustion. CO is formed from the partial oxidation of fuel carbon. Factors that influence CO formation include improper fuel-to air ratios, inadequate fuel mixing, inadequate combustion temperatures, and reduced excess O_2. Combustion turbine operation at lower loads (below approximately 50%) can also affect combustion controls and the formation of CO.

In natural gas-fired combustion turbines, combustion controls designed to minimize NO_X formation, including sub-stoichiometric combustion and reduced peak combustion temperatures, can increase the formation of CO. NO_X control methods such as lean premix combustion, low flame temperature, and water/steam injection can increase CO. Combustors can be designed to minimize the formation of CO while reducing the peak combustion temperature and NO_X emissions.

5.3.1 Step 1: Identify Feasible CO Control Options

Potentially available control options were identified based on a comprehensive review of available information. CO control technologies with potential application to the SGS Units 1-4 are listed in Table 5-8.

Table 5-8. List of Potential CO Control Options (Units 1-4)

Control Technology
Baseline Combustion Controls (DLN1 Combustors) and Existing CO Catalyst System
Combustor Upgrades and Existing CO Catalyst System
CO Catalyst System Upgrades
CO Catalyst System Upgrades and Combustor Upgrades
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)
Catalytic Combustion (Xonon™)

5.3.2 Step 2: Technical Feasibility of CO Control Options

The potential CO control options identified in Table 5-8 are described below. In addition to providing a description of each potential control technology, technically feasible and commercially available control options are identified.

5.3.2.1 Baseline Combustion Controls (DLN1 Combustors) and Existing CO Catalyst System

Units 1-4 currently utilize combustion controls and an oxidation catalyst system to minimize CO emissions. A general description of current and potential CO emissions controls for SGS Units 1-4 is provided below.

Baseline Combustion Controls (DLN Combustors)

As discussed in Section 5.2.2.1, combustion controls designed to minimize NO_X formation, including lower peak combustion temperatures and less excess oxygen, tend to increase the formation of CO emissions. Burner vendors attempt to address these issues by improving fuel air mixing and ensuring adequate residence times within the combustion zone. Improved mixing will minimize the potential for fuel-rich areas and the resulting formation of CO. Increased residence time within the combustion zone provides the oxygen needed for more complete oxidation.

A properly designed and operated combustion turbine effectively functions as a thermal oxidizer. CO formation is minimized when combustion turbine temperature and excess oxygen availability are adequate for complete combustion. Minimizing CO emissions is also in the economical best interest of the combustion turbine operator because CO represents unutilized energy exiting the process. Proper combustor design and operation can minimize NO_x emissions, while maintaining CO at acceptable levels.

The original combustors for Units 1 through 4 were replaced with GE's Dry Low NO_x (DLN-1) combustors in 2001. The DLN-1 combustors are two-stage premix combustors designed to fire both natural gas and fuel oil. The DLN-1 combustors for Units 1-4 were required to achieve CO levels of 10 ppmvd @ 15% O_2 and NO_x levels of 20 ppmvd @ 15% O_2 while firing natural gas.

Baseline Post-Combustion Controls (Oxidation Catalyst)

Catalytic oxidation systems are designed to oxidize CO to CO_2. Catalytic oxidation is a post-combustion technology which reduces CO emissions without the addition of chemical reagents. The oxidation catalyst, typically consisting of a noble metal, promotes the oxidation of CO at temperatures approximately 50% below the temperature required for oxidation without the catalyst. The operating temperature range for commercially available CO oxidation catalysts is between 650 and 1,150°F. On a natural gas-fired combined cycle unit this temperature window occurs within the HRSG.

Oxidation catalyst efficiency varies with inlet CO concentration, inlet gas temperature, and flue gas residence time. In general, removal efficiency will increase with increased flue gas temperatures and increased catalyst bed depth. Bed depth will be limited by pressure drop across the catalyst.

Oxidation catalyst systems were installed on Units 1-4 in 2003. These systems were designed to achieve 60% CO reduction, or a controlled CO level of 4 ppmvd @ 15% O_2. Approximately 70 ft^3 of catalyst is currently installed in the CT plenum outlet where exhaust temperatures are approximately 1000°F. As indicated in Section 4.1.2, Units 1-4 are generally achieving less than 4 ppm CO at full and mid loads.

5.3.2.2 Combustion Controls Upgrades and Existing CO Catalyst System

Since 2001, DLN combustor technology has matured and DLN systems installed on new combustion turbines have demonstrated the ability to achieving both NO_x and CO levels below 10 ppmvd @ 15% O_2. Combustor upgrades are a technically feasible and commercially available option for reducing CO emissions. Based on information from combustor vendors, combustor upgrades can be implemented to minimize both NO_x and CO emissions. For this evaluation, Units 1-4 will be based on a controlled CO level of 9 ppmvd @ 15% O_2 while firing natural gas and operating from 50% to 100% load. A CO level 9 ppmvd @ 15% O_2 assumes that the combustors will be designed to achieve a NO_x level of 8 ppmvd @ 15% O_2.

Units 1-4 currently include CO catalyst systems that are designed to achieve 60% CO reduction. With an uncontrolled CO level 9 ppmvd @ 15% O_2, the CO catalyst would therefore be capable of reducing CO emissions to 3.6 ppmvd @ 15% O_2, which represents a CO reduction of approximately 10% from the baseline level of 4 ppm.

5.3.2.3 CO Catalyst System Upgrades

As described above, the oxidation catalyst systems that are currently installed on Units 1-4 are designed to achieve 60% CO reduction. Approximately 70 ft^3 of catalyst is currently installed in the CT plenum outlet where exhaust temperatures are approximately 1000°F. Based on review of current HRSG and oxidation catalyst system design information, catalyst system modifications can be made thereby resulting in reduced CO emissions.

Catalytic oxidation systems for natural gas-fired combined cycle units have been designed, and demonstrated the ability, to achieve controlled CO emissions of 2.0 ppmvd @ 15% O_2. CO catalyst upgrades on Units 1-4 would consist of: (1) removing the existing catalyst, internal frame and expansion seals, (2) installing new ceramic based catalyst modules (catalyst volume would be increased), (3) modifying or replacing the duct spool piece.

Oxidation catalyst system upgrades are considered technically feasible and commercially available control options for Santan Units 1- 4. Based on a review of emission rates achieved in practice at similar sources and emission limits included in recently issued PSD permits for natural gas-fired combined cycle facilities, it is concluded that an upgraded oxidation catalyst system could be designed to achieve a controlled CO emission rate of 2.0 ppmvd @ 15% O_2 at loads ranging from 50 to 100%, thereby representing a CO reduction of approximately 50% from the baseline level.

5.3.2.4 Oxidation Catalyst w/ Potassium Carbonate Absorption

The EMx™ (formerly SCONOx™) control system is described in the NO_x control technology analysis (section 5.2.2.2). EMx™ is a post-combustion, multi-pollutant control technology that uses a coated oxidation catalyst to remove NO_x, CO, and VOC emissions in the turbine exhaust gas by oxidizing CO to CO_2, NO to NO_2, and hydrocarbons to CO_2 and water. The CO_2 is then emitted to the atmosphere, and the NO_2 is absorbed onto the potassium carbonate coating on the EMx™ catalyst to form potassium nitrate/nitrite. Depending on flue gas temperatures, the EMx™ oxidation catalyst should achieve CO removal efficiencies similar to those achievable with an oxidation catalyst.

As discussed in section 5.2.2.2, there are several currently unresolved technical issues associated with application of the control technology on a large natural gas-fired combined cycle unit. Potential issues include:

- For large-scale combined cycle applications, the EMx™ catalyst would have to be placed in the HRSG where the exhaust gas temperatures will be in the range of 500 to 700 °F. Performance of the EMx™ catalyst in a high-temperature application has not been demonstrated in practice.
- The dampers and damper bearings, which are moving parts exposed to the hot exhaust gas, could present long-term maintenance and reliability problems. This is particularly true as the damper size and number of dampers increase, as would be necessary in order to use this technology for Units 1-4.
- Regeneration of the EMx™ catalyst would require hydrogen gas to be continuously generated (from natural gas) and introduced into the high-temperature zone of the HRSG. Because hydrogen gas is explosive, any leaks in the dampers used to isolate the catalyst for regeneration could create a serious hazard.
- In addition to periodic regeneration, the EMx™ catalyst would have to be cleaned at least once per year by removing the catalyst beds from the HRSG and dipping them in a potassium carbonate solution.
- The EMx™ and ESx™ processes have the potential to create additional air pollutants, such as hydrogen sulfide (H_2S). Emissions of these additional pollutants have not been completely quantified.

To date, the EMx™ (SCONOx) multi-pollutant control system has not been installed and operated on a large combined cycle application. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system for Units 1-4. Therefore, at this time the EMx™ control system is not considered an available CO control system, and will not be further evaluated in this analysis.

5.3.2.5 Catalytic Combustion (Xonon™)

Catalytic combustion systems are described in the NO_x control evaluation (section 5.2.2.2). Catalytic combustion uses a catalyst within the combustor to oxidize a lean air-to-fuel mixture rather than burning with a flame. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_x, and potentially lower CO emissions. One technical challenge associated with catalytic combustion has been achieving catalyst life long enough to make the combustor commercially viable. The Xonon™ combustion system works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is lower temperature partial combustion followed by flameless catalytic combustion to reduce CO formation.

As described in section 5.2.2.2, to date, the system has successfully completed pilot- and full-scale testing, and has been demonstrated on a 1.5 MW Kawasaki gas turbine. However, the Xonon™ combustion system has not been demonstrated for extended periods of time on a large natural gas-fired combustion turbine. Applications of this technology have been in the 1 to 15 MW range. It is likely that SRP would be required to conduct extensive design engineering and testing to evaluate the technical feasibility and long-term effectiveness of the control system for Units 1-4. Therefore, at this time, catalytic combustion systems (including Xonon™) are not considered available CO control systems, and will not be further evaluated in this analysis.

The results of Step 2 of the CO control technology analysis (technical feasibility analysis of potential CO control technologies) are summarized in Table 5-9.

Table 5-9. Technical Feasibility of CO Control Technologies (Units 1-4)

Control Technology	Approximate Controlled CO Emission Rate (ppmvd@15%O_2)	In Service on Existing Gas-Fired Combined Cycle Units?	Technically Feasible on the SGS Units 1-4?
Baseline Combustion Controls (DLN1 Combustors) and Existing CO Catalyst System	4	Yes	Yes - currently installed
Combustor Upgrades and Existing CO Catalyst System	3.6	Yes	Yes
CO Catalyst System Upgrades	2	Yes	Yes
CO Catalyst System Upgrades and Combustor Upgrades	2	Yes	Yes
Oxidation Catalyst w/ Potassium Carbonate Absorption (EMx™ formerly SCONOx™)	NA	limited application	This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for the Units 1-4
Catalytic Combustion (Xonon™)	NA	limited application	This control technology has not been demonstrated on a large gas fired combined cycle unit, and, at this time, is not considered technically feasible or commercially available for the Units 1-4

5.3.3 Step 3: Rank the Technically Feasible CO Control Options by Effectiveness

The technically feasible and commercially available CO control technologies are listed in Table 5-10 in descending order of control efficiency.

Table 5-10. Ranking of Technically Feasible CO Control Technologies (Units 1-4)

Control Technology	Approximate Controlled CO Emission Rate (80-100% loads) (ppmvd@15%O_2)	% Reduction (from base case)
CO Catalyst System Upgrades and Combustor Upgrades	2	50%
CO Catalyst System Upgrades	2	50%
Combustor Upgrades and Existing CO Catalyst System	3.6	10%
Baseline Combustion Controls (DLN1 Combustors) and Existing CO Catalyst System	4	NA

The most effective CO control system, in terms of reduced emissions, that is considered to be technically feasible for Units 1-4 consists of upgrades to the Units' existing oxidation catalyst system. The effectiveness of the oxidation catalyst system is dependent on several site-specific system variables including inlet CO concentrations, the size of the oxidation catalyst system (e.g., catalyst volume), flue gas temperatures, and catalyst deactivation rate. This combination of controls should be capable of achieving the most stringent controlled CO emission rates on an on-going long-term basis. The other effective CO control system that is considered technically feasible and commercially available is combustor upgrades (install DLN1+ combustors).

5.3.4 Step 4: Evaluation of Technically Feasible CO Controls

An evaluation of the economic, environmental and energy impacts of each technically feasible and commercially available CO emissions control option is provided below.

CO Control Technologies – Economic Evaluation

Economic impacts associated with the potentially feasible CO control systems were evaluated in accordance with guidelines found in EPA's New Source Review Workshop Manual (Draft, 1990). For the economic impact analysis, projected annual emissions (tpy) were used to evaluate average cost effectiveness (i.e., dollar per ton removed). Annual emissions (tpy) were calculated assuming: (1) baseline control option emissions are equal to the actual, maximum reported level from years 2008 and 2009; (2) post-control emissions are equal to the baseline control option emissions times the assumed percent reduction associated with each control option.[5]

Cost estimates were compiled from a number of data sources. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Cost Control Manual. Major equipment costs were developed based on published information available from equipment vendors and equipment costs recently developed for similar projects. Capital costs include the equipment, material, labor, and all other direct costs needed to install the control technologies. Fixed and variable O&M costs were developed for each control system.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent (if applicable), byproduct management, and power requirements. The annual O&M costs include both of these fixed and variable O&M components. O&M costs account for actual unit capacity factors provided by SRP.

Maximum annual CO emission rates associated with each CO control technology are summarized in Table 5-11. Table 5-12 presents the capital costs and annual operating costs associated with building and operating each control system. Table 5-13 shows the average annual and incremental cost effectiveness for each control system. Detailed cost estimates are provided in Attachment 6.

[5] The baseline emission rates are currently based on actual reported emissions for 2008 and 2009. The emissions estimates included in this evaluation are subject to change if the potential project timeline and respective baseline periods are adjusted.

Table 5-11. Annual CO Emissions (Units 1-4)

Control Technology	Annual Emissions Rate[1] (tpy)	Annual Reduction in Emissions[2] (tpy from base case)
CO Catalyst System Upgrades	24.9	24.9
CO Catalyst System Upgrades and Combustor Upgrades	24.9	24.9
Combustor Upgrades and Existing CO Catalyst System	44.9	4.9
Baseline Combustion Controls (DLN1 Combustors) and Existing CO Catalyst System	50.0	

(1) Baseline combustion control annual emissions based on maximum, actual emission rates for years 2008 and 2009.
(2) Annual emissions reductions for CO catalyst upgrade and combustor upgrade options are based on control efficiencies identified in Table 5-10

Table 5-12. CO Emissions Control System Cost Summary (Units 1-4)

Control Technology	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Annual Operating Cost ($/year)	Total Annual Costs ($/year)
CO Catalyst System Upgrades	$7,784,000	$860,000	$731,000	$1,591,000
CO Catalyst System Upgrades and Combustor Upgrades	$27,732,000	$3,064,000	$804,000	$3,868,000
Combustor Upgrades and Existing CO Catalyst System	$19,948,000	$2,204,000	$73,000	$2,277,000
Baseline Combustion Controls (DLN1 Combustors) and Existing CO Catalyst System	NA	NA	NA	NA

Table 5-13. CO Emissions Control System Cost Effectiveness (Units 1-4)

Control Technology	Total Annual Costs ($/year)	Annual Emission Reduction (tpy)	Average Annual Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness ($/ton)
CO Catalyst System Upgrades	**$1,591,000**	**24.9**	**$63,895**	**NA**
CO Catalyst System Upgrades and Combustor Upgrades	**$3,868,000**	**24.9**	**$155,341**	**$79,550**
Combustor Upgrades and Existing CO Catalyst System	**$2,277,000**	**4.9**	**$464,694**	**NA**
Baseline Combustion Controls (DLN1 Combustors) and Existing CO Catalyst System	**NA**	**NA**	**NA**	**NA**

Table 5-13 indicates that the average annual cost effectiveness of the CO control systems for Units 1-4 range from $63,895 per ton (CO catalyst upgrades) to $464,694 per ton (combustor upgrades) CO removed. Equipment costs, energy costs, and annual operating costs (e.g., routine catalyst replacement) all have a significant impact on the cost of the oxidation catalyst control system.

Total capital costs associated with oxidation catalyst system upgrades for Units 1-4 (estimated at $7,784,000), as well as O&M costs (including power costs and catalyst replacement costs) are both significant. The total differential power costs associated with increased backpressure on the turbine resulting from the catalyst system upgrades are estimated to be $39,000 per year. The total differential catalyst replacement costs are estimated to be in the range of $692,000 per year. Total annual costs associated with the oxidation catalyst system upgrades, including capital recovery are estimated to be $1,591,000 per year. The significant increase in total annual costs coupled with the relatively small decrease in annual emissions (estimated at 24.9 tpy) results in a very high average cost effectiveness for the oxidation catalyst control system upgrades.

The other technically feasible and commercially available options (i.e., upgrade the CT combustors, and CO catalyst system upgrades and combustor upgrades) are even less cost effective control options. Oxidation catalyst system upgrades will achieve greater emissions reduction for less cost than the other options.

CO Control Technologies – Environmental Impacts

Combustion modifications designed to decrease CO formation also tend to increase the formation and emission of NO_x. Combustion controls, including dry low- NO_x burners, need to be designed to reduce the formation of NO_x while maintaining CO at acceptable levels. Other than the NO_x /CO trade-off, there are no environmental issues associated with using combustion controls to reduce CO emissions from a natural gas-fired combustion turbine.

Operation of an oxidation catalyst control system has certain collateral environmental consequences. The most significant environmental impact is associated with increased condensable PM_{10} emissions. The oxidation catalyst also tends to oxidize flue gas SO_2 to SO_3. Based on information available from catalyst vendors, the SO_2 to SO_3 oxidation rate varies with flue gas temperatures, but will be in the range of 50% for high temperature CO catalyst. SO_3 can react with water to form sulfuric acid mist, or with ammonia slip from the SCR to form ammonium sulfate and/or ammonium bisulfate. Sulfuric acid mist and ammonium sulfate are classified as condensable particulates; thus, oxidation catalyst control could possibly result in increased PM_{10} emissions.

CO Control Technologies – Energy Impacts

Compared with the existing DLN1 combustors, new DLN1+ combustors may reduce the efficiency of Units 1-4. Based on vendor information for the DLN1+ combustor, the Units 1-4 power output could be reduced by approximately 1.2 MW and the heat rate could increase by 4 Btu/kWh. Assuming a 1.2 MW power output reduction, a power cost of $50/MWh, and a capacity factor of approximately 14%, reduced power costs for combustor modifications will $73,000 per year. This cost was included in the economic impact evaluation of the combustor modification option, and contributes to the relatively high cost effectiveness value of the system for the control of CO emissions.

Post-combustion CO control with an oxidation catalyst control system increases the pressure drop of the combustion turbine exhaust. The additional pressure drop results in a reduction in the combustion turbine power output. Based on engineering calculations and information provided by catalyst vendors, upgrading the existing oxidation catalyst system to achieve greater than 80% reduction in CO emissions will result in an increased pressure drop of approximately 2.0 in. w.c. per unit. Assuming 80 kW/inch power output reduction, and a power cost of $50/MWh, and a capacity factor of approximately 14%, total reduced power costs for the oxidation catalyst control system will be $39,000 per year. This cost was included in the economic impact evaluation of the oxidation catalyst system, and contributes to the relatively high cost effectiveness value of the system for the control of CO emissions.

A summary of the Step 4 economic, environmental and energy impact analysis is provided in Table 5-14.

Table 5-14. Summary of CO Controls Evaluation (Units 1-4)

Control Technology	Emissions (tpy)	Emissions Reduction (tpy)	Total Annual Costs ($/year)	Average Cost Effectiveness ($/ton)	Incremental Annual Cost Effectiveness ($/ton)	Environmental Impact
CO Catalyst System Upgrades	24.9	24.9	$1,591,000	$63,895	NA	Increased H_2SO_4 / PM emissions, and catalyst disposal.
CO Catalyst System Upgrades and Combustor Upgrades	24.9	24.9	$3,868,000	$155,341	$79,550	Increased H_2SO_4 / PM emissions, and catalyst disposal.
Combustor Upgrades and Existing CO Catalyst System (1)	44.9	4.9	$2,277,000	$464,694	NA	NA
Baseline Combustion Controls (DLN1 Combustors) and Existing CO Catalyst System	50.0	NA	NA	NA	NA	NA

(1) Control option is considered "inferior"

5.3.5 Step 5: Summary of Potential CO Improvements for Units 1-4

The CO control technology evaluation for Units 1-4 has shown that combustor upgrade and oxidation catalyst upgrade options are technically feasible and effective control systems in terms of reduced emissions. An economic evaluation performed for each option indicates that, based on the use of actual baseline emissions and capacity factors, expected emissions reductions, and estimated control costs, the average annual cost effectiveness of the CO control systems for Units 1-4 range from $63,895 per ton (CO catalyst upgrades) to $464,694 per ton (combustor upgrades) CO removed.

EPA has not defined a cost threshold at which CO control technologies for existing power plants are considered "cost effective." Cost effectiveness thresholds are typically set at the discretion of regulating agencies on a project-specific basis. However, based on a review of publicly available documents, it is common for agencies to consider CO control options "cost prohibitive" at levels exceeding $4,000 per ton CO removed (see Attachment 8 for a table of reference documents). Therefore, based on the range of costs identified for SGS Units 1-4 CO control options, and an assumed cost effectiveness threshold of $4,000 per ton CO removed, CO emissions improvements for SGS Units 1-4 would be considered cost prohibitive.

Because the cost effectiveness values are dependent upon the assumed utilization of each unit, figures showing CO control cost sensitivities versus capacity factors have been prepared and can be found in Attachment 7.

5.4 PROJECT SCHEDULE

5.4.1 Introduction

Summary Level project schedules for development, design, construction, and startup of the project were prepared based on a multiple firm price construction contracting strategy. The schedule, as currently outlined, represents the most cost effective and least risky option. However, there exists some flexibility in activity durations, equipment lead times, and predecessor/successor relationships at the risk of higher financial expense. That notwithstanding, as shown below, permitting timelines (including uncertainty associated with greenhouse gas permitting requirements) and constructability issues that could preclude activities being completed on multiple units simultaneously, would in most circumstances prevent the work from being completed in accordance with the time frame established in Condition 38 of the Santan CEC.

The construction contracts for the Combustor Upgrades, Oxidation Catalyst Replacement, and Combustor Upgrades plus Oxidation Catalyst Replacement option would include:

- GT Combustor Replacement Specification (including installation)
- Oxidation Catalyst Installation
- Start-up & Commissioning
- Performance Testing & Inspection

The construction contracts for the SCR option and the Combustor Upgrades plus SCR option would include:

- Underground Survey
- Above ground Survey
- Substructure
- Mechanical & Structural General Work
- Electrical & Instrumentation General Work
- Start-up & Commissioning
- Performance Testing & Inspection

5.4.2 Project Milestones – Combustor Upgrades Option

The total project duration, from a decision to proceed to the completion of the tie-in outage is approximately 24 months for the first unit. Although space constraints would not preclude the work on all four units from being completed at the same time, this type or work is normally conducted in accordance with other planned major maintenance events in future years. Based on

SGS's prior combustor replacement activities, an 8 week outage to install the upgrades is used for each unit.

Development of the schedule was based on the following milestones:

Table 5-15. Combustor Upgrades Schedule Milestones

Milestone	Months After Decision To Proceed
Decision to Proceed	0
Submit Air Permit Applications	3
Permit Issuance	15
Award Combustor Replacement Contract	15
Award Performance Testing Contract	16
Start Construction	20
Complete Construction	22
Final Performance Test Report	24

5.4.3 Project Milestones – Oxidation Catalyst Replacement Option

The total project duration, from a decision to proceed to the completion of the tie-in outage is approximately 28 months for the first unit. Space constraints could preclude the work on all four units from being completed at the same time. In addition, this type of work is normally conducted in accordance with other planned major maintenance events, so subsequent units would be expected to be completed in future years. An 8 week outage to install the upgrades is assumed for each unit, similar to the combustor replacement option. This outage duration may be conservative, since the work is expected to be limited to replacement of catalyst modules and installation of flow correction devices.

Development of the schedule was based on the following milestones:

Table 5-16. Oxidation Catalyst Replacement Schedule Milestones

Milestone	Months After Decision To Proceed
Decision to Proceed	0
Submit Air Permit Applications	3
Permit Issuance	15
Award Oxidation Catalyst & Flow Model Contract	15
Award Performance Testing Contract	16
Flow Model Test Report	19
Award Oxidation Catalyst Installation Contract	21
Start Construction	24
Complete Tie In Outage	26
Final Performance Test Report	28

5.4.4 Project Milestones – Oxidation Catalyst Replacement & Combustor Upgrades Option

The total project duration, from a decision to proceed to the completion of the tie-in outage is approximately 28 months for the first unit. The schedule is effectively the same as the oxidation catalyst schedule above, with the addition of the award of the combustor upgrade contract.

Development of the schedule was based on the following milestones:

Table 5-17. Oxidation Catalyst Replacement & Combustor Upgrades Schedule Milestones

Milestone	Months After Decision To Proceed
Decision to Proceed	0
Submit Air Permit Applications	3
Permit Issuance	15
Award Combustor Replacement Contract	15
Award Oxidation Catalyst & Flow Model Contract	15
Award Performance Testing Contract	16
Flow Model Test Report	19
Award Oxidation Catalyst Installation Contract	21
Start Construction	24
Complete Tie In Outage	26
Final Performance Test Report	28

5.4.5 Project Milestones – SCR Option

The total project duration, from a decision to proceed to the completion of the tie-in outage is 34 months for the first unit. Space constraints would likely preclude the work on all four units from being completed at the same time. In addition, this type of work is normally conducted in accordance with other planned major maintenance events, so subsequent units would be expected to be completed in future years.

Development of the schedule was based on the following milestones:

Table 5-18. SCR Schedule Milestones

Milestone	Months After Decision To Proceed
Decision to Proceed	0
Submit Air Permit Applications	3
Permit Issuance	15
Award Underground Survey Contract	15
Award Above Ground Survey Contract	15
Award SCR System & Flow Modeling Contract	16
Award Ammonia System Contract	17
Award Performance Testing Contract	23
Award Substructure Installation Contract	24
Start Construction	26
Award Mechanical / Structural Installation Contract	27
Award Electrical / I&C Installation Contract	27
Award Startup & Commissioning Contract	28
Start Tie In Outage	30
Complete Tie In Outage	32
Final Performance Test Report	34

5.4.6 Project Milestones – SCR & Combustor Upgrades Option

The total project duration, from a decision to proceed to the completion of the tie-in outage is 34 months for the first unit. The schedule is effectively the same as the SCR schedule above, with the addition of the award of the combustor upgrade contract.

Development of the schedule was based on the following milestones:

Table 5-19. SCR & Combustor Upgrades Schedule Milestones

Milestone	Months After Notice To Proceed
Decision to Proceed	0
Submit Air Permit Applications	3
Permit Issuance	15
Award Combustor Replacement Contract	15
Award Underground Survey Contract	15
Award Above Ground Survey Contract	15
Award SCR System & Flow Modeling Contract	16
Award Ammonia System Contract	17
Award Performance Testing Contract	23
Award Substructure Installation Contract	24
Start Construction	26
Award Mechanical / Structural Installation Contract	27

Award Electrical / I&C Installation Contract	27
Award Startup & Commissioning Contract	28
Start Tie In Outage	30
Complete Tie In Outage	32
Final Performance Test Report	34

5.5 SUMMARY OF PHASE 2 EVALUATION EMISSIONS ASSESSMENT

The NO_x control technology assessment identified three options that are considered technically feasible and commercially available for control of NO_x emissions from Units 1-4: (1) combustor upgrades, (2) SCR system, and (3) SCR system and combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness ranges from approximately $22,104 per ton (combustor upgrades) and $74,369 per ton (SCR + combustor upgrades).

The CO control technology assessment identified three options that are considered technically feasible and commercially available for control of CO emissions from Units 1-4: (1) combustor upgrades, (2) upgraded oxidation catalyst system, and (3) oxidation catalyst system and combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness ranges from approximately $63,895 per ton (CO catalyst upgrades) to $464,694 per ton (CO catalyst + combustor upgrades).

Summary Level project schedules for development, design, construction, and startup of the options were developed. The schedules suggest that permitting timelines (including uncertainty associated with greenhouse gas permitting requirements) and constructability issues that could preclude activities being completed on multiple units simultaneously, would in most circumstances prevent the work from being completed in accordance with the time frame established in Condition 38 of the Santan CEC.

6 CONCLUSION

The "Phase 1" emissions assessment concluded that there is potential for CO and NO_x emissions reductions from SGS Units 1-4. Therefore, emissions improvements for Units 1-4 were further evaluated in the "Phase 2" evaluation. Emissions improvements were not further evaluated for the other SGS emissions sources at this time based on the following: (1) Units 5-6 are currently operating at or below levels generally required for similar, recently permitted facilities, (2) cooling towers currently include mist eliminators designed to achieve 0.0005% drift, (3) diesel engine improvements are not practical due to limited annual operation, (4) a new dust collector has been installed on the abrasive blasting equipment, (5) the gasoline storage tank vapor losses are minimized due to proper tank design, fuel handling procedures, and limited annual gasoline throughput, and (6) the key elements of a comprehensive O&M program are utilized at SGS.

The "Phase 2" NO_x control technology assessment performed for Units 1-4 identified three control options that are considered technically feasible and commercially available: (1) combustor upgrades, (2) SCR system, and (3) SCR system and combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness ranges from approximately $22,104 per ton (combustor upgrades) to $74,369 per ton (SCR + combustor upgrades).

The "Phase 2" CO control technology assessment identified three options that are considered technically feasible and commercially available for control of CO emissions from Units 1-4: (1) combustor upgrades, (2) upgraded oxidation catalyst system, and (3) upgraded oxidation catalyst system and combustor upgrades. An economic evaluation performed for each option indicates that, based on the use of actual annual emission rates and capacity factors, the average cost effectiveness ranges from approximately $63,895 per ton (CO catalyst upgrades) to $464,694 per ton (CO catalyst + combustor upgrades).

Based on review of recent NO_x and CO control evaluations for other fossil fuel-fired electric generating units (EGU), the estimated NO_x and CO control costs for SGS Units 1-4 can be considered cost prohibitive.

Summary Level project schedules for development, design, construction, and startup of the options were developed. The schedules suggest that permitting timelines (including uncertainty associated with greenhouse gas permitting requirements) and constructability issues that could preclude activities being completed on multiple units simultaneously, would in most circumstances prevent the work from being completed in accordance with the time frame established in Condition 38 of the Santan CEC.

Attachment 1

ACC Certificate of Environmental Compatibility Conditions (CEC) for Santan Expansion Project

BEFORE THE ARIZONA POWER PLANT AND TRANSMISSION LINE SITING COMMITTEE

Arizona Corporation Commission
DOCKETED

MAY 01 2001

DOCKETED BY ad

In the matter of the Application of Salt River Project Agricultural Improvement and Power District in conformance with the requirements of Arizona Revised Statutes Sections 40-360-03 and 40-360.06, for a Certificate of Environmental Compatibility authorizing the Expansion of its Santan Generating Station, located at the intersection of Warner Road and Val Vista Drive, in Gilbert, Arizona, by adding 825 megawatts of new capacity in the form of three combined cycle natural gas units, and associated intraplant transmission lines.	Case No. 105 Docket No. L-00000B-00-0105 Decision No. 63611

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY

Pursuant to notice given as provided by law, the Arizona Power Plant and Transmission Line Siting Committee (the "Committee") held public hearings at the Dobson Ranch Inn, 1644 South Dobson Road, Mesa, Arizona, on September 14, 2000, and various days following, in conformance with the requirements of Arizona Revised Statutes section 40-360 *et seq.*, for the purpose of receiving evidence and deliberating on the Application of Salt River Project Agricultural Improvement and Power District ("Applicant") for a Certificate of Environmental Compatibility in the above-captioned case (the "Application").

The following members or designees of members of the Committee were present for the hearing on the Application:

Paul A. Bullis	Chairman, Designee for Arizona Attorney General Janet Napolitano
Steve Olea	Designee of Chairman of the Arizona Corporation Commission

Richard Tobin	Designee for the Arizona Department of Environmental Quality
Dennis Sundie	Designee for the Director of the Department of Water Resources
Mark McWhirter	Designee for the Director of the Energy Office of the Arizona Department of Commerce
George Campbell	Appointed Member
Jeff Mcguire	Appointed Member
A. Wayne Smith	Appointed Member
Sandie Smith	Appointed Member
Mike Whalen	Appointed Member

The Applicant was represented by Kenneth C. Sundlof, Jr., Jennings, Strouss & Salmon PLC. There were seventeen intervenors: Arizona Utilities Investor Association, by Ray Heyman; Arizona Corporation Commission Staff, by Janice Alward; Arizona Center for Law in the Public Interest, by Timothy Hogan, Mark Kwiat, Elisa Warner, David Lundgreen, Cathy LaTona, Sarretta Parrault, Mark Sequeira, Cathy Lopez, Michael Apergis, Marshal Green, Charlie Henson, Jennifer Duffany, Christopher Labban, Bruce Jones and Dale Borger. There were a number of limited appearances.

The Arizona Corporation Commission has considered the grant by the Power Plant and Line Siting Committee of a Certificate of Environmental Compatibility to SRP and finds that the provisions of A.R.S. §40-360.06 have complied with, and, in addition, that documentary evidence was presented regarding the need for the Santan Expansion Project. Credible testimony was presented concerning the local generation deficiency in Arizona and the need to locate additional generation within the East Valley in order to minimize transmission constraints and ensure reliability of the transmission grid. The evidence included a study that assessed the needs of the East Valley. The analysis

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found that the East Valley peak load currently exceeds the East Valley import capability and within the next 5 years the East Valley load will exceed the load serving capability.

Additional testimony was presented regarding SRP's projected annual 3.7% load growth in its service territory. By 2008, SRP will need approximately 2700 MW to meet its load. This local generation plant will have power available during peak periods for use by SRP customers.

At the conclusion of the hearing and deliberations, the Committee, having received and considered the Application, the appearance of Applicant and all intervenors, the evidence, testimony and exhibits presented by Applicant and all intervenors, the comments made by persons making limited appearances and the comments of the public, and being advised of the legal requirements of Arizona Revised Statutes Sections 40-360 to 40-360.13, upon motion duly made and seconded, voted to grant Applicant the following Certificate of Environmental Compatibility (Case No. L-00000B-00-0105):

Applicant and its assignees are granted a Certificate of Environmental Compatibility authorizing the construction of an 825 megawatt generating facility consisting of three combined cycle units with a total net output of 825 megawatts together with related infrastructure and appurtenances, in the Town of Gilbert, on Applicant's existing Santan Generating Station site, and related switchyard and transmission connections, as more specifically described in the Application (collectively, the "Project"). Applicant is granted flexibility to construct the units in phases, with different steam turbine configurations, and with different transmission connection configurations, so long as the construction meets the general parameters set forth in the application.

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This certificate is granted upon the following conditions:

1. Applicant shall comply with all existing applicable air and water pollution control standards and regulations, and with all existing applicable ordinances, master plans and regulations of the State of Arizona, the Town of Gilbert, the County of Maricopa, the United States, and any other governmental entities having jurisdiction.

2. This authorization to construct the Project will expire five (5) years from the date the Certificate is approved by the Arizona Corporation Commission unless construction of the Project is completed to the point that the project is capable of operating at its rated capacity; provided, however, that Applicant shall have the right to apply to the Arizona Corporation Commission for an extension of this time limitation.

3. Applicant's project has two (2) approved transmission lines emanating from its power plant" transmission switchyard and interconnecting with the existing transmission system. This plant interconnection must satisfy the single contingency criteria (N-1) without reliance on remedial action such as a generator unit tripping or load shedding.

4. Applicant shall use reasonable efforts to remain a member of WSCC, or its successor, and shall file a copy of its WSCC Reliability Criteria Agreement or Reliability Management System (RMS) Generator Agreement with the Commission.

5. Applicant shall use reasonable efforts to remain a member of the Southwest Reserve Sharing Group, or its successor.

6. Applicant shall meet all applicable requirements for groundwater set forth in the Third Management Plan for the Phoenix Active Management Area.

7. With respect to landscaping and screening measures, including the improvements listed in the IGA, Applicant agrees to develop and implement a public process consistent with the process chart (Exhibit 89) presented during the hearings, modifying the dates in the IGA with the Town of Gilbert, if necessary, to correspond with the schedule in Exhibit 89.

   The new Community Working Group (CWG) will consist of 12 members, selected as follows: one member selected by the Town of Gilbert, four members selected by neighborhood homeowner associations, four representatives selected by intervenors, and three members selected by SRP (not part of the aforementioned groups) who were part of the original community working group. Applicant and landscaping consultants shall act as advisors to the CWG. CWG meetings shall be noticed to and be open to the general public. The initial meeting shall take place on an evening or weekend in the Town of Gilbert.

The objective of the CWG shall be to refine the landscaping and mitigation concept plans submitted during these hearings (Exhibit 88). The CWG shall work to achieve appropriate visual mitigation of plant facilities and to facilitate the design and installation of the concept plan components so as to maximize the positive impact on the community and to increase, wherever possible, the values of the homes in the neighboring areas. The refinement of the mitigation plans shall be reasonably consistent with the planning criteria of the Town of Gilbert, the desires of neighboring homeowner associations, and the reasonable needs of Applicant.

Applicant shall retain an independent facilitator, acceptable to the CWG, to conduct the CWG meetings. It shall be the role of the facilitator to assist in initial education and in conducting an orderly and productive process. The facilitator may, if necessary, employ dispute resolution mechanisms.

The CWG shall also assist in establishing reasonable maintenance schedules for landscaping of Applicant's plant site in public-view areas.

Applicant will develop with the Town of Gilbert a continuous fund, to be administered by the Town of Gilbert, to provide for the construction and maintenance of off-site landscaping in the areas depicted in the off-site landscaping concepts as developed by the CWG in an amount sufficient to fund the concepts in Exhibit 88 or concepts developed by the CWG, whichever is greater.

8. The visual mitigation efforts shall be in general compliance with the plans and concepts presented in these proceedings and constitute a commitment level by Applicant. Applicant will not reduce the overall level of mitigation as set forth in its Application and this proceeding, except as may be reasonably changed during the CWG process. The plans agreed to by the CWG shall be approved by the Town of Gilbert.

9. Applicant shall, where reasonable to do so, plant on site trees by the fall of 2001. Because planting of trees must await the improvement of Warner Road and the design and construction of berms, this condition will largely apply to trees on the East side of the site, and some of the trees on the North side. All landscaping will be installed prior to the installation of major plant equipment such as, but not limited to, exhaust stacks, combustion turbines, and heat recovery steam generators, except where delays are reasonably necessary to facilitate construction activities.

10. Applicant shall operate the Project so that during normal operations the Project shall not exceed the most restrictive of applicable (i) HUD residential

noise guidelines, (ii) EPA residential noise guidelines, or (iii) applicable City of Tempe standards. Additionally, construction and operation of the facility shall comply with OSHA worker safety noise standards. Applicant agrees that it will use its best efforts to avoid during nighttime hours construction activities that generate significant noise. Additionally, Applicant agrees to comply with the standards set forth in the Gilbert Construction Noise Ordinance, Ordinance No. 1245, during construction of the project. In no case shall the operational noise level be more than 3 db above background noise as of the noise study prepared for this application. The Applicant shall also, to the extent reasonably practicable, refrain from venting between the hours of 10:00 p.m. and 7:00 a.m.

11. Applicant will work with the Gilbert Unified School District to assist it in converting as many as possible of its school bus fleet to green diesel or other alternative fuel, as may be feasible and determined by Gilbert Unified School District, and will contribute a minimum of $330,000 to this effort.

12. Applicant shall actively work with all interested Valley cities, including at a minimum, Tempe, Mesa, Chandler, Queen Creek and Gilbert, to fund a Major Investment Study through the Regional Public Transit Authority to develop concepts and plans for commuter rail systems to serve the growing population of the East Valley. Applicant will contribute a maximum of $400,000 to this effort.

13. Within six months of approval of this Order by the Arizona Corporation Commission, Applicant shall either relocate the gas metering facilities to the interior of the plant site or construct a solid wall between the gas metering facilities at the plant site and Warner Road. The wall shall be of such strength and size as to deflect vehicular traffic (including a fully loaded concrete truck) that may veer from Warner Road to the gas-metering site.

14. Applicant will use only SRP surface water, CAP water or effluent water for cooling and power plant purposes. The water use for the plant will be consistent with the water plan submitted in this proceeding and acceptable to the Department of Water Resources. Applicant will work with the Town of Gilbert to attempt to use available effluent water, where reasonably feasible.

15. Applicant agrees to comply with all applicable federal, state and local regulations relative to storage and transportation of chemicals used at the plant.

16. Applicant agrees to maintain on file with the Town of Gilbert safety and emergency plans relative to emergency conditions that may arise at the plant site. On at least an annual basis Applicant shall review and update, if necessary, the emergency plans. Copies of these plans will be made available to the public and on Applicant's web site. Additionally Applicant

will cooperate with the Town of Gilbert to develop an emergency notification plan and to provide information to community residents relative to potential emergency situations arising from the plant or related facilities. Applicant agrees to work with the Gilbert police and fire departments to jointly develop on site and off-site evacuation plans, as may be reasonably appropriate. This cooperative work and plan shall be completed prior to operation of the plant expansion.

17. In obtaining air offsets required by EPA and Maricopa County, Applicant will use its best efforts to obtain these offsets as close as practicable to the plant site.

18. In order to reduce the possibility of generation shortages and the attendant price volatility that California is now experiencing, SRP will operate the facilities consistent with its obligation to serve its retail load and to maintain a reliable transmission system within Arizona.

19. Beginning upon operation of the new units, Applicant will establish a citizens' committee, elected by the CWG, to monitor air and noise compliance and water quality reporting. Applicant will establish on-site air and noise monitoring facilities to facilitate the process. Additionally Applicant shall work with Maricopa County and the Arizona Department of Environmental Quality to enhance monitoring in the vicinity of the plant site in a manner acceptable to Maricopa County and the Arizona Department of Environmental Quality. Results of air monitoring will be made reasonably available to the public and to the citizens' committee. Applicant shall provide on and off-site noise monitoring services (at least on a quarterly basis), testing those locations suggested by the citizens' committee. The off-site air monitoring plan shall be funded by the Applicant and be implemented before operation of the plant expansion.

20. Applicant will explore, and deploy where reasonably practicable, the use of available technologies to reduce the size of the steam plumes from the unit cooling towers. This will be a continuing obligations throughout the life of the plant.

21. SRP will, where practicable, work with El Paso Natural Gas Company to use the railroad easements for the installation of the new El Paso gas line.

22. Other than the Santan/RS 18 lines currently under construction, Applicant shall not construct additional Extra High Voltage transmission lines (115kV and above) into or out of the Santan site, including the substation on the site.

23. Applicant will replace all Town of Gilbert existing street sweepers with certified PM10 efficient equipment. A PM10 efficient street sweeper is a street sweeper that has been certified by the South Coast Air Quality

Management District (California) to comply with the District's performance standards under its Rule 1186 (which is the standard referenced by the Maricopa Association of Governments).

24. Applicant shall work in a cooperative effort with the Office of Environmental Health of the Arizona Department of Health Services to enhance its environmental efforts.

25. Applicant shall operate, improve and maintain the plant consistent with applicable environmental regulations and requirements of the Environmental Protection Agency, the Arizona Department of Environmental Quality, Maricopa County and the Town of Gilbert.

26. Applicant shall actively work in good faith with Maricopa County in its efforts to establish appropriate standards relative to the use of distillate fuels in Valley generating facilities.

27. Applicant shall install continuous emission monitoring equipment on the new units and will make available on its website emissions data from both the existing and new units according to EPA standards. Applicant shall provide information to the public on its website in order to assist the public in interpreting the data, and provide viable information in a reasonable time frame.

28. Applicant will comply with the provisions of the Intergovernmental Agreement dated April 25, 2000 between Applicant and the Town of Gilbert, as modified pursuant to this Certificate.

29. During the proceeding neighbors to the plant site raise significant concern about the impact of the plant expansion on residential property values. In performing each of the conditions in this order Applicant, in conjunction where applicable, with the Town of Gilbert and the plant site neighbors, shall consider and attempt to maximize the positive effect of its activities on the values of the homes in the surrounding neighborhoods.

30. Applicant shall construct the auxiliary boiler stack at such height as may be determined by air modeling requirements. Applicant shall situate the auxiliary boiler stack so that it is not visible from off the plant site.

31. Applicant will construct the heat recovery steam generators ("HRSG") approximately 15 feet below grade and will construct the HRSGs so that the overall height of the HRSG module from the natural grade is no more than 80 feet.

32. Applicant will complete the installation of the dry low NOX burners on the existing units prior to the construction of the new units.

33. Applicant shall not transfer this Certificate to any other entity for a period of 20 years from the date of approval by the Corporation Commission, other than as part of a financing transaction where operational responsibilities will remain with Applicant, and where Applicant will continue to operate the plant in accordance with this Certificate.

34. Applicant shall post on its website, when its air quality permit application is submitted to the Maricopa County Environmental Services Department. Also, Applicant shall post on its website any official notice that may be required to be posted in newspapers for its air quality permit application.

GRANTED this 14th day of February, 2001

ARIZONA POWER PLANT AND TRANSMISSION LINE SITING COMMITTEE

Paul A. Bullis

By Paul A. Bullis
Its Chairman

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE APPLICATION OF SALT RIVER PROJECT, OR THEIR ASSIGNEE(S), IN CONFORMANCE WITH THE REQUIREMENTS THE ARIZONA REVISED STATUTES 40-360.03 AND 40-360.06 FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING THE CONSTRUCTION OF NATRUAL GAS-FIRED, COMBINED CYCLE GENERATING FACILITIES AND ASSOCIATED INTRAPLANT TRANSMISSION LINES, SWITCHYARD IN GILBERT, ARIZONA, LOCATED NEAR AND WEST OF THE INTERSECTION OF VAL VISTA AND WARNER ROAD	Case No. 105 Docket No. L-00000B-00-0105 Decision No. 63611

The Arizona Corporation Commission (Commission) has conducted its review, as prescribed by A.R.S. § 40-360.07. Pursuant to A.R.S. § 40.360.07(B), the Commission, in compliance with A.R.S. § 40-360.06, and in balancing the broad public interest, the need for an adequate, economical and reliable supply of electric power with the desire to minimize the effect thereof on the environment and ecology of this state;

The Commission finds and concludes that the Certificate of Environmental Compatibility should be granted upon the additional and modified conditions stated herein.

35. The Santan Expansion Project shall be required to meet the Lowest Achievable Emission Rate (LAER) for Carbon Monoxide (CO), Nitrogen Oxides (NO_x), Volatile Organic Carbons (VOCs), and Particulate Matter less than ten micron in aerodynamic diameter (PM_{10}). The Santan Expansion Project shall be required to submit an air quality permit application requesting this LAER to the Maricopa County Environmental Services Department.

36. Due to the plant's location in a non-attainment area, the Applicant shall not use diesel fuel in the operation of any combustion turbine or heat recovery steam generator located at the plant.

37. In obtaining emissions reductions related to Carbon Monoxide (CO) emissions, Applicant shall where technologically feasible obtain those emission reductions onsite to the Santan Expansion Project.

38. Beginning upon commercial operation of the new units, Applicant shall conduct a review of the Santan Generating facility operations and equipment every five years and shall, within 120 days of completing such review, file with the Commission and all parties in this docket, a report listing all improvements which would reduce plant emissions and the costs associated with each potential improvement. Commission Staff shall review the report and issue its findings on the report, which will include an economic feasibility study, to the Commission within 60 days of receipt. Applicant shall install said improvements within 24 months of filing the review with the Commission, absent an order from the Commission directing otherwise.

39. Applicant shall provide $20,000 to the Pipeline Safety Revolving Fund on an annual basis, thus improving the overall safety of pipelines throughout the State of Arizona.

40. Where feasible, Applicant shall strive to incorporate local and in-state contractors in the construction of the three new generation units for the expansion projects.

41. Applicant shall construct a 10 foot high block wall surrounding the perimeter of the Santan plant, and appropriately landscape the area consistent with the surrounding neighborhood, unless otherwise agreed to by the Salt River Project and the Citizens Working Group.

APPROVED AS AMENDED BY ORDER OF THE ARIZONA CORPORATION COMMISSION

William A. Mundell

Chairman | Commissioner | Commissioner

IN WITNESS WHEREOF, I, Brian C. McNeil, Executive Secretary of the Arizona Corporation Commission, set my hand and cause the official seal of the Commission to be affixed this 18 day of May, 2001.

By ______________________
Brian C. McNeil
Executive Secretary

Dissent: ______________________

Attachment 2

RACT/BACT/LAER Clearinghouse (RBLC) Database Summary – NO_X, CO, VOC Emissions (CT/HRSG)

Facility Name	State	Permit Date	Emission Source	Fuel	Load (MW)	Pollutant	Control Description	CO Emission Limit
PASTORIA ENERGY FACILITY	CA	12/23/2004	3 COMBUSTION TURBINES	NATURAL GAS	168	Carbon Monoxide	XONON CATALYTIC COMBUSTORS OR DRY LOW NOX BURNERS & SCR	6 PPMVD
GILA BEND POWER GENERATING STATION	AZ	5/15/2002	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	NATURAL GAS	170	Carbon Monoxide	OXIDATION CATALYST	4 PPM @ 15% O2
SACRAMENTO MUNICIPAL UTILITY DISTRICT	CA	9/1/2003	GAS TURBINES, (2)	NATURAL GAS	1611 MMBTU/H	Carbon Monoxide	GOOD COMBUSTION CONTROL	4 PPM @ 15% O2
SUTTER POWER PLANT	CA	8/16/2004	2 COMBUSTION TURBINES	NATURAL GAS	170	Carbon Monoxide	OXIDATION CATALYST SYSEM	4 PPMVD
BLYTHE ENERGY PROJECT II	CA	4/25/2007	2 COMBUSTION TURBINES	NATURAL GAS	170	Carbon Monoxide		4 PPMVD
SALT RIVER PROJECT/SANTAN GEN. PLANT	AZ	3/7/2003	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	NATURAL GAS	175	Carbon Monoxide	CATALYTIC OXIDIZER	3 PPM @ 15% O2
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	AZ	11/12/2003	TURBINE, COMBINED CYCLE & DUCT BURNER	NATURAL GAS	325	Carbon Monoxide	CATALYTIC OXIDIZER	3 PPM @ 15% O2
WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	NATURAL GAS	180	Carbon Monoxide	OXIDATION CATALYST	3 PPM @ 15% O2
WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	NATURAL GAS	170	Carbon Monoxide	OXIDATION CATALYST	3 PPM @ 15% O2
LA PAZ GENERATING FACILITY	AZ	9/4/2003	GE COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS	NATURAL GAS	1040	Carbon Monoxide	OXIDATION CATALYST	3 PPMVD
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	AZ	11/12/2003	TURBINE, COMBINED CYCLE	NATURAL GAS	325	Carbon Monoxide	CATALYTIC OXIDIZER	2 PPM @ 15% O2
VERNON CITY LIGHT & POWER	CA	5/27/2003	GAS TURBINE: COMBINED CYCLE < 50 MW	NATURAL GAS	43	Carbon Monoxide	SCR SYSTEM, AND OXIDATION CATALYST	2 PPMVD @ 15% O2
MAGNOLIA POWER PROJECT, SCPPA	CA	5/27/2003	GAS TURBINE: COMBINED CYCLE >= 50 MW	NATURAL GAS	181	Carbon Monoxide	SCR SYSTEM AND OXIDATION CATALYST	2 PPMVD @ 15% O2

Facility Name	State	Permit Date	Emission Source	Fuel	Load (MW)	Pollutant	Control Description	NOX Emission Limit
PASTORIA ENERGY FACILITY	CA	12/23/2004	3 COMBUSTION TURBINES	NATURAL GAS	168	Nitrogen Oxides (NOx)	XONON CATALYTIC COMBUSTORS OR DRY LOW NOX BURNERS WITH SCR	2.5 PPMVD
SUTTER POWER PLANT	CA	8/16/2004	2 COMBUSTION TURBINES	NATURAL GAS	170	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS & SCR	2.5 PPMVD
GILA BEND POWER GENERATING STATION	AZ	5/15/2002	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	NATURAL GAS	170	Nitrogen Oxides (NOx)	SCR AND LOW NOX COMBUSTORS	2 PPM @ 15% O2
SALT RIVER PROJECT/SANTAN GEN. PLANT	AZ	3/7/2003	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	NATURAL GAS	175	Nitrogen Oxides (NOx)	SCR	2 PPM @ 15% O2
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	AZ	11/12/2003	TURBINE, COMBINED CYCLE & DUCT BURNER	NATURAL GAS	325	Nitrogen Oxides (NOx)	SCR	2 PPM @ 15% O2
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	AZ	11/12/2003	TURBINE, COMBINED CYCLE	NATURAL GAS	325	Nitrogen Oxides (NOx)	SCR	2 PPM @ 15% O2
WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	NATURAL GAS	180	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION	2 PPM @ 15% O2
WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	NATURAL GAS	170	Nitrogen Oxides (NOx)	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION	2 PPM AT 15% O2
LA PAZ GENERATING FACILITY	AZ	9/4/2003	GE COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS	NATURAL GAS	1040	Nitrogen Oxides (NOx)	LOW NOX BURNERS WITH SELECTIVE CATALYTIC REDUCTION	2 PPMVD
SACRAMENTO MUNICIPAL UTILITY DISTRICT	CA	9/1/2003	GAS TURBINES, (2)	NATURAL GAS	1611 MMBTU/H	Nitrogen Oxides (NOx)	SCR	2 PPM @ 15% O2
VERNON CITY LIGHT & POWER	CA	5/27/2003	GAS TURBINE: COMBINED CYCLE < 50 MW	NATURAL GAS	43	Nitrogen Oxides (NOx)	SCR SYSTEM, AND OXIDATION CATALYST	2 PPMVD @ 15% O2
MAGNOLIA POWER PROJECT, SCPPA	CA	5/27/2003	GAS TURBINE: COMBINED CYCLE >= 50 MW	NATURAL GAS	181	Nitrogen Oxides (NOx)	SCR SYSTEM AND OXIDATION CATALYST	2 PPMVD @ 15% O2
BLYTHE ENERGY PROJECT II	CA	4/25/2007	2 COMBUSTION TURBINES	NATURAL GAS	170	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION	2 PPMVD

Facility Name	State	Permit Date	Emission Source	Fuel	Load (MW)	Pollutant	Control Description	VOC Emission Limit
LA PAZ GENERATING FACILITY	AZ	9/4/2003	GE COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS	NATURAL GAS	1040	Volatile Organic Compounds (VOC)	OXIDATION CATALYST	4.5 PPMVD
SALT RIVER PROJECT/SANTAN GEN. PLANT	AZ	3/7/2003	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	NATURAL GAS	175	Volatile Organic Compounds (VOC)	CATALYTIC OXIDIZER	4 PPM @ 15% O2
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	AZ	11/12/2003	TURBINE, COMBINED CYCLE & DUCT BURNER	NATURAL GAS	325	Volatile Organic Compounds (VOC)		4 PPM
WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	NATURAL GAS	180	Volatile Organic Compounds (VOC)	OXIDATION CATALYST	3 PPM @ 15% O2
WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	NATURAL GAS	170	Volatile Organic Compounds (VOC)	OXIDATION CATALYST	3 PPM @ 15% O2
VERNON CITY LIGHT & POWER	CA	5/27/2003	GAS TURBINE: COMBINED CYCLE < 50 MW	NATURAL GAS	43	Volatile Organic Compounds (VOC)	SCR SYSTEM, AND OXIDATION CATALYST	2 PPMVD @ 15% O2
MAGNOLIA POWER PROJECT, SCPPA	CA	5/27/2003	GAS TURBINE: COMBINED CYCLE >= 50 MW	NATURAL GAS	181	Volatile Organic Compounds (VOC)	SCR SYSTEM AND OXIDATION CATALYST	2 PPMVD @ 15% O2
GILA BEND POWER GENERATING STATION	AZ	5/15/2002	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	NATURAL GAS	170	Volatile Organic Compounds (VOC)	OXIDATION CATALYST AND GOOD COMBUSTION PRACTICE	1.4 PPM @ 15% O2
SACRAMENTO MUNICIPAL UTILITY DISTRICT	CA	9/1/2003	GAS TURBINES, (2)	NATURAL GAS	1611 MMBTU/H	Volatile Organic Compounds (VOC)		1.4 PPM @ 15% O2
DUKE ENERGY ARLINGTON VALLEY (AVEFII)	AZ	11/12/2003	TURBINE, COMBINED CYCLE	NATURAL GAS	325	Volatile Organic Compounds (VOC)		1 PPM

Attachment 3

RACT/BACT/LAER Clearinghouse (RBLC) Summary – PM Emissions (Cooling Tower)

Facility Name	State	Permit Date	Emission Source	Flow Rate (GPM)	Pollutant	Control Description	Emission Limit
LA PAZ GENERATING FACILITY	AZ	9/4/2003	MECHANICAL DRAFT COOLING TOWERS FOR GE TURBINES	173870	Particulate matter, filterable < 10 µ (FPM10)	DRIFT ELIMINATORS	0.0005 % BY VOL TOTAL DRIFT RATE
LA PAZ GENERATING FACILITY	AZ	9/4/2003	MECHANICAL DRAFT COOLING TOWERS FOR SIEMENS TURBINES	141400	Particulate matter, filterable < 10 µ (FPM10)	DRIFT ELIMINATORS	0.0005 % BY VOL TOTAL DRIFT RATE
LA PAZ GENERATING FACILITY	AZ	9/4/2003	MECHANICAL DRAFT COOLING TOWERS FOR GE TURBINES	173870	Particulate matter, filterable < 10 µ (FPM10)	DRIFT ELIMINATORS	0.0005 % BY VOL TOTAL DRIFT RATE
LA PAZ GENERATING FACILITY	AZ	9/4/2003	MECHANICAL DRAFT COOLING TOWERS FOR SIEMENS TURBINES	141400	Particulate matter, filterable < 10 µ (FPM10)	DRIFT ELIMINATORS	0.0005 % BY VOL TOTAL DRIFT RATE
ARIZONA CLEAN FUELS YUMA	AZ	4/14/2005	COOLING TOWER		Particulate Matter (PM)	HIGH EFFICIENCY DRIFT ELIMINATORS	0.0005 % BY VOL
WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	MECHANICAL DRAFT COOLING TOWERS	170000	Particulate matter, filterable < 10 µ (FPM10)	DRIFT ELIMINATORS (NOT TO EXCEED A TOTAL DRIFT RATE OF 0.0005 PERCENT OF CIRCULATING WATER FLOW)	0.0005 LB/H
WELLTON MOHAWK GENERATING STATION	AZ	12/1/2004	MECHANICAL DRAFT COOLING TOWERS	170000	Particulate matter, filterable < 10 µ (FPM10)	DRIFT ELIMINATORS (NOT TO EXCEED A TOTAL DRIFT RATE OF 0.0005 PERCENT OF CIRCULATING WATER FLOW)	0.0005 % BY VOL
SPRNGERVILLE GENERATING STATION	AZ	4/29/2002	COOLING TOWERS		Particulate matter, filterable (FPM)	HIGH-EFFICIENCY DRIFT ELIMINATORS-TOTAL LIQUID DRIFT NOT TO EXCEED 0.0005% OF CIRULATING WATER FLOW RATE	0.0005 % BY VOL
SPRNGERVILLE GENERATING STATION	AZ	4/29/2002	COOLING TOWERS		Particulate matter, filterable (FPM)	HIGH-EFFICIENCY DRIFT ELIMINATORS-TOTAL LIQUID DRIFT NOT TO EXCEED 0.0005% OF CIRULATING WATER FLOW RATE	0.0005 % BY VOL
ARIZONA CLEAN FUELS YUMA	AZ	4/14/2005	COOLING TOWER		Particulate Matter (PM)	HIGH EFFICIENCY DRIFT ELIMINATORS	1.6 LB/H

Attachment 4

NO_X Control Cost Summaries (Units 1-4)

SRP - Santan Generating Station
NOx Control Cost Summary -- Units 1-4

Unit S1 - NOx Control Costs

Net Generation	90	MW
Net Generation	100676	MWh
Capacity Factor:	12.77%	
Net Heat Rate	9,591	Btu/kWh
Actual Annual Heat Input:	965,584	MMBtu/yr
Actual Annual Fuel Consumption:	947	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline CT/HRSG Emissions (DLN1)	77.4	0.076	36.6		
Combustor Upgrades (DLN1+)	30.9	0.030	14.6	60%	22.0
SCR	7.7	0.008	3.7	90%	33.0
SCR + Combustor Upgrades	7.7	0.008	3.7	90%	33.0

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline CT/HRSG Emissions (DLN1)	36.6								
Combustor Upgrades (DLN1+)	14.6	22.0	$4,987,200	$551,400	$17,000	$568,400	**$25,869**		
SCR	3.7	33.0	$12,403,000	$1,371,000	$935,000	$2,306,000	**$69,966**	11.0	$158,161
SCR + Combustor Upgrades	3.7	33.0	$17,390,200	$1,922,400	$947,000	$2,869,400	**$87,060**	11.0	$209,443

Unit S2 - NOx Control Costs

Net Generation	90	MW
Net Generation	97710	MWh
Capacity Factor:	12.39%	
Net Heat Rate	9,447	Btu/kWh
Actual Annual Heat Input:	923,066	MMBtu/yr
Actual Annual Fuel Consumption:	905	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline CT/HRSG Emissions (DLN1)	87.8	0.086	39.7		
Combustor Upgrades (DLN1+)	35.1	0.034	15.9	60%	23.8
SCR	8.8	0.009	4.0	90%	35.7
SCR + Combustor Upgrades	8.8	0.009	4.0	90%	35.7

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline CT/HRSG Emissions (DLN1)	39.7								
Combustor Upgrades (DLN1+)	15.9	23.8	$4,987,200	$551,400	$16,000	$567,400	**$23,809**		
SCR	4.0	35.7	$12,403,000	$1,371,000	$936,000	$2,307,000	**$64,538**	11.9	$145,994
SCR + Combustor Upgrades	4.0	35.7	$17,390,200	$1,922,400	$946,000	$2,868,400	**$80,242**	11.9	$193,109

Unit S3 - NOx Control Costs

Net Generation	90	MW
Net Generation	118091	MWh
Capacity Factor:	14.98%	
Net Heat Rate	9,412	Btu/kWh
Actual Annual Heat Input:	1,111,472	MMBtu/yr
Actual Annual Fuel Consumption:	1,090	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline CT/HRSG Emissions (DLN1)	95.7	0.094	52.1		
Combustor Upgrades	38.3	0.038	20.9	60%	31.3
SCR	9.6	0.009	5.2	90%	46.9
SCR + Combustor Upgrades	9.6	0.009	5.2	90%	46.9

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline CT/HRSG Emissions (DLN1)	52.1								
Combustor Upgrades	20.9	31.3	$4,987,200	$551,400	$20,000	$571,400	**$18,266**		
SCR	5.2	46.9	$12,403,000	$1,371,000	$940,000	$2,311,000	**$49,250**	15.6	$111,218
SCR + Combustor Upgrades	5.2	46.9	$17,390,200	$1,922,400	$953,000	$2,875,400	**$61,278**	15.6	$147,301

Unit S4 - NOx Control Costs

Net Generation	90	MW
Net Generation	129952	MWh
Capacity Factor:	16.48%	
Net Heat Rate	9,285	Btu/kWh
Actual Annual Heat Input:	1,206,604	MMBtu/yr
Actual Annual Fuel Consumption:	1,183	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline CT/HRSG Emissions (DLN1)	73.1	0.072	43.3		
Combustor Upgrades (DLN1+)	29.3	0.029	17.3	60%	26.0
SCR	7.3	0.007	4.3	90%	38.9
SCR + Combustor Upgrades	7.3	0.007	4.3	90%	38.9

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline CT/HRSG Emissions (DLN1)	43.3								
Combustor Upgrades (DLN1+)	17.3	26.0	$4,987,200	$551,400	$22,000	$573,400	**$22,093**		
SCR	4.3	38.9	$12,403,000	$1,371,000	$940,000	$2,311,000	**$59,361**	13.0	$133,897
SCR + Combustor Upgrades	4.3	38.9	$17,390,200	$1,922,400	$956,000	$2,878,400	**$73,935**	13.0	$177,621

Cost Evaluation
S1_DLN1+_NOx

SRP - Santan Generating Station
Units S1-S4 -- NO_x/CO Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.076**
Post DLN1+ NOx Emission Rate	**0.030**
% NOx Reduction w/ DLN1+	**60%**
Baseline CO Emission Rate (lb/mmBtu)	**0.027**
Post DLN1+ CO Emission Rate	**0.024**
% CO Reduction w/ DLN1+	**10.0%**
Capacity Factor used for Cost Estimates (%)	**12.8%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,500,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor
Total Purchased Equipment Cost (PEC)	$2,500,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,553,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Direct Capital Costs (DC)	**$4,053,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$57,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Controls Engineering/Design	$31,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Training	$11,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Field Services	$4,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Indirect Capital Costs (IC)	**$103,000**		
Contingency	$831,200	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$4,987,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$551,400**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$17,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$17,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Maintenance Materials	$0		
Maintenance Labor	$0		
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$17,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$551,400**		
Annual Operating Cost	**$17,000**		
Total Annual Cost	**$568,400**		

SRP - Santan Generating Station
Units S1-S4 -- NO_x/CO Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.076**
Post DLN1+ NOx Emission Rate	**0.030**
% NOx Reduction w/ DLN1+	**60%**
Baseline CO Emission Rate (lb/mmBtu)	**0.027**
Post DLN1+ CO Emission Rate	**0.024**
% CO Reduction w/ DLN1+	**10.0%**
Capacity Factor used for Cost Estimates (%)	**12.4%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,500,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor
Total Purchased Equipment Cost (PEC)	$2,500,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,553,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Direct Capital Costs (DC)	**$4,053,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$57,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Controls Engineering/Design	$31,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Training	$11,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Field Services	$4,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Indirect Capital Costs (IC)	**$103,000**		
Contingency	$831,200	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$4,987,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$551,400**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$16,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$16,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Maintenance Materials	$0		
Maintenance Labor	$0		
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$16,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$551,400**		
Annual Operating Cost	**$16,000**		
Total Annual Cost	**$567,400**		

Cost Evaluation
S3_DLN1+

SRP - Santan Generating Station
Units S1-S4 -- NO_x/CO Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.076**
Post DLN1+ NOx Emission Rate	**0.030**
% NOx Reduction w/ DLN1+	**60%**
Baseline CO Emission Rate (lb/mmBtu)	**0.027**
Post DLN1+ CO Emission Rate	**0.024**
% CO Reduction w/ DLN1+	**10.0%**
Capacity Factor used for Cost Estimates (%)	**15.0%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,500,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor
Total Purchased Equipment Cost (PEC)	$2,500,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,553,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Direct Capital Costs (DC)	**$4,053,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$57,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Controls Engineering/Design	$31,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Training	$11,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Field Services	$4,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Indirect Capital Costs (IC)	**$103,000**		
Contingency	$831,200	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$4,987,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$551,400**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$20,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$20,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Maintenance Materials	$0		
Maintenance Labor	$0		
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$20,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$551,400**		
Annual Operating Cost	**$20,000**		
Total Annual Cost	**$571,400**		

SRP - Santan Generating Station
Units S1-S4 -- NO_x/CO Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	800.0
Approximate MW output	90.0
Baseline NOx Emission Rate (lb/mmBtu)	0.076
Post DLN1+ NOx Emission Rate	0.030
% NOx Reduction w/ DLN1+	60%
Baseline CO Emission Rate (lb/mmBtu)	0.027
Post DLN1+ CO Emission Rate	0.024
% CO Reduction w/ DLN1+	10.0%
Capacity Factor used for Cost Estimates (%)	16.5%

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,500,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor
Total Purchased Equipment Cost (PEC)	$2,500,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,553,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Direct Capital Costs (DC)	**$4,053,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$57,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Controls Engineering/Design	$31,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Training	$11,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Field Services	$4,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Indirect Capital Costs (IC)	**$103,000**		
Contingency	$831,200	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$4,987,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+ i)^n / (1 + i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$551,400**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$22,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$22,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Maintenance Materials	$0		
Maintenance Labor	$0		
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$22,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$551,400**		
Annual Operating Cost	**$22,000**		
Total Annual Cost	**$573,400**		

Cost Evaluation
S1_SCR

SRP - Santan Generating Station
Unit S1 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.076**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.008**
% Reduction w/ SCR	**90%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**12.8%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$9,081,000		Based on SRP (APS) turnkey estimate of $9,081,150, which includes catalyst placed in middle o evap section, raised piping, tubes, drums, stack by 30 ft.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$9,081,000		
Direct Installation Costs			
Installation	$1,255,000		Based on SRP cost estimate, includes engineering/design and installation
Total Direct Capital Costs (DC)	**$10,336,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,067,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$12,403,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$1,371,000**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	37	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$9,000	$ 450	Based on ammonia injection rate ammonia reagent cost of $450/ton.
Catalyst Replacement Cost	$62,000	5.0	Based on catalyst cost of $7000/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$9,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$84,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$147,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$22,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$186,000	1.5%	of TCI. OAQPS Section 4.2, Chapter 2, page 2-45.
Total Fixed O&M Cost	$355,000		
Indirect Operating Cost			
Property Taxes	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Insurance	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Administration	$248,000	2%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$496,000		
Total Annual Operating Cost	**$935,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,371,000**		
Annual Operating Cost	**$935,000**		
Total Annual Cost	**$2,306,000**		

SRP - Santan Generating Station
Unit S2 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.086**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.009**
% Reduction w/ SCR	**90%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**12.4%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$9,081,000		Based on SRP (APS) turnkey estimate of $9,081,150, which includes catalyst placed in middle o evap section, raised piping, tubes, drums, stack by 30 ft.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$9,081,000		
Direct Installation Costs			
Installation	$1,255,000		Based on SRP cost estimate, includes engineering/design and installation
Total Direct Capital Costs (DC)	**$10,336,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,067,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$12,403,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,371,000**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	41	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$10,000	$ 450	Based on ammonia injection rate ammonia reagent cost of $450/ton.
Catalyst Replacement Cost	$62,000	5.0	Based on catalyst cost of $7000/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$9,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$85,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$147,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$22,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$186,000	1.5%	of TCI. OAQPS Section 4.2, Chapter 2, page 2-45.
Total Fixed O&M Cost	$355,000		
Indirect Operating Cost			
Property Taxes	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Insurance	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Administration	$248,000	2%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$496,000		
Total Annual Operating Cost	**$936,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,371,000**		
Annual Operating Cost	**$936,000**		
Total Annual Cost	**$2,307,000**		

Cost Evaluation
S3_SCR

SRP - Santan Generating Station
Unit S3 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.094**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.009**
% Reduction w/ SCR	**90%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**15.0%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$9,081,000		Based on SRP (APS) turnkey estimate of $9,081,150, which includes catalyst placed in middle o evap section, raised piping, tubes, drums, stack by 30 ft.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$9,081,000		
Direct Installation Costs			
Installation	$1,255,000		Based on SRP cost estimate, includes engineering/design and installation
Total Direct Capital Costs (DC)	**$10,336,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,067,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$12,403,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$1,371,000**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	44	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$13,000	$ 450	Based on ammonia injection rate ammonia reagent cost of $450/ton.
Catalyst Replacement Cost	$62,000	5.0	Based on catalyst cost of $7000/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$10,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$89,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$147,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$22,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$186,000	1.5%	of TCI. OAQPS Section 4.2, Chapter 2, page 2-45.
Total Fixed O&M Cost	$355,000		
Indirect Operating Cost			
Property Taxes	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Insurance	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Administration	$248,000	2%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$496,000		
Total Annual Operating Cost	**$940,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,371,000**		
Annual Operating Cost	**$940,000**		
Total Annual Cost	**$2,311,000**		

Cost Evaluation
S4_SCR

SRP - Santan Generating Station
Unit S4 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.072**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.007**
% Reduction w/ SCR	**90%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**16.5%**

CAPITAL COSTS	**[$]**			**Basis**
Direct Capital Costs				
NOx Control Equipment	$9,081,000			Based on SRP (APS) turnkey estimate of $9,081,150, which includes catalyst placed in middle o evap section, raised piping, tubes, drums, stack by 30 ft.
Instrumentation	$0			Included in NOx control equipment cost
Sales Taxes	$0			Included in NOx control equipment cost
Freight	$0			Included in NOx control equipment cost
Total Purchased Equipment Cost	$9,081,000			
Direct Installation Costs				
Installation	$1,255,000			Based on SRP cost estimate, includes engineering/design and installation
Total Direct Capital Costs (DC)	**$10,336,000**			Sum of purchased equipment costs and installation costs
Indirect Capital Costs				
Engineering	$0			Included in NOx control direct installation costs
Construction and Field Expenses	$0			Included in NOx control direct installation costs
Contractor Fees	$0			Included in NOx control direct installation costs
Start-Up	$0			Included in NOx control direct installation costs
Performance Testing	$0			Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**			
Contingency	$2,067,000		20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$12,403,000**			sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106		20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,371,000**		9.13%	pretax marginal rate of return on private investment
OPERATING COSTS				**Basis**
Operating & Maintenance Costs				
Variable O&M Costs				
Ammonia Injection Rate (lb/hr)	35		0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560		18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$11,000	$	450	Based on ammonia injection rate ammonia reagent cost of $450/ton.
Catalyst Replacement Cost	$62,000		5.0	Based on catalyst cost of $7000/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$	500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$12,000		2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$89,000			
Fixed O&M Costs				
Additional Operators per shift	0.50			Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$147,000			Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$22,000		15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$186,000		1.5%	of TCI. OAQPS Section 4.2, Chapter 2, page 2-45.
Total Fixed O&M Cost	$355,000			
Indirect Operating Cost				
Property Taxes	$124,000		1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Insurance	$124,000		1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Administration	$248,000		2%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$496,000			
Total Annual Operating Cost	**$940,000**			
TOTAL ANNUAL COST				
Annualized Capital Cost	**$1,371,000**			
Annual Operating Cost	**$940,000**			
Total Annual Cost	**$2,311,000**			

Cost Evaluation
S1_SCR wDLN1+

SRP - Santan Generating Station
Unit S1 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.030**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.008**
% Reduction w/ SCR	**75%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**12.8%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	$9,081,000		Based on SRP (APS) turnkey estimate of $9,081,150, which includes catalyst placed in middle o evap section, raised piping, tubes, drums, stack by 30 ft.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$9,081,000		
Direct Installation Costs			
Installation	$1,255,000		Based on SRP cost estimate, includes engineering/design and installation
Total Direct Capital Costs (DC)	**$10,336,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,067,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$12,403,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$1,371,000**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	17	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$4,000	$ 450	Based on ammonia injection rate ammonia reagent cost of $450/ton.
Catalyst Replacement Cost	$62,000	5.0	Based on catalyst cost of $7000/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$9,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$79,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$147,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$22,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$186,000	1.5%	of TCI. OAQPS Section 4.2, Chapter 2, page 2-45.
Total Fixed O&M Cost	$355,000		
Indirect Operating Cost			
Property Taxes	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Insurance	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Administration	$248,000	2%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$496,000		
Total Annual Operating Cost	**$930,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,371,000**		
Annual Operating Cost	**$930,000**		
Total Annual Cost	**$2,301,000**		

Cost Evaluation
S2_SCR wDLN1+

SRP - Santan Generating Station
Unit S2 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.034**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.009**
% Reduction w/ SCR	**75%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**12.4%**

CAPITAL COSTS	[$]		Basis
Direct Capital Costs			
NOx Control Equipment	$9,081,000		Based on SRP (APS) turnkey estimate of $9,081,150, which includes catalyst placed in middle o evap section, raised piping, tubes, drums, stack by 30 ft.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$9,081,000		
Direct Installation Costs			
Installation	$1,255,000		Based on SRP cost estimate, includes engineering/design and installation
Total Direct Capital Costs (DC)	**$10,336,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,067,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$12,403,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$1,371,000**	9.13%	pretax marginal rate of return on private investment

OPERATING COSTS			Basis
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	18	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$4,000	$ 450	Based on ammonia injection rate ammonia reagent cost of $450/ton.
Catalyst Replacement Cost	$62,000	5.0	Based on catalyst cost of $7000/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$9,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$79,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$147,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$22,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$186,000	1.5%	of TCI. OAQPS Section 4.2, Chapter 2, page 2-45.
Total Fixed O&M Cost	$355,000		
Indirect Operating Cost			
Property Taxes	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Insurance	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Administration	$248,000	2%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$496,000		
Total Annual Operating Cost	**$930,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,371,000**		
Annual Operating Cost	**$930,000**		
Total Annual Cost	**$2,301,000**		

Cost Evaluation
S3_SCR wDLN1+

SRP - Santan Generating Station
Unit S3 - NOx Control Costs
SCR Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.038**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.009**
% Reduction w/ SCR	**75%**
Stack Flue Gas Flow Rate (acfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**15.0%**

CAPITAL COSTS	[$]		Basis
Direct Capital Costs			
NOx Control Equipment	$9,081,000		Based on SRP (APS) turnkey estimate of $9,081,150, which includes catalyst placed in middle o evap section, raised piping, tubes, drums, stack by 30 ft.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$9,081,000		
Direct Installation Costs			
Installation	$1,255,000		Based on SRP cost estimate, includes engineering/design and installation
Total Direct Capital Costs (DC)	**$10,336,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,067,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$12,403,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$1,371,000**	9.13%	pretax marginal rate of return on private investment

OPERATING COSTS			Basis
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	19	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$6,000	$ 450	Based on ammonia injection rate ammonia reagent cost of $450/ton.
Catalyst Replacement Cost	$62,000	5.0	Based on catalyst cost of $7000/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$10,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$82,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$147,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$22,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$186,000	1.5%	of TCI. OAQPS Section 4.2, Chapter 2, page 2-45.
Total Fixed O&M Cost	$355,000		
Indirect Operating Cost			
Property Taxes	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Insurance	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Administration	$248,000	2%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$496,000		
Total Annual Operating Cost	**$933,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,371,000**		
Annual Operating Cost	**$933,000**		
Total Annual Cost	**$2,304,000**		

Cost Evaluation
S4_SCR wDLN1+

SRP - Santan Generating Station
Unit S4 - NOx Control Costs
SCR Worksheet

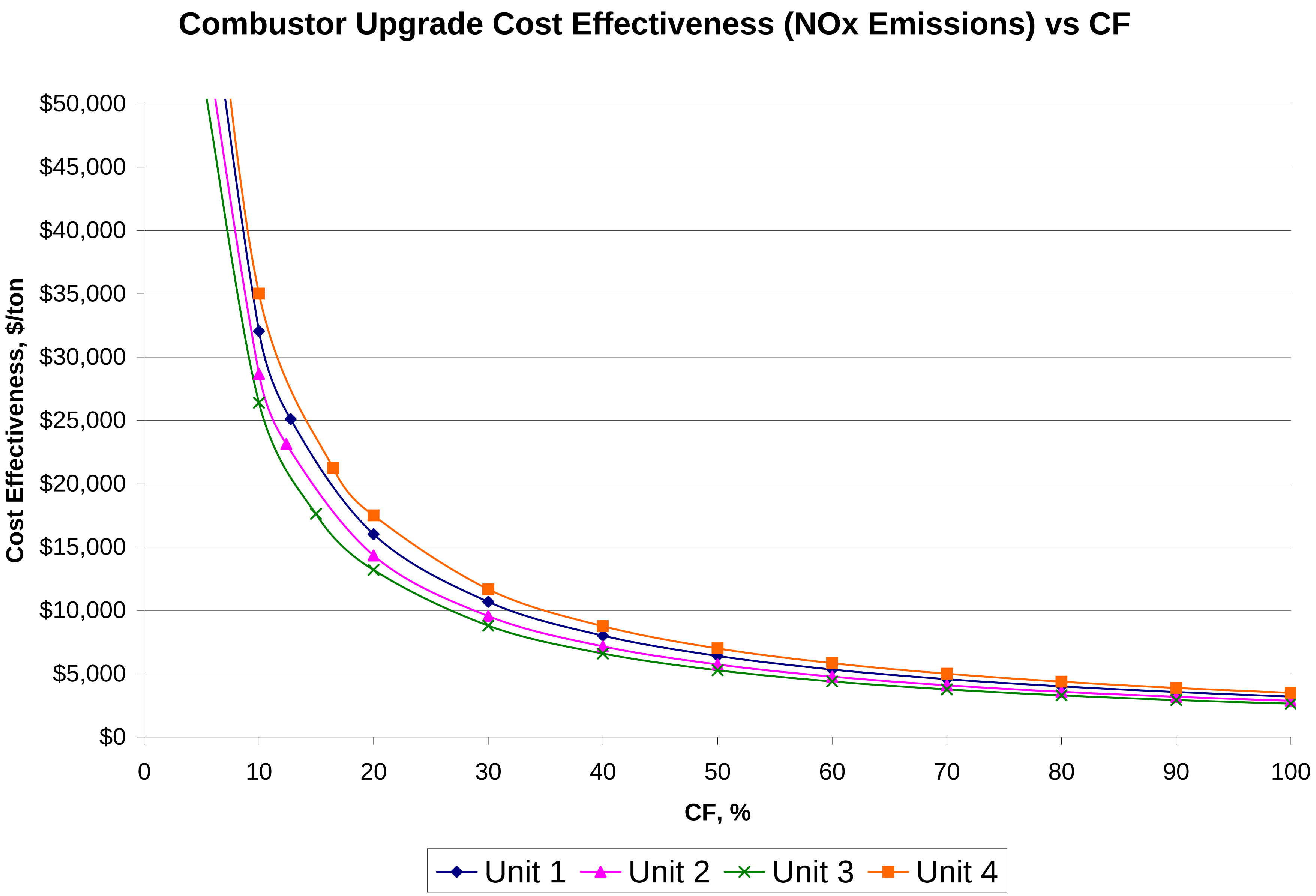
	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.029**
Post SCR NOx Emission Rate (lb/mmBtu)	**0.007**
% Reduction w/ SCR	**75%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**16.5%**

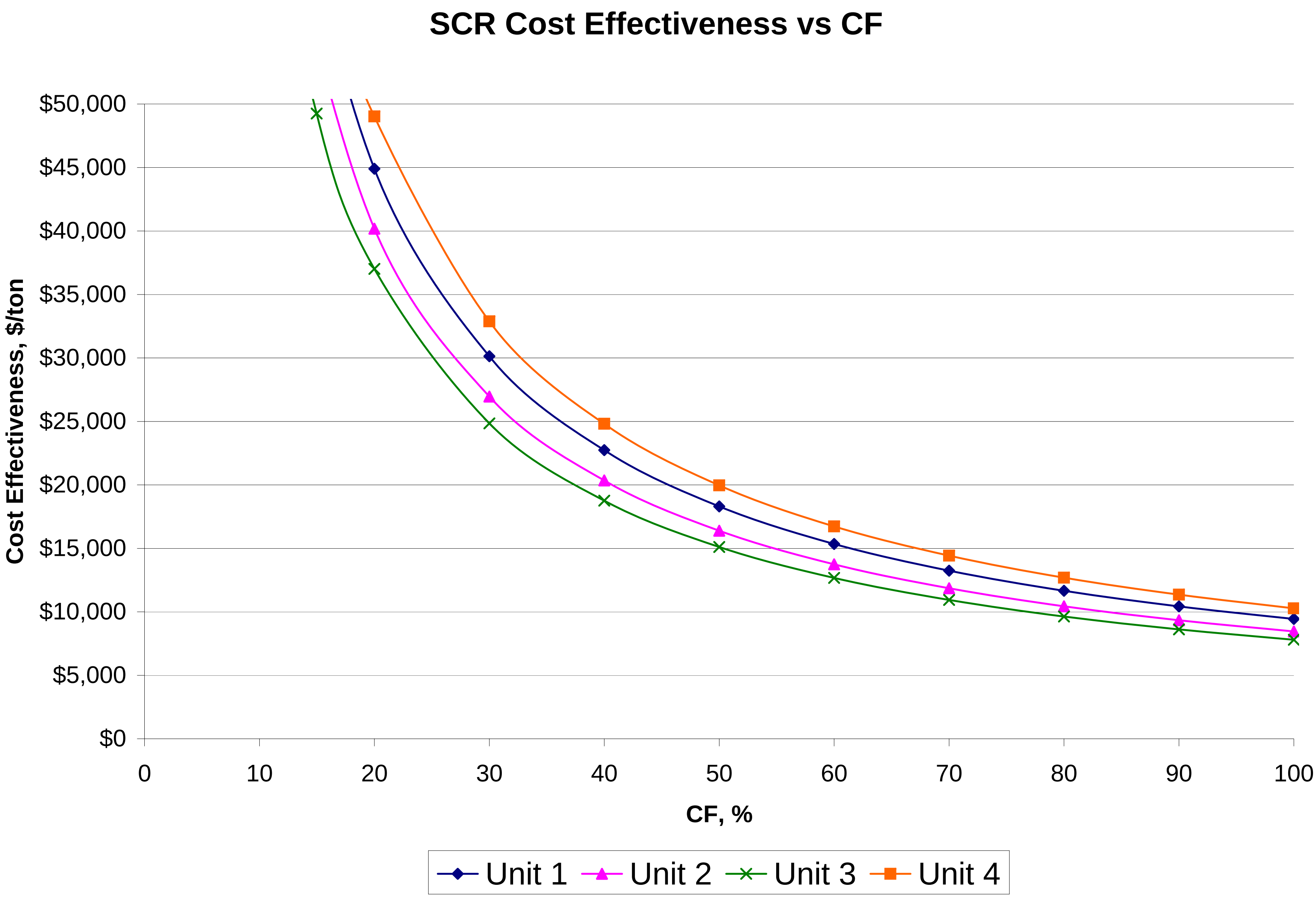
CAPITAL COSTS	[$]		Basis
Direct Capital Costs			
NOx Control Equipment	$9,081,000		Based on SRP (APS) turnkey estimate of $9,081,150, which includes catalyst placed in middle o evap section, raised piping, tubes, drums, stack by 30 ft.
Instrumentation	$0		Included in NOx control equipment cost
Sales Taxes	$0		Included in NOx control equipment cost
Freight	$0		Included in NOx control equipment cost
Total Purchased Equipment Cost	$9,081,000		
Direct Installation Costs			
Installation	$1,255,000		Based on SRP cost estimate, includes engineering/design and installation
Total Direct Capital Costs (DC)	**$10,336,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Engineering	$0		Included in NOx control direct installation costs
Construction and Field Expenses	$0		Included in NOx control direct installation costs
Contractor Fees	$0		Included in NOx control direct installation costs
Start-Up	$0		Included in NOx control direct installation costs
Performance Testing	$0		Included in NOx control direct installation costs
Total Indirect Capital Costs (IC)	**$0**		
Contingency	$2,067,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$12,403,000**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$1,371,000**	9.13%	pretax marginal rate of return on private investment

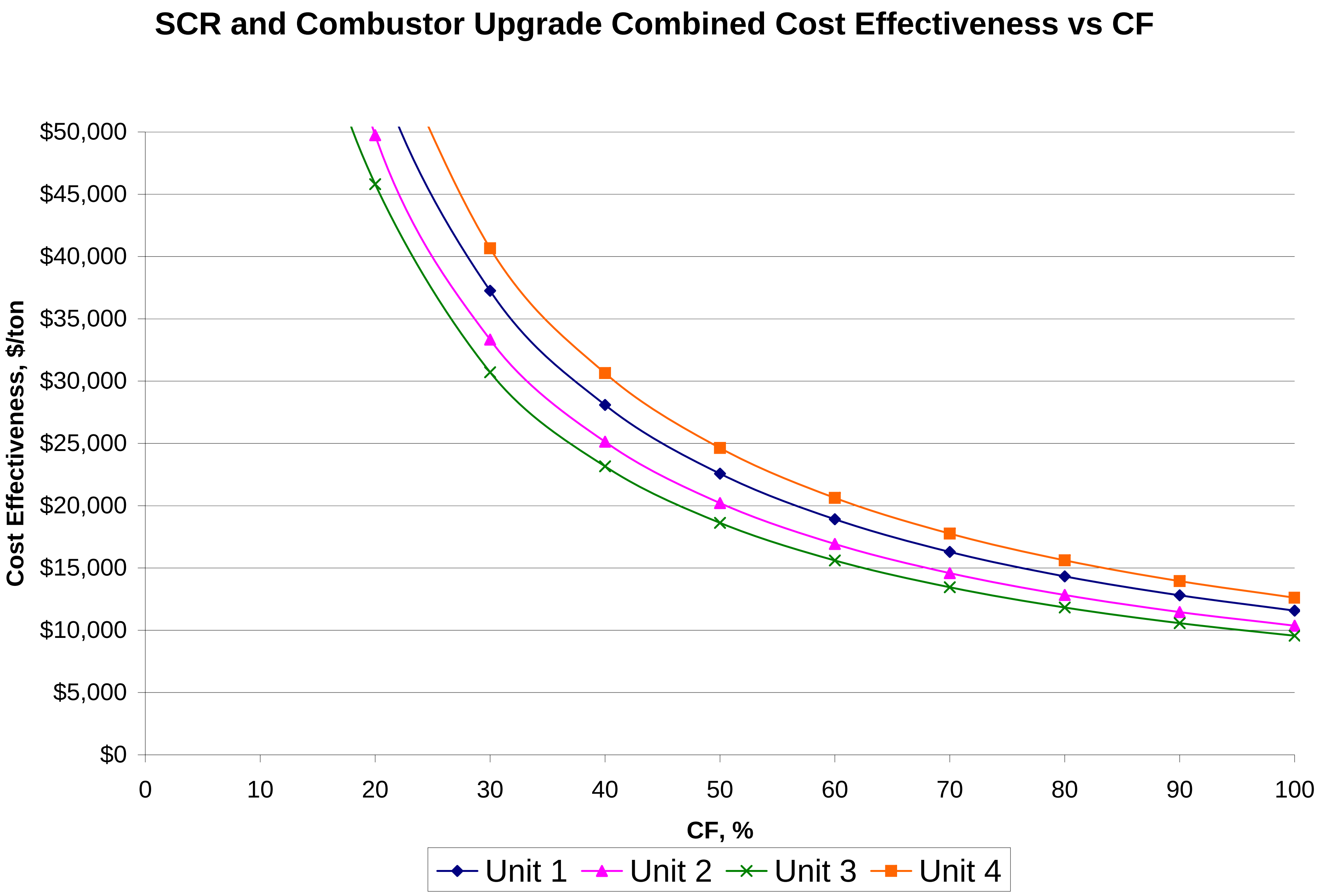
OPERATING COSTS			Basis
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	16	0.50	Based on maximum heat input, NOx removal rate (lb/hr), 5 ppm NH3 slip, and NO/NO2 ratio listed to the left.
Catalyst Volume (ft3)	1,560	18,810	Calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Ammonia Reagent Cost	$5,000	$ 450	Based on ammonia injection rate ammonia reagent cost of $450/ton.
Catalyst Replacement Cost	$62,000	5.0	Based on catalyst cost of $7000/m3 and 5 year catalyst life
Spent Catalyst Handling Cost	$4,000	$ 500	Based on the catalyst life and a catalyst handling cost of $500/m3
Auxiliary Power Cost	$12,000	2	Based on the pressure drop across the SCR (listed to the left in in w.c.), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$83,000		
Fixed O&M Costs			
Additional Operators per shift	0.50		Assumed 0.5 additional operator per shift needed for the oxidation catalyst system.
Operating Labor	$147,000		Based on additional operators per shift, $33.50/hour (salary + benefits), 3 shifts/day.
Supervisory Labor	$22,000	15%	of operating labor. OAQPS Section 1, Chapter 2, page 2-31.
Annual Maintenance Cost	$186,000	1.5%	of TCI. OAQPS Section 4.2, Chapter 2, page 2-45.
Total Fixed O&M Cost	$355,000		
Indirect Operating Cost			
Property Taxes	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Insurance	$124,000	1%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Administration	$248,000	2%	of TCI. OAQPS Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$496,000		
Total Annual Operating Cost	**$934,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$1,371,000**		
Annual Operating Cost	**$934,000**		
Total Annual Cost	**$2,305,000**		

Attachment 5

NO_X Control Cost Sensitivities Versus Capacity Factors (Units 1-4)


Combustor Upgrade Cost Effectiveness (NOx Emissions) vs CF
$50,000
$45,000
$40,000
$35,000
$30,000
$25,000
$20,000
$15,000
$10,000
$5,000
$0
Cost Effectiveness, $/ton
0
10
20
30
40
50
60
70
80
90
100
CF, %
Unit 1
Unit 2
Unit 3
Unit 4


SCR Cost Effectiveness vs CF
Cost Effectiveness, $/ton
$50,000
$45,000
$40,000
$35,000
$30,000
$25,000
$20,000
$15,000
$10,000
$5,000
$0
0
10
20
30
40
50
60
70
80
90
100
CF, %
Unit 1
Unit 2
Unit 3
Unit 4


SCR and Combustor Upgrade Combined Cost Effectiveness vs CF
Cost Effectiveness, $/ton
$50,000
$45,000
$40,000
$35,000
$30,000
$25,000
$20,000
$15,000
$10,000
$5,000
$0
0
10
20
30
40
50
60
70
80
90
100
CF, %
Unit 1
Unit 2
Unit 3
Unit 4

Attachment 6

CO Control Cost Summaries (Units 1-4)

SRP - Santan Generating Station
CO Control Cost Summary -- Units 1-4

Unit S1 - CO Control Costs

Net Generation	90	MW
Net Generation	91087	MWh
Capacity Factor:	11.55%	
Net Heat Rate	9,812	Btu/kWh
Actual Annual Heat Input:	893,746	MMBtu/yr
Actual Annual Fuel Consumption:	876	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline - Existing DLN1 Combustors and CO Catalyst System	27.1	0.027	11.9		
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	24.4	0.024	10.7	10%	1.2
CO Catalyst System Upgrades and Combustor Upgrades	13.5	0.013	5.9	50%	5.9
CO Catalyst System Upgrades with Existing DLN1 Combustors	13.5	0.013	5.9	50%	5.9

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline - Existing DLN1 Combustors and CO Catalyst System	11.9								
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	10.7	1.2	$4,987,200	$551,400	$15,000	$566,400	**$477,270**		
CO Catalyst System Upgrades and Combustor Upgrades	5.9	5.9	$6,933,000	$766,400	$196,000	$962,400	**$162,191**	4.7	$83,421
CO Catalyst System Upgrades with Existing DLN1 Combustors	5.9	5.9	$1,945,800	$215,000	$181,000	$396,000	**$66,737**	4.7	NA

Unit S2 - CO Control Costs

Net Generation	90	MW
Net Generation	97710	MWh
Capacity Factor:	12.39%	
Net Heat Rate	9,447	Btu/kWh
Actual Annual Heat Input:	923,066	MMBtu/yr
Actual Annual Fuel Consumption:	905	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline - Existing DLN1 Combustors and CO Catalyst System	22.9	0.022	10.4		
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	20.6	0.020	9.3	10%	1.0
CO Catalyst System Upgrades and Combustor Upgrades	11.4	0.011	5.2	50%	5.2
CO Catalyst System Upgrades with Existing DLN1 Combustors	11.4	0.011	5.2	50%	5.2

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline - Existing DLN1 Combustors and CO Catalyst System	10.4								
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	9.3	1.0	$4,987,200	$551,400	$16,000	$567,400	**$548,080**		
CO Catalyst System Upgrades and Combustor Upgrades	5.2	5.2	$6,933,000	$766,400	$198,000	$964,400	**$186,312**	4.1	$95,871
CO Catalyst System Upgrades with Existing DLN1 Combustors	5.2	5.2	$1,945,800	$215,000	$182,000	$397,000	**$76,696**	4.1	NA

Unit S3 - CO Control Costs

Net Generation	90	MW
Net Generation	118091	MWh
Capacity Factor:	14.98%	
Net Heat Rate	9,412	Btu/kWh
Actual Annual Heat Input:	1,111,472	MMBtu/yr
Actual Annual Fuel Consumption:	1,090	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline - Existing DLN1 Combustors and CO Catalyst System	24.3	0.024	13.2		
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	21.8	0.021	11.9	10%	1.3
CO Catalyst System Upgrades and Combustor Upgrades	12.1	0.012	6.6	50%	6.6
CO Catalyst System Upgrades with Existing DLN1 Combustors	12.1	0.012	6.6	50%	6.6

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline - Existing DLN1 Combustors and CO Catalyst System	13.2								
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	11.9	1.3	$4,987,200	$551,400	$20,000	$571,400	**$432,077**		
CO Catalyst System Upgrades and Combustor Upgrades	6.6	6.6	$6,933,000	$766,400	$203,000	$969,400	**$146,607**	5.3	$75,239
CO Catalyst System Upgrades with Existing DLN1 Combustors	6.6	6.6	$1,945,800	$215,000	$183,000	$398,000	**$60,191**	5.3	NA

Unit S4 - CO Control Costs

Net Generation	90	MW
Net Generation	129952	MWh
Capacity Factor:	16.48%	
Net Heat Rate	9,285	Btu/kWh
Actual Annual Heat Input:	1,206,604	MMBtu/yr
Actual Annual Fuel Consumption:	1,183	MMSCF/yr

Control Technology	lb/mmscf (annual avg)	lb/mmBtu (annual avg)	Actual Emissions (ton/year)	Control Efficiency (%)	Emissions Reduction (ton/year)
Baseline - Existing DLN1 Combustors and CO Catalyst System	24.5	0.024	14.5		
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	22.0	0.022	13.0	10%	1.4
CO Catalyst System Upgrades and Combustor Upgrades	12.2	0.012	7.2	50%	7.2
CO Catalyst System Upgrades with Existing DLN1 Combustors	12.2	0.012	7.2	50%	7.2

Control Technology	Emissions (tpy)	Tons of NOx Removed (tpy)	Total Capital Investment ($)	Annual Capital Recovery Cost ($/year)	Total Annual Operating Costs ($/year)	Total Annual Costs ($)	Average Cost Effectiveness ($/ton)	Incremental Annual Emission Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
Baseline - Existing DLN1 Combustors and CO Catalyst System	14.5								
Combustor Upgrades (DLN1+) with Existing CO Catalyst System	13.0	1.4	$4,987,200	$551,400	$22,000	$573,400	**$396,419**		
CO Catalyst System Upgrades and Combustor Upgrades	7.2	7.2	$6,933,000	$766,400	$207,000	$973,400	**$134,592**	5.8	$69,135
CO Catalyst System Upgrades with Existing DLN1 Combustors	7.2	7.2	$1,945,800	$215,000	$185,000	$400,000	**$55,308**	5.8	NA

Cost Evaluation
S1_DLN1+_CO

SRP - Santan Generating Station
Units S1-S4 -- NO_x/CO Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.076**
Post DLN1+ NOx Emission Rate	**0.030**
% NOx Reduction w/ DLN1+	**60%**
Baseline CO Emission Rate (lb/mmBtu)	**0.027**
Post DLN1+ CO Emission Rate	**0.024**
% CO Reduction w/ DLN1+	**10.0%**
Capacity Factor used for Cost Estimates (%)	**11.6%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,500,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor
Total Purchased Equipment Cost (PEC)	$2,500,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,553,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Direct Capital Costs (DC)	**$4,053,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$57,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Controls Engineering/Design	$31,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Training	$11,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Field Services	$4,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Indirect Capital Costs (IC)	**$103,000**		
Contingency	$831,200	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$4,987,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$551,400**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$15,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$15,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Maintenance Materials	$0		
Maintenance Labor	$0		
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$15,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$551,400**		
Annual Operating Cost	**$15,000**		
Total Annual Cost	**$566,400**		

Cost Evaluation
S2_DLN1+

SRP - Santan Generating Station
Units S1-S4 -- NO_x/CO Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.076**
Post DLN1+ NOx Emission Rate	**0.030**
% NOx Reduction w/ DLN1+	**60%**
Baseline CO Emission Rate (lb/mmBtu)	**0.027**
Post DLN1+ CO Emission Rate	**0.024**
% CO Reduction w/ DLN1+	**10.0%**
Capacity Factor used for Cost Estimates (%)	**12.4%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,500,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor
Total Purchased Equipment Cost (PEC)	$2,500,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,553,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Direct Capital Costs (DC)	**$4,053,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$57,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Controls Engineering/Design	$31,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Training	$11,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Field Services	$4,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Indirect Capital Costs (IC)	**$103,000**		
Contingency	$831,200	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$4,987,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$551,400**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$16,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$16,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Maintenance Materials	$0		
Maintenance Labor	$0		
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$16,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$551,400**		
Annual Operating Cost	**$16,000**		
Total Annual Cost	**$567,400**		

Cost Evaluation
S3_DLN1+

SRP - Santan Generating Station
Units S1-S4 -- NO_x/CO Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	800.0
Approximate MW output	90.0
Baseline NOx Emission Rate (lb/mmBtu)	0.076
Post DLN1+ NOx Emission Rate	0.030
% NOx Reduction w/ DLN1+	60%
Baseline CO Emission Rate (lb/mmBtu)	0.027
Post DLN1+ CO Emission Rate	0.024
% CO Reduction w/ DLN1+	10.0%
Capacity Factor used for Cost Estimates (%)	15.0%

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,500,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor
Total Purchased Equipment Cost (PEC)	$2,500,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,553,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Direct Capital Costs (DC)	**$4,053,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$57,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Controls Engineering/Design	$31,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Training	$11,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Field Services	$4,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Indirect Capital Costs (IC)	**$103,000**		
Contingency	$831,200	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$4,987,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+ i)^n / (1 + i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$551,400**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$20,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$20,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Maintenance Materials	$0		
Maintenance Labor	$0		
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$20,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$551,400**		
Annual Operating Cost	**$20,000**		
Total Annual Cost	**$571,400**		

SRP - Santan Generating Station
Units S1-S4 -- NO_x/CO Control Costs
Combustor Upgrade Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline NOx Emission Rate (lb/mmBtu)	**0.076**
Post DLN1+ NOx Emission Rate	**0.030**
% NOx Reduction w/ DLN1+	**60%**
Baseline CO Emission Rate (lb/mmBtu)	**0.027**
Post DLN1+ CO Emission Rate	**0.024**
% CO Reduction w/ DLN1+	**10.0%**
Capacity Factor used for Cost Estimates (%)	**16.5%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
NOx Control Equipment	**$2,500,000**		Based on budgetary estimate obtained from GE for DLN1+ combustor
Total Purchased Equipment Cost (PEC)	$2,500,000		
Direct Installation Costs			
Installation + Major Inspection Labor	$1,553,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Direct Capital Costs (DC)	**$4,053,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
Inspection Materials	$57,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Controls Engineering/Design	$31,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Training	$11,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Field Services	$4,000		Based on SRP DLN1 Installation Costs (adjusted to 2010 dollars)
Total Indirect Capital Costs (IC)	**$103,000**		
Contingency	$831,200	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$4,987,200**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+ i)^n / (1 + i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$551,400**	9.13%	pretax marginal rate of return on private investment
OPERATING COSTS			**Basis**
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Injection Rate (lb/hr)	0		NA
Catalyst Volume (ft3)	0		NA
Ammonia Reagent Cost	$0		NA
Catalyst Replacement Cost			NA
Spent Catalyst Handling Cost			NA
Auxiliary Power Cost	$22,000	300	Based on reduced power output at full load (listed to the left in kw), and $50/MWh.
Total Variable O&M Cost	$22,000		
Fixed O&M Costs			
Additional Operators per shift	0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervisory Labor	$0		
Maintenance Materials	$0		
Maintenance Labor	$0		
Total Fixed O&M Cost	$0		
Indirect Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating Cost	**$22,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$551,400**		
Annual Operating Cost	**$22,000**		
Total Annual Cost	**$573,400**		

SRP - Santan Generating Station
Unit S1 -- CO Control Costs
Oxidation Catalyst Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline CO Emission Rate (lb/mmBtu)	**0.027**
Post CO Catalyst Emission Rate (lb/mmBtu)	**0.013**
% Reduction w/ CO Catalyst Upgrades	**50%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**11.6%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
Control Equipment	$1,060,000		Based on budgetary costs for oxidation catalyst system upgrades. Includes costs for catalyst replacement and new internal frame.
Instrumentation	$0		Included in CO control equipment cost
Sales Taxes	$0		Included in CO control equipment cost
Freight	$0		Included in CO control equipment cost
Total Purchased Equipment Cost	$1,060,000		
Direct Installation Costs			
Installation	$318,000	30%	Engineering estimate: 30% of PEC
Total Direct Capital Costs (DC)	**$1,378,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
General Facilities	$53,000	5%	Calculated as percent of Total Direct Capital Costs. Based on OAQPS Capital Cost Factors for an SCR system (Section 4, Chapter 2), and assuming that the same factors would apply fo an Oxidation Catalyst System
Engineering and Home Office Fees	$106,000	10%	
Process Contingency	$53,000	5%	
Startup and Performance Tests	$31,800	3%	
Total Indirect Capital Costs (IC)	**$243,800**		
Contingency	$324,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$1,945,800**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs (Capital Recover Factor x Total Capital Investment)	**$215,000**	9.13%	pretax marginal rate of return on private investment
OPERATING & MAINTENANCE COSTS			**Basis**
Variable O&M Costs			
Reagent Cost	$0		NA
Catalyst Volume	323	90,847	Catalyst Volume (in ft^3) calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Catalyst Replacement Cost	$173,000	5.0	Based on the differetial catalyst cost (60% reduction vs 80% reduction) ($1,060,000 - $194,000) and 5 year catalyst life
Auxiliary Power Cost	$8,000	2	Based on the increased pressure drop across the CO catalyst (listed to the left in inches), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$181,000		
Fixed O&M Costs			
Additional Operators per shift	0.0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervision	$0		
Maintenance Labor and Materials	$0		
Total Direct Annual Costs	$0		
Indirect Annual Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating & Maintenance Cost	**$181,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$215,000**		
Annual Operating & Maintenance Cost	**$181,000**		
Total Annual Cost	**$396,000**		

Cost Evaluation
S2_CO Catalyst

SRP - Santan Generating Station
Unit S2 -- CO Control Costs
Oxidation Catalyst Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline CO Emission Rate (lb/mmBtu)	**0.022**
Post CO Catalyst Emission Rate (lb/mmBtu)	**0.011**
% Reduction w/ CO Catalyst Upgrades	**50%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**12.4%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
Control Equipment	$1,060,000		Based on budgetary costs for oxidation catalyst system upgrades. Includes costs for catalyst replacement and new internal frame.
Instrumentation	$0	0%	Included in CO control equipment cost
Sales Taxes	$0	0%	Included in CO control equipment cost
Freight	$0	0%	Included in CO control equipment cost
Total Purchased Equipment Cost	$1,060,000		
Direct Installation Costs			
Installation	$318,000	30%	Engineering estimate 30% of PEC
Total Direct Capital Costs (DC)	**$1,378,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
General Facilities	$53,000	5%	
Engineering and Home Office Fees	$106,000	10%	Calculated as percent of Total Direct Capital Costs. Based on OAQPS Capital Cost Factors
Process Contingency	$53,000	5%	for an SCR system (Section 4, Chapter 2), and assuming that the same factors would apply fo
Startup and Performance Tests	$31,800	3%	an Oxidation Catalyst System
Total Indirect Capital Costs (IC)	**$243,800**		
Contingency	$324,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$1,945,800**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$215,000**	9.13%	pretax marginal rate of return on private investment
OPERATING & MAINTENANCE COSTS			**Basis**
Variable O&M Costs			
Reagent Cost	$0		NA
Catalyst Volume	323	90,847	Catalyst Volume (in ft^3) calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Catalyst Replacement Cost	$173,000	5.0	Based on the differetial catalyst cost (60% reduction vs 80% reduction) ($1,060,000 - $194,000) and 5 year catalyst life
Auxiliary Power Cost	$9,000	2	Based on the increased pressure drop across the CO catalyst (listed to the left in inches), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$182,000		
Fixed O&M Costs			
Additional Operators per shift	0.0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervision	$0		
Maintenance Labor and Materials	$0		
Total Direct Annual Costs	$0		
Indirect Annual Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating & Maintenance Cost	**$182,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$215,000**		
Annual Operating & Maintenance Cost	**$182,000**		
Total Annual Cost	**$397,000**		

Cost Evaluation
S3_CO Catalyst

SRP - Santan Generating Station
Unit S3 -- CO Control Costs
Oxidation Catalyst Worksheet

	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline CO Emission Rate (lb/mmBtu)	**0.024**
Post CO Catalyst Emission Rate (lb/mmBtu)	**0.012**
% Reduction w/ CO Catalyst Upgrades	**50%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**15.0%**

CAPITAL COSTS	**[$]**		**Basis**
Direct Capital Costs			
Control Equipment	$1,060,000		Based on budgetary costs for oxidation catalyst system upgrades. Includes costs for catalyst replacement and new internal frame.
Instrumentation	$0	0%	Included in CO control equipment cost
Sales Taxes	$0	0%	Included in CO control equipment cost
Freight	$0	0%	Included in CO control equipment cost
Total Purchased Equipment Cost	$1,060,000		
Direct Installation Costs			
Installation	$318,000	30%	Engineering estimate 30% of PEC
Total Direct Capital Costs (DC)	**$1,378,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
General Facilities	$53,000	5%	
Engineering and Home Office Fees	$106,000	10%	Calculated as percent of Total Direct Capital Costs. Based on OAQPS Capital Cost Factors
Process Contingency	$53,000	5%	for an SCR system (Section 4, Chapter 2), and assuming that the same factors would apply fo
Startup and Performance Tests	$31,800	3%	an Oxidation Catalyst System
Total Indirect Capital Costs (IC)	**$243,800**		
Contingency	$324,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$1,945,800**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$215,000**	9.13%	pretax marginal rate of return on private investment
OPERATING & MAINTENANCE COSTS			**Basis**
Variable O&M Costs			
Reagent Cost	$0		NA
Catalyst Volume	323	90,847	Catalyst Volume (in ft^3) calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Catalyst Replacement Cost	$173,000	5.0	Based on the differetial catalyst cost (60% reduction vs 80% reduction) ($1,060,000 - $194,000) and 5 year catalyst life
Auxiliary Power Cost	$10,000	2	Based on the increased pressure drop across the CO catalyst (listed to the left in inches), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$183,000		
Fixed O&M Costs			
Additional Operators per shift	0.0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervision	$0		
Maintenance Labor and Materials	$0		
Total Direct Annual Costs	$0		
Indirect Annual Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating & Maintenance Cost	**$183,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$215,000**		
Annual Operating & Maintenance Cost	**$183,000**		
Total Annual Cost	**$398,000**		

Cost Evaluation
S4_CO Catalyst

SRP - Santan Generating Station
Unit S4 -- CO Control Costs
Oxidation Catalyst Worksheet

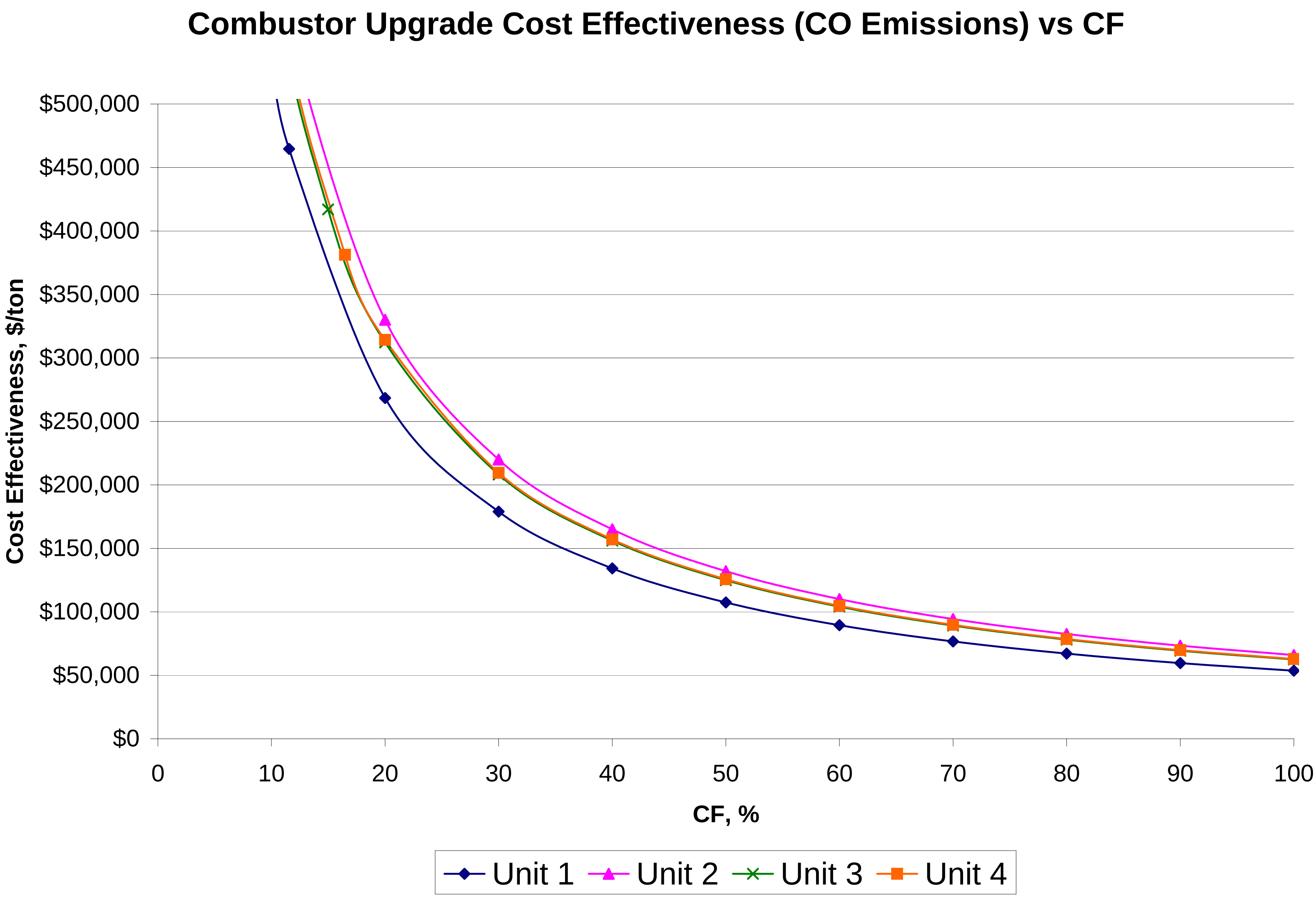
	INPUT
CT Heat Input (mmBtu/hr)	**800.0**
Approximate MW output	**90.0**
Baseline CO Emission Rate (lb/mmBtu)	**0.024**
Post CO Catalyst Emission Rate (lb/mmBtu)	**0.012**
% Reduction w/ CO Catalyst Upgrades	**50%**
Stack Flue Gas Flow Rate (scfm)	**489,060**
Capacity Factor used for Cost Estimates (%)	**16.5%**

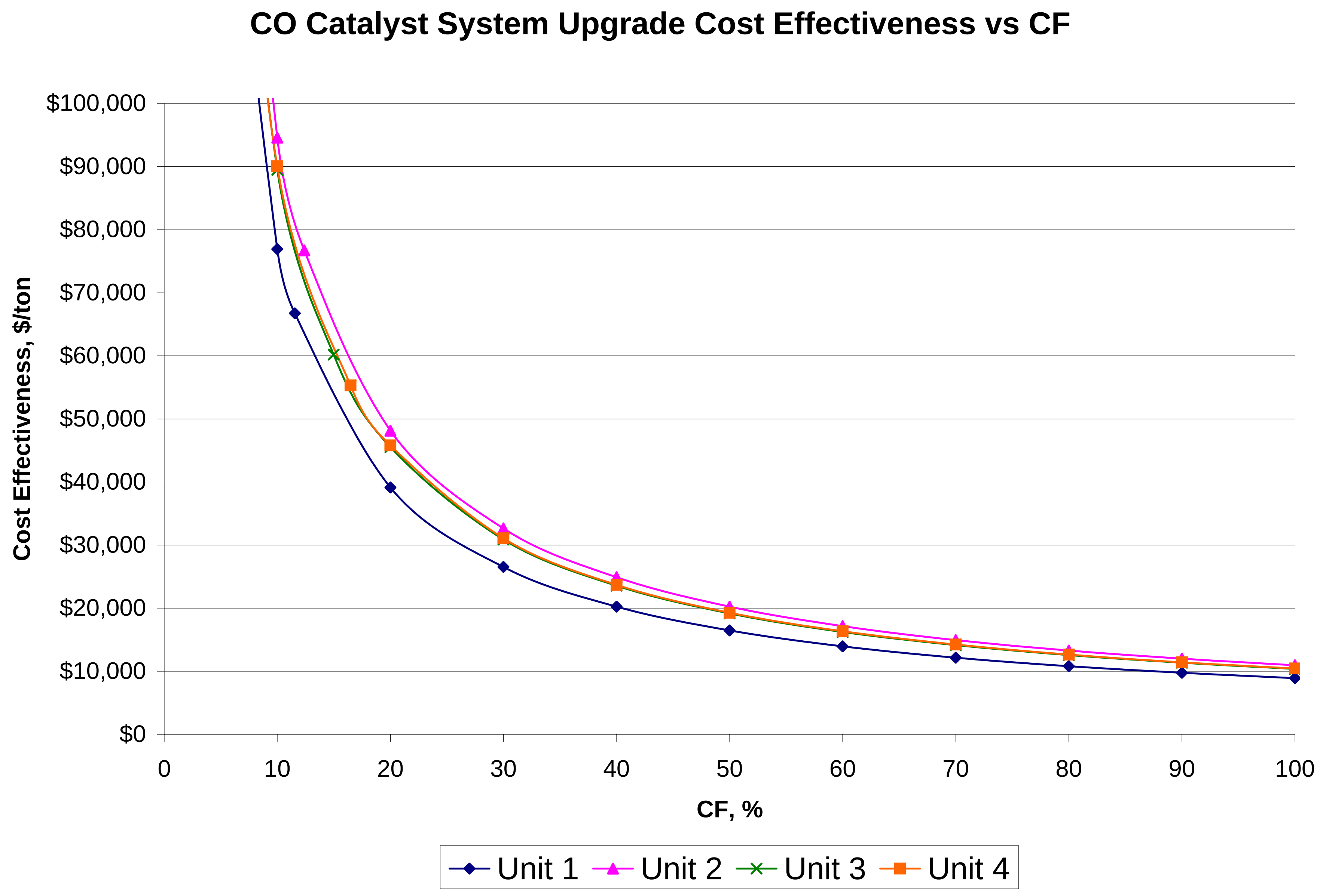
CAPITAL COSTS	[$]		Basis
Direct Capital Costs			
Control Equipment	$1,060,000		Based on budgetary costs for oxidation catalyst system upgrades. Includes costs for catalyst replacement and new internal frame.
Instrumentation	$0	0%	Included in CO control equipment cost
Sales Taxes	$0	0%	Included in CO control equipment cost
Freight	$0	0%	Included in CO control equipment cost
Total Purchased Equipment Cost	$1,060,000		
Direct Installation Costs			
Installation	$318,000	30%	Engineering estimate 30% of PEC
Total Direct Capital Costs (DC)	**$1,378,000**		Sum of purchased equipment costs and installation costs
Indirect Capital Costs			
General Facilities	$53,000	5%	
Engineering and Home Office Fees	$106,000	10%	Calculated as percent of Total Direct Capital Costs. Based on OAQPS Capital Cost Factors
Process Contingency	$53,000	5%	for an SCR system (Section 4, Chapter 2), and assuming that the same factors would apply fo
Startup and Performance Tests	$31,800	3%	an Oxidation Catalyst System
Total Indirect Capital Costs (IC)	**$243,800**		
Contingency	$324,000	20%	of direct and indirect capital costs.
Total Capital Investment (TCI)	**$1,945,800**		sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor = $i(1+i)^n / (1+i)^n - 1$	0.1106	20	life of equipment (years)
Annualized Capital Costs			
(Capital Recover Factor x Total Capital Investment)	**$215,000**	9.13%	pretax marginal rate of return on private investment

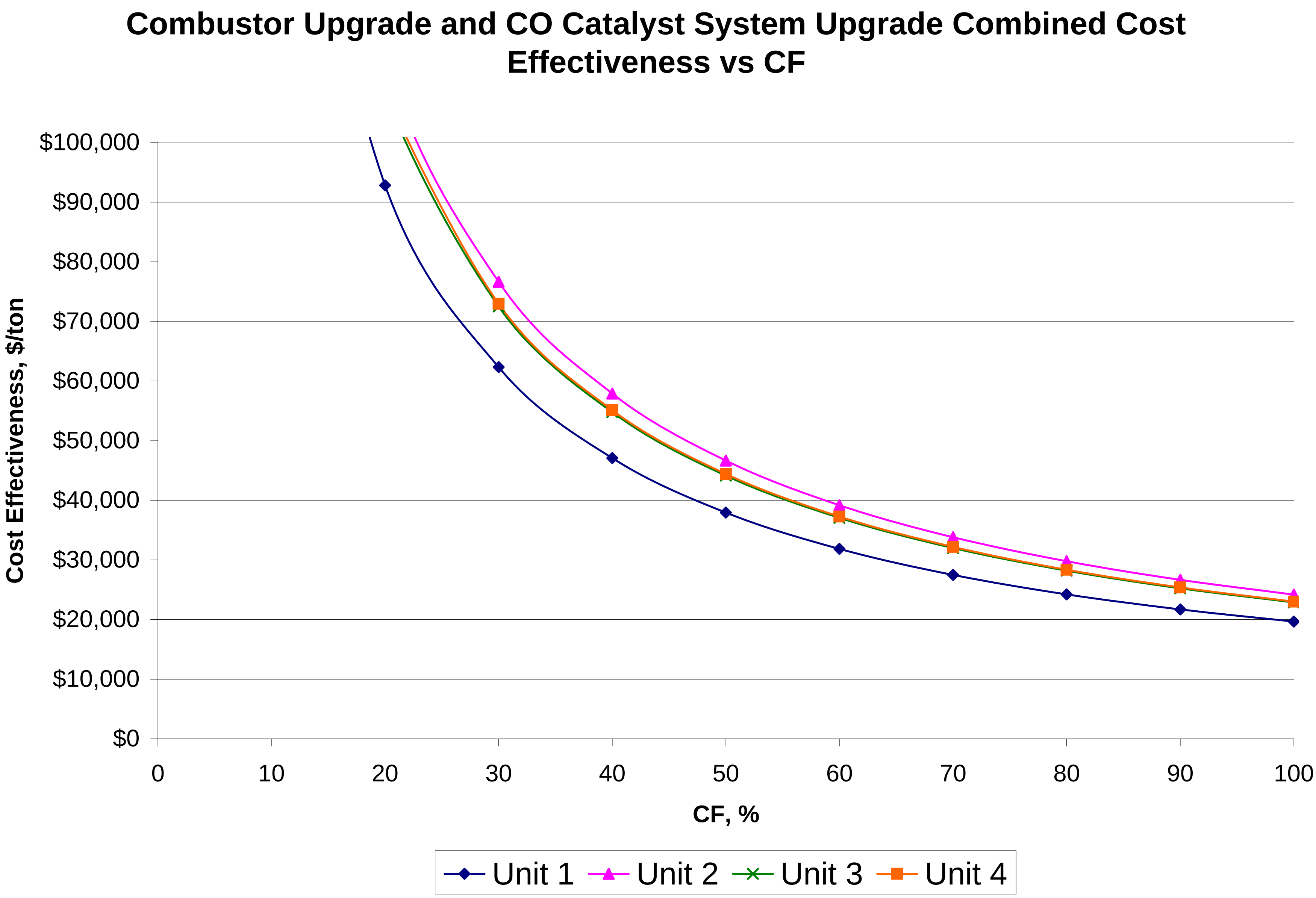
OPERATING & MAINTENANCE COSTS			Basis
Variable O&M Costs			
Reagent Cost	$0		NA
Catalyst Volume	323	90,847	Catalyst Volume (in ft^3) calculated based on the exhaust gas flow rate and the space velocity listed to the left (1/hr).
Catalyst Replacement Cost	$173,000	5.0	Based on the differetial catalyst cost (60% reduction vs 80% reduction) ($1,060,000 - $194,000) and 5 year catalyst life
Auxiliary Power Cost	$12,000	2	Based on the increased pressure drop across the CO catalyst (listed to the left in inches), 80 kW/inch auxiliary power requirement, and $50/MWh.
Total Variable O&M Cost	$185,000		
Fixed O&M Costs			
Additional Operators per shift	0.0		Assume no additional fixed O&M costs
Operating Labor	$0		
Supervision	$0		
Maintenance Labor and Materials	$0		
Total Direct Annual Costs	$0		
Indirect Annual Operating Cost			
Property Taxes	$0		Assume no additional indirect operating costs
Insurance	$0		
Administration	$0		
Total Indirect Operating Cost	$0		
Total Annual Operating & Maintenance Cost	**$185,000**		
TOTAL ANNUAL COST			
Annualized Capital Cost	**$215,000**		
Annual Operating & Maintenance Cost	**$185,000**		
Total Annual Cost	**$400,000**		

Attachment 7

CO Control Cost Sensitivities Versus Capacity Factors (Units 1-4)


Combustor Upgrade Cost Effectiveness (CO Emissions) vs CF
Cost Effectiveness, $/ton
$500,000
$450,000
$400,000
$350,000
$300,000
$250,000
$200,000
$150,000
$100,000
$50,000
$0
0
10
20
30
40
50
60
70
80
90
100
CF, %
Unit 1
Unit 2
Unit 3
Unit 4


CO Catalyst System Upgrade Cost Effectiveness vs CF
Cost Effectiveness, $/ton
$100,000
$90,000
$80,000
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
0
10
20
30
40
50
60
70
80
90
100
CF, %
Unit 1
Unit 2
Unit 3
Unit 4


Combustor Upgrade and CO Catalyst System Upgrade Combined Cost Effectiveness vs CF
Cost Effectiveness, $/ton
$100,000
$90,000
$80,000
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
0
10
20
30
40
50
60
70
80
90
100
CF, %
Unit 1
Unit 2
Unit 3
Unit 4

Attachment 8

Reference Documents for Estimating Cost Thresholds

New York State Department of Environmental Conservation, "Air Guide 20 Economic and Technical Analysis for Reasonably Available Control Technology.”

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Westar Energy Letter to Ms. Mindy Bowman, Kansas Department of Health and Environment, ”Response to USEPA Comments on Draft PSD Permit for Emporia Energy Center,” April 13, 2007.

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United States Environmental Protection Agency Region 4, “National Combustion Turbine Spreadsheet,” March 30, 2005.

Montana Department of Environmental Quality Permitting and Compliance Division, “Air Quality Permit #4256-00, Basin Electric Power Cooperative – Culbertson Generating Station,” January 21, 2009.

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Attachment 9

Santan Emissions Operating and Maintenance Practices Assessment Report

Delivering more than power.

SALT RIVER PROJECT
SANTAN GENERATING STATION

SANTAN EMISSIONS OPERATING AND MAINTENANCE PRACTICES ASSESSMENT REPORT

SL-10663
Rev. 0
Final

Prepared By:

Sargent & Lundy LLC

Project No. 12046-018
June 3, 2011

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CERTIFICATION

FOR

SALT RIVER PROJECT

SANTAN GENERATING STATION

SANTAN EMISSIONS – OPERATING AND MAINTENANCE PRACTICES ASSESSMENT REPORT

I CERTIFY THAT THIS REPORT WAS PREPARED BY ME OR UNDER MY SUPERVISION AND THAT I AM A REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARIZONA.

Electronic copy of final document;

Sealed original is with Arvind A. Patel

Certificate No. 48573

REVISION	CERTIFIED BY	DATE

APPROVAL PAGE

FOR

SALT RIVER PROJECT

SANTAN GENERATING STATION

SANTAN EMISSIONS – OPERATING AND MAINTENANCE PRACTICES ASSESSMENT REPORT

Rev.	Date/ Purpose	Discipline	Prepared	Reviewed	Approved
0	06/03/2011 Final	-	J. Nolan	T. Ryszka	A. Patel

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1.0 INTRODUCTION

Per Condition 38 of the Certificate of Environmental Compatibility (CEC) issued by the Arizona Corporation Commission (ACC), SRP is required to perform an air emissions assessment for Santan Generating Station (SGS) every five (5) years. This assessment is to investigate the possibility of reducing emissions from current operating levels by either: a) changing operating and maintenance (O&M) practices or b) implementing new emissions reduction technologies.

Proper operations and maintenance of plant equipment plays a key role in maintaining air emission levels. This report contains S&L's assessment of the O&M processes and programs utilized at SGS with respect to the potential for reducing air emissions. A separate report will be provided to address emissions reductions, and associated costs, for implementing new technologies as applicable.

The O&M processes and programs associated with the emission sources listed below were reviewed as part of this assessment.

i. Units S1-S4 Combustion Turbines
ii. Units S5A, S5B and S6A Combustion Turbines & HRSGs (w/duct burners)
iii. Cooling Towers CT1, CT5 and CT6
iv. Emergency Fire Pump
v. Emergency Diesel Generators
vi. Abrasive Blasting Equipment
vii. Paint Booth

2.0 ASSESSMENT APPROACH

The approach to the O&M practices assessment encompassed reviewing SRP's Title V Permit V95-008 (renewal date 12/23/2010), conducting a site visit, reviewing plant O&M documentation, and discussing O&M practices with key plant technical, operating, and maintenance personnel. S&L reviewed documentation and data supplied by SRP to become familiar with the units' operating histories and performance and to determine areas of review that would require attention during the site visit. During the site visit, S&L reviewed the following types of documents:

- Inspection Reports
- Equipment Manuals and Data Sheets
- Listing of Preventive Maintenance Tasks and Work Orders

3.0 OPERATIONS & MAINTENANCE PLANS

3.1 Discussion

The Title V Permit has many conditions that are directed towards the operating and maintenance practices for the permitted equipment. The most stringent of these conditions requires SRP to follow an established Operations and Maintenance Plan which specifies the procedures used to operate and maintain a specific piece of equipment. The four (4) items listed below are subject to this condition:

- S1 – S4 Dry Low-NOx Burners
- S1 – S4 CO Oxidation Catalyst Emissions Control System
- S5A, S5B and S6 CO Oxidation Catalyst Emissions Control System
- S5A, S5B and S6 Selective Catalytic Reduction System

The O&M Plan must specify operating parameters to be monitored to assure compliance, the methodology to be utilized to record the operating parameter, and the maintenance procedures to be performed along with the frequency of each procedure.

In addition, SGS has a Blast Booth on its Equipment List (Appendix A). Specific Condition 25 of the permit refers the Permittee to County Rule 312 for compliance of Abrasive Blasting activities. County Rule 312 requires an O&M Plan for Abrasive Blasting.

3.2 S&L Review

S&L reviewed the O&M Plans for the listed equipment and found them to be consistent with standard industry practices for content and frequency. S&L also reviewed the maintenance history for the procedures specified and found them complete and without any indications that equipment was malfunctioning. An overview of the equipment O&M Plans is provided in the following sections.

3.2.1 Units 1 - 4 Dry Low NOx Burners

The S1 – S4 Dry Low-NOx Burners O&M Plan addresses NOx emissions. For this Plan, the CEMS system is utilized to measure NOx as the operating parameter, and combustion inspections are required as the maintenance procedure. The burners installed are designed to minimize NOx formation during the combustion process. The burners are an assembly of components such as nozzles, liners, igniters, flame scanners, etc. These components are inspected for wear and replaced or repaired as required to assure optimal performance. The SGS maintenance records indicate that these inspections / repairs were completed on the recommended intervals.

3.2.2 CO Catalyst & SCR System

The CO Catalyst and SCR Systems are combined into one O&M Plan. Operating parameters include the CEMS measurement of CO and NOx, and other system temperatures and pressures that assure operation within the appropriate ranges for the chemical reactions to occur. The maintenance procedures in the plan identify preventive maintenance activities such as device calibrations and catalyst inspections. Replacement activities associated with filter and catalyst replacement are also addressed. A review of the maintenance records indicates these procedures are being followed.

The Alstom SCR and CO Catalyst manual for Units 5A, 5B and 6A, and the Englehard manual for Units 1 – 4 were also reviewed as part of this assessment. These documents would be used in conjunction with the procedures in the aforementioned O&M plan to provide additional guidance.

3.2.3 Baghouse for Abrasive Blasting Equipment

The Dust Collector Operation and Maintenance (O&M) Plan addresses particulate emissions associated with sandblasting activities. An abrasive blast shed is utilized to clean parts and equipment. Dust and particles from the cleaning process are collected on the outside of fabric filter elements located inside of a dust collector. The filter elements are pulse cleaned using compressed air, in which the particulate material is captured in a hopper and storage container for disposal.

To help assure proper equipment operation, the operating plan requires visual observations emissions, and monitoring of the filter pressure drop each operating day. The maintenance plan identifies procedures for performing time-based preventative maintenance activities. These activities were reviewed and appear to be appropriate for minimizing emissions from the type of dust collector installed at SGS.

4.0 SUPPLEMENTAL PERMIT REQUIREMENTS

4.1 Discussion

4.1.1 Diesel Engines

The permit requires that the diesel engines for the emergency fire pump and emergency generators operate only during emergency conditions or routine maintenance checks (testing). The routine maintenance check running time for each engine is limited to 37.5 hours per year on a rolling twelve-month basis.

4.1.2 Cooling Towers

The permit requires that Santan Generating Station inspect the cooling tower drift eliminators monthly for proper operation only if the drift eliminator can be viewed safely and does not require the Permittee to walk the tower. If the drift eliminators cannot be safely inspected monthly, then they must be inspected for integrity during a regularly scheduled outage when the cooling tower is not operating or not less than once per year.

4.2 S&L Review

4.2.1 Diesel Engines

Based upon discussions with various operating personnel, S&L understands that the operating practices described below are currently utilized for performing routine checks on the diesel engines.

The fire pump (one for the entire site) is tested on a weekly schedule while the emergency generators (two installed on site) are run on a monthly schedule. The duration of each test is 30 minutes; therefore the engines are operated within the permit requirements for routine checks.

In addition, a propane-fired emergency generator is installed in the switchyard at SGS to charge the substation batteries as necessary during an extended outage, This engine does not have any special permit requirements. This engine is tested monthly for up to 15 minutes, quarterly for approximately an hour for quarterly checks, and an additional hour annually for annual checks. This engine is also given an annual two hour load test. The total run time is approximately 12 hours per year for testing and maintenance.

S&L believes these are reasonable operating practices that maintain equipment reliability while minimizing wear.

4.2.2 Cooling Towers

S&L reviewed engineering inspection reports pertaining to the cooling tower as part of this assessment. The records were complete and indicate an adequate inspection program is in place.

5.0 WORK MANAGEMENT

5.1 Background & Discussion

Work Management is the process by which maintenance, modifications, surveillances, testing, engineering support, and other work activities requiring plant coordination or schedule integration are implemented. An effective work management process does the following:

- Promote safety.
- Improve equipment performance and system health.
- Provide a proper methodology for work prioritization to ensure activities are performed in the right time frame.
- Increase productivity and reduce costs through the efficient use of resources.
- Provide for a long-range plan to include major design changes, predictive, and preventive maintenance activities.
- Incorporate an effective feedback loop that promotes and ensures continual process improvement.

As part of the Work Management Process, maintenance planning and scheduling is a disciplined approach to maintain equipment performance, reduce downtime and minimize overall costs. This is accomplished through:

- Prioritizing work
- Developing the physical steps to complete the job

- Procuring necessary tools and materials
- Scheduling the work to be done
- Identifying any additional work to be completed on the equipment
- Filing written documentation for equipment history

A Computerized Maintenance Management System (CMMS) maintains a database of information about a facility's equipment and maintenance history. This information is used to assist maintenance workers in the performance of their work activities and to help management make informed decisions. A CMMS typically has capabilities regarding:

- Work orders
- Preventive maintenance
- Asset management
- Inventory control
- Safety/Permits

5.2 S&L Review

Based on discussions with plant personnel, Santan Generating Station utilizes a Work Management process. Upcoming work activities are prioritized and scheduled through a planning and scheduling organization. For immediate "fix-it-now" items, maintenance resources are made available to the operating staff.

MAXIMO is the CMMS software utilized by Salt River Project. The system has the capability to provide equipment history, manage parts inventory, create work orders for scheduled work, and provide management reporting. MAXIMO is a comprehensive work management system that can provide both resource planning and work measurement information to management.

6.0 PREVENTIVE AND PREDICTIVE MAINTENANCE

6.1 Background Discussion

Preventive Maintenance (PM) can be defined as tests, measurements, adjustments, and parts replacement, performed specifically to prevent faults from occurring. Preventive maintenance is conducted to keep equipment working properly and/or extend the life of the equipment. Preventive maintenance activities include partial or complete overhauls at specified periods, oil changes, lubrication and so on. In addition, workers can record equipment deterioration so they know to replace or repair worn parts before they cause system failure. The ideal preventive maintenance program would prevent all equipment failure before it occurs.

Predictive Maintenance (PdM) techniques help determine the condition of in-service equipment in order to predict when maintenance should be performed. This approach offers cost savings over routine or time-based preventive maintenance because tasks are performed only when warranted. PdM, or condition-based maintenance, attempts to evaluate the condition of equipment by performing periodic or continuous (online) equipment condition monitoring. The ultimate goal of PdM is to perform maintenance at a scheduled point in time when the maintenance activity is most cost-effective and before the equipment loses optimum performance.

6.2 S&L Review

S&L reviewed the preventive maintenance program used at SGS. The program consists of tasks with associated instructions which are stored in MAXIMO. These tasks apply to the complete site and many of these specifically pertain to equipment covered by this emissions assessment. These PM tasks were developed utilizing manufacturers' recommendations, industry standards and plant experience. MAXIMO is also utilized to manage equipment inspections. S&L's review indicates that the Santan PM program is comprehensive in scope, tasks are appropriately scheduled, and findings are stored in the system for further use.

Santan Generating Station also has a predictive maintenance program in place. Although not reviewed in detail for this assessment, this program includes both vibration analysis and lubrication oil analysis, both of which are designed to detect equipment degradation prior to failure.

Finally, Santan utilizes several performance monitoring systems to assure proper operation of the equipment. These systems include:

a. General Electric (GE), the manufacturer of the 5A, 5B and 6A combustion turbines, offers remote monitoring capabilities to its clients. Santan Generating Station has subscribed to this service which provides continuous monitoring by GE technical staff. GE will provide recommendations to its clients if it notices any abnormalities, and can adjust the combustion turbines' controls remotely with the plant's permission.
b. Santan has also recently installed the EtaPRO performance monitoring system developed by the General Physics Corporation. The main intent of this system is to provide operators with accurate instantaneous heat rate monitoring. This system will allow the station to trend its fuel consumption and identify deviations from baseline heat rate. Heat rate degradation is an early indicator of equipment problems.
c. Santan is also converting its data acquisition capabilities to a new PI data acquisition system. The system also serves as the plant's data historian. PI is an established system used throughout the industry and is a reliable database for equipment performance monitoring.
d. Santan has also recently installed the Smart Signal performance monitoring system by GE. Smart Signal monitors equipment to detect and identify events of abnormal behavior by the differences between real-time actual data and predicted normal behavior in lieu of thresholds for actual values. This system also performs diagnostic and prioritization analysis. In addition, a weekly conference is held with the GE Smart Signal Team to discuss analysis results and recommendations.

By utilizing these tools, station personnel can monitor and trend parameters that may adversely affect operating equipment which in turn can lead to emissions issues.

7.0 CONTROL ROOM OPERATIONS

7.1 Discussion

The Santan control room is manned at all times by two (2) Control Room Operators (CRO). These CROs are responsible for starting up and shutting down the units, communicating with the dispatch authorities, and directing O&M activities at the plant. They are assisted by three (3) roving operators who perform equipment surveillances and manual operations required at the equipment.

S&L had discussions with control room operating staff regarding operating flexibility and maintenance activities to understand the interfaces between O&M practices and its impact on unit emissions. The CROs stated they had the necessary personnel resources to manage operations of the facility. In addition to the roving operators, maintenance staff was available at all times for “fix-it-now” activities. The CROs that spoke with S&L were very knowledgeable about the units, the emission control equipment, and the permit requirements associated with the various pollutants.

7.2 S&L Review

The control systems utilized at Santan are of current vintage. The original controls on Units 1 – 4 have been replaced by an upgraded system. Unit start-up and shutdown controls are essentially programmed into the system and require mainly CRO oversight and response to alarm situations. The SCRs on Units 5A, 5B and 6A are also pre-programmed for automatic start-up and shutdown. The CROs will input the unit load into the automatic generation control and the dispatching function will move unit load to match the system requirements. The CRO manually starts and stops cooling tower fans to optimize condenser performance. Therefore there is minimal operator intervention with the emission control equipment under normal operating conditions.

8.0 CONCLUSION

As part of the CEC Condition 38 assessment required by the ACC for Santan Generating Station, this O&M assessment finds that the key elements of a comprehensive integrated Operation and Maintenance program are utilized at SGS. The Santan Generating Station O&M Program encompasses the following activities:

i. A documented Preventive Maintenance and Inspection program for the emission control equipment,
ii. A Preventive / Predictive Maintenance program to maintain equipment reliability and performance,
iii. A Work Management Process to complete station activities efficiently,
iv. Several Performance Monitoring Systems to provide technical information for plant staff, and
v. Reliable modern control systems that automate system operations.

The assessment did not find opportunities where a change in operations and maintenance practices would help reduce air emissions without adversely impacting capital assets.