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Trinity Consultants

April 27, 2017

Utah Division of Air Quality
John Jenks
New Source Review Engineer
195 North 1950 West
Salt Lake City, UT 84114
(801) 536-4459

RE: ***BACM/BACT analysis for the West Valley Power Plant***

Mr. Jenks:

On behalf of Utah Municipal Power Agency (UMPA), Trinity Consultants Inc. is submitting the enclosed Best Available Control Measures or Technologies (BACM/BACT) analysis. This analysis was completed in response to the letter received by UMPA from the Utah Division of Air Quality (UDAQ), on 1/23/17.

The UMPA West Valley Power Plant (West Valley) is a natural gas-fired electric generating plant consisting of five General Electric LM6000 PC SPRINT natural gas simple cycle turbines. The enclosed analysis evaluates all applicable control measures and whether each is technically, environmentally, or economically feasible for the West Valley turbines.

If you have any questions or comments about the information presented in this analysis, please do not hesitate to call me at (208) 472 - 8837.

Sincerely,
TRINITY CONSULTANTS

Melissa Armer

Melissa Armer, P.E.
Senior Consultant

CC:
Kevin Garlick, UMPA Power Resource Manager
Jerame Blevins, West Valley Plant Manager
Dave Strohm, Trinity Consultants Inc.

Enclosure:
Request letter from UDAQ dated 1/23/17
West Valley Plant BACM/BACT analysis

State of Utah
GARY R. HERBERT
Governor
SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality
Alan Matheson
Executive Director
DIVISION OF AIR QUALITY
Bryce C. Bird
Director

RECEIVED
JAN 25 2017

DAQE-044-17

January 23, 2017

Kevin Garlick
Utah Municipal Power Agency
75 West 300 North
P.O. Box 818
Spanish Fork, Utah 84660

Dear Mr. Garlick:

RE: Serious Nonattainment Area (NAA) State Implementation Plan (SIP) Control Strategy Requirements

The Division of Air Quality (DAQ) has begun work on a serious area attainment control plan as required by and as detailed in 40 CFR 51 Subpart Z (See FR Vol. 81, No. 164, August 24, 2016, pp. 58151). This rule requires the DAQ to identify, adopt, and implement Best Available Control Measures (BACM) on major sources of $PM_{2.5}$ and $PM_{2.5}$ precursors. The Approval Order (AO) issued to *(Utah Municipal Power Agency)* allows emissions of 70 tons or more per year for $PM_{2.5}$ and/or $PM_{2.5}$ precursors, which is the major source threshold in an area of serious nonattainment for $PM_{2.5}$. In accordance with the implementation rule, *(Utah Municipal Power Agency)* is a major source and is therefore subject to the rule.

As a major source subject to the rule, your emission units will be included in the serious area attainment control plan, and the DAQ is requesting your assistance in determining acceptable pollution controls.

Subpart Z requires that we identify all potential control measures to reduce emissions of direct $PM_{2.5}$ as well as $PM_{2.5}$ precursors (SOx, NOx, VOC, and ammonia), and assess these potential measures for both technological and economic feasibility. Also necessary will be an assessment of when a potential measure could actually be implemented.

The criteria for determining whether these potential control measures are feasible will be more stringent than they had been when such measures were evaluated in the Moderate Area SIPs, where the benchmark had been Reasonably Available Controls (RACM/RACT). Once reclassified, Serious Areas must implement Best Available Controls (BACM/BACT) in order to meet the $PM_{2.5}$ health standards.

Should the area not be able to meet the $PM_{2.5}$ standards by the statutory Serious Area attainment date (December 31, 2019), whether by modeled prediction or actual ambient monitoring, the standard of control measure feasibility would rise once more to what are called Most Stringent Measures (MSM).

While it is possible that your company may have recently performed a BACT analysis under the new source review permitting program, or for moderate SIP control measures, please be aware that reaching attainment under the Serious SIP requires that all applicable control measures and techniques be identified and evaluated or re-evaluated to determine their applicability. This evaluation must be a detailed, written justification of each available control strategy, taking into account technological and economic feasibility, and including documentation to justify the elimination of any available controls.

A second but related evaluation must also be performed regarding the proper establishment of emission limits and emissions monitoring for each emitting unit. As you conduct your BACT analysis, the DAQ requests that you propose appropriate limits and monitoring requirements for each emitting unit, along with a justification for the adequacy of your suggested measures.

DAQ staff will be conducting related research to meet the requirements of the implementation rule so it can perform a detailed review of the information you provide, and select appropriate controls. The DAQ must complete the SIP process by the end of July so that it can be reviewed and approved for public comment by the Air Quality Board (AQB) in September and then finalized in December for submittal to the Environmental Protection Agency (EPA) by December 31, 2017. The DAQ understands the magnitude of this effort but believes it can be completed in a timely manner with your assistance. Please submit your analysis to the DAQ no later than April 30, 2017.

Given the short time period available to develop and implement these control strategies, we ask that you contact your current New Source Review (NSR) permitting engineer as soon as possible to discuss any questions you have regarding this analysis. If you are pursuing emissions reductions to no longer be a major source subject to the implementation rule, the required action (Notice of Intent (NOI) or reduction in emissions) must be submitted to the DAQ before February 15, 2017. You can also reach me at (801) 536-4151 with any questions.

Sincerely,

Mart. D Gray

Martin D. Gray, Manager
New Source Review Section
Utah Division of Air Quality

MDG:kw

PM$_{2.5}$ SERIOUS NONATTAINMENT SIP BACM ANALYSIS

Utah Municipal Power Agency > West Valley, Utah

Prepared For:

Kevin Garlick– Power Resource Manager
75 West 300 North
Spanish Fork, UT 84660

Prepared By:

Melissa Armer – Senior Consultant

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702 W. Idaho Street
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April 2017

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Trinity Consultants

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1. EXECUTIVE SUMMARY

The Utah Division of Air Quality (UDAQ) is required to submit a Serious Area Attainment Control Plan as specified with 40 CFR 51, Subpart Z (Federal register (FR) Vol 81, No 164, August 24, 2016) in accordance with the $PM_{2.5}$ serious nonattainment re-designation issued by the United States Environmental Protection Agency (U.S. EPA) on December 16, 2016.[1] This rule requires UDAQ to identify, adopt, and implement Best Available Control Measures or Technologies (BACM/BACT) for major sources of direct $PM_{2.5}$ and $PM_{2.5}$ precursors (Sulfur Dioxide (SO_2), Nitrogen oxide (NO_X), volatile organic compounds (VOCs), and ammonia (NH_3)).

The Utah Municipal Power Agency (UMPA) West Valley Power Plant (West Valley) has the potential to emit more than 70 tons or more per year for $PM_{2.5}$ and/or $PM_{2.5}$ precursors, therefore West Valley is considered a major source. DAQ has requested that each major source prepare a BACM/BACT Analysis which includes the following information:

- Detailed analysis of all applicable control measures and techniques (BACM/BACT Analysis);
- Evaluation of emission limits; and
- Evaluations of emissions monitoring.

The UDAQ must complete the SIP process by the end of July 2017 so that it can be reviewed and approved for public comment by the Air Quality Board (AQB) in September and finalized in December for submittal to the EPA by December 31, 2017. As such, UMPA is submitting this BACT analysis in order to meet DAQ's submission deadline of May 1, 2017 as requested in the letter received by UMPA from UDAQ on January, 23, 2017.

[1] Federal Register Vol. 81, No. 164, August 24, 2016, pp. 58151

2. INTRODUCTION

2.1. DESCRIPTION OF FACILITY

The UMPA West Valley Power Plant (West Valley) is a natural gas-fired electric generating plant consisting of five General Electric LM6000 PC SPRINT natural gas simple cycle turbines. Each turbine has power output rated at 43.4 MW and is equipped with water injection, evaporative spray mist inlet air cooling, Selective Catalytic Reduction (SCR) catalyst and CO oxidation catalyst. The primary purpose of the Plant is to produce electricity for sale via the utility power distribution system to meet the demands of the Salt Lake Valley service area.

The Plant is located in Salt Lake County and is a Phase II Acid Rain source and a major source of NO_x and CO. The Plant location and environmental contact is shown below:

Utah Municipal Power Agency
75 West 300 North Spanish Fork, UT 84660
Facility Contact: Kevin Garlick, Power Resource Manager
Phone: (801) 798-7489

2.2. PERMITTING HISTORY

On August 5, 2016 UMPA assumed ownership of the West Valley plant. The plant was previously owned by West Valley Power, LLC. The facility's Title V Operating Permit number is 3500527003 and was last renewed on July 21, 2014. The operating permit also incorporates Approval Order DAQE-282-02 dated April 28, 2002 which added the fifth turbine. Turbines 3 and 4 became operational in 2001, and turbines 1, 2 and 5 became operational in 2002.

2.3. SOURCES ONSITE

Table 2-1 Permitted Sources

Source/Source Type	Current Potential to Emit Emission Estimates (tpy)				
	$PM_{2.5}$	NO_x	SO_2	VOC	NH_3
Individual Turbines	8.21	32.41	5.94	3.67	38.1
Facility Wide	41.03	162.06	29.68	18.33	190.5

a Ammonia emissions are not quantified in the current Title V permit or in the Title V permit renewal application; estimated based on ppvd.

3. BEST AVAILABLE CONTROL MEASURES/TECHNOLOGY (BACM/BACT)

3.1. BACM/BACT METHODOLOGY

In a memorandum dated December 1, 1987, the U.S. EPA stated its preference for a "top-down" BACT analysis.[2] After determining if any New Source Performance Standard (NSPS) is applicable, the first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically, environmentally, or economically infeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Presented below are the five basic steps of a top-down BACT analysis as identified by the U.S. EPA.

3.1.1. Step 1 - Identify All Control Technologies

Available control technologies are identified for each emission unit in question. The following methods are used to identify potential technologies: 1) researching the Reasonably Available Control Technology (RACT)/BACT/ Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database, 2) surveying regulatory agencies, 3) drawing from previous engineering experience, 4) surveying air pollution control equipment vendors, and/or 5) surveying available literature.

3.1.2. Step 2 - Eliminate Technically Infeasible Options

The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those that are clearly technically infeasible are eliminated. U.S. EPA states the following with regard to technical feasibility:[3]

> A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

3.1.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Once technically infeasible options are removed from consideration, the remaining options are ranked based on their control effectiveness. If there is only one remaining option or if all of the remaining technologies could achieve equivalent control efficiencies, ranking based on control efficiency is not required.

In a retroactive BACT analysis, this step differs from the equivalent step in the New Source Review (NSR) BACT process in that the baseline from which control effectiveness is evaluated is the current emission rate, and not some hypothetical "uncontrolled" level.

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[2] U.S. EPA, Office of Air and Radiation. Memorandum from J.C. Potter to the Regional Administrators. Washington, D.C. December 1, 1987.

[3] U.S. EPA, New Source Review Workshop Manual (Draft): Prevention of Significant Deterioration and Nonattainment Area Permitting, October 1990.

3.1.4. Step 4 - Evaluate Most Effective Controls and Document Results

Beginning with the most effective control option in the ranking, detailed economic, energy, and environmental impact evaluations are performed. If a control option is determined to be economically feasible without adverse energy or environmental impacts, it is not necessary to evaluate the remaining options with lower control effectiveness.

The economic evaluation centers on the cost effectiveness of the control option. Costs of installing and operating control technologies are estimated and annualized following the methodologies outlined in the U.S. EPA's *OAQPS Control Cost Manual* (CCM) and other industry resources.[4] Note that the analysis is not whether controls are affordable, but whether the expenditure is effective.

3.1.5. Step 5 - Select BACT

In the final step, one pollutant-specific control option is proposed as BACT for each emission unit under review based on evaluations from the previous steps.

The U.S. EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements that the agency believes must be met by any BACT determination, regardless of whether the "top-down" approach is used. First, the BACT analysis must include consideration of the most stringent available control technologies, i.e., those which provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts."[5]

The UDAQ Notice of Intent (NOI) Guide also details the requirement to achieve BACT as required in the State of Utah permitting process. The proposed BACT must be based on the most effective engineering techniques and control equipment to minimize emission of air contaminants into the outside environment from its process.

3.2. SIMPLE CYCLE GAS TURBINE-GENERATORS

The West Valley Plant consists of five GE LM6000 PC SPRINT natural gas simple cycle turbines. Each turbine has power output rated at 43.4 MW and is equipped with water injection, evaporative spray mist inlet air cooling, Selective Catalytic Reduction (SCR) catalyst and CO oxidation catalyst. Each gas turbine has a design heat input rate of 404.15 MMBtu/hr at full load operation utilizing the higher heating value of the natural gas fuel supply. The Plant is designed to operate as a peaking facility.

3.2.1. NO_x Emissions

The emissions unit for which BACT is being considered is a simple-cycle gas turbine with a nominal output of 43.4 MW. Potential control technologies were identified by searching the following sources for determinations pertaining to combustion gas turbines:

- South Coast Air Quality Management District (SCAQMD) BACT Determinations;

[4] Office of Air Quality Planning and Standards (OAQPS), *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA 452-02-001 (http://www.epa.gov/ttn/catc/products.html#cccinfo), Daniel C. Mussatti & William M. Vatavuk, January 2002.

[5] Ibid.

- San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Clearinghouse;
- Bay Area Air Quality Management District (BAAQMD) BACT Guidelines;
- EPA RBLC;
- Other district and state BACT Guidelines; and
- BACT/LAER requirements in NSR permits issued by a local air district or other air pollution control agency.

Outlined below are the technologies for control of NO_x that were identified.

- Low NO_x burner design (e.g., dry low NO_x (DLN) combustors)
- Water or steam injection
- SCR system capable of continuously complying with a limit of 2.5 ppmvd @15% oxygen (O_2)
- Selective Non-Catalytic Reduction (SNCR) capable of continuously complying with a limit of 4.5 ppmvd @15% O2
- An EM$_x$™ (formerly SCONO$_x$™) system capable of continuously complying with a limit of 2.0 ppmvd @15% O_2

The most recent NO_x BACT listings for simple-cycle combustion turbines in this size range are summarized in Table 3.1. The most stringent NO_x limit in these recent BACT determinations is a 2.5 ppmvd limit averaged over a 1-hour averaging period, excluding startups and shutdowns. This level is achieved using water injection and SCR. The existing LM6000 gas turbines located at the West Valley plant are equipped with water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NO_x emissions at 5 ppmvd @ 15% O_2 which is comparable to the levels for current-generation water-injected gas turbines with SCR control, but higher than the most stringent limits.

Selective Noncatalytic Reduction

The Selective Non-Catalytic Reduction (SNCR) process reduces NO_x emissions using ammonia or urea injection similar to SCR but operates at higher temperature. NO_x reduction levels range from 30-50% for SNCR alone and between 65-75% for SNCR applied in conjunction with combustion controls. The optimal temperature range is between 1600°F and 2200°F at which NO_x, is reduced to molecular nitrogen (N_2) and water vapor (H_2O). Since SNCR does not require a catalyst, it is more attractive than SCR from an economic standpoint, however, it is not compatible with gas turbine exhaust temperatures, which do not exceed 1100°F. Because the exhaust temperature at the exit of the existing turbines (approximately 828 °F) is less than the optimum temperature range for the application of this technology, it is not technically feasible to apply and it will be eliminated from further evaluation in this BACT analysis.

SCONOx™

A relatively new post-combustion technology from Goal Line Environmental Technologies (now distributed by EmeraChem) is $SCONO_x$, which utilizes a coated oxidation catalyst to remove both NO_x and CO without a reagent such as ammonia. $SCONO_x$™ has been primarily installed on co-generation or combined cycle systems where the exhaust gas temperature is reduced by recovering energy to produce steam. The $SCONO_x$™ system catalyst is installed in the flue gas at a point where the temperature is between 280°F and 650°F. Because the exhaust temperature at the exit of the existing turbines (approximately 828°F) is greater than the optimum temperature range for the application of this technology, it is not technically feasible to apply and it will be eliminated from further evaluation in this BACT analysis.

Facility	District	NO_x Limit[a]	Avg. Period	Control Method	Date Permit Issued
City Public Service Leon Creek Plant (LM6000)	TCEQ	5 ppmv	Unknown	Water injection and SCR	6/26/2003
PacifiCorp- Gadsby Power Plant (LM6000)	UDAQ	5 ppmv	30-day rolling avg.	Water injection and SCR	6/14/2002
El Colton (LM6000)	SCAQMD	3.5 ppmv	3 hrs	Water injection and SCR	2/10/2004
Hanford LP	SJVAPCD	3.4 ppmv	3 hrs	Water injection and SCR	6/14/2001
CalPeak Power LC	SJVAPCD	3.0 ppmv	3 hrs	Water injection and SCR	5/12/2001
Bayonne Energy Center LLC (64 MW)	NJDEP LAER	2.5 ppmv	1 hr	Water injection and SCR	8/26/16
Mariposa Energy Project (LM6000)	BAAQMD	2.5 ppmv	1 hr	Water injection and SCR	11/2010
St. George City-Millcreek Power Plant (LM6000)	UDAQ	2.5 ppmv	30-day rolling avg.	Water injection and SCR	9/30/2008

Note: a. All concentrations expressed as parts per million by volume dry (ppmvd),, corrected to 15% O_2.

SCR, in combination with combustion controls, is capable of achieving a NO_x emission level of 2.5 ppmvd @ 15% O_2. It is the remaining control technology that will be evaluated in Step 4.

SCR has been achieved in practice at combustion turbine installations throughout the country. There are simple-cycle gas turbine projects that limit NO_x emissions between 2.5- 5 ppmvd using SCR technology, as shown in Table 3-1. An evaluation of the achievement of 2.5 ppmvd in comparison to the current West Valley turbines NO_x level of 5 ppmvd is summarized below.

Feasibility and Cost Impact: NO_x emissions from the LM6000 PC SPRINT natural gas turbines is generally guaranteed at 25 ppmvd. Achieving a controlled NOx limit of 2.5 ppm would require SCR technology to achieve reductions of 90 percent. UMPA reached out to several vendors to determine the changes that would be required to the existing SCR systems and the associated costs. Vendors indicated that each control system is complex and is designed to a specific emission limit. There are numerous factors that interrelate when evaluating an existing system and determining the modifications necessary to achieve the emissions reductions being evaluated in this analysis. Vendors indicated that a detailed and comprehensive technical analysis of the existing turbines and existing SCR system would be needed to definitively determine the changes necessary. However, for this analysis they were able to provide general information on the expected changes that would be required.

It is expected that the required changes will include some combination of catalyst replacement, catalyst design modification, and ammonia injection/vaporization system re-design to reduce NO_x emissions from 5 ppmvd to 2.5 ppmvd.

The estimated capital costs associated with the installation, startup and equipment costs of modifying the existing SCR/oxidation catalyst to achieve a 90% reduction in NO_x emissions is between $300,000 and $600,000. The range is dependent on the type and amount of catalyst that may be needed, as well as any redesign that may be necessary for the existing system. The annualized costs including an estimated additional 25% ammonia usage cost as well as capital cost recovery are outlined in Table 3-3 below. Included in Appendix A is supporting documentation received from vendors which was used to develop the costs. Table 3-4 below outlines the estimated cost per ton of pollutant removed to reduce NO_x emissions from 5 ppm to 2.5 ppm.

Since the West Valley turbines are peaking units, they do not operate continuously as a base load unit would operate. Therefore, the annual tons of NO_x emissions removed is based on the baseline actual operating hours from 2014 and 2015. Table 3-2 summarizes the operating hours per turbine from 2014 and 2015. The baseline actual operating hours used in the cost assessment is 646 hours per year per turbine. This is a conservative estimate based on West Valley's current run profile and available resource planning information.

Turbine	2014 Actual (hr/yr)	2015 Actual (hr/yr)	Average (hr/yr)
Turbine 1	631	693	662
Turbine 2	428	597	513
Turbine 3	674	807	741
Turbine 4	673	681	677
Turbine 5	551	720	636

Costs (AC) per Turbine	Cost Per Turbine
Capital cost to replace existing catalyst including installation (DCC)	$450,000
Additional annual ammonia cost (AC)	$9,000
Future worth factor [a] (FWF)	0.0724
Total Annual Cost = DCC*FWF + AC	$41,580

a Assumed catalyst life of each unit is 10 years with an interest rate of 7%. (EPA02; EPA, EPA Air Pollution Control Cost Manual, 2002)

Current SCR System	SCR Modification	NO_x Reduction (ton/yr)	Annual Cost of SCR Modification	$ Per Ton NO_x Removed
5 ppm (7.4 lb/hr) 2.39 tpy	2.5 ppm (3.7 lb/hr) 1.195 tpy	1.195 tpy	$41,580	$34,795

Conclusion: SCR technology capable of achieving NO_x levels of 2.5 ppmvd is considered to be achievable at the West Valley facility. However, since the West Valley turbines are peaking units and do not operate continuously, the cost associated with achieving this level of NO_x reduction is economically infeasible.

BACT is proposed to be water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NO_x emissions at 5 ppmvd @ 15% 02 which is comparable to the levels for current-generation water-injected gas turbines with SCR control, but higher than the most stringent limits.

MSM for the West Valley turbines would be the use of water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NO_x emissions at 2.5 ppmvd @ 15% O_2. This emission rate is achievable in practice, but has been shown to be economically infeasible for the West Valley turbines, due to the large capital investment and limited operating hours for these turbines.

The estimated lead time to obtain new SCR catalyst is approximately four months and installation time is estimated to be one week.

3.2.2. Volatile Organic Compound Emissions

Most VOCs emitted from natural gas-fired turbines are the result of incomplete combustion of fuel. Therefore, most of the VOCs are methane and ethane, which are not effectively controlled by an oxidation catalyst. However, oxidation catalyst technology designed to control CO can also provide some degree of control of VOC emissions, especially the more complex and toxic compounds formed in the combustion process. Therefore, the use of good combustion practices is generally considered BACT for VOC, with some additional benefit provided by an oxidation catalyst.

The only technology under consideration is combustion controls, with some additional benefit provided by an oxidation catalyst. This combination of technologies has been demonstrated to be feasible in many applications. No other technologies have been identified that are capable of achieving the same level of control. As a result, the goal of the rest of this analysis is to determine the appropriate emission limit that constitutes BACT for this analysis. A summary of recent VOC BACT determination is shown in Table 3-5.

Facility	District	VOC Limit[a]	Avg. Period	Control Method	Date Permit Issued
El Colton (LM6000)	SCAQMD	2.0 ppmv	3 hrs	Oxidation Catalyst	2/10/2004
Hanford LP	SJVAPCD	2.0 ppmv	-	Oxidation Catalyst	6/14/2001
CalPeak Power LC	SJVAPCD	2.0 ppmv	-	Oxidation Catalyst	5/12/2001
Bayonne Energy Center LLC (64 MW)	NJDEP LAER	2.0 ppmv	3 hr	Oxidation Catalyst	8/26/16
Mariposa Energy Project (LM6000)	BAAQMD	2.0 ppmv	-	Oxidation Catalyst	11/2010

Note: a. All concentrations expressed as parts per million by volume dry (ppmvd), corrected to 15% O_2.

The existing LM6000 gas turbines located at the West Valley plant are equipped with water injection, evaporative spray mist inlet air cooling, SCR catalyst, and CO oxidation catalyst and are estimated to achieve VOC emissions at 2 ppmvd @ 15% O_2 which is equivalent to the current BACT control limits.

The control technologies under consideration have the same ranking as each result in VOCs emission of 2.0 ppmvd @ 15% O_2.

This step evaluates any source-specific environmental, energy, or economic impacts that demonstrate that the top alternative listed in the previous step is inappropriate as BACT. The West Valley turbines meet a 2.0 ppmvd limit, which is the level identified as meeting BACT.

The VOC emission limit of 2.0 ppmvd is considered to be BACT for the West Valley turbines.

No other measures have been found that are more stringent than the current BACT limit.

3.2.3. Sulfur Oxide Emissions

Natural gas fired combustion turbines have inherently low SO_x emissions due to the small amount of sulfur present in the fuel. With typical pipeline quality natural gas sulfur content below 20 grain/100 scf, the SO_x emissions for natural gas fired combustion turbines are much lower than oil-fired turbines. Firing by natural gas, and the resulting control of SO_x emissions, has been used by numerous combustion turbines throughout the country. Due to the prevalence of the use of natural gas to control SO_x emissions from combustion turbines, only an abbreviated discussion of post-combustion controls will be addressed in this section.

Post-combustion SO_x control systems include dry and wet scrubber systems. These types of systems are typically installed on high SO_x emitting sources such as coal-fired power plants.

All of the control options discussed above are technically feasible.

The typical SO_x control level for a well-designed wet or dry scrubber installed on a coal-fired boiler ranges from approximately 70% to 90%[6], with some installations achieving even higher control levels.

The use of low sulfur content pipeline quality natural gas has been achieved in practice at numerous combustion turbine installations throughout the country, and the use of this fuel minimizes SO_x emissions. While it would be theoretically feasible to install some type of post-combustion control such as a dry/wet scrubber system on a natural gas fired turbine, due to the inherently low SO_x emissions associated with the use of natural gas, these systems are not cost effective and regulatory agencies do not require them. Consequently, no further discussion of post-combustion SO_x control is necessary.

BACT for this project is the use of pipeline-quality natural gas. The SO_x control method for the West Valley turbines is the use of pipeline-quality natural gas. Consequently, the existing turbine design is consistent with BACT requirements.

No other measures have been found that are more stringent than the current BACT limit.

3.2.4. $PM_{2.5}$ Emissions

Particulate Matter (PM) emissions from natural gas-fired turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are minimized by using clean-burning pipeline quality natural gas with low sulfur content. A summary of recent $PM_{10}/PM_{2.5}$ BACT guidance is shown in Table 3-6.

The CARB BACT Clearinghouse, as well as the BAAQMD BACT guideline, identifies the use of natural gas as the primary fuel as "achieved in practice" for the control of $PM_{10}/PM_{2.5}$ for combustion gas turbines.

[6] Air Pollution Control Manual, Air and Waste Management Association, Second Edition, page 206.

CARB's BACT guidance document for stationary gas turbines used for power plant configurations[7] indicates that BACT for the control of PM emissions is an emission limit corresponding to natural gas with a fuel sulfur content of no more than 1 grain/100 standard cubic foot.

Facility	District	PM Limit[a]	Avg. Period	Control Method	Date Permit Issued
El Colton (LM6000)	SCAQMD	1 grain/100 scf sulfur. 11 lb/hr	-	Water injection and SCR	2/10/2004
Hanford LP	SJVAPCD	0.0066 lb/MMBtu	-	PUC-regulated natural gas, air inlet cooler/filter and lube oil coalescer	6/14/2001
CalPeak Power LC	SJVAPCD	0.0066 lb/MMBtu	-	PUC-regulated natural gas, air inlet cooler/filter and lube oil coalescer	5/12/2001
Bayonne Energy Center LLC (64 MW)	NJDEP LAER	5 lb/hr	-	Natural gas and ultra low sulfur distillate fuel oil with sulfur < 15ppm	8/26/16
Mariposa Energy Project (LM6000)	BAAQMD	-	-	CPUC-regulated grade natural gas	11/2010
St. George City-Millcreek Power Plant (LM6000)	UDAQ	20 grains/100 scf sulfur	-	Water injection and SCR	9/30/2008

The current sulfur content limit identified in West Valley's current Title V permit for natural gas used at the facility is less than 20 grains/100 scf. The fuel source for the Plant consists exclusively of pipeline quality compressed natural gas. The Plant is constructed and operated such that compressed natural gas can be supplied as required from two independent sources. Kern River and Questar have compressed natural gas pipe lines, with associated terminals located at the West Valley Plant that can be used to supply pipeline quality fuel to the Plant's five simple cycle gas turbines.

The current Kern River fuel tariff sheet states that the quality of gas provided to the West Valley plant will contain no more than 0.75 grains/100 scf.

No control technology other than use of pipeline quality natural gas fuel has been identified for this application.

[7] CARB, Guidance for Power Plant Siting and Best Available Control Technology, July 22, 1999, Table I-1. Available at https://www.arb.ca.gov/energy/powerpl/guidocfi.pdf

No control technology other than use of clean natural gas fuel has been identified for this application.

Based upon the results of this analysis, the use of natural gas with a sulfur content less than 1 grains/100 scf as the primary fuel source constitutes BACT for $PM_{10}/PM_{2.5}$ emissions from combustion gas turbines. This is the type of fuel and sulfur content that is readily available to the West Valley plant.

No other measures have been found that are more stringent than the current BACT limit.

3.2.5. Ammonia (NH_3) Emissions

SCR uses ammonia as a reducing agent in the process of controlling NO_x emissions from gas turbines. The portion of the unreacted ammonia passing through the catalyst and emitted out of the exhaust stack is called "ammonia slip." Ammonia slip does not remain constant as the SCR system operates but increases as the catalyst activity decreases. Properly designed SCR systems, which operate close to the theoretical stoichiometry and supply adequate catalyst volume, maintain low ammonia slip levels.

Gas turbines using SCR typically have been limited to between 5 ppmvd and 10 ppmvd at 15% O_2 ammonia slip. A summary of recent ammonia BACT guidance is shown in Table 3-7.

Facility	District	Ammonia Limit[a]	Avg. Period	Control Method	Date Permit Issued
Black Hills Power, Inc.	WYDEQ	10 ppmv	3 hr	Water injection and SCR	11/2010
Bosque Power Company, LLC	TCEQ	10 ppmv 7 ppmv	3 hr Annual avg.	Water injection and SCR	9/30/2008
El Colton (LM6000)	SCAQMD	5 ppmv	3 hrs	Water injection and SCR	2/10/2004

Note: a. All concentrations expressed as parts per million by volume dry (ppmvd), corrected to 15% O_2.

Ammonia (NH_3) can be monitored through tracking of NH_3 injection rate and mass balance calculation; compliance with limits during periods between source testing can be monitored with surrogate parameters that limit potential emissions or correlate with emissions.

The existing LM6000 gas turbines located at the West Valley plant are equipped with water injection, evaporative spray mist inlet air cooling, and SCR catalyst which has a manufacturer design ammonia slip of 10 ppmvd @ 15% O_2. This is comparable to the levels for current-generation water-injected gas turbines with SCR control, but higher than the most stringent limits.

SCR, in combination with combustion controls, is capable of achieving a NH_4 emission level of 5 ppmvd @ 15% O_2. It is the existing control technology that will be evaluated in Step 4.

SCR has been achieved in practice at combustion turbine installations throughout the country. There are simple-cycle gas turbine projects that limit NH_3 emissions between 5- 10 ppmv using SCR technology, as shown in Table 3-7. An evaluation of the achievement of 5 ppmv in comparison to the current West Valley turbines NH_3 level of 10 ppmv, is summarized below.

Feasibility and Cost Impact: The current SCR system is designed to have a maximum NH_3 emission concentration of 10 ppm. UMPA reached out to several vendors to determine the changes that would be required to the existing SCR systems to meet a NH_3 concentration of 5 ppm and the associated costs. Vendors indicated that at a minimum, cleaning and tuning the existing ammonia injection grid (AIG) would improve performance, however this alone may not meet a 5 ppm NH_3 emission concentration. The estimated cost to clean and tune the existing AIG was estimate to be $100,000. If replacement of the ammonia injection grid is necessary, the cost is estimated to be $350,000-$500,000 per turbine. Included in Appendix A is supporting documentation received from vendors which was used to develop the costs. Due to the uncertainty and wide cost range, the average cost of approximately $300,000 was used for the cost per ton evaluation.

Table 3-8 below outlines the estimated cost per ton of pollutant removed to reduce NH_3 emissions from 10 ppm to 5 ppm. Since the West Valley turbines are peaking units, they do not operate continuously as a base load unit would operate. Therefore, the annual tons of NH_3 emissions removed is based on baseline actual operating hours of 646 hours per year per turbine. This is a conservative estimate based on West Valley's current run profile and available resource planning information.

Costs (AC) per Turbine	Cost Per Turbine
Capital cost to replace existing NH_3 grid including installation (DCC)	$300,000
Future worth factor [a] (FWF)	0.0724
Total Annual Cost = DCC*FWF + AC	$21,720

a Assumed injection grid life of each unit is 10 years with an interest rate of 7%. (EPA02; EPA, EPA Air Pollution Control Cost Manual, 2002)

Current SCR System	SCR Modification	NH_3 Reduction (ton/yr)	Annual Cost of AIG Modification	$ Per Ton NO_X Removed
10 ppm (8.7 lb/hr) 2.81 tpy	5 ppm (4.35 lb/hr) 1.41 tpy	1.41 tpy	$21,720	$15,404

Conclusion: SCR technology capable of achieving ammonia slip levels of 5 ppm is considered to be achieved in practice. However, since the West Valley turbines are peaking units and do not operate continuously, the cost associated with achieving this level of NH_3 reduction is economically infeasible.

BACT is proposed to be water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NH_3 emissions at 10 ppmvd @ 15% O2 which is comparable to the levels for current-generation water-injected gas turbines with SCR control, but higher than the most stringent limits.

MSM for the West Valley turbines would be the use of water injection, evaporative spray mist inlet air cooling, and SCR catalyst and achieve NH_3 emissions at 5 ppmvd @ 15% O_2. This emission rate is achievable in practice, but has been shown to be economically infeasible for the West Valley turbines, due to the large capital investment and limited operating hours for these turbines.

The estimated lead time to obtain a new ammonia injection grid is approximately four months and installation time is estimated to be two weeks.

4.1. EMISSION JUSTIFICATION

BACT is proposed to be water injection, evaporative spray mist inlet air cooling, and SCR catalyst which is the current control technology installed on the existing turbines. UMPA is proposing that BACT emission limits are equivalent to the current emission limits achieved by the facility. However, UMPA has determined that there are MSM that have lower achievable emission limits than what the existing turbines achieve with the same control technology.

4.2. EMISSION SUMMARY

The following table provides emission limits during normal operation that are reflective of the most stringent measures identified in this analysis. Normal operation is the only scenario that was identified for MSM; startup, shutdown and maintenance emissions would need to be evaluated at a later date based on further discussions with vendors.

Potential to emit is based on continuous operation or 8,760 hr/year for each turbine, consistent with the facility's current Title V permit. Projected future actual emission estimates are based on 646 hr/yr for each turbine, which is consistent with the baseline actual run profile and available resource planning information.

Table 4-1 MSM Facility-Wide Impact of Emission Units

PTE Operating Scenario	Polluant				
	$PM_{2.5}$	NO_x	SO_2	VOC	NH_3 [a]
Current Emissions Limit (ppmvd)	-	5	-	2	10
MSM Limit (ppmvd)	-	2.5	-	2	5
Potential Annual Emissions/Turbine (tpy)	8.21	32.41	5.94	3.67	38.11
MSM Annual Emissions/Turbine (tpy)	8.21	16.21	5.94	3.67	19.05
MSM Annual Facility Wide Reduction (tpy) [b]	-	81.05	-	-	95.27
Projected Actual Operating Scenario	**Polluant**				
	$PM_{2.5}$	NO_x	SO_2	VOC	NH_3 [a]
Current Emissions Limit (ppmvd)	-	5	-	2	10
MSM Limit (ppmvd)	-	2.5	-	2	5
Actual Annual Emissions/Turbine (tpy)	0.6	2.39	0.44	0.27	2.81
MSM Annual Emissions/Turbine (tpy)	0.6	1.20	0.44	0.27	1.41
MSM Annual Facility Wide Reduction (tpy) [b]	-	5.98	-	-	7.02

[a] Ammonia emissions are not quantified in the current Title V permit or in the Title V permit renewal application; estimated based on ppvd.

[b] Takes into consideration emissions reductions for all five turbines.

APPENDIX A: COST ANALYSIS REFERENCE

CALL RECORD

Title: **UMPA BACT Analysis discussion with Groome**
By: Melissa Armer **Date:** 4/20/17
Client: Utah Municipal Power Agency **Project #:** 171301.0008

BACKGROUND NOTES

- Jerame Blevins the West Valley plant manager provided Trinity Consultants Inc. with contact information for a vendor they have used to service their SCR system.

Christina Juarez
Technical Sales-Western Region HRSG
Groome Industrial Service Group
155 Franklin Turnpike
Waldwick, NJ 07463
800-505-6100 Voice
559-289-3060 Cell
Cjuarez@groomeindustrial.com

CALL AGENDA

1. Evaluate the feasibility and cost associated with reducing NOx emissions from 5 ppm to 2.5 ppm..
   - Provide a written description of the equipment or operational changes that would be necessary
   - A complete cost breakdown associated with making these changes, including but not limited to: capital equipment cost, installation cost, annual operating cost etc.

2. Ammonia slip reductions: We need to evaluate the feasibility and cost associated with reducing NH_3 slip from 10 ppm to 5 ppm. Same information needed as listed above.

PARTICIPANTS

- Christina Juarez, Groome Industrial Service Group
- Melissa Armer, Trinity Consultants Inc.

CALL SUMMARY

- Groome indicated that each control system is complex and is designed to a specific emission limit. There are numerous factors that interrelate when evaluating an existing system and determining the modifications necessary to achieve the emissions reductions being evaluated in this analysis.
- Groome provided a proposal for them to complete a detailed and comprehensive technical analysis of the existing turbines and existing SCR system in order to definitively determine the changes necessary.
- For this analysis only general estimates are needed at this time as UMPA is only considering these modifications and will present the information to UDAQ for further review.
- For this analysis we need to provide general information on the expected changes that would be required.
- Changes necessary to reduce NOx may include
  - Catalyst re-sizing
  - Catalyst design modification
  - Ammonia injection/vaporization system re-design

- The estimated capital costs associated with the installation, startup and equipment costs of modifying the existing SCR/oxidation catalyst to this removal rate is approximately $500,000 per unit.
- To reduce ammonia emissions replacement of the ammonia injection grid may be necessary
    - Cost associated with a new ammonia injection grid are estimated to be between $350,000-$500,000 per turbine.

ACTION ITEMS

1. Christina to confirm estimated costs with her engineering department. Costs were confirmed: 4/24/17

CALL RECORD

Title: **UMPA BACT Analysis discussion with Haldor Topsoe**
By: Melissa Armer — **Date:** 4/26/17
Client: Utah Municipal Power Agency — **Project #:** 171301.0008

BACKGROUND NOTES

- Haldor Topsoe is the vendor the supplied the catalyst currently being used in two of the four catalyst bays for the West Valley SCR systems.
- Trinity Consultants Inc. contacted Haldor Topsoe (HT) on 4/18/17 to gather information to evaluate the feasibility and cost associated with reducing NOx emissions from 5 ppm to 2.5 ppm.

Nathan White
Director | Air Emissions Control | Sustainables
Haldor Topsoe, Inc.
5510 Morris Hunt Drive
Fort Mill, SC 29708, USA
Phone (direct): +1 803 835 0571
Mobile: +1 281 684 8809

PARTICIPANTS

- Nathan White, Director | Air Emissions Control | Sustainables Haldor Topsoe, Inc.
- Melissa Armer, Trinity Consultants Inc.

CALL SUMMARY

- HT indicated that the current catalyst may be able to meet the NOx outlet of 2.5 ppm and NH_3 at 5 ppm but it would reduce the service life of the catalyst from 30,000 hrs to 20,000 hrs.
- He recommended that run tests be completed to determine what the ammonia slip would be at a NOx outlet of 2.5 ppm. This would help to determine the deactivation factor for the current catalyst and determine how close to the service life the current catalyst is.
- As indicated by other vendors, each system is unique and a more detailed evaluation of the current operating parameters and performance would be needed to definitively identify the modifications necessary for each system.
- Another option presented that would guarantee NOx outlet of 2.5 ppm and NH_3 at 5 ppm would be to change out the existing catalyst with a new DNX GT-301 catalyst. The new catalyst would have an expected service life of 30,000 hours, which is similar to the current catalyst service life.
- The current cost of a new GT-301 catalyst charge in modules plus removal of the old catalyst and installation of the new catalyst is approximately $300,000 per unit.
- Another possible option would be to add additional catalyst to the third bay of each system, which may allow for operation at a NOx outlet of 2.5 ppm and NH_3 at 5 ppm. However, this option may not be feasible from an operations standpoint because it will result in a pressure drop which would reduce the power output of each turbine.
- Since the West Valley turbines are used for peak power demand they need to be able to provide their full power output when called upon.
- When asked about the ammonia injection grid, he thought tuning may be necessary, which would have an estimated cost of $25,000.

EMAIL RECORD

From: Shane Minor [mailto:sminor@wheelercat.com]
Sent: Wednesday, April 26, 2017 6:28 PM
To: Melissa Armer <marmer@trinityconsultants.com>
Subject: FW: West Valley BACT analysis

Melissa,

See below. I hope this is helpful. David with Safety power has been awesome on this.

Shane Minor | Govt. Util, Int. Sales | Wheeler Machinery Co.

4901 West 2100 South, Salt Lake City, UT 84120

Office: 801.978.1533 | Mobile: 801.201.0929 | Fax: 801.978.1570

sminor@wheelercat.com | www.wheelercat.com

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From: David Stelzer [mailto:david.stelzer@safetypower.ca]
Sent: Wednesday, April 26, 2017 2:29 PM
To: Shane Minor <sminor@wheelercat.com>
Cc: Bob Stelzer <bob.stelzer@safetypower.ca>
Subject: RE: West Valley BACT analysis

Hi Shane,

Following up with my voicemail yesterday. The good news is that a catalyst replacement and system retuning is all that's required to achieve the new emission levels.

Unfortunately HTI won't provide the catalyst upgrade/ replacement service directly. That being said they did provide me with the catalyst pricing. Based on this info I would estimate that the upgrade would cost the following:

Catalyst Material: $515,000.
Catalyst installation and retuning of the Ammonia Injection Grid: $85,000.
Total Cost Per 40MW Turbine = $600,000 USD.

This upgrade would achieve 2.5 ppm NOx, 5 ppm NH3 slip, 2 ppm VOC (@ 15% O2).

Pricing is budgetary. If we had more time and if this project progressed to the next stage, I would put you in contact with a system integrator that Wheeler CAT/UMPA could deal with directly.

It's important to note that this upgrade would consume slightly more ammonia to achieve the required NOx reduction.

Kind Regards,

David Stelzer, P.E., MSc.
Senior Sales & Marketing Engineer
Safety Power Inc
Office: 1-800-657-1280 x 30
Mobile: 416-994-5925
www.safetypowerinc.com
https://www.youtube.com/c/SafetyPowerInc

CALL RECORD

Title: **UMPA BACT Analysis discussion with General Electric**
By: Melissa Armer | **Date:** 4/25/17
Client: Utah Municipal Power Agency | **Project #:** 171301.0008

BACKGROUND NOTES

- Trinity Consultants Inc. originally contacted General Electric (GE) on 3/15/17 to gather information to evaluate the feasibility and cost associated with reducing NOx emissions from 5 ppm to 2.5 ppm..
  - Provide a written description of the equipment or operational changes that would be necessary
  - A complete cost breakdown associated with making these changes, including but not limited to: capital equipment cost, installation cost, annual operating cost etc.

- Ammonia slip reductions: We need to evaluate the feasibility and cost associated with reducing NH3 slip from 10 ppm to 5 ppm. Same information needed as listed above.
- GE indicated that they could provide this information, but they would need to get in contact with their engineering department.
- In late April, GE responded to Trinity and indicated that they do not provide this equipment and work through vendors to specify add-on control equipment.
- Contact who specifies control equipment for new construction:
  Ty Remington
  Account Manager, Mtn West
  GE Power, Gas Power Systems
  T 518-334-0601
  8000 E. Maplewood Ave., Suite 250
  Greenwood Village, CO 80111

PARTICIPANTS

- Ty Remington, GE Power, Gas Power Systems
- Melissa Armer, Trinity Consultants Inc.

CALL SUMMARY

- GE indicated that each control system is unique and they do not typically deal with a retrofit, but rather specifying new equipment for new turbines.
- Ty confirmed that NO_x levels of 2.5 ppm and NH_3 at 5 ppm are achievable and he has seen new LM6000 SPRINT turbines meeting these levels in operation.
- He indicated that he would expect that increasing the ammonia slip may be an operational change that would further reduce the NO_x emissions, however that would also increase the ammonia slip.
- He thought that a combination of replacing the catalyst and changing the ammonia injection rate would likely get the plant to the desired emission levels. However, he was not sure if the existing system would be large enough to house new and potentially more catalyst, so he thought additional catalyst modules may also be needed.
- Since Ty does not deal with retrofits he was not sure what the cost would be for a retrofit.
- He indicated for a completely new SCR system the total installed cost was about $3 Million dollars.
- He did not have the cost breakdown for how much the catalyst alone would cost.