Ocotillo Power Plant

Application to construct five (5) new natural gas-fired General Electric LMS100 simple cycle gas turbine generators

Appendix B.

Control Technology Review

Best Available Control Technology (BACT) analysis for the natural gas-fired General Electric LMS100 simple cycle gas turbine generators, cooling tower, emergency diesel generators, diesel fuel oil storage tank, SF_6 insulated electrical equipment, and natural gas piping systems.

Original Date:	**April, 2014**
Updated:	**July 14, 2014**
Updated:	**January 25, 2015**
Updated:	**September 21, 2015**

Prepared for:

aps

Arizona Public Service
400 North 5th Street
Phoenix, Arizona 85004
www.aps.com

Prepared By:

RTP ENVIRONMENTAL ASSOCIATES INC.
1591 Tamarack Ave.
Boulder, CO 80304

Executive Summary

This document is a control technology review or Best Available Control Technology (BACT) analysis for the Ocotillo Power Plant Modernization Project. The location of the Ocotillo Power Plant is currently classified as a serious nonattainment area for particulate matter less than 10 microns (PM_{10}), a marginal nonattainment area for ozone, and an attainment or unclassified area for all other Prevention of Significant Deterioration (PSD) regulated pollutants.

APS is proposing to construct 5 new gas-fired combustion turbines (GTs) and associated equipment, and permanently retire the existing Ocotillo steam electric generating units 1 and 2. Based on the total potential emissions for the Project as proposed in this application and the current actual emissions of the retired Unit 1 and 2 steamers, the Project will result in an emissions increase and a net emissions increase in carbon monoxide (CO), particulate matter (PM), $PM_{2.5}$, and greenhouse gas (GHG) emissions that are above the PSD significant emission rates. Therefore, the Project is subject to PSD requirements for these pollutants, and this document presents the PSD BACT analyses.

The Project is not subject to NANSR requirements for PM_{10}, VOC, or NOx, and therefore no Lowest Acheivable Emission Rate (LAER) control technology analysis is required for those pollutants.

In addition to the PSD requirements, Maricopa County's Air Pollution Control Regulations (MCAPCR), Rule 241, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of NO_x or VOC emissions. Because the GTs would have maximum NO_x and VOC emissions which exceed these thresholds, this document includes the County required BACT analyses for NO_x and VOC emissions to address MCAPCR Rule 241.

Table of Contents

TABLES

Chapter 1. Control Technology Review Methodology.

1.1 Best Available Control Technology (BACT).

The Clean Air Act defines "best available control technology" (BACT) as:

> "…an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under this paragraph as it existed prior to November 15, 1990."

Under the Maricopa County Air Pollution Control Regulations, Rule 100, Section 200.24, "best available control technology" (BACT) means:

200.24 **BEST AVAILABLE CONTROL TECHNOLOGY (BACT)** - An emissions limitation, based on the maximum degree of reduction for each pollutant, subject to regulation under the Act, which would be emitted from any proposed stationary source or modification, which the Control Officer, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of such pollutant. Under no circumstances shall BACT be determined to be less stringent than the emission control required by an applicable provision of these rules or of any State or Federal laws ("Federal laws" include the EPA approved State Implementation Plan (SIP)). If the Control Officer determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The BACT requirement applies for a given pollutant to each individual new or modified emission unit when the project, on a facility-wide basis, has a significant net emissions increase for that pollutant. Individual BACT determinations are performed on a unit-by-unit, pollutant-by-pollutant basis.

1.2 Top Down BACT Methodology.

The United States Environmental Protection Agency (U.S. EPA) recommends a "top-down" approach in conducting a BACT or Lowest Available Emission Rate (LAER) analysis. This method evaluates progressively less stringent control technologies until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The five steps of a top-down BACT analysis are:

1. Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;
2. Eliminate all technically infeasible control technologies;
3. Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
4. Evaluate most effective controls and document results; and
5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The impact analysis of any BACT review includes an evaluation of environmental, energy, technical, and economic impacts. The net environmental impact associated with a control alternative may be considered if dispersion modeling analyses are performed. The energy impact analysis estimates the direct energy impacts of the control alternatives in units of energy consumption. If possible, the energy requirements for each control option are assessed in terms of total annual energy consumption. The most important issue of the BACT review is generally the economic impact. The economic impact of a control option is assessed in terms of cost effectiveness and ultimately, whether the option is economically reasonable. The economic impacts are reviewed on a cost per ton controlled basis, as directed by the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual, Fifth Edition.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes, must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that 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" contained in the record of the permit decisions.

1.3 Technical Feasibility.

Step 2 of the BACT analysis involves the evaluation of all of the identified available control technologies from Step 1 to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option.

The technology must be commercially available for it to be considered as a candidate for BACT. EPA's New Source Review Workshop Manual, page B.12 states, "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

In general, if a control technology has been "demonstrated" successfully for the type of emission source under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. Page B.17 of the New Source Review Workshop Manual states:

> Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.
>
> Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:
>
> - concept stage;
> - research and patenting;
> - bench scale or laboratory testing;
> - pilot scale testing;
> - licensing and commercial demonstration; and
> - commercial sales.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission source), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission source may not be applicable to a similar source depending on differences in physical and chemical gas stream characteristics.

1.4 Economic Feasibility.

Economic feasibility is normally evaluated according to the average and incremental cost effectiveness of the control option. From the U.S. EPA's New Source Review Manual, page B.31, average cost effectiveness is the dollars per ton of pollutant reduced. The incremental cost effectiveness is the cost per ton reduced from the technology being evaluated as compared to the next lower technology. The EPA NSR Review Manual states that, "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those sources and the particular source under review".

In addition to the average and incremental cost effectiveness analysis, EPA has also used direct comparisons of control technology costs to overall project costs as part of recent GHG BACT determinations. Regarding economic impacts, in its PSD GHG BACT guidance EPA states[1]:

> EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.

The U.S. EPA evaluated the costs of CCS in its Response to Public Comments (October, 2011) for the Palmdale Hybrid Power Project, a 570 MW power plant based on approximately 520 MW of natural gas-fired combined cycle units and 50 MW of solar photovoltaic systems. In the EPA's analysis, the estimated capital costs for the Project are $615-$715 million, equal to an annualized cost of about $35 million over the 20 year lifetime of the facility. In comparison, the estimated annual cost for CCS for this Project is about $78 million, ***or more than twice the value of the facility's annual capital costs***. Based on these very high costs, EPA eliminated CCS as an economically infeasible control option. The EPA's decision to reject CCS based on these very high annual costs was upheld on appeal by the U.S. EPA's Environmental Appeals Board (EAB), PSD Appeal No. 11 -07, decided September 17, 2012.

The EAB also rejected a challenge to a PSD permit for the construction of a new ethylene production unit in Baytown, Texas. The EAB upheld the determination that the installation of CCS was too expensive, on a total cost basis, to be selected as BACT for limiting GHG emissions from the proposed unit.

1.1.1 Average Cost Effectiveness.

In the EPA's New Source Review Manual, page B.37, average cost effectiveness is calculated as:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emission rate} - \text{Control option emissions rate}}$$

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. In the draft Workshop Manual, the EPA states that the baseline emission rate represents uncontrolled emissions for the source. However, the manual also states that when calculating the cost effectiveness of adding controls to inherently lower emitting processes, baseline emissions may be assumed to be the emissions from the lower emitting process itself.

[1] EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases*, (Mar. 2011), page 42.

1.1.2 Incremental Cost Effectiveness.

In addition to determining the average cost effectiveness of a control option, the U.S. EPA's New Source Review Manual states that the incremental cost effectiveness between dominant control options should also be calculated. The incremental cost effectiveness compares the costs and emissions performance level of a control option to those of the next most stringent control option:

$$\text{Incremental Cost (\$ per incremental ton removed)} = \frac{\text{Control option annualized cost} - \text{Next control option annualized cost}}{\text{Next control option emission rate} - \text{Control option emissions rate}}$$

1.5 Scope of the Control Technology Review.

The U.S. EPA has a longstanding policy regarding the scope of control technology options which the review agency may consider in a control technology review or BACT analysis. The scope of potential options relates directly to a proposed project's basic purpose or design. In short, the list of options should not include processes or options that would fundamentally redefine the source proposed by the applicant.

In the U.S. EPA EAB decision on the Prairie State Generating Station, PSD Appeal No. 05-05, the EAB explained (pages 27-28) that the facility's "basic purpose" or basic design," as defined by the applicant, is the fundamental touchstone of EPA's policy on "redefining the source":

> …Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through the application of BACT. The parties' arguments, properly framed in light of their agreement on this central proposition, thus concern the proper demarcation between those aspects of a proposed facility that are subject to modification through the application of BACT and those that are not.
>
> We see no fundamental conflict in looking to a facility's basic "purpose" or to its "basic design" in determining the proper scope of BACT review, nor do we believe that either approach is at odds with past Board precedent.

This EAB decision was upheld by the United States Court of Appeals, 7th Circuit.[2]

When EPA issued guidance in 2011 for conducting control technology reviews for greenhouse gas (GHG) emissions, EPA confirmed that a BACT analysis should not redefine the source's purpose:[3]

> While Step 1 [of a BACT process] is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include lower pollution processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

---

[2] *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

[3] U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases* 26 (Mar. 2011) (citing *Prairie State*, 13 E.A.D. at 23).

The EAB has analyzed the redefinition of the source concept in the context of a past permitting proceeding similar to the proposed Ocotillo Modernization Project. In their challenges to a PSD permit issued for the Pio Pico Energy Center, petitioners asserted before the EAB that EPA had erred in eliminating combined-cycle gas turbines in Step 2 of its BACT analysis for GHG emissions. Like Ocotillo, Pio Pico is a simple cycle gas-fired facility designed to back up renewable generation by providing peaking and load-shaping capability. As the EAB recognized in its Pio Pico decision and consistent with EPA guidance, a permitting authority can consider peaking facilities, intermediate load facilities and base load facilities to be different electricity generation source types. The EAB explained how "plants operating in 'peaking mode' typically remain idle much of the time, but can be started up when power demand increases … and, unlike base load plants, typically use simple-cycle rather than combined-cycle units as well as smaller turbines."[4]

The U.S. EPA has also addressed the issue of whether a peaking facility must consider energy storage such as batteries in the control technology review. For example, in the U.S. EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[5] issued for a peaking facility to be comprised of reciprocating internal combustion engines (RICE), EPA determined that "energy storage cannot be required in the Step 1 BACT analysis as a matter of law." *Id.* at 1 (explaining that "'incorporating energy storage' in Step 1 of the BACT analysis for a [RICE] resource would constitute the consideration of an alternative means of power production in violation of long-established principles for what can occur in Step 1 of the BACT analysis") (citing *Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007)). EPA concluded that energy storage, either "to replace all or part of the proposed . . . project," would fundamentally redefine the source. *Id.* at 2.

Like the Ocotillo Modernization Project, the purpose of the Red Gate project was to provide reliable, rapidly dispatchable power to support renewables and the transmission grid. Because "energy storage first requires separate generation and the transfer of the energy to storage to be effective . . . [it] is a fundamentally different design than a RICE resource that does not depend upon any other generation source to put energy on the grid." *Id.* Energy storage could not meet that production purpose for the duration or scale needed. *Id.* at 2-3. As EPA correctly observed, "[t]he nature of energy storage and the requirement to replenish that storage with another resource goes against the fundamental purpose of the facility." *Id.* at 3.

Similarly, in another PSD permit for a peaking facility for the Shady Hills Generating Station (Jan 2014), this time with natural gas-fired simple cycle units, EPA also concluded that energy storage would not meet the business purpose of the facility and therefore should not be considered in the BACT analysis. [6]

---

[4] *In re Pio Pico Energy Center*, PSD Appeal Nos. 12-04 through 12-06, slip op. at 63 (EAB Aug. 2, 2013).

[5] *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions, PSD-TX-1322-GHG (Nov. 2014), http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-resp2sierra-club.pdfNov%2014 .

[6] Responses to Public Comments, Draft Greenhouse Gas PSD Air Permit for the Shady Hills Generating Station at 10-11 (Jan 2014), http://www.epa.gov/region04/air/permits/ghgpermits/shadyhills/ShadyHillsRTC%20_011314.pdf.

Chapter 2. Project Purpose and Need.

The purposes for the Project are to provide peaking and load shaping electric capacity in the range of 25 to 500 MW (including quick ramping capability to backup renewable power and other distributed energy sources), to replace the 200MW of peak generation that will be retired at Ocotillo with cleaner units, and to provide an additional 300MW of peak generation to handle future growth. This Project has been reviewed and the Certificate of Environmental Compatibility has been approved by the Arizona Corporation Commission (ACC) after a lengthy public comment period and hearing process.

APS is continuing to add renewable energy, especially solar energy, to the electric power grid, with the goal of achieving a renewable portfolio equal to 15% of APS's total generating capacity by 2025 as mandated by the ACC. However, because renewable energy is an intermittent source of electricity, a balanced resource mix is essential to maintain reliable electric service. As of January 1, 2015, APS has approximately 1,200 MW of renewable generation and an additional 46 MW in development. Within Maricopa County and the Phoenix metropolitan area, APS has about 115 MW of solar power and there is an additional 300 – 400 MW of rooftop Photovoltaic (PV) solar systems.

One of the major impediments to grid integration of solar generation is the variable nature of the power provided and how that variability impacts the electric grid. According to the Electric Power Research Institute (EPRI) study on the variability of solar power generation capacity, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, the total plant output for three large PV plants in Arizona have ramping events of up to 40% to 60% of the rated output power over 1-minute to 1-hour time intervals[7]. Considering only the solar capacity in Maricopa County, the required electric generating capacity ramp rate required to back up these types of solar systems would therefore range from 165 to 310 MW per minute. The actual renewable energy load swings experienced on the APS system have also shown rapid load changes from renewable energy sources of 25 to 300 MW in very short time periods, in agreement with the estimates found in the EPRI study.

To backup the current and future renewable energy resources, the Project design requires quick start and power escalation capability to meet changing power demands and mitigate grid instability caused by the intermittency of renewable energy generation. To achieve these requirements, the project design is based on five General Electric (GE) LMS100 gas-fired simple cycle combustion turbine generators (GTs), which have the capability to meet these design needs while complying with the proposed BACT air emission limits at loads ranging from 25% to 100% of the maximum output capability of the turbines. The proposed LMS100 GTs can provide an electric power ramp rate equal to 50 MW per minute per GT which is critical for the project to meet its purpose. When all 5 proposed GTs are operating at 25% load, the entire project can provide approximately 375 MW of ramping capacity (i.e., from 125 to 500 MW) in less than 2 minutes.

---

[7] Electric Power Research Institute (EPRI) report, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, 3002001387, Technical Update, December 2013, conclusion, page 6-1.

Chapter 3. GT Carbon Monoxide (CO) Control Technology Review.

Carbon monoxide (CO) is emitted from simple cycle combustion turbines as a result of incomplete combustion. Therefore, the most direct approach for reducing CO emissions (and also reduce the other related pollutants) is to improve combustion. Incomplete combustion also leads to emissions of volatile organic compounds (VOC) and organic hazardous air pollutants (HAP) such as formaldehyde. CO emissions as well as VOC and organic HAP emissions may also be reduced using post combustion control systems including oxidation catalyst systems.

3.1 BACT Baseline.

There are no current State Implementation Plan (SIP) regulations or federal regulations applicable to CO or VOC emissions from these simple cycle gas turbines.

Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1 requires the application of BACT to any new stationary source which emits more than 550 lbs/day or 100 tons/yr of carbon monoxide.

3.2 STEP 1. Identify All Available Control Technologies.

Table B3-1 is a summary of CO control technologies and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database. The lowest reported emission limit is 4 ppm for an F-class, 175 MW Siemens turbine. However, this limit is only for operating loads above 70% of the maximum rated capacity of the turbine. This unit has additional CO BACT limits of 10 ppm for loads between 60% and 70%, and 150 ppm for loads less than 60%. This F-class turbine is a much larger gas turbine with a different design than the LMS100 aero derivative units, and cannot meet a single CO emission limit across the wide range of loads that the proposed Ocotillo GTs must operate.

There are also three permits with a CO emission limit of 5 ppm, all located in New Jersey. Two of these facilities utilize 68 MW Rolls Royce Trent turbines, and one utilizes GE LMS6000 gas turbines. The BACT clearinghouse database does not include descriptions of the operating load range over which this limit may apply. It does not appear that this BACT limit does not apply to the low load operating ranges between 25% and 50% over which these proposed LMS100 gas turbines are designed to operate.

Table B3-2 is a summary of CO emission limits for natural gas-fired simple cycle gas turbines from the South Coast Air Quality Management District's LAER/BACT determinations. The BACT emission limits for similar turbines range from 6 to 10 ppmdv, corrected to 15% excess oxygen. Several determinations in 2012 concluded that the use of oxidation catalysts and a CO limit of 6.0 ppmdv at 15% O_2 is BACT. The San Joaquin Valley Air Pollution Control District lists BACT for CO emissions from simple cycle gas turbines of 0.024 lb/mmBtu, equal to 10 ppmdv @ 15% O_2.

This database indicates two major control technologies used to control CO and VOC emissions, including Good Combustion Practices (GCP), and Oxidation Catalysts (OC). Included within the category of good combustion practices is Water Injection (WI), dry low NO_x (DLN) combustion, and steam injection (SI). There are several other potential advanced control technologies including catalytic combustion (such as XONON) and catalytic absorption/oxidation technology (such as SCONOx™).

Based on this review, the following technologies have potential for applicability to these turbines:

1. Good Combustion Practices (GCP), including:
   a) Steam injection (SI)
   b) Dry low NO_x (DLN) combustion, and
   c) Water Injection (WI)
2. Oxidation Catalyst (OC)
3. Catalytic Combustion and Catalytic Absorption/Oxidation (EMx or SCONOx™)

With respect to steam injection, the combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs. Therefore, steam injection is not an available control option for the LMS 100 GTs and is therefore eliminated as a control technology option[8].

With respect to Dry Low NO_x (DLN) combustion, DLN is an available option for the LMS100 GTs. However, the DLN equipped GTs produce much more CO and other products of incomplete combustion than the water injected GTs. As a result, DLN equipped GTs cannot meet the CO BACT emission limit below 75% load, while the water injected GTs can also achieve the CO BACT limit continuously down to 25% of load. Because a GT turndown to 25% load is a major design criterion for the Project to adequately backup renewable energy resources, utilizing DLN would require changing the basic purpose and design of the facility and may therefore be eliminated under Step 1 as redefining the source[9].

DLN equipped LMS100 GTs also have a lower peak electric generating capacity than the water injected units. The peak electric output at 105 ^{o}F is reduced significantly; from 109.9 MW (gross) for the water injected GTs to only 97.2 MW for the DLN equipped GTs. This is a significant reduction in peak generating and ramping capacity which directly affects the ability of the project to meet its basic design requirements, another reason for dismissal under Step 1 of BACT.

---

[8] The GE paper *New High Efficiency Simple Cycle Gas Turbine – GE's LMS100*™ which is available at GE's website at http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf is a 2004 paper that does indicate steam injection as a potential option. However, this paper preceded the first commercial operating date for an LMS 100 GT in June 2006. In an e-mail from Phil Tinne, GE Power & Water, to Scott E McLellan, Arizona Public Service dated May 14, 2015, Mr. Tinne states " I confirm that we have not developed steam injection for the LMS100, either for NOx control or power supplementation, thus it is not on our option list."

[9] The significant lack of turndown capability for the DLN equipped GTs also makes the DLN equipped LMS 100 GTs technically infeasible for these peaking units and therefore would be eliminated under Step 2.

TABLE B3-1. Carbon monoxide (CO) control technologies and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	CONTROL METHOD	LIMIT, ppmdv at 15% O_2
Great River Energy - Elk River Station	MN	07/01/2008	OC	4
PSEG Fossil Kearny Generating Station	NJ	10/27/2010	OC, GCP	5
Bayonne Energy Center	NJ	09/24/2009	OC	5
Howard Down Station	NJ	09/16/2010	OC	5
Arvah B. Hopkins Generating Station	FL	10/26/2004	OC	6
Cheyenne Prairie Generating Station	WY	08/28/2012	OC	6
Lonesome Creek Generating Station	ND	09/16/2013	OC	6
Pioneer Generating Station	ND	05/14/2013	OC	6
EI Colton, LLC	CA	01/10/2003	OC	6
Shady Hills Generating Station	FL	01/12/2009		6.5
FPL Manatee Plant - Unit 3	FL	04/15/2003	GCP	7.4
Progress Bartow Power Plant	FL	01/26/2007	GCP	8
FPL Martin Plant	FL	04/16/2003	GCP	8
Louisville Gas And Electric Company	KY	06/06/2003	GCP	9
Dahlberg Electric Generating Facility	GA	05/14/2010	GCP	9
Bosque County Power Plant	TX	02/27/2009	GCP	9
ODEC - Marsh Run Facility	VA	02/14/2003	GCP	9
ODEC - Louisa	VA	03/11/2003	GCP	9
ODEC -Marsh	VA	02/14/2003	GCP	9
ODEC - Louisa Facility	VA	03/11/2003	GCP	9
Fairbault Energy Park	MN	07/15/2004	GCP	10

Footnotes

OC means Oxidation Catalyst; GCP means Good Combustion Practices.

TABLE B3-2. CO emission limits for natural gas-fired simple cycle gas turbines from the South Coast Air Quality Management District's LAER/BACT determinations.

FACILITY	PERMIT DATE	TURBINE DESCRIPTION	CO LIMIT, ppmdv at 15% O_2	AVERAGING PERIOD
EI Colton, LLC	1/10/2003	GE LM6000	6.0	3-hr
Indigo Energy (Wildflower Energy LP)	7/13/2001	GE LM6000	6.0	1-hr
Los Angeles Dept of Water & Power	5/18/2001	GE LM6000	6.0	3-hr

3.3 STEP 2. Identify Technically Feasible Control Technologies.

3.3.1 Good Combustion Practices.

Good combustion practice including the use of water injection is an effective method for controlling CO and VOC emissions from these gas turbines. Water injection is the most widely used combustion control technology for aero derivative gas turbines and gas turbines with capacities less than 100 MW. The injection of water directly into the turbine combustor lowers the peak flame temperature and reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (e.g., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

A significant advantage of water injection for these simple cycle gas turbines is the ability to achieve higher peak power output levels with water injection. The use of water injection increases the mass flow through the turbine which increases power output, especially at high ambient temperatures when peak power is often needed from these turbines. This is especially important for these gas turbines because the Ocotillo Power Plant is located in a region with high ambient temperatures.

Since 2013, three peaking power plants consisting of 19 water-injected LMS 100 simple cycle GTs have commenced commercial operation in California. These plants include the Walnut Creek Energy Park (City of Industry, 5 units), the CPV Sentinel Energy Project (Riverside County, 8 units), and the Haynes Generating Station Repowering Project (6 units). Water injection was concluded to represent BACT for all of these GTs. In 2013, a water-injected LMS100 GT also commenced commercial operation at El Paso Electric Company's Rio Grande Power Plant in Sunland Park, New Mexico (this unit does not appear to be subject to PSD review). In addition, the Pio Pico Energy Center (San Diego County) received a PSD construction permit for 3 water-injected LMS 100 simple cycle GTs in 2013. The water-injected LMS 100 GTs have been selected as BACT for these peaking power plants because of their very high efficiency when operating in simple cycle mode, their fast start times, high turndown rates, flexible operation, and high peak electric output, especially under high ambient temperature conditions. Therefore, the water-injected LMS 100 GT is an available control option that is demonstrated, available and technically feasible for these proposed peaking duty GTs.

3.3.2 Oxidation Catalysts.

For natural gas turbines applications, the lowest CO and VOC emission levels have been achieved using oxidation catalysts installed as post combustion control systems. The typical oxidation catalyst is a rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is typically installed in a reactor with flue gas inlet and outlet distribution plates. CO and VOC react with oxygen (O_2) in the presence of the catalyst to form carbon dioxide (CO_2) and water (H_2O) according to the following general equations:

$$2CO + O_2 \rightarrow 2CO_2$$
$$2C_nH_{2n+2} + (3n+1)O_2 \rightarrow 2nCO_2 + (2n+2)H_2O$$

Acceptable catalyst operating temperatures range from 400 – 1,250 °F, with the optimum temperature range of 850 - 1,100 °F. Below approximately 400 ^{o}F, catalyst activity (and oxidation potential) is negligible. This temperature range is generally achievable with simple cycle GTs except at low load startup and shutdown conditions. Oxidation catalysts have the potential to achieve approximately 90% reductions in "uncontrolled" CO emissions at steady state operation.

3.3.3 Catalytic Combustion.

Catalytic combustion involves the use of a catalyst to reduce combustion temperatures while increasing combustion efficiency. In a catalytic combustor, fuel and air are premixed and passed through a catalyst bed. In the bed, the mixture oxidizes at reduced temperatures. The improved combustion efficiency from the catalyst has the potential to reduce CO formation to approximately 5 ppm. However, the cooler combustion temperatures would decrease the Carnot efficiency of the turbines, since the efficiency for converting heat into mechanical energy is determined by the temperature difference between heat source and sink. The reduced unit efficiency is expected to be approximately 15%.

Catalytic combustion has the potential for application to most combustor types and fuels. However, the catalyst has a limited operating temperature and pressure range, and the catalyst has the potential to fail when subjected to the extreme temperature and pressure cycles that occur in simple cycle gas turbines. Commercial acceptance of catalytic combustion by gas turbine manufacturers and by power generators has been slowed by the need for durable substrate materials. Of particular concern is the need for catalyst substrates which are resistant to thermal gradients and thermal shock.[10]

Catalytic combustors have not been commercialized for industrial gas turbines. Much of the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. Catalytica, Inc., (now owned by Renegy) developed Xenon Cool Combustion, a catalytic technology that combusts fuel flamelessly. Other company's such as Precision Combustion Inc. and Catacel™ have patented technologies for catalytic combustors for gas turbines. However, we are not aware of any technologies commercially available for large industrial turbines, and General Electric does not supply the LMS100 turbines with catalytic combustors. Therefore, this technology is not technically feasible for these GTs.

3.3.4 EMx™ Catalytic Absorption/Oxidation (SCONOx™).

EMx™ Catalytic Absorption/Oxidation (the second-generation of the SCONOx™ NOx Absorber technology), available through EmeraChem, is based on a proprietary catalytic oxidation and absorption technology. EMx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce NO_x and CO emissions from natural gas fired gas turbines. The catalyst oxidizes carbon monoxide (CO) to carbon dioxide (CO_2), and nitric oxide (NO) to nitrogen dioxide (NO_2). The NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Dilute hydrogen gas is periodically passed

---

[10] R.E. Hayes and S.T. Kolaczkowski, *Introduction to Catalytic Combustion* (Amsterdam: Gordon and Breach Science Publishers, 1997); E.M. Johansson, D. Papadias, P.O. Thevenin, A.G. Ersson, R. Gabrielsson, P.G. Menon, P.H. Bjornbom and S.G. Jaras, "*Catalytic Combustion for Gas Turbine Applications*," Catalysis 14 (1999): 183-235.

across the surface of the catalyst to regenerate the K_2CO_3 catalyst coating. The regeneration cycle converts KNO_2 and KNO_3 to K_2CO_3, water (H_2O), and elemental nitrogen (N_2). This makes the K_2CO_3 available for further absorption and the water and nitrogen are exhausted.

Because the operation of EMx™ to oxidize CO to CO_2 is similar to the use of an oxidation catalyst, there is effectively no difference between EMx™ and an oxidation catalyst in terms of CO control. Therefore, EMx™ and an oxidation catalyst may be treated as the same technology for CO control.

3.4 STEP 3. Rank the Technically Feasible Control Technologies.

Based on the above analysis, the use of Good Combustion Practices (GCP), including water injection, and the use of oxidation catalysts as a post combustion control system are technically feasible control options. Given that the lowest BACT emission limit identified cannot be achieved at loads less than 70%, and that the Ocotillo GTs must operate over a wide range of loads from 25% to 100% of the rated turbine capacity, Table B3-3 summarizes the technically feasible CO control technologies and expected achievable emission rates for these GTs.

TABLE B3-3. Achievable emission rates for technically feasible CO control technologies.

Control Option	Emission Rate, ppmdv at 15% O_2	Averaging Period
Good Combustion Practices plus Oxidation Catalysts	6.0	3-hour
Good Combustion Practices	20.0	3-hour

3.5 STEP 4. Evaluate the Most Effective Controls.

The use of good combustion practices in combination with oxidation catalysts would achieve the greatest reductions in CO (and VOC) emissions. Although the use of oxidation catalysts would achieve the greatest reductions in CO (and VOC) emissions from these GTs, the use of oxidation catalysts would increase operating costs and reduce the thermal efficiency of these GTs by increasing auxiliary power requirements and by increasing back pressure against the GT exhaust which reduces power output. However, the reduced power output is expected to be less than 1% of the gross output of these GTs.

3.6 STEP 5. Proposed Carbon Monoxide (CO) BACT Determination.

Based on this analysis, APS has concluded that the use of good combustion practices (water injection) in combination with the use of oxidation catalysts represents the best available control technology (BACT) for the control of CO emissions from the proposed GE LMS100 simple-cycle gas turbines. APS proposes the following limits as BACT for the control of CO emissions from the GTs:

1. Carbon monoxide (CO) emissions may not exceed 6.0 parts per million, dry, volume basis (ppmdv), corrected to 15% O_2, based on a 3-hour average, when operated during periods other than startup/shutdown and tuning/testing mode.

Chapter 4. GT Nitrogen Oxides (NO_x) Control Technology Review.

Based on the PSD and NANSR applicability analysis in Chapter 4 of the construction permit application, the proposed Project will not trigger either PSD BACT or NANSR LAER requirements. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of nitrogen oxides (NO_x). Based on the emission limits in this application, the proposed new GTs would have maximum daily NO_x emissions (based on continuous, full load operation of all 5 GTs combined) in excess of these thresholds. Therefore, these GTs are subject to Rule 241, Section 301.1 and a BACT analysis has been performed.

In accordance with Maricopa County Air Quality Department's memorandum "REQUIREMENTS, PROCEDURES AND GUIDANCE IN SELECTING BACT and RACT", revised July, 2010, section 8, "To streamline the BACT selection process, the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above." The following is an analysis of recent NO_x BACT determinations in California. APS proposes a BACT level which reflects these NOx BACT determinations.

Nitrogen oxides (NO_x) consist of both nitrogen oxide (NO), and nitrogen dioxide (NO_2). During combustion, NO usually accounts for about 90% of the total NO_x emissions. However, since NO is converted to NO_2 in the atmosphere, the mass emission rate of NO_x is usually reported as NO_2.

NO_x is formed during combustion by two major mechanisms; thermal formation ("Thermal NO_x"), and fuel formation ("Fuel NO_x"). Thermal NO_x results from the high temperature oxidation of nitrogen (N_2) and oxygen (O_2). In this mechanism, N_2 is supplied from air, which is 78% N_2 by volume. Thermal NO_x formation increases exponentially with temperature, becoming significant at temperatures above 2800 °F. Fuel NO_x results from the oxidation of organic nitrogen compounds in the fuel. Because fuel bound nitrogen is more easily converted to NO_x during combustion, nitrogen levels in fuel have a significant impact on NO_x formation. However, since natural gas has only trace organic nitrogen compounds, thermal NO_x is the primary source of NO_x emissions from natural gas-fired gas turbines.

4.1 BACT Baseline.

4.1.1 Standards of Performance for Stationary Gas turbines, 40 CFR Part 60, Subpart KKKK.

The standards of performance for stationary gas turbines under 40 CFR Part 60, Subpart KKKK regulate emissions from these GTs and are incorporated by reference in County Rule 360 § 301.84. Each of the proposed new natural gas-fired GE Model LMS100 simple cycle gas turbines has a maximum design heat input capacity of 970 mmBtu per hour. The applicable standards in 40 CFR Part 60, Subpart KKKK, Table 1 are summarized below.

Excerpts from Table 1 to 40 CFR Part 60, Subpart KKKK: NO_x emission limits for new stationary gas turbines.

Gas turbine type	Gas turbine heat input at peak load (HHV)	NO_x emission standard
New, modified, or reconstructed turbine firing natural gas.	Greater than 850 mmBtu/hr	15 ppm at 15 percent O_2 or 0.43 lb/MWh

4.2 BACT Control Technology Determinations.

Table B4-1 is a summary of NO_x emission limits for similar simple cycle gas turbines. These facilities and emission limits are from the South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Air Quality District (SJVACD), the Bay Area Air Quality Management District (BAAQMD), and the U.S. EPA's RACT/BACT/LAER Clearinghouse. The most stringent NO_x emission limit for similar simple cycle gas turbines is 2.5 ppmdv at 15% O_2, based on a 1-hour average.

It is important to limit the review of BACT limits to similar sized simple-cycle gas turbines. Combined cycle GTs are not feasible for the Ocotillo Modernization Project because combined cycle GTs would not meet the basic purpose and need of the Project for peaking generation (see additional discussion in Section 7.5.2.3).

4.3 Available Control Technologies.

Recent BACT determinations from the U.S. EPA's RACT/BACT/LAER Clearinghouse and the review of literature indicates four major control technologies used to control NO_x emissions:

1. Good Combustion Practices (GCP), including:
   a) Steam injection (SI),
   b) Dry low NO_x (DLN) combustion, and
   c) Water Injection (WI)
2. Selective Catalytic Reduction (SCR), including hot SCR
3. EMx™ Catalytic Absorption process (EMx or SCONOx™)
4. Selective non-catalytic reduction (SNCR).

With respect to steam injection, as previously noted in Section 3.2 the combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs. Therefore, steam injection is not an available control option for the LMS 100 GTs and may be eliminated as a control technology option.

Dry Low NO_x (DLN) combustion is available for the LMS100 GTs and under certain operating conditions can achieve the same NOx emission rate as water injection, equal to a GT exhaust prior to the SCR systems of 25 ppmdv at 15% O_2. However, while water injected LMS100 GTs can achieve the NO_x emission rate of 25 ppm continuously down to 25% of load, the DLN equipped units cannot achieve this NO_x emission rate at loads below 50% of load. Furthermore, the DLN equipped GTs produce much more carbon monoxide (CO) and other products of incomplete combustion than the water injected GTs. As a result, the DLN equipped GTs can only meet the CO BACT emission limit down to 75% load, while the water injected GTs can also achieve the CO BACT limit continuously down to 25% of load. Because a GT turndown to 25% load is a major design criterion for the Project, utilizing DLN would require changing the basic purpose and design of the facility, and is therefore properly dismissed under Step 1 as redefining the source. In addition, the significant lack of turndown capability for the DLN equipped GTs makes the DLN equipped LMS100 GTs technically infeasible for these peaking units. Therefore, even if DLN were retained in Step 1, DLN would be dismissed under Step 2 as technically infeasible.

DLN equipped LMS100 GTs also have a lower peak electric generating capacity than the water injected units. The peak electric output at 105 ^oF is reduced significantly; from 109.9 MW (gross) for the water injected GTs to only 97.2 MW for the DLN equipped GTs. This is a significant reduction in peak generating and ramping capacity which directly affects the ability of the project to meet its basic design requirements, another reason for dismissal under Step 1 of BACT.

Since 2013, three peaking power plants consisting of 19 water-injected LMS 100 simple cycle GTs have commenced commercial operation in California. These plants include the Walnut Creek Energy Park (City of Industry, 5 units), the CPV Sentinel Energy Project (Riverside County, 8 units), and the Haynes Generating Station Repowering Project (6 units). Water injection was concluded to represent BACT for all of these GTs. In 2013, a water-injected LMS100 GT also commenced commercial operation at El Paso Electric Company's Rio Grande Power Plant in Sunland Park, New Mexico (this unit does not appear to be subject to PSD review). In addition, the Pio Pico Energy Center (San Diego County) received a PSD construction permit for 3 water-injected LMS 100 simple cycle GTs in 2013. The water-injected LMS 100 GTs have been selected as BACT for these peaking power plants because of their very high efficiency when operating in simple cycle mode, their fast start times, high turndown rates, flexible operation, and high peak electric output, especially under high ambient temperature conditions. Therefore, the water-injected LMS 100 GT is an available control option that is demonstrated, available and technically feasible for these proposed peaking duty GTs.

As noted in the CO control technology review, catalytic combustors have not been commercialized for industrial gas turbines. We are not aware of any technologies commercially available for large industrial turbines, and General Electric does not supply the LMS100 turbines with catalytic combustors. Therefore, this technology is also not technically feasible for these GTs.

TABLE B4-1. Recent NO_x BACT limits for simple-cycle, natural gas-fired gas turbines.

Facility	State	Permit Date	Control	NO_X Limit, ppm at 15% O_2	Averaging Period
Pio Pico Energy Center	CA	Nov 2012	WI and SCR	2.5	1-hr
Walnut Creek Energy Park	CA	May 2011	WI and SCR	2.5	1-hr
TID Almond 2 Power Plant	CA	Dec 2010	WI and SCR	2.5	1-hr
PSEG Kearny Gen. Station	NJ	Oct 2010	SCR	2.5	
Howard Down Station	NJ	Sep 2010	SCR	2.5	
Canyon Power Plant	CA	Mar 2010	WI and SCR	2.5	60 min
El Cajon Energy	CA	Dec 2009	WI and SCR	2.5	1-hr
Orange Grove Energy	CA	Dec 2008	WI and SCR	2.5	1-hr
Miramar Energy Facility II	CA	Nov 2008	WI and SCR	2.5	3-hr
Escondido Energy Center	CA	Jul 2008	WI and SCR	2.5	1-hr
Starwood Power – Midway	CA	Jan 2008	WI and SCR	2.5	1-hr
Panoche Energy	CA	Dec 2007	WI and SCR	2.5	1-hr
Niland Power Plant	CA	Oct 2006	WI and SCR	2.5	1-hr
El Colton	CA	Jan 2003	SCR	3.5	3-hr
Lambie Energy Center	CA	Dec 2002	SCR	2.5	3-hr
CalPeak Power El Cajon	CA	Jun 2001	SCR	3.5	1-hr
Lonesome Creek Gen. Station	ND	Sep 2013	SCR	5	
Pioneer Generating Station	ND	May 2013	SCR	5	
Cheyenne Prairie Gen. Station	WY	Aug 2012	SCR	5	

Footnotes

WI means water injection; SCR means selective catalytic reduction.

4.3.1 Selective Catalytic Reduction (SCR).

Selective Catalytic Reduction (SCR) is a flue gas treatment technique for the reduction of NO_x emissions which uses an ammonia (NH_3) injection system and a catalytic reactor. An SCR system utilizes an injection grid which disperses NH_3 in the flue gas upstream of the catalyst. NH_3 reacts with NO_x in the presence of the catalyst to form nitrogen (gas) and water according to the following equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

Catalysts are substances which evoke chemical reactions that would otherwise not take place, and act by providing a reaction mechanism that has a lower activation energy than the uncatalyzed mechanism. For SCR, the catalyst is usually a noble metal, a base metal (titanium or vanadium) oxide, or a zeolite-based material. Noble metal catalysts are not typically used in SCR because of their very high cost. To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to critical temperature considerations, the NH_3 injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x. Excessive ammonia injection will result in NH_3 emissions, called ammonia slip.

SCR has the capability to make substantial reductions in NO_x emissions. For these simple cycle gas turbines, the use of SCR is expected to reduce NO_x emissions by 80 - 90%. This reduction range would equate to emission rates of 2.5 to 5 ppm.

4.3.2 Selective Non-Catalytic Reduction (SNCR).

In a selective non-catalytic reduction (SNCR) control system, urea or ammonia is injected into boilers where the flue gas temperature is approximately 1,600 °F to 2,100 °F. At these temperatures, urea [$CO(NH_2)_2$] or ammonia [NH_3], reacts with NO_x, forming elemental nitrogen [N_2] and water without the need for a catalyst. The overall NO_x reduction reactions are similar to those for SCR. Multiple injection points are required to thoroughly mix the reagent into the boiler furnace. The limiting factor for a SNCR system is the ability to contact the NO_x with the reagent as the concentration decreases without resulting in excessive ammonia slip, and without excessive ammonia decomposition before the NO_x emissions can be reduced.

SNCR has been widely used in circulating fluidized bed (CFB) boilers where the high alkaline ash loading of the CFB boilers makes 'high dust' loading SCR systems technically infeasible. However, the time and temperature range for SNCR is not compatible with gas turbines. We are not aware of the application of SNCR to any gas turbine either in the U.S. or worldwide. Therefore, SNCR is not a technically feasible control technology for the Paris gas turbines.

4.3.3 EMx™ Catalytic Absorption/Oxidation (formerly SCONOx™).

EMx™ Catalytic Absorption/Oxidation (the second-generation of the SCONOx™ NOx Absorber technology), available through EmeraChem, is based on a proprietary catalytic oxidation and absorption technology. EMx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce NO_x and CO emissions from natural gas fired gas turbines. The catalyst oxidizes carbon monoxide (CO) to carbon dioxide (CO_2), and nitric oxide (NO) to nitrogen dioxide (NO_2). The NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Dilute hydrogen gas is periodically passed across the surface of the catalyst to regenerate the K_2CO_3 catalyst coating. The regeneration cycle converts KNO_2 and KNO_3 to K_2CO_3, water (H_2O), and elemental nitrogen (N_2). This makes the K_2CO_3 available for further absorption and the water and nitrogen are exhausted.

ABB Alstom Power purchased a proprietary technology called SCONOx™ from Goal Line Environmental Technologies. A SCONOx™ system has been in operation since December of 1996 on the 30 MW Sun Law Energy Federal cogeneration plant in Vernon, California. Since August of 1999, SCONOx has been in operation on a 5 MW cogeneration plant at Genetics Institute in Andover, Massachusetts. The Redding Electric Utility in Redding, California installed a SCONOx™ system on a 43 MW combined cycle plant in 2002. ABB Alstom Power subsequently completed design of a scaled-up SCONOx™ system for 100 MW and greater combined cycle gas turbines.

A significant advantage of SCONOx™ is that it does not require ammonia or urea as a reagent. However, SCONOx™ is designed for operation at temperatures of 300 °F to 700 °F. Therefore, SCONOx™ has potential application to combined cycle and cogeneration gas turbines which have lower exhaust gas temperatures than simple cycle CTs. This operating range is too low for the exhaust gas temperatures from the proposed LMS100 gas turbines.

4.4 Proposed NO_x BACT Determination.

APS has concluded that the use of good combustion practices (water injection) in combination with the use of selective catalytic reduction (SCR) represents the best available control technology (BACT) for the control of NO_x emissions from the proposed GE LMS100 simple-cycle gas turbines. This BACT determination is the same as BACT determinations that have been approved by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD.

Based on this analysis, APS proposes the following limits as BACT for the control of NO_x emissions from the new GTs:

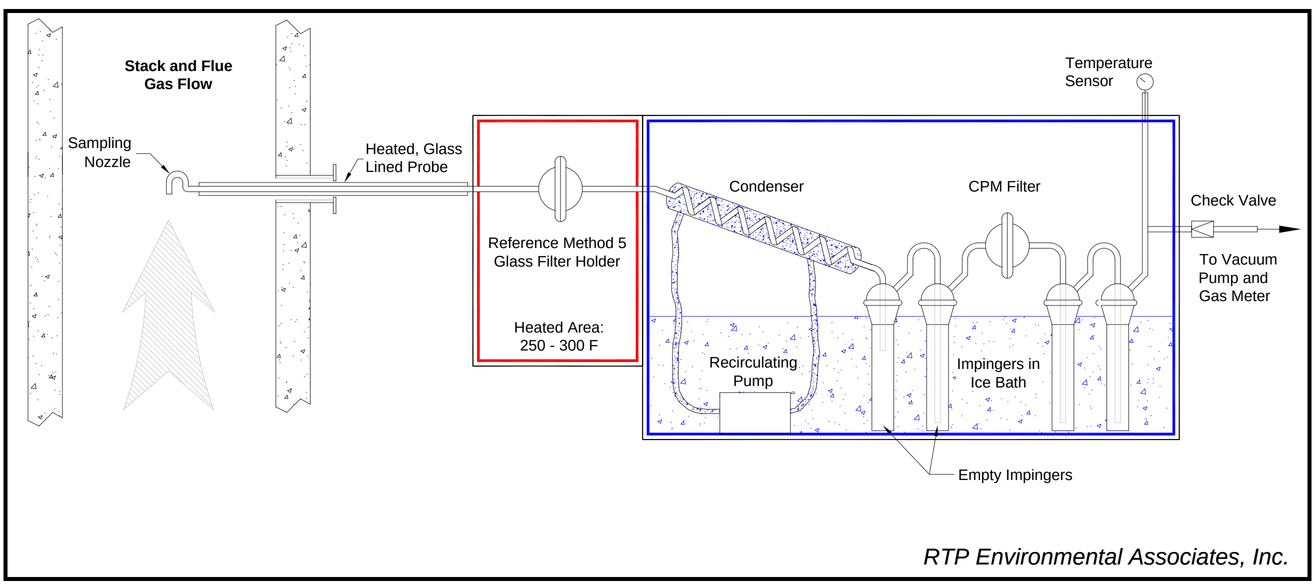
1. Nitrogen oxide (NO_x) emissions may not exceed 2.5 parts per million, dry, volume basis (ppmdv), corrected to 15% O_2, based on a 3-hour average, when operated during periods other than startup/shutdown and tuning/testing mode.

Chapter 5. GT Particulate Matter (PM) and $PM_{2.5}$ Control Technology Review.

Emissions of particulate matter (PM), PM with particle sizes less than 10 microns (PM_{10}), and PM with particle sizes less than 2.5 microns ($PM_{2.5}$) from gas turbines result from PM in the combustion air, from ash in the fuel and injected water, and from products of incomplete combustion. For this analysis, all PM emissions from the GTs are also assumed to be PM_{10} and $PM_{2.5}$ emissions. Since natural gas has virtually no inorganic ash, fuel ash is not a significant source of PM emissions. As a result, the primary sources of PM emissions from these GTs is expected to result from products of incomplete combustion, from solids in the water used for water injection, turbine wear, and particulate matter in the ambient air.

PM which exists as a solid or liquid at temperatures of approximately 250 ^{o}F are measured using U.S. EPA's Reference Method 5 or17 and are commonly referred to as "front half" emissions. PM which exists as a solid or liquid at the lower temperature of 32 ^{o}F are measured using U.S. EPA's Reference Method 202, and is commonly referred to as "back half" or "*condensable*" PM. Condensable PM may include acid gases such as sulfuric acid mist, volatile organic compounds (VOC) and other materials, but does not include condensed water vapor.

FIGURE B5-1. Reference Method 5 and Reference Method 202 sample train.



5.1 BACT Baseline.

There are currently no emission standards for combustion or gas turbines under the New Source Performance Standards.

5.2 STEP 1. Identify All Available Control Technologies.

Table B5-1 is a summary of PM control technologies and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database. Note that of the 32 emission limits from the U.S. EPA's RBLC database summarized in Table B5-1, 23 of the permitted emission limits (72% of the permitted sources) are stated as a mass emission rate, expressed in pounds of PM per hour. The available technologies for the control of PM emissions from natural gas-fired gas turbines identified in this database includes the use of good combustion practices and low ash / low sulfur fuels as the PM control technologies used in practice. Good combustion practices include dry low NO_x (DLN) combustion and water injection.

The following PM and $PM_{2.5}$ control technologies were identified for natural gas-fired gas turbines:

1. Good Combustion Practices, including:
   a. Steam Injection,
   b. Dry Low NO_x (DLN) Combustion, and
   c. Water Injection (WI)
2. Low Ash / Low Sulfur Fuel (i.e., natural gas and/or distillate fuel oil).
3. Post combustion control systems including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, cyclones, and multiclones.

With respect to steam injection, as noted in Section 3.2 the combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs. Therefore, steam injection is not an available control option for the LMS 100 GTs and is therefore eliminated as a control technology option.

Dry Low NO_x (DLN) combustion is available for the LMS100 GTs. However, as previously discussed in Sections 3.2 and 4.3, utilizing DLN would require changing the basic purpose and design of the facility, and is therefore properly dismissed under Step 1 as redefining the source. In addition, the significant lack of turndown capability for the DLN equipped GTs makes the DLN equipped LMS100 GTs technically infeasible for these peaking units, and DLN would also be dismissed under Step 2 as technically infeasible.

Gas turbines are internal combustion engines. Numerous other PM control systems are also available for solid fuel-fired *external* combustion sources such as boilers and process heaters, including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones. However, we are not aware of any examples where these control systems have been applied to natural gas-fired gas turbines. This is because natural gas-fired gas turbines already have very low PM emission rates similar to or even less than the *controlled* emission rates from solid fuel-fired boilers after the use of these post combustion control systems. In addition, the high exhaust gas flowrates and high exhaust gas temperatures from simple cycle gas turbines are not compatible with these PM control technologies intended primarily for solid fuel-fired boilers.

The lowest reported BACT emission limit, stated in equivalent lb/mmBtu, is 0.0049 lb/mmBtu for the Michoud Electric Generating Plant. This proposed unit was a phased combustion turbine project consisting of 175 MW F-class gas turbines which were ultimately intended to operate in combined cycle mode. These turbines were first permitted to operate in simple cycle mode without SCR or oxidation catalysts. Therefore, booth the size of the turbines and the lack of control systems make renders this BACT entry irrelevant to the Ocotillo LMS100 BACT analysis, since SCR and oxidation catalysts are potential sources of PM emissions. Finally, this project was never constructed.

TABLE B5-1. Recent PM BACT limits for simple-cycle, natural gas-fired gas turbines.

Facility	State	Permit Date	Through-put	Unit	Permit Limit, as Stated		Equivalent Limit (calculated) lb/mmBtu
					Limit	Units	
Michoud Electric Gen. Plant	LA	Oct-04	1,595	mmBtu/hr	7.85	lb/hr	0.0049
Pio Pico Energy Center	CA	Feb-14	300	MW	0.0053	lb/mmBtu	0.0053
Goodsprings Compressor Station	NV	May-06	98	mmBtu/hr	0.0066	lb/mmBtu	0.0066
Dayton Power and Light Company	OH	Mar-06	1,115	mmBtu/hr	8.0	lb/hr	0.0072
Sabine Pass LNG Terminal	LA	Dec-11	286	mmBtu/hr	2.1	lb/hr	0.0073
Warren Peaking Power Facility	MS	Jan-03	960	mmBtu/hr	7.0	lb/hr	0.0073
R.M. Heskett Station	ND	Feb-13	986	mmBtu/hr	7.3	lb/hr	0.0074
Bayonne Energy Center	NJ	Sep-09	603	mmBtu/hr	5.0	lb/hr	0.0083
Western Farmers Elec. Anadarko	OK	Jun-08	463	mmBtu/hr	4.0	lb/hr	0.0086
Moselle Plant	MS	Dec-04	1,143	mmBtu/hr	10.0	lb/hr	0.0087
Calcasieu Plant	LA	Dec-11	1,900	mmBtu/hr	17.0	lb/hr	0.0089
SMEPA - Silver Creek Generating	MS	May-03	1,109	mmBtu/hr	10.0	lb/hr	0.0090
Fairbault Energy Park	MN	Jul-04	1,663	mmBtu/hr	0.010	lb/mmBtu	0.0100
Bosque County Power Plant	TX	Feb-09	170	MW	0.010	lb/mmBtu	0.0100
South Harper Peaking Facility	MO	Dec-04	1,455	mmBtu/hr	15.25	lb/hr	0.0105
Rincon Power Plant	GA	Mar-03	172	MW	0.011	lb/mmBtu	0.0110
ODEC - Louisa Facility	VA	Mar-03	1,624	mmBtu/hr	18.0	lb/hr	0.0111
ODEC – Louisa	VA	Mar-03	1,624	mmBtu/hr	18.0	lb/hr	0.0111
ODEC - Louisa Facility	VA	Mar-03	901	mmBtu/hr	10.0	lb/hr	0.0111
ODEC – Louisa	VA	Mar-03	901	mmBtu/hr	10.0	lb/hr	0.0111
Pioneer Generating Station	ND	May-13	451	mmBtu/hr	5.4	lb/hr	0.0120
CPV St Charles	MD	Nov-08			0.012	lb/mmBtu	0.0120
Lonesome Creek Gen. Station	ND	Sep-13	412	mmBtu/hr	5.0	lb/hr	0.0121
Texas Genco Units 1 and 2	TX	Sep-05	550	mmBtu/hr	7.0	lb/hr	0.0127

5.3 STEP 2. Identify Technically Feasible Control Technologies.

The following PM, PM_{10}, and $PM_{2.5}$ control technologies were identified for natural gas-fired gas turbines:

1. Low Ash / Low Sulfur Fuel (i.e., natural gas)
2. Post combustion control systems including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, cyclones, and multiclones.

5.3.1 Low Ash / Low Sulfur Fuel.

PM, PM_{10}, and $PM_{2.5}$ emissions from gas turbines can be affected by ash and inorganic sediments in the fuel, and by the level of sulfur compounds in the fuel. While the inorganic ash and sediments may be emitted directly as particulate matter, sulfur compounds are emitted primarily as sulfur dioxide (SO_2). However, because of the high excess oxygen levels and high temperatures in the exhaust gas of gas turbines, SO_2 may be further oxidized to sulfur trioxide (SO_3). While SO_3 is a gas, SO_3 will spontaneously react with water when temperatures drop below the acid dew point to form sulfuric acid (H_2SO_4). Sulfuric acid mist is condensable PM, and, by definition, it is also a part of the $PM_{2.5}$ emissions.

Regardless of the reaction mechanisms, natural gas is a very low ash and a very low sulfur fuel. In fact, natural gas has the lowest ash and sulfur content of the available fossil fuels.

5.3.2 Post Combustion PM Control Systems.

As noted in Step 1, gas turbines are internal combustion engines. Numerous other PM control systems are available for solid fuel-fired *external* combustion sources such as boilers and process heaters, including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones. However, we are not aware of any examples where these control systems have been applied to natural gas-fired gas turbines. This is because natural gas-fired gas turbines already have very low PM emission rates similar to or even less than the *controlled* emission rates from solid fuel-fired boilers after the use of these post combustion control systems. In addition, the high exhaust gas flowrates and high exhaust gas temperatures from simple cycle gas turbines are not compatible with these PM control technologies intended for solid fuel-fired boilers.

Because there is no evidence that the use of post combustion PM control systems such as fabric filter baghouses could actually reduce the already very low PM emission rates from gas turbines, and because the exhaust gas temperatures from simple cycle CTs are much higher than the maximum design temperatures for these PM control systems, fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones are not technically feasible control technologies for the control of PM emissions from these gas turbines.

5.4 STEP 3. Rank the Technically Feasible Technologies.

Based on the above analysis, the use of low ash and low sulfur containing fuels including natural gas is a technically feasible control option for these gas turbines. The use of this control is expected to achieve a PM, PM_{10}, and $PM_{2.5}$ emission rate in the range of 0.0053 to 0.0066 lb/mmBtu of heat input (the two lowest relevant emission limits listed in Table B4-1).

5.5 STEP 4. Evaluate the Most Effective Controls.

APS proposes to utilize the use of low ash and low sulfur fuel (natural gas) as the best available control technology. Other control options, including post combustion PM control systems, are not available and are technically infeasible control options. Therefore, further evaluation is unnecessary.

5.6 STEP 5. Proposed Particulate Matter (PM), and $PM_{2.5}$ BACT Determination.

APS has concluded that the use of low sulfur fuel (natural gas) represents the best available control technology (BACT) for the control of particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions from the proposed GE LMS100 simple-cycle gas turbines. The lowest emission limits reported in EPA's RACT/BACT/LAER database for simple cycle GTs range from 0.0053 to 0.0066 lb/mmBtu. Using the full load heat input rate for the Ocotillo LMS100 GTs of 970 mmBtu/hr, these reported emission limits range from 5.0 to 6.2 lb/hr.

The lowest report emission limit is for the Pio Pico Energy Center (PPEC), and is based on a recent BACT determination by EPA Region 9. Region 9 originally established the PM_{10} and $PM_{2.5}$ PPEC BACT limit at 0.0065 lb/mmBtu. In response to an Environmental Appeals Board decision, EPA revised their BACT analysis by reviewing the lowest permitted emission limits and recent stack test data for similar sized natural gas-fired CTs. Region 9 considered a number of technical factors with the potential to impact the reliability and usefulness of the stack test data in projecting achievable emissions. EPA noted that there was significant variability in the test data from the three facilities analyzed. In addition, data for two of the three facilities reviewed was from the initial compliance tests on new units, while for the third facility the emission units were only four years old. EPA noted in its analysis that CTs are expected to last more than 20 to 30 years. It is unclear how much PM emissions may vary as the equipment ages and therefore it would be inappropriate to rely only on this emissions data to set a limit that is achievable on an ongoing basis over the life of the equipment. Setting a BACT limit based on limited testing of new units may not address long-term achievable emissions.

EPA's review focused on three facilities that were all located in the same region, and stated that because fuel sulfur content is one of the main contributors to PM emissions from gas turbines, and because the sulfur content in natural gas varies by region, that it was appropriate to use data from the same region in California as the PPEC for setting the PM emission limit. EPA's revised BACT analysis concluded that a BACT emission limit of 0.0055 lb/mmBtu would be appropriate. An emission rate of 0.0055 lb/mmBtu is equal to a mass emission rate of 5.34 lb/mmBtu at the rated heat input of 970 mmBtu per hour for the proposed GTs. However, the applicant requested a BACT limit of 0.0053 lb/mmBtu, which EPA accepted as the final permit limit.

Sulfur in the natural gas will be oxidized to form sulfur dioxide (SO_2), and it may also be oxidized to form sulfur trioxide (SO_3). When the exhaust gas temperature reaches the acid dew point (which will only occur in the atmosphere or in a stack testing reference method sample train), SO_3 will react spontaneously with water to form sulfuric acid (H_2SO_4, $H_2SO_4 \cdot H_2O$, or $H_2SO_4 \cdot 2H_2O$). Sulfuric acid is "condensable" particulate matter which is measured using Reference Method 202 used for determining PM_{10} and $PM_{2.5}$ emissions. In addition, some of the sulfur dioxide in the sample flue gas may dissolve in the Method 202 sample train and eventually react with water to form sulfuric acid mist. This unintended reaction of SO_2 to form condensable particulate matter creates particulate matter which is an artifact of the reference method. In this context "artifact" means something observed (i.e. condensable particulate matter) in a scientific investigation or experiment (i.e., the reference method test) that is not naturally present but occurs as a result of the investigative procedure.

Because the GTs have high excess oxygen levels, and because the GTs will be equipped with oxidation catalysts, it is possible that relatively high percentages of SO_2 may be converted to SO_3. We have estimated a 10% conversion rate on a mass basis, equal to a potential sulfuric acid mist emission rate of 0.06 lb/hr. As noted above, EPA's revised BACT analysis for Pio Pico concluded that a total PM BACT emission limit of 0.0055 lb/mmBtu would be appropriate. An emission rate of 0.0055 lb/mmBtu is equal to a mass emission rate of 5.34 lb/hr at the rated heat input of 970 mmBtu per hour for the proposed GTs. The addition of the estimated Ocotillo sulfuric acid mist emission rate of 0.06 lb/hr to the Pio Pico total PM emission rate results in a total PM emission rate of 5.4 lb/hr.

Given that sulfur content in natural gas fuel varies by region and will also vary over time, and allowing for variability in test results over the long-term operating life of the proposed GTs, APS proposes the following BACT emission limit for the control of particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions from the new GTs:

1. Particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions may not exceed 5.4 pounds per hour (lb/hr), based on a 3-hour average.

Chapter 6. GT Volatile Organic Compound (VOC) Control Technology Review.

Based on the PSD and NANSR applicability analyses in Chapter 4 of the construction permit application, the proposed Project will not trigger BACT or LAER control technology review requirements. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of VOC emissions. Based on the emission limits in this application, the proposed new GTs would have maximum daily VOC emissions in excess of these thresholds. Therefore, the following BACT analysis is being conducted to comply with Maricopa County Rule 241, Section 301.1.

In accordance with Maricopa County Air Quality Department's memorandum "REQUIREMENTS, PROCEDURES AND GUIDANCE IN SELECTING BACT and RACT", revised July, 2010, section 8, "To streamline the BACT selection process, the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above." The following is an analysis of recent VOC BACT determinations in California. APS proposes a BACT level which reflects these VOC BACT determinations.

Like CO emissions, VOC is emitted from simple cycle gas turbines as a result of incomplete combustion. Therefore, the most direct approach for reducing VOC emissions (and also reduce the other related pollutants) is to improve combustion. Incomplete combustion also leads to emissions of organic hazardous air pollutants (HAP) such as formaldehyde. VOC and organic HAP emissions may also be reduced using post combustion control systems including oxidation catalyst systems.

6.1 BACT Baseline.

Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of VOC emissions. Based on the emission limits in this application, the proposed new GTs would have maximum daily VOC emissions of 37 tons per year.

6.2 BACT Control Technology Determinations.

Table B6-1 is a summary of VOC emission limits for similar simple cycle gas turbines. These facilities and emission limits are from the South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Air Quality District (SJVACD), the Bay Area Air Quality Management District (BAAQMD), and the U.S. EPA's RACT/BACT/LAER Clearinghouse. The BAAQMD identifies BACT for POCs of 2.0 ppmdv at 15% O_2. However, several permits that have been issued since 2010 have limits of 3 to 5 ppmdv at 15% O_2.

TABLE B6-1. Recent VOC BACT limits for simple-cycle, natural gas-fired gas turbines.

Facility	State	Permit Date	Control	VOC Limit, ppm at 15% O_2	Averaging Period
Walnut Creek Energy Park	CA	May 2011	OC	2	1-hr
PSEG Kearny Generating Station	NJ	Oct 2010	OC	4	
Sun Valley Energy Project	CA		OC	2	1-hr
El Cajon Energy	CA	Dec 2009	OC	2	1-hr
CPV Sentinel Energy Project	CA		OC	2	1-hr
Escondido Energy Center	CA	Jul 2008	OC	2	1-hr
Dahlberg Combustion Turbine Electric Generating Plant	GA	May 2010	OC	5	
El Colton	CA	Jan 2003	OC	2	
Riverview Energy Center	CA		OC	2	1-hr
Cheyenne Prairie Gen. Station	WY	Aug 2012	OC	3	

Footnotes

OC means oxidation catalyst.

6.3 Available Control Technologies.

Based on this review, the following VOC controls have potential for applicability to these GTs:

1. Good Combustion Practices (GCP), including:
   a) Steam injection (SI)
   b) Dry low NO_x (DLN) combustion, and
   c) Water Injection (WI)
2. Oxidation Catalyst (OC)
3. Catalytic Combustion and Catalytic Absorption/Oxidation (EMx or SCONOx™)

With respect to steam injection, as noted in Section 3.2 the combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs.   Therefore, steam injection is not an available control option for the LMS 100 GTs and is therefore eliminated as a control technology option.

Dry Low NO_x (DLN) combustion is available for the LMS100 GTs. However, as previously discussed in Sections 3.2 and 4.3, utilizing DLN does not meet the basic purpose and design of the facility, and is therefore properly dismissed under Step 1 as redefining the source. In addition, the significant lack of turndown capability for the DLN equipped GTs makes the DLN equipped LMS100 GTs technically infeasible for these peaking units, and DLN DLN would also be dismissed under Step 2 as technically infeasible.Good Combustion Practices.

Good combustion practices including the use of water injection is an effective method for controlling CO and VOC emissions from these gas turbines. Water injection is the most widely used combustion control technology for aero derivative gas turbines and gas turbines with capacities less than 100 MW. The injection of water directly into the turbine combustor lowers the peak flame temperature and reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (e.g., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

A significant advantage of water injection for these simple cycle gas turbines is the ability to achieve higher peak power output levels with water injection. The use of water injection increases the mass flow through the turbine which increases power output, especially at high ambient temperatures when peak power is often needed from these turbines. This is especially important for these gas turbines because the Ocotillo Power Plant is located in a region with high ambient temperatures.

Since 2013, three peaking power plants consisting of 19 water-injected LMS 100 simple cycle GTs have commenced commercial operation in California. These plants include the Walnut Creek Energy Park (City of Industry, 5 units), the CPV Sentinel Energy Project (Riverside County, 8 units), and the Haynes Generating Station Repowering Project (6 units). Water injection was concluded to represent BACT for all of these GTs. In 2013, a water-injected LMS100 GT also commenced commercial operation at El Paso Electric Company's Rio Grande Power Plant in Sunland Park, New Mexico (this unit does not appear to be subject to PSD review).   In addition, the Pio Pico Energy Center (San Diego County) received a PSD construction permit for 3 water-injected LMS 100 simple cycle GTs in 2013. The water-injected LMS 100 GTs have been selected as BACT for these peaking power plants because of their very high efficiency when operating in simple cycle mode, their fast start times, high turndown rates, flexible operation, and high peak electric output, especially under high ambient temperature conditions. Therefore, the water-injected LMS 100 GT is an available control option that is demonstrated, available and technically feasible for these proposed peaking duty GTs.

6.3.1 Oxidation Catalysts.

For natural gas turbines applications, the lowest CO and VOC emission levels have been achieved using oxidation catalysts installed as post combustion control systems. The typical oxidation catalyst is a rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is typically installed in a reactor with flue gas inlet and outlet distribution plates. CO and VOC react with oxygen

(O_2) in the presence of the catalyst to form carbon dioxide (CO_2) and water (H_2O) according to the following general equations:

$$2CO + O_2 \rightarrow 2CO_2$$
$$2C_nH_{2n+2} + (3n + 1)O_2 \rightarrow 2nCO_2 + (2n+2)H_2O$$

Acceptable catalyst operating temperatures range from 400 – 1,250 °F, with the optimum temperature range of 850 - 1,100 °F. Below approximately 400 ^{o}F, catalyst activity (and oxidation potential) is negligible. This temperature range is generally achievable with simple cycle gas turbines except at low load startup and shutdown conditions. Oxidation catalysts have the potential to achieve approximately 90% reductions in "uncontrolled" CO emissions at steady state operation. VOC reduction capabilities are less, typically 50 to 60% reduction.

6.3.2 Catalytic Combustion.

Catalytic combustion involves the use of a catalyst to reduce combustion temperatures while increasing combustion efficiency. In a catalytic combustor, fuel and air are premixed and passed through a catalyst bed. In the bed, the mixture oxidizes at reduced temperatures. The improved combustion efficiency has the potential to reduce CO formation to approximately 5 ppm, and is expected to also reduce VOC emissions. However, the cooler combustion temperatures would decrease the Carnot efficiency of the turbines, since the efficiency for converting heat into mechanical energy is determined by the temperature difference between heat source and sink. The reduced efficiency is expected to be approximately 15%.

Catalytic combustion has the potential for application to most combustor types and fuels. However, the catalyst has a limited operating temperature and pressure range, and the catalyst has the potential to fail when subjected to the extreme temperature and pressure cycles that occur in simple cycle gas turbines. Commercial acceptance of catalytic combustion by gas turbine manufacturers and by power generators has been slowed by the need for durable substrate materials. Of particular concern is the need for catalyst substrates which are resistant to thermal gradients and thermal shock.[11]

Catalytic combustors have not been commercialized for industrial gas turbines. Much of the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. Catalytica, Inc., (now owned by Renegy) developed Xenon Cool Combustion, a catalytic technology that combusts fuel flamelessly. Other company's such as Precision Combustion Inc. and Catacel™ have patented technologies for catalytic combustors for gas turbines. However, we are not aware of any technologies commercially available for large industrial turbines, and General Electric does not supply the LMS100 turbines with catalytic combustors. Therefore, this technology is not technically feasible for these GTs.

---

[11] R.E. Hayes and S.T. Kolaczkowski, *Introduction to Catalytic Combustion* (Amsterdam: Gordon and Breach Science Publishers, 1997); E.M. Johansson, D. Papadias, P.O. Thevenin, A.G. Ersson, R. Gabrielsson, P.G. Menon, P.H. Bjornbom and S.G. Jaras, "*Catalytic Combustion for Gas Turbine Applications*," Catalysis 14 (1999): 183-235.

6.3.3 EMx™ Catalytic Absorption/Oxidation (SCONOx™).

EMx™ Catalytic Absorption/Oxidation (the second-generation of the SCONOx™ NOx Absorber technology), available through EmeraChem, is based on a proprietary catalytic oxidation and absorption technology. EMx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce NO_x and CO emissions from natural gas fired gas turbines. The catalyst oxidizes carbon monoxide (CO) to carbon dioxide (CO_2), and nitric oxide (NO) to nitrogen dioxide (NO_2). The NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Dilute hydrogen gas is periodically passed across the surface of the catalyst to regenerate the K_2CO_3 catalyst coating. The regeneration cycle converts KNO_2 and KNO_3 to K_2CO_3, water (H_2O), and elemental nitrogen (N_2). This makes the K_2CO_3 available for further absorption and the water and nitrogen are exhausted.

Because the operation of EMx™ to oxidize VOC to CO_2 and water is essentially identical to the use of an oxidation catalyst, there is effectively no difference between EMx™ and an oxidation catalyst in terms of CO and VOC control. Therefore, EMx™ and an oxidation catalyst may be treated as the same technology for VOC control.

6.4 Proposed VOC BACT Determination.

APS has concluded that the use of good combustion practices (water injection) in combination with the use of oxidation catalyst systems (OC) represents the best available control technology (BACT) for the control of VOC emissions from the proposed GE LMS100 simple-cycle gas turbines. This BACT determination is the same as BACT determinations that have been approved by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD.

Based on this analysis, APS proposes the following limits as BACT for the control of VOC emissions from the new GTs:

1. Volatile organic compound (VOC) emissions may not exceed 2.0 parts per million, dry, volume basis (ppmdv), corrected to 15% O_2, based on a 3-hour average, when operated during periods other than startup/shutdown and tuning/testing mode.

Chapter 7. GT Greenhouse Gas (GHG) Emissions Control Technology Review.

On May 13, 2010, the U.S. EPA issued a final “tailoring” rule that establishes requirements for greenhouse gas (GHG) emissions from stationary sources under the Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21. This rule sets thresholds for GHG emissions that establish when permits are required for new stationary sources under the PSD program. The final rule “tailors” the requirements of the PSD program to limit which facilities will be required to obtain PSD permits and meet substantive PSD program requirements for GHG emissions. After January 2, 2011, new major stationary sources that are subject to the PSD permitting program due to potential emissions of a pollutant other than GHGs would be subject to the PSD requirements for GHG emissions. GHG emission increases of 75,000 tons per year or more of total GHG, on a total CO_2 equivalent basis (CO_2e), will need to determine the Best Available Control Technology (BACT) for GHG emissions.

The final rule includes the following regulated GHG emissions:

1. Carbon dioxide (CO_2)
2. Methane (CH_4)
3. Nitrous oxide (N_2O)
4. Hydrofluorocarbons (HFCs)
5. Perfluorocarbons (PFCs)
6. Sulfur hexafluoride (SF_6)

From 40 CFR §98, Table A-1, the global warming potential for these pollutants are:

Name	Global Warming Potential (100 yr.)
1. Carbon dioxide (CO_2)	1
2. Methane (CH_4)	25
3. Nitrous oxide (N_2O)	298

The potential emission rate for each individual greenhouse gas is then multiplied by its global warming potential, and summed to determine the total CO_2 equivalent emissions (CO_2e) for the source.

7.1 Project Operational Requirements.

The purposes for the Project are to provide peaking and load shaping electric capacity in the range of 25 to 500 MW (including quick ramping capability to backup renewable power and other distributed energy sources), to replace the 200MW of peak generation that will be retired at Ocotillo with cleaner units, and to provide an additional 300MW of peak generation to handle future growth. This Project has been reviewed and the Certificate of Environmental Compatibility has been approved by the Arizona Corporation Commission (ACC) after a lengthy public comment period and hearing process.

APS is continuing to add renewable energy, especially solar energy, to the electric power grid, with the goal of achieving a renewable portfolio equal to 15% of APS's total generating capacity by 2025 as mandated by the ACC. However, because renewable energy is an intermittent source of electricity, a balanced resource mix is essential to maintain reliable electric service. As of January 1, 2015, APS has approximately 1,200 MW of renewable generation and an additional 46 MW in development. Within Maricopa County and the Phoenix metropolitan area, APS has about 115 MW of solar power and there is an additional 300 – 400 MW of rooftop Photovoltaic (PV) solar systems.

One of the major impediments to grid integration of solar generation is the variable nature of the power provided and how that variability impacts the electric grid. According to the Electric Power Research Institute (EPRI) study on the variability of solar power generation capacity, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, the total plant output for three large PV plants in Arizona have ramping events of up to 40% to 60% of the rated output power over 1-minute to 1-hour time intervals[12]. Considering only the solar capacity in Maricopa County, the required electric generating capacity ramp rate required to back up these types of solar systems would therefore range from 165 to 310 MW per minute. The actual renewable energy load swings experienced on the APS system have also shown rapid load changes from renewable energy sources of 25 to 300 MW in very short time periods, in agreement with the estimates found in the EPRI study.

To backup the current and future renewable energy resources, the Project design requires quick start and power escalation capability to meet changing power demands and mitigate grid instability caused by the intermittency of renewable energy generation. To achieve these requirements, the project design is based on five General Electric (GE) LMS100 gas-fired simple cycle combustion turbine generators (GTs), which have the capability to meet these design needs while complying with the proposed BACT air emission limits at loads ranging from 25% to 100% of the maximum output capability of the turbines. The proposed LMS100 GTs can provide an electric power ramp rate equal to 50 MW per minute per GT which is critical for the project to meet its purpose. When all 5 proposed GTs are operating at 25% load, the entire project can provide approximately 375 MW of ramping capacity (i.e., from 125 to 500 MW) in less than 2 minutes.

[12] Electric Power Research Institute (EPRI) report, *Monitoring and Assessment of PV Plant Performance and Variability Large PV Systems*, 3002001387, Technical Update, December 2013, conclusion, page 6-1.

7.2 Potential Greenhouse Gas (GHG) Emissions.

GHG emissions from natural gas-fired gas turbines include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The federal *Mandatory Greenhouse Gas Reporting Requirements* under 40 CFR Part 98 requires reporting of greenhouse gas (GHG) emissions from large stationary sources. Under 40 CFR Part 98, facilities that emit 25,000 metric tons or more per year of GHG emissions are required to submit annual reports to EPA. Table C-1 of this rule includes default emission factors for CO_2. The CO_2 emission factor for natural gas combustion is 53.02 kg per mmBtu, equal to 116.6 pounds per million Btu, based on the higher heating value (HHV) of natural gas.

Methane (CH_4) emissions result from incomplete combustion. The federal *Mandatory Greenhouse Gas Reporting rule*, 40 CFR Part 98, Table C-2 lists a methane emission factor for natural gas combustion of 0.001 kg/mmBtu (0.0022 lb/mmBtu). Methane emissions may also result from natural gas fuel leaks which may occur from valves and piping, and also during maintenance and operation of the GTs.

Nitrous oxide (N_2O) emissions from gas turbines result primarily from low temperature combustion. The federal *Mandatory Greenhouse Gas Reporting rule*, 40 CFR Part 98, Table C-2 lists a default N_2O emission factor for natural gas combustion of 0.0001 kg/mmBtu (0.00022 lb/mmBtu).

Potential GHG emissions for each gas turbine based on the proposed operating limits in this permit application are summarized in Tables B7-1, B7-2, and B7-3. From Table B7-3, CO_2 emissions account for more than 99.9% of the total GHG emissions. ***Because CO_2 emissions account for the vast majority of GHG emissions from these gas turbines, this control technology review for GHG emissions will focus on CO_2 emissions.***

7.3 BACT Baseline.

On August 3, 2015, the U.S. EPA announced the final Clean Power Plan which will regulate GHG emissions from new and existing power plants. Under the final *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units* in 40 CFR 60 Subpart TTTT, EPA established standards for newly constructed "base load" and "non-base load" fossil fuel-fired stationary combustion turbines. Subpart TTTT is applicable to combustion turbines with a base load heat input rating greater than 250 MMBtu/hr and the capability of selling more than 25 MW-net of electricity to the grid. The emission limitation for new natural gas-fired base load combustion turbines is 1,000 pounds of CO_2 per MWh of gross energy output, and for non-base load natural gas-fired combustion turbines the limit is a fuel-based heat input standard of 120 pounds of CO_2 per mmBtu of heat input.

In setting the fuel-based standard for non-base load combustion turbines, the EPA concluded that the Best System of Emission Reduction (BSER) is the use of clean fuels (i.e., natural gas with an allowance for a small amount of distillate oil). In selecting this BSER, EPA made the following conclusions:

1. Carbon capture and sequestration (CCS) does not meet the BSER criteria because;

a. The low capacity factors and irregular operating patterns (frequent starting and stopping and operating at part load) of non-base load units make the technical challenges associated with CCS even greater than those associated with base load units.

b. Because the CCS system would remain idle for much of the time while these units are not running, the cost-effectiveness of CCS for these units would be much higher than for base load units[13].

2. High-efficiency natural gas-fired combined cycle (NGCC) units designed for base load applications do not meet any of the BSER criteria for non-base load units because:

   a. Non-base load units need to be able to start and stop quickly, and NGCC units designed for base load applications require relatively long startup and shutdown periods. Therefore, conventional NGCC designs are not technically feasible for the non-base load subcategory.

   b. Non-base load units operate less than 10 percent of the time on average. As a result, conventional NGCC units designed for base load applications, which have relatively high capital costs, will not be cost-effective if operated as non-base load units.

   c. It is not clear that a conventional NGCC unit will lead to emission reductions if used for non-base load applications. As some commenters noted, conventional NGCC units have relatively high startup and shutdown emissions and poor part-load efficiency, so emissions may actually be higher compared with simple cycle technologies that have lower overall design efficiencies but better cycling efficiencies[14].

   d. Because the majority of non-base load combustion turbines operate less than 10 percent of the time, it would be cost-prohibitive to require fast-start NGCC, which have relatively high capital costs compared to simple cycle turbines, as the BSER for all non-base load applications.

3. High-efficiency simple cycle turbines are primarily used for peaking applications.

4. High-efficiency simple cycle turbines often employ aeroderivative designs because they are more efficient at a given size and are able to startup and ramp to full load more quickly than industrial frame designs.

---

[13] Pre-publication version of the Clean Power Plan *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, page 533 of 768.

[14] Pre-publication version of the Clean Power Plan *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, page 533 and 534 of 768.

Under Subpart TTTT, a combustion turbine is classified as a non-base load unit if it supplies less than its *design efficiency* times its *potential electric output* as net electric sales on a 3-year rolling average. These terms are defined as:

> *Design efficiency* means the rated overall net efficiency (e.g., electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (e.g., CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass). Design efficiency shall be determined using one of the following methods: ASME PTC 22 Gas Turbines (incorporated by reference, see §60.17), ASME PTC 46 Overall Plant Performance (incorporated by reference, see §60.17) or ISO 2314:2009 Gas turbines – acceptance tests (incorporated by reference, see §60.17).
>
> *Potential electric output* means 33 percent or the base load rating design efficiency at the maximum electric production rate (e.g., CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10^6 Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 310,000 MWh 12 month potential electric output capacity).
>
> *Base load rating* means the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions. For a stationary combustion turbine, base load rating includes the heat input from duct burners.

The proposed LMS100 GTs have an estimated design heat rate of 7,776 Btu/kWh (LHV) and a gross electric output of 116.2 MW. The baseload rating of each GT is 904 mmBtu/hr (LHV), or 1,002 mmBtu/hr (HHV) at ISO conditions (not at site conditions), and the estimated ISO design efficiency is 43.9%. Therefore, these units meet the applicability requirements for Subpart TTTT. The *potential electric output* for the LMS100 is estimated as:

$$Potential\ electric\ output = 43.9\% \times \left(\frac{904\ mmBtu}{hr}\right)\left(\frac{10^6\ Btu}{mmBtu}\right)\left(\frac{kWh}{3{,}413\ Btu}\right)\left(\frac{MWh}{1{,}000\ kWh}\right)\left(\frac{8{,}760\ hr}{yr}\right)$$

$$Potential\ electric\ output\ = 1{,}018{,}593\ MWh$$

Based on the above estimated values, to be classified as non-baseload units the electric output of each GT must be less than the *design efficiency* (43.9%) times its *potential electric output* (1,018,593 MWh), or approximately 447,162 MWh as net electric sales on a 3-year rolling average. APS is proposing to limit operations of the LMS100 GTs so they are classified as non-baseload gas-fired units. The net electric sales for each LMS100 GT will be limited to no more than the design efficiency times the potential electric output on a 3-year rolling average. The design efficiency and potential electric output will be determined during the initial performance test using the methods referenced in 40 CFR 60 Subpart TTTT.

Since these GTs will be classified as non-baseload gas-fired units, the relevant 40 CFR 60 Subpart TTTT performance standard is the fuel-based heat input standard of 120 pounds of CO_2 per mmBtu of heat input. Compliance with this emission limit can be demonstrated simply by combusting natural gas as the exclusive fuel.

TABLE B7-1. Potential greenhouse gas (GHG) emissions for each GE LMS100 gas turbine during normal operation.

Pollutant		Emission Factor	Heat Input Capacity	Total GHG Emission Factor		Potential to Emit, EACH TURBINE		Fuel Use Limit	Potential to Emit, G3 – G7
		lb/mmBtu	mmBtu/hr	CO_2e Factor[4]	lb/mmBtu	lb/hour	tons/yr	10^6 mmBtu/yr	tons/yr
Carbon Dioxide	CO_2	116.98	970	1	117.0	113,466.8	496,985	18.8	1,012,190
Methane	CH_4	0.002205	970	25	0.0551	53.5	234	18.8	477
Nitrous Oxide	N_2O	0.000220	970	298	0.0657	63.7	279	18.8	568
TOTAL GHG EMISSIONS, AS CO_2e					**117.1**	**113,584.0**	**497,498**		**1,013,235**

TABLE B7-2. Potential greenhouse gas (GHG) emissions for each GE LMS100 gas turbine during periods of startup and shutdown.

Pollutant		GHG Emission Factor	Startup		Shutdown		SU/SD Operation	Potential to Emit	Potential to Emit, G3 – G7
		lb/mmBtu	minutes	lb/event	minutes	lb/event	events/yr	ton/year	tons/yr
Carbon Dioxide	CO_2	116.98	30	42,813.2	11	5,030.0	730	17,463	87,314
Methane	CH_4	0.055	30	20.2	11	2.4	730	8	41
Nitrous Oxide	N_2O	0.066	30	24.0	11	2.8	730	10	49
TOTAL, AS CO_2e		**117.1**		**42,857.5**		**5,035.2**		**17,481**	**87,404**

TABLE B7-3. Total potential greenhouse gas (GHG) emissions for all five proposed GE Model LMS100 gas turbines.

Pollutant		Normal Operation	Startup / Shutdown	TOTAL
Carbon Dioxide	CO_2	1,012,190	87,314	1,099,504
Methane	CH_4	477	41	518
Nitrous Oxide	N_2O	568	49	618
TOTAL, AS CO_2e		972,252	1,013,235	**1,100,640**

Footnotes

1. Potential emissions for each turbine are based on 8,760 hours per year of operation. Potential emissions for all turbines combined are based on an operational limit of 18,800,000 mmBtu per year of natural gas heat input for all five turbines combined.

2. The emission factors for the greenhouse gases, including CO_2, N_2O and CH_4 are from 40 CFR Part 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

7.4 STEP 1. Identify All Potential Control Technologies.

The first step in a top-down BACT analysis is to identify all "available" control options. Available control options are those control technologies or techniques with a practical potential for application to the emissions unit and pollutant being evaluated. Air pollution control technologies and techniques include the application of production process or available methods, systems, controls, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for the affected pollutant.

Table B7-4 is a summary of CO_2 control technologies and emission limits for natural gas-fired simple cycle gas turbines from the U.S. EPA's RACT/BACT/LAER database and other recent permit decisions. Recent BACT emission limits have been expressed on both a pound per megawatt hour of electric output basis (both gross and net output), and also based on mass emission limits expressed in tons per year. The averaging periods for these emission limits are typically long term, 12-month limits. This long term averaging period is also consistent with the proposed standards of performance for CO_2 emissions under 40 CFR 60 Subpart KKKK. The available technologies for the control of CO_2 emissions from recently permitted simple cycle natural gas-fired gas turbines identified in this database includes the use of energy efficient processes.

TABLE B7-4. Recent GHG BACT limits for natural gas-fired simple-cycle gas turbines.

Facility	State	Permit Date	Limit	Units	Averaging Period
Troutdale Energy Center, LLC	OR	Mar-14	1,707	lb CO_2/MWhr (g)	12-month
El Paso Electric Montana Power Station	TX	Mar-14	1,100	lb CO_2/MWhr (g)	5,000 op. hours
EFS Shady Hills LLC	FL	Jan-14	1,377	lb CO_2/MWhr (g)	12-month
Basin Electric Power Coop. Lonesome Creek Gen. Sta.	ND	Sep-13	220,122	ton/year	12-month
Basin Electric Power Coop. Pioneer Generating Station	ND	May-13	243,147	ton/year	12-month
Montana-Dakota Utilities R.M. Heskett Station	ND	Feb-13	413,198	ton/year	12-month
Cheyenne Light, Fuel & Power	WY	Sep-12	1,600	lb CO_2e/MWhr (g)	365 day
Pio Pico Energy Center	CA	Nov-12	1,328	lb CO_2/MWhr (g)	720 op. hours
York Plant Holding, LLC Springettsbury	PA	2012	1,330	lb CO_2e/MWhr (n)	30-day
LADWP Scattergood Generating Station	CA	2013	1,260	lb CO_2e/MWhr (n)	12-month

Footnotes

1. Emission limits expressed on lb CO_2/MWhr (g) means gross electric output; limits based on lb CO_2/MWhr (n) means net electric output.

CO_2 emissions result from the oxidation of carbon in the fuel. When combusting natural gas, this reaction is responsible for much of the heat released in the gas turbine, and is therefore unavoidable. There are four potential control options for reducing CO_2 emissions from these gas turbines:

1. **The use of low carbon containing or lower emitting primary fuels,**
2. **The use of energy efficient processes and technologies, including,**
   a. Efficient simple cycle gas turbine generators,
   b. Combined cycle gas turbines,
   c. Reciprocating internal combustion engine generators,
3. **Good combustion, operating, and maintenance practices,**
4. **Carbon capture and sequestration (CCS) as a post combustion control system.**

As will be demonstrated in the Step 1 analysis, the use of combined cycle GTs would change the project in such a fundamental way that the requirement to use these technologies would effectively redefine the Project. As EPA noted in its guidance, *U.S. EPA, EPA-457/B-11-001, PSD and Title V Permitting Guidance for Greenhouse Gases 26 (Mar. 2011)*, page 26:

> While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.
>
> In assessing whether an option would fundamentally redefine a proposed source, EPA recommends that permitting authorities apply the analytical framework recently articulated by the Environmental Appeals Board. Under this framework, a permitting authority should look first at the administrative record to see how the applicant defined its goal, objectives, purpose or basic design for the proposed facility in its application. The underlying record will be an essential component of a supportable BACT determination that a proposed control technology redefines the source.

7.4.1 Alternative combustion technologies for the combustion turbines.

Combustion turbines may use different combustion technologies to enhance performance or reduce emissions. Combustion technologies for gas turbines include diffusion flame combustion with water injection, diffusion flame combustion with steam injection, and lean premix combustion using dry low NO_x combustion.

7.4.1.1 Steam Injection.

The combustion turbine manufacturer, General Electric (GE) has never built an LMS 100 GT with steam injection (either the single annular combustor (SAC) or the steam injected gas turbine (STIG) variations) and does not currently offer the LMS 100 with these designs. Therefore, steam injection is not an available control option for the LMS 100 GTs and is therefore eliminated as a control technology option[15].

7.4.1.2 Dry Low NO_x Combustion.

Dry Low NO_x (DLN) combustion is available for the LMS100 GTs and under certain operating conditions can achieve the same NOx emission rate as water injection, equal to a GT exhaust prior to the SCR systems of 25 ppmdv at 15% O_2. However, while water injected LMS100 GTs can achieve the NO_x emission rate of 25 ppm continuously down to 25% of load, the DLN equipped units cannot achieve this NO_x emission rate at loads below 50% of load. Furthermore, the DLN equipped GTs produce much more carbon monoxide (CO) and other products of incomplete combustion than the water injected GTs. As a result, the DLN equipped GTs can only meet the CO BACT emission limit down to 75% load, while the water injected GTs can also achieve the CO BACT limit continuously down to 25% of load. Because a GT turndown to 25% load is a major design criterion for the Project, utilizing DLN would require changing the basic purpose and design of the facility, and is therefore properly dismissed under Step 1 as redefining the source. In addition, the significant lack of turndown capability for the DLN equipped GTs makes the DLN equipped LMS100 GTs technically infeasible for these peaking units. Therefore, even if DLN were retained in Step 1, DLN would be dismissed under Step 2 as technically infeasible.

DLN equipped LMS100 GTs also have a lower peak electric generating capacity than the water injected units. The peak electric output at 105 ^oF is reduced significantly; from 109.9 MW (gross) for the water injected GTs to only 97.2 MW for the DLN equipped GTs. This is a significant reduction in peak generating and ramping capacity which directly affects the ability of the project to meet its basic design requirements, another reason for dismissal under Step 1 of BACT.

7.4.1.3 Water Injection.

Good combustion practices including the use of water injection is an effective method for controlling CO and VOC emissions from these gas turbines. Water injection is the most widely used combustion control technology for aero derivative gas turbines and gas turbines with capacities less than 100 MW. The injection of water directly into the turbine combustor lowers the peak flame temperature and reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (e.g., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

---

[15] The GE paper *New High Efficiency Simple Cycle Gas Turbine – GE's LMS100™* which is available at GE's website at http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf is a 2004 paper does indicate steam injection as a potential option. However, this paper preceded the first commercial operating date for an LMS 100 CTG in June 2006. The steam injected units are not available. In an e-mail from Phil Tinne, GE Power & Water, to Scott E McLellan, Arizona Public Service dated May 14, 2015, Mr. Tinne states "I confirm that we have not developed steam injection for the LMS100, either for NOx control or power supplementation, thus it is not on our option list."

A significant advantage of water injection for these simple cycle gas turbines is the ability to achieve higher peak power output levels with water injection. The use of water injection increases the mass flow through the turbine which increases power output, especially at high ambient temperatures when peak power is often needed from these turbines. This is especially important for these gas turbines because the Ocotillo Power Plant is located in a region with high ambient temperatures.

Since 2013, three peaking power plants consisting of 19 water-injected LMS 100 simple cycle GTs have commenced commercial operation in California. These plants include the Walnut Creek Energy Park (City of Industry, 5 units), the CPV Sentinel Energy Project (Riverside County, 8 units), and the Haynes Generating Station Repowering Project (6 units). Water injection was concluded to represent BACT for all of these GTs. In 2013, a water-injected LMS100 GT also commenced commercial operation at El Paso Electric Company's Rio Grande Power Plant in Sunland Park, New Mexico (this unit does not appear to be subject to PSD review). In addition, the Pio Pico Energy Center (San Diego County) received a PSD construction permit for 3 water-injected LMS 100 simple cycle GTs in 2013. The water-injected LMS 100 GTs have been selected as BACT for these peaking power plants because of their very high efficiency when operating in simple cycle mode, their fast start times, high turndown rates, flexible operation, and high peak electric output, especially under high ambient temperature conditions. Therefore, the water-injected LMS 100 GT is an available control option that is demonstrated, available and technically feasible for these proposed peaking duty GTs.

7.4.2 Reciprocating internal combustion engine generators.

If the largest available RICE engines were used for this project, this power plant would need to construct and operate at least twenty eight (28) RICE engines. This would be a more complex power plant to construct and operate, and this many generating units may not actually fit on the plant site. This control technology is further analyzed in Step 2 of the BACT analysis.

7.4.3 Combined cycle gas turbines.

The use of combined cycle gas turbines would change the project in such a fundamental way that the plant could not meet its stated purpose of a peaking power plant. As EPA notes in its GHG BACT guidance, *U.S. EPA, EPA-457/B-11-001, PSD and Title V Permitting Guidance for Greenhouse Gases 26 (Mar. 2011)*, page 26:

> While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.
>
> In assessing whether an option would fundamentally redefine a proposed source, EPA recommends that permitting authorities apply the analytical framework recently articulated by the Environmental Appeals Board. Under this framework, a permitting authority should look first at the administrative record to see how the applicant defined its

> goal, objectives, purpose or basic design for the proposed facility in its application. The underlying record will be an essential component of a supportable BACT determination that a proposed control technology redefines the source.

The Ocotillo Modernization Project is being proposed to provide quick start and power escalation capability over the range of 25 MW to 500 MW to meet changing and peak power demands and mitigate grid instability caused in part by the intermittency of renewable energy generation. Electric utilities primarily use simple-cycle combustion turbines as peaking units, while combined cycle combustion turbines are installed to provide baseload capacity. The proposed LMS 100 GTs can provide an electric power ramp rate equal to 50 MW per minute per GT which is critical for the project to meet its purpose. When all 5 proposed GTs are operating at 25% load, the entire project can provide more than 375 MW of capacity in less than 2 minutes. Combined cycle units cannot provide this very fast response time over a range of 25 MW to 500 MW, which is a design requirement of this Project.

Combined cycle units are unable to respond rapidly to the large swings in generation which can be caused by a sudden drop in generation from renewable energy sources. The long startup time for combined cycle units is incompatible with the purpose of the Project which is to provide quick response to changes in the supply and demand of electricity in which these turbines may be required to startup and shutdown multiple times per day. Therefore, the use of combined cycle GTs is technically infeasible for the Project. This conclusion is consistent with the U.S. EPA Region 9 evaluation and conclusion regarding the technical feasibility of combined cycle units for the Pio Pico Energy Center. This conclusion is also consistent with the U.S. EPA Region 4 conclusion regarding the use of combined cycle units at the EFS Shady Hills Project in which EPA stated, “Based on the short startup and shutdown periods the simple cycle combustion turbines (SCCTs) offer, along with the purpose of the Project, CCCTs were considered a redefinition of the source and therefore, not considered in the BACT analysis.”

Combined cycle GTs have other technical problems which also make them infeasible for this Project. When a combined cycle GT is started from a full stop as is typical for a peaking unit, the GT is simply operating in the simple cycle mode. The large frame GTs typically used in combined cycle applications do not have the high turndown ratio that can be achieved with aero-derivative GTs like the LMS 100. Large frame GTs also have longer startup times. And because the LMS 100 GTs have an intercooler which is not used in large frame GTs, the large frame GTs are not as efficient when operated in simple cycle mode. Therefore, constructing a combined cycle unit and then operating the combined cycle unit as a peaking unit would mean that the combined cycle unit would operate primarily in the simple cycle mode and would result in more GHG emissions than properly constructing the plant using the proposed simple cycle GTs.

Even a fast-start combined cycle GT is only capable of achieving startup within 30 minutes if the unit is already hot. If the unit is not hot, the combined cycle GT may require up to 3½ hours to achieve full load under some conditions. These longer startup times are incompatible with the purpose of the proposed project to provide a rapid response to changes in the supply and demand of electricity. To keep the heat recovery steam generator (HRSG) and the steam turbine at a sufficiently high temperature to allow for quick startup of the GT, the facility would either have to operate continuously (and therefore it would no longer be a peaking facility) or it would have to operate an auxiliary boiler. The auxiliary boiler would need to be operated even when the peaking unit is not in service to keep the unit in hot standby, resulting in additional emissions of GHGs and other pollutants.

For the above reasons, combined cycle GTs are rejected in Step 1 because, as EPA stated in the EFS Shady Hills Project, combined cycle GTs would not meet the basic purpose and need of the Ocotillo Modernization Project and would therefore constitute a redefinition of the source. Nevertheless, combined cycle GTs have also been analyzed in Step 2 of the BACT analysis.

7.4.4 Energy Storage Options.

Several types of energy storage technologies are available including batteries, compressed air energy storage (CAES), liquid air energy storage (LAES), pumped hydro, and flywheels. However, incorporating energy storage into the project is not an available BACT control option because these options would fundamentally redefine the source. In EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[16] issued for a peaking facility to be comprised of reciprocating internal combustion engines (RICE), EPA determined that "energy storage cannot be required in the Step 1 BACT analysis as a matter of law."

Like the Ocotillo Modernization Project, the purpose of the Red Gate project was to provide power for renewables and transmission grid support. EPA determined that "energy storage first requires separate generation and the transfer of the energy to storage to be effective . . . [it] is a fundamentally different design than a RICE resource that does not depend upon any other generation source to put energy on the grid." *Id.* Energy storage could not meet that production purpose for the duration or scale needed. *Id.* at 2-3. As EPA correctly observed, "[t]he nature of energy storage and the requirement to replenish that storage with another resource goes against the fundamental purpose of the facility." *Id.* at 3.

Similarly, in another PSD permit for a peaking facility for the Shady Hills Generating Station consisting of natural gas-fired simple cycle combustion turbines (Jan 2014), EPA also concluded that energy storage would not meet the business purpose of the facility and therefore should not be considered in the BACT analysis. [17]

Even if there were some off-site generation source charging energy storage on the Ocotillo site, and even if it were appropriate to consider energy storage options in Step 1 of the BACT analysis, as explained further below, we are not aware of any available energy storage option that could supply a maximum power output of 500 MW for a potentially extended period of time, which is what this project requires.

---

[16] *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions, PSD-TX-1322-GHG (Nov. 2014), http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-resp2sierra-club.pdfNov%2014 .

[17] Responses to Public Comments, Draft Greenhouse Gas PSD Air Permit for the Shady Hills Generating Station at 10-11 (Jan 2014), http://www.epa.gov/region04/air/permits/ghgpermits/shadyhills/ShadyHillsRTC%20_011314.pdf.

7.4.4.1 Battery Storage.

The largest grid-connected battery storage systems that we are aware of include the 32 MW lithium-ion battery-based Laurel Mountain Wind Farm (W. Virginia) and the 36 MW lead-acid battery-based Notrees Battery Facility (Texas). The Laurel Mountain facility has 8.0 MWh of energy storage (and output); the Notree facility has 9.0 MWh of energy storage. The Ocotillo Project will be designed for a maximum energy output of more than 500 MWh, potentially for extended periods of time. The required electric energy output of the Ocotillo Project is therefore more than 50 times larger than the largest battery storage facilities currently in service. We are not aware of any demonstrated battery storage facilities that can provide the required maximum power capacity of 500 MW for multiple Therefore, the battery storage option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project – to provide between 25 MW to 500 MW of electrical energy as needed[18] on an immediate basis, thereby redefining the source, and under Step 2 because it is not technically feasible at this time to produce up to 500 MW of electrical energy using this method.

7.4.4.2 Liquid air energy storage (LAES).

Liquid air energy storage (LAES), also called cryogenic energy storage (CES), uses low temperature (cryogenic) liquids such as liquid air to store energy. This technology is being developed by Highview Power Storage in the United Kingdom. However, we are not aware of any commercially operating LAES facilities on the electric power output scale of the proposed Ocotillo Power Plant. Therefore, like batteries, the LAES option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project, which is to generate and provide to the grid 25to 500 MW of electricity as needed.

It is important to note that energy storage technologies are not "zero emissions" technologies. The "round trip" energy efficiency of LAES is expected to be 50 – 60%[19]. Therefore, while this technology may have near zero emissions at the site, the technology simply stores energy produced elsewhere. If that energy were produced for example at a natural gas-fired combined cycle facility with a GHG emission rate of 1,000 lb CO_2/MWh, the net emission rate after the LAES storage would be 1,670 to 2,000 lb CO_2/MWh.

---

[18] See the U.S. EPA's *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions PSD-TX-1322-GHG, page 7. http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-final-rtc.pdf. EPA states with respect to the use of batteries as a BACT control option, "Thus, the option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the project – to provide up 225MW of energy for necessary time periods – and it may also be eliminated at Step 2 of the BACT analysis because it does not meet the technical requirements of the project – to provide such power for multiple days."

[19] For example, the document *Liquid Air Energy Storage (LAES): Pilot Plant to Multi MW Demonstration Plant, Highview Power Storage*, LAES technology benefits include "60% efficiency in stand alone mode. Integrates well with other industrial process plant (utilizing waste heat/cold) to enhance performance e.g. 70%+" Note that the Ocotillo Power Plant does not have waste heat/cold available to achieve the higher potential efficiency.

7.4.4.3 Flywheel energy storage (FES).

Flywheel energy storage (FES) uses electric energy input to spin a flywheel and store energy in the form of rotating kinetic energy. An electric motor-generator uses electric energy to accelerate the flywheel to speed. When needed, the energy is discharged by drawing down the kinetic energy using the same motor-generator. Because FES incurs limited wear even when used repeatedly, FES are best used for low energy applications that require many cycles such as for uninterruptible power supply (UPS) applications. Temporal Power, in collaboration with the Ministry of Energy and NRStor developed the first grid-connected flywheel energy storage facility in Ontario, Canada. This is a 2 MW system primarily designed for short term energy balancing on the power grid. We are not aware of larger FES systems installed to date. Therefore, like batteries and LAES, the flywheel energy storage option has not been developed on a scale similar to the Project and may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project.

7.4.4.4 Compressed air energy storage (CAES).

Compressed air energy storage (CAES) stores compressed air in suitable underground geologic structures when off-peak power is available, and the stored high-pressure air is returned to the surface to produce power when generation is needed during peak demand periods. There are two operating CAES plants in the world; a 110 MW plant in McIntosh, Alabama (1991) and a 290 MW plant in Huntorf, Germany (1978). Both plants store air underground in excavated salt caverns produced by solution mining. Other geological structures such as basalt flows may also be feasible CAES geologic formations. However, the Ocotillo Power Plant does not have any suitable geological structures in the vicinity of the plant. Like the other energy storage options, the CAES option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project, and it can also be eliminated at Step 2 of the BACT analysis as technically infeasible.

7.4.4.5 Pumped hydroelectric storage.

Pumped hydroelectric storage projects move water between two reservoirs located at different elevations to store energy and generate electricity. When electricity demand is low, excess electric generating capacity is used to pump water from a lower reservoir to an upper reservoir. When electricity demand is high, the stored water is released from the upper reservoir to the lower reservoir through a turbine to generate electricity. Pumped storage projects have relatively high round trip efficiencies of 70 to 80%. However, there are no available water reservoirs at or near the Ocotillo Power Plant, and water resources in the Phoenix area are scarce. Therefore, this technology is not an “available control option” at the Ocotillo Power Plant and may be eliminated as a BACT option in Step 1 of the BACT analysis.

7.5 STEP 2. Identify Technically Feasible Control Technologies.

Step 2 of the BACT analysis involves the evaluation of the identified available control technologies to determine their technical feasibility. Generally, a control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source. In addition, the technology must be commercially available for it to be considered as a candidate for BACT.

Potential CO_2 controls for these gas turbines include the use of low carbon containing fuels, energy efficient processes and technologies including efficient simple cycle gas turbines, combined cycle gas turbines, reciprocating internal combustion engines, and the use of post combustion control systems, including carbon capture and sequestration (CCS).

7.5.1 Lower Emitting Primary Fuels.

EPA's guidance document "*PSD and Title V Permitting Guidance for Greenhouse Gases*" notes that because the CAA includes "clean fuels" in the definition of BACT, clean fuels which would reduce GHG emissions but do not result in the use of a different primary fuel type or a redesign of the source should be considered in the BACT analysis. Table B7-5 is a summary of the CO_2 emission rate for coal, distillate fuel oil, and natural gas. With respect to the use of lower emitting or low carbon containing "clean" fuels, APS is proposing the use of natural gas as the primary fuel for these GTs. Because natural gas is the lowest CO_2 emitting fossil fuel available for this Project, further evaluation of clean fuels is not necessary.

TABLE B7-5. Potential CO_2 emissions for various fossil fuels.

Fuel	CO_2 Emission Rate, lb/mmBtu
Bituminous Coal	205.9
Subbituminous Coal	213.9
Distillate Fuel Oil	162.7
Natural Gas	116.9

Footnotes

The CO_2 emission rates are from *Mandatory Greenhouse Gas Reporting Requirements* 40 CFR Part 98.

7.5.2 Energy Efficient Processes and Technologies.

The use of energy efficient processes and technologies is a technically feasible CO_2 control option. As stated by the Bay Area Air Quality Management District in the Statement of Basis for the Russell City Energy Center, "The only effective means to reduce the amount of CO_2 generated by (a) fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output." Energy efficient processes and technologies include efficient simple cycle gas turbines, as well as reciprocating internal combustion engines (RICE), and combined-cycle gas turbines.

7.5.2.1 High Efficiency Simple Cycle Gas turbines.

APS is proposing to install five natural gas-fired LMS100 simple cycle GTs for this Project. The LMS100 GTs are among the most efficient, and therefore the lowest CO_2 emitting, simple cycle gas turbines which are commercially available at this time. The LMS100 simple cycle gas turbine generators utilize an aero derivative gas turbine coupled to an electric generator to produce electric energy. A gas turbine is an internal combustion engine which uses air as a working fluid to produce mechanical power and consists of an air inlet system, a compressor section, a combustion section, and a power section. The compressor section includes an air filter, noise silencer, and a multistage axial compressor. During operation, ambient air is drawn into the compressor section where it is compressed and discharged to the combustion section of the turbine where high-pressure natural gas is injected into the turbine and the air/fuel mixture is ignited. Water is also injected into the combustion section of the turbine which reduces flame temperatures and reduces thermal NO_x formation. The heated air, water, and combustion gases pass through the power or expansion section of the turbine which consists of blades attached to a rotating shaft, and fixed blades or buckets. The expanding gases cause the blades and shaft to rotate. The power section of the turbine extracts energy from the hot gases. The power section of the turbine produces the power to drive both the compressor and the electric generator.

To improve efficiency, the LMS100 uses an innovative intercooling system which takes the intermediate pressure air out of the turbine, cools it to an optimum temperature in an external water-cooled heat exchanger (the intercooler), and then redelivers this air to the high-pressure compressor. The near constant stream of low temperature air to the high pressure compressor reduces the work of compression, resulting in a higher pressure ratio (42:1), increased mass flow, and increased power output. This reduced work of compression also improves the overall gas turbine thermal efficiency. The use of the intercooler combined with higher combustor firing temperatures allows the LMS100 to achieve a simple cycle thermal efficiency of approximately 44% at 100% load operation. The result is that the LMS100 GTs are among the most efficient, and therefore the lowest CO_2 emitting simple cycle gas turbines which are commercially available at this time.

7.5.2.2 Reciprocating Internal Combustion Engines.

Reciprocating internal combustion engines (RICE) are well-suited for peaking applications and are technically feasible for the proposed Project. RICE engines will be further evaluated in this control technology review.

7.5.2.3 Combined-Cycle Gas turbines.

Combined cycle gas turbines are highly efficient power plants. However, the purpose of this Project is to construct peaking power capacity. The Ocotillo Modernization Project is being proposed to provide quick start and power escalation capability over the range of 25 MW to 500 MW to meet changing and peak power demands and mitigate grid instability caused in part by the intermittency of renewable energy generation. To satisfy the basic purpose of this plant, the peaking units must be able to start quickly even under "cold" start conditions, the units must be able to repeatedly start and stop as needed, and the units must be able to operate at low loads to provide power escalation capacity.

These requirements for the purpose and need for this peaking capacity make combined-cycle gas turbines technically infeasible for this Project because combined cycle GTs cannot meet the rapid startup and shutdown requirements for this peak power capacity. The start-up of a combined-cycle GT is normally conducted in three steps:

1. Purging of the heat recovery steam generator (HRSG),
2. Gas turbine startup, synchronization, and loading, and
3. Steam turbine speed-up, synchronization, and loading.

The third step of the startup process is dependent on the amount of time that the unit has been shut down prior to being restarted. As a result, the startup of a combined cycle GT are often classified as "cold" starts, "warm" starts, and "hot" starts. The HRSG and steam turbine must be started carefully to avoid severe thermal stress which can cause damage to the equipment and unsafe operating conditions for plant personnel. For this reason, the startup time for a combined cycle GT is normally much longer than that of a similarly-sized simple cycle GT. Even with fast-start technology, new combined-cycle units may require more than 3 hours to achieve full load, as compared to approximately 30 minutes to full electric output for the proposed GE Model LMS100 simple cycle gas turbines.

Combined cycle units are unable to respond rapidly to the large swings in generation which can be caused by a sudden drop in generation from renewable energy sources. For example, the Huntington Beach Energy Plant (HBEP) "peaking project" is an example of a fast-start combined cycle plant that can provide peak power. The HBEP is a 939 MW power plant, which is almost twice the size of the proposed Project. HBEP will consist of two power blocks each with a three-on-one configuration, i.e., each power block will have three Mitsubishi turbines, three heat recovery steam generators, and one steam turbine. The HBEP has a maximum ramp rate of 110 MW/minute, or 220 MW for the entire project. This can be compared to the five LMS100s proposed for Ocotillo; when all 5 GTs are operating at 25% load, the project can provide approximately 375 MW of ramping capacity in less than 2 minutes. Therefore, the ramp rate capacity of a fast-start combined cycle project such as the HBEP would not meet the Project needs.

In summary, the long startup time and reduced ramp rate capacity for combined cycle units is incompatible with the purpose of the Project. Therefore, the use of combined cycle GTs is technically infeasible for the Project. This conclusion is consistent with the EPA Region 9 determination for the Pio Pico Energy Center and the EPA Region 4 determination for the EFS Shady Hills Project peaking projects.

7.5.3 Good Combustion, Operating, and Maintenance Practices.

Good combustion and operating practices are a potential control option by improving the efficiency of the any combustion related generating technology, including simple cycle gas turbines and RICE generators.

Good combustion practices include the proper maintenance and tune-up of the combustion turbines or RICE on an annual basis, or more frequent basis, in accordance with the manufacturer's specifications.

7.5.4 Carbon Capture and Sequestration (CCS).

There are three approaches for Carbon Capture and Sequestration (CCS), including pre-combustion capture, post-combustion capture, and oxyfuel combustion[20]. Pre-combustion capture is applicable primarily to fuel gasification plants, where solid fuel such as coal is converted into gaseous fuels. The conversion process could allow for the separation of the carbon containing gases for sequestration. Pre-combustion capture is not technically feasible for this proposed project which is based on natural gas combustion which does not require gas conversion. Oxyfuel combustion is not commercially available for gas turbine applications.

Post-combustion CCS is theoretically applicable for gas turbine power plants. However, in contrast to readily-available high-efficiency simple cycle GT technologies, emerging CCS technologies are not currently commercially available for simple cycle GT projects. There are no current CCS systems currently operating on full-scale power plants in the United States. Under the final *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units* in 40 CFR 60, Subpart TTTT, EPA established standards for newly constructed "base load" and "non-base load" fossil fuel-fired stationary combustion turbines. In setting these standards, EPA stated that there is not sufficient information to determine that CCS is adequately demonstrated for base load natural-gas fired combustion turbines.[21] Further, in setting the fuel-based standard for non-base load combustion turbines, the EPA concluded that the low capacity factors and irregular operating patterns (e.g., frequent starting and stopping and operating at part load) of non-base load units make the technical challenges associated with CCS even greater than those associated with base load units.

A Post Combustion CCS system involves three steps: 1) capturing CO_2 from the emissions unit, 2) transporting the CO_2 to a permanent geological storage site, and 3) permanently storing the gas. Before CO_2 emitted from these gas turbines can be sequestered, it must be captured as a relatively pure gas. CO_2 may be captured from the gas turbine exhaust gas using adsorption, physical absorption, chemical absorption, cryogenic separation, gas membrane separation, and mineralization. Many of these methods are either still in development or are not suitable for treating GT flue gas due to the characteristics of the exhaust stream. The low concentration of CO_2 in natural gas-fired gas turbine applications adds to the challenge of CO_2 capture over coal-fired power plants. The gas turbines proposed for this Project are expected to contain approximately 5 to 6% CO_2 concentration in the flue gas exhaust. This concentration is much lower than coal-fired power plants, where the CO_2 concentration is typically 12 to 15%. As a result, there are a number of serious operational challenges and additional equipment which would be

[20] Intergovernmental Panel on Climate Change (IPCC), 2005.

[21] Pre-publication version of the Clean Power Plan *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, page 527 of 768.

required for these natural gas-fired simple cycle gas turbines used for peaking load operation, because of the highly variable exhaust gas flow and low CO_2 concentration. These challenges and additional equipment would have significant impacts on the operation of these turbines and the ability of these turbines to meet the basic project design requirements to provide peak power capacity. These challenges would also significantly affect the power output, efficiency, and cost of this Project.

Post-combustion carbon capture has been demonstrated on a gas turbine exhaust with a low CO_2 concentration in the exhaust stream at Florida Power and Light's natural gas power plant in Bellingham, MA. As noted in the POWER article, *Commercially Available CO_2 Capture Technology*, Dennis Johnson; Satish Reddy, PhD; and James Brown, PE, (available at www.powermag.com/coal/2064.html), Fluor Corporation has developed an amine-based post-combustion CO_2 capture technology called Econamine FG Plus (EFG+). There are more than 25 licensed plants worldwide that employ the EFG+ technology — from steam-methane reformers to gas turbine power plants.

One of the most significant power applications of this CO_2 removal system is at Florida Power & Light's licensed plant at the Bellingham Energy Center in Bellingham, MA. This plant captures about 365 short tons per day of CO_2 from the exhaust of a natural gas-fired turbine. However, each of the proposed GTs could produce about 6,570 tons of CO_2 per day, or almost 20 times more than the CO_2 capture system at the Bellingham Energy Center. While this technology is available, it has not yet been deployed at a scale that could serve these GTs.

Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology, and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes. Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines. Therefore, MEA is the only carbon capture technology considered in this analysis.

In 2003, Fluor and British Petroleum (BP) completed a joint feasibility study that examined capturing CO_2 from eleven simple cycle gas turbines at BP's Central Gas Facility (CGF) gas processing plant in Alaska (Hurst & Walker, 2005; Simmonds et al., 2003). This project was not actually implemented. The absorption of CO_2 by MEA is a reversible exothermic reaction. To actually capture CO_2 using MEA, the turbine exhaust gas must be cooled to about 50 ^oC (122 ^oF) to improve absorption and minimize solvent loss due to evaporation. In the feasibility study for the CGF, the GT flue gas was to be cooled by a heat recovery steam generator (HRSG) to complete most of the cooling, followed by a direct contact cooler (DCC). Hurst & Walker (2005) found that the DCC alone would be insufficient for the gas turbines due to the high exhaust gas temperature of 480 - 500 ^oC (900 – 930 ^oF). Note that the LMS100 GTs have exhaust gas temperatures of 750 to 840 ^oF. Therefore, to be able to actually capture CO_2 emissions, the exhaust gas would need to be reduced by 630 to 720 ^oF. The only feasible way to achieve this significant temperature reduction is to use a HRSG.

In a carbon capture system, after the MEA is loaded with CO_2 in the absorber, it would be sent to a stripper where it is heated to reverse the reaction and liberate the CO_2. In the CGF facility study, heat for this regeneration stage was to have come from the steam generated in the HRSG, with excess steam to be used to generate electricity. Unfortunately, the integration of a HRSG to the simple cycle CTs would convert the turbines from simple-cycle to combined-cycle operation. As noted above, combined cycle CTs are not technically feasible for the proposed project because of the fast startup times required for the Project. Therefore, while carbon capture with an MEA absorption process may be technically feasible for base load combined-cycle gas turbines, it is not feasible for simple-cycle non-base load GTs. Because combined-cycle GTs are not technically feasible for this Project, CCS is also not technically feasible for this Project.

7.5.5 Conclusions regarding technically feasibility control options.

Table B7-6 is a summary of the technically feasible control technologies for the control of GHG emissions from the proposed gas turbines based on the above analysis.

TABLE B7-6. Summary of the technically feasible GHG control technologies for the turbines.

Control Technology	Technical Feasibility
1. The use of low carbon containing or lower emitting primary fuels,	Feasible
2. The use of energy efficient processes and technologies, including:	
a. Efficient simple cycle gas turbines	Feasible
b. Combined cycle gas turbines	Infeasible
c. Reciprocating internal combustion engines	Feasible
3. Good combustion and operating practices,	Feasible
4. Carbon capture and sequestration (CCS).	Infeasible

7.6 STEP 3. Rank The Technically Feasible Control Technologies.

Based on the above analysis, the following are technically feasible control technologies for the control of GHG emissions from this proposed peak electric generating capacity:

1. The use of low carbon containing or lower emitting primary fuels,
2. Efficient simple cycle gas turbine generators,
3. Good combustion and operating practices,
4. Reciprocating internal combustion engine (RICE) generators.

With respect to the use of lower emitting primary fuels, both GT and RICE generators may use the lowest commercially available carbon containing fuel – natural gas. Therefore, the lowest CO_2 and GHG emitting generating technology will be based on the efficiency of the technology.

Table B7-7 includes detailed performance data for the proposed GE LMS100 GTs. The lowest *guaranteed* design heat rate (i.e., the highest efficiency) for these turbines at 100% load and an ambient temperature of 20 ^{o}F (an unusual operating temperature for these GTs) is 8,711 Btu per kWh of gross electric energy output (Btu/kWh_g). One Btu is equal to 3,413 kWh; therefore, a gross heat rate of 8,711 Btu/kWh_g is equal to an electric efficiency of 39.2% and 1,018 lb CO_2/MWh_g. The estimated actual performance from Table B5-7 at this ambient temperature and site elevation is 8,667 Btu/kWh_g, equal to 39.4% and 1,021 lb CO_2/MWh_g (this is the predicted initial performance before GT performance degradation due to normal operation).

Please note that these efficiency values are based on the *higher heating value* (HHV) of natural gas. The turbine manufacturer's quoted efficiency of approximately 43% at 100% load is based on the *lower heating value* of the fuel, and is also based on the gross output of the turbine without SCR and oxidation catalyst air quality control systems. From Table B5-7, the HHV is 1.109 times the LHV, or approximately 10% higher.

Some natural gas-fired lean burn RICE engines have design heat rates as low as approximately 7,500 Btu/kWh_g again based on the LHV of natural gas, or approximately 8,250 Btu/kWhg based on the HHV. This heat rate is equal to an efficiency of approximately 45.5% (LHV), or 41.4% (HHV). This RICE generator efficiency is equal to a CO_2 emission rate of 964 lb CO_2/MWh_g. The largest natural gas-fired engine currently manufactured has a maximum continuous rating of up to 18.3 MW. However, only one manufacturer currently makes this engine – the Wärtsilä 50SG. It is also important to note that this engine does require a small amount of fuel oil to be combusted even when firing on natural gas. The above CO_2 emission rate is based on 100% natural gas combustion. Other manufacturers such as Caterpillar make natural gas engines of up to approximately 10 MW in size. Therefore, to achieve the same gross electric output, the Project would require from 28 to 50 RICE generators. The existing Ocotillo Generating Station may not have sufficient space for this many RICE generators.

Table B7-8 is a ranking of the technically feasible GHG control technologies based on the above stated efficiencies, heat rates, and CO_2 emission rates for the RICE generators and the GTs.

TABLE B7-8. Ranking of the technically feasible GHG control technologies for the turbines.

Technology	Minimum Heat Rate Btu/kWh_g	Actual CO_2 Emission Rate at the Stated Heat Rate lb/MWh_g
Natural Gas-Fired RICE Engines	8,250	964
Natural Gas-Fired GE LMS100 Gas Turbines	8,667	1,013

TABLE B7-7. Performance data for the General Electric Model LMS100 simple cycle gas turbines at various load and ambient air conditions.

Case #	100	105	110	115	116	121	126	131	228	233	238	243	180	185	190	195	196	201	206	211	212	217	222	227	MAX
Dry Bulb Temperature, °F	20	20	20	20	41	41	41	41	73	73	73	73	105	105	105	105	113	113	113	113	120	120	120	120	120
Wet Bulb Temperature, °F	17	17	17	17	34	34	34	34	57	57	57	57	71	71	71	71	75	75	75	75	78	78	78	78	78
Relative Humidity, %	60	60	60	60	51	51	51	51	37	37	37	37	19	19	19	19	17	17	17	17	15	15	15	15	60
Engine Inlet																									
Conditioning	HEAT	HEAT	HEAT	HEAT	NONE	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	CHILL	NONE	NONE	NONE	
Tons Chill or kBtu/hr Heat	4,203	3,753	3,428	2,868					1,063				2,598				2,605				2,609				4,203
Partial Load, %	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	
Gross Generation, MW	111.3	83.5	55.7	27.8	111.0	83.3	55.5	27.8	109.8	82.3	54.9	27.4	109.9	82.4	54.9	27.5	108.1	81.1	54.0	27.0	106.8	80.1	53.4	26.7	111.3
Gross Generation, kW	111,334	83,505	55,668	27,835	111,000	83,253	55,505	27,752	109,790	82,341	54,892	27,448	109,856	82,392	54,925	27,465	108,071	81,055	54,033	27,018	106,817	80,110	53,403	26,702	111,334
Est. Btu/kW-hr, LHV	7,815	8,215	9,305	12,053	7,831	8,241	9,327	12,089	7,843	8,309	9,389	12,183	7,847	8,387	9,418	12,216	7,878	8,436	9,476	12,303	7,901	8,475	9,520	12,366	12,366
Guar. Btu/kW-hr, LHV	7,854	--	--	--	7,870	--	--	--	7,883	--	--	--	7,886	--	--	--	7,918	--	--	--	7,941	--	--	--	7,941
Est. Btu/kW-hr, HHV	8,667	9,111	10,320	13,367	8,684	9,140	10,344	13,407	8,698	9,215	10,413	13,511	8,702	9,301	10,445	13,547	8,737	9,356	10,509	13,644	8,763	9,398	10,558	13,714	13,714
Guar. Btu/kW-hr, HHV	8,711				8,728				8,742				8,746				8,781				8,807				8,807
Fuel and Water Flow																									
MMBtu/hr, LHV	870	686	518	336	869	686	518	336	861	684	515	334	862	691	517	336	851	684	512	332	844	679	508	330	870
MMBtu/hr, HHV	965	761	574	372	964	761	574	372	955	759	572	371	956	766	574	372	944	758	568	369	936	753	564	366	965
Fuel (Nat Gas) Flow, lb/hr	42,250	33,312	25,152	16,291	42,209	33,320	25,139	16,292	41,814	33,225	25,028	16,237	41,859	33,553	25,122	16,291	41,346	33,203	24,864	16,141	40,985	32,966	24,690	16,035	42,250
Water Flow, lb/hr	27,619	18,990	12,516	6,383	27,568	19,012	12,496	6,371	25,627	17,902	11,670	5,782	25,401	17,433	11,074	5,315	24,415	16,950	10,621	5,014	23,795	16,731	10,379	4,852	27,619
																									0
Exhaust Parameters																									0
Temperature, °F	771	750	794	854	784	766	807	868	787	782	817	878	786	806	824	883	790	811	828	886	793	817	833	890	890
Temperature, °R	311	291	334	394	324	306	347	409	327	322	357	418	327	346	364	423	330	352	368	426	334	358	373	431	431
Exhaust Flow, lb/hr	1,815,959	1,578,099	1,260,994	893,661	1,796,111	1,556,233	1,244,993	882,351	1,779,526	1,525,792	1,227,049	870,908	1,780,587	1,498,024	1,219,368	866,800	1,759,546	1,478,851	1,205,746	858,761	1,743,421	1,463,464	1,194,151	851,480	1,815,959
Exhaust Molecular Weight	16.087	15.952	15.877	15.767	16.107	15.976	15.898	15.787	16.117	16.010	15.923	15.812	16.118	16.056	15.945	15.830	16.122	16.062	15.950	15.834	16.126	16.067	15.956	15.839	16.126
Exhaust Flowrate, ACFM	446,520	365,183	336,861	283,659	458,654	378,508	345,576	290,143	458,630	390,276	349,643	292,588	458,178	409,808	353,494	294,419	457,360	411,213	353,467	293,610	457,995	413,843	354,881	293,967	458,654
Estimated Stack Emissions with Exhaust System in GE Scope of Supply and the Notes Below																									
NO_x ppmvd Ref 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
NO_x, lb/hr	9.3	7.3	5.5	3.6	9.3	7.3	5.5	3.6	9.2	7.3	5.5	3.6	9.2	7.4	5.5	3.6	9.1	7.3	5.5	3.5	9.0	7.2	5.4	3.5	9.3
NH_3 Slip, ppmdv, 15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
NH_3 Slip, lb/hr	6.9	5.4	4.1	2.6	6.9	5.4	4.1	2.6	6.8	5.4	4.1	2.6	6.8	5.4	4.1	2.6	6.7	5.4	4.0	2.6	6.7	5.4	4.0	2.6	6.9
CO ppmvd Ref 15% O2	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
CO, lb/hr	13.5	10.7	8.1	5.2	13.5	10.7	8.1	5.2	13.4	10.6	8.0	5.2	13.4	10.7	8.0	5.2	13.2	10.6	8.0	5.2	13.1	10.6	7.9	5.1	13.5
VOC ppmdv, 15% O2, as C	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
VOC, lb/hr (MW = 14.36)	2.6	2.0	1.5	1.0	2.6	2.0	1.5	1.0	2.6	2.0	1.5	1.0	2.6	2.1	1.5	1.0	2.5	2.0	1.5	1.0	2.5	2.0	1.5	1.0	2.6
PM_{10}, lbs/hr	5.4				5.4				5.4				5.4				5.4				5.4				5.4
CO_2, weight %, wet basis	6.2572	5.6816	5.3711	4.9124	6.3196	5.7619	5.4365	4.9747	6.3187	5.8590	5.4908	5.0225	6.3217	6.0251	5.5456	5.0625	6.3188	6.0394	5.5505	5.0627	6.3215	6.0593	5.5650	5.0724	6.3217
CO_2, lb/hr	113,628	89,661	67,729	43,900	113,507	89,669	67,684	43,894	112,443	89,396	67,375	43,741	112,563	90,257	67,621	43,882	111,182	89,314	66,925	43,476	110,210	88,676	66,455	43,190	113,628
CO_2, lb/mmBtu	117.8	117.9	117.9	118.0	117.8	117.8	117.9	118.0	117.7	117.8	117.9	117.9	117.7	117.8	117.9	117.9	117.8	117.8	117.9	117.9	117.7	117.8	117.9	117.9	118.0
CO_2, lb/MWhr (gross)	1,021	1,074	1,217	1,577	1,023	1,077	1,219	1,582	1,024	1,086	1,227	1,594	1,025	1,095	1,231	1,598	1,029	1,102	1,239	1,609	1,032	1,107	1,244	1,617	1,617
CO_2, lb/MWhr (gross, deg)	1,082	1,138	1,290	1,672	1,084	1,142	1,293	1,677	1,086	1,151	1,301	1,689	1,086	1,161	1,305	1,694	1,091	1,168	1,313	1,706	1,094	1,173	1,319	1,715	1,715

Footnotes

1. Performance data is from General Electric, Engine LMS-100PA, generator BDAX 82-445ERH Tewac 60Hz, 13.8kV, 0.85PF (EffCurve#: 32398; CapCurve#: 34089). Data run conducted on 5/28/2014.
2. All data for elevation of 1,178 ft and pressure of 14.081 (0.95815 atm).
3. Performance and emissions data are based on the following natural gas fuel values: Btu/lb, LHV 20,593 Btu/lb, HHV 22,838 Ratio, HHV to LHV 1.109
4. CO_2 emissions are calculated from GE performance data and were not provided by GE. Emission rates expressed as "deg" are based on a 6% degradation in engine efficiency due to normal operation of the engine.

7.7 STEP 4. Evaluate the Most Effective Controls.

7.7.1 Natural Gas-Fired RICE Engines.

From Table B7-6, the use of RICE engines would have the lowest potential CO_2 emission rate of the technically feasible control options. At the CO_2 emission rates in Table B6-8, the use of these RICE engines may reduce CO_2 emissions by approximately 5% during normal operation, or, based on the proposed limits in this application, by approximately 55,000 tons per year. Note that this is an estimate of the potential reduction in CO_2 emissions. The use of from 28 to 50 RICE engines rather than 5 gas turbine generators may have other issues which could impact the overall efficiency of the power plant and the total CO_2 emissions.

However, while RICE engines may have a relatively small improvement in CO_2 emissions, the use of RICE engines would have other significant environmental impacts. The U.S. EPA has a long standing policy that the use of a control technology may be eliminated if the use of that technology would lead to increases in other pollutants, and that those increases would have significant adverse effects that may outweigh the benefits from the use of that technology. In the U.S. EPA's *New Source Review Workshop Manual*, page B.49, EPA states:

> One environmental impact is the trade-off between emissions of the various pollutants resulting from the application of a specific control technology. The use of certain control technologies may lead to increases in emissions of pollutants other than those the technology was designed to control. For example, the use of certain volatile organic compound (VOC) control technologies can increase nitrogen oxides (NOx) emissions. In this instance, the reviewing authority may want to give consideration to any relevant local air quality concern relative to the secondary pollutant (in this case NOx) in the region of the proposed source. For example, if the region in the example were nonattainment for NOx, a premium could be placed on the potential NOx impact. This could lead to elimination of the most stringent VOC technology (assuming it generated high quantities of NOx) in favor of one having less of an impact on ambient NOx concentrations.

The U.S. EPA's guidance document *PSD and Title V Permitting Guidance For Greenhouse Gases*, November, 2010 recommends that the environmental impact analysis of Step 4 of a GHG BACT analysis should concentrate on impacts other than the direct impacts due to emissions of the regulated pollutant in question. EPA has recognized that consideration of a wide variety of collateral environmental impacts is appropriate in Step 4, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, demand on local water resources, and emissions of other pollutants subject to NSR or pollutants not regulated under NSR such as air toxics. Where GHG control strategies affect emissions of other regulated pollutants, permitting authorities should consider the potential trade-offs of selecting particular GHG control strategies. Permitting authorities have flexibility when evaluating the trade-offs associated with decreasing one pollutant while increasing another, and the specific considerations made will depend on the facts of the specific permit at issue.

In this case, while the use of RICE engines may result in a small reduction in CO_2 emissions, the use of RICE engines would result in a substantial increase in other regulated PSD pollutants, especially NO_x and PM_{10} emissions. The NO_x emission rate representing BACT for RICE engines equipped with selective catalytic reduction (SCR) is typically 5 to 6 ppm. For example, the air permit for Pacific Gas & Electric Company's Humboldt Bay Power Plant in Eureka, California authorized the use of 10 new Wärtsilä 18V50DF16.3 MW lean-burn RICE generators equipped with SCR and oxidation catalysts. This permit was issued in 2009 and limits NO_x emissions to 6.0 ppmdv at 15% O_2, or more than twice the emission concentration for the proposed gas turbines. The use of these engines would increase total potential NO_x emissions for the Project during normal operation by 50 – 100% as compared to the proposed GE LMS100 GTs.

In addition, the permit for these engines at the Humboldt Bay Power Plant also limits PM_{10} emissions to 3.6 lb/hr for each engine. Since each engine is rated at 16.3 MWe, the total RICE generator emissions for an equivalent of 100 MW electric output would be approximately 22 lb/hr, or more than 5 times the proposed limit for each of the LMS100 gas turbines. Thus, the use of these engines would increase total potential PM_{10} and $PM_{2.5}$ emissions for the Project by approximately 142 tons per year, from approximately 58 tons per year, to more than 200 tons per year.

The Ocotillo Power Plant is located in the City of Tempe, Maricopa County, Arizona. The location of the power plant is currently designated nonattainment for particulate matter less than 10 microns (PM_{10}) (classification of serious) and the 1997 and 2008 8-hour ozone standards (classification of marginal). Based on the ozone and PM_{10} nonattainment status of the area, it is appropriate to favor the technology that reduces NO_x and PM_{10} emissions over relatively small and potentially uncertain reductions in GHG emissions, especially when the difference in both NO_x and PM_{10} emissions between the two technologies is so great. EPA Region 9 considered these same types of collateral environmental impacts from RICE generators in Step 4 of the Pio Pico GHG BACT analysis, and concluded that it was appropriate to eliminate RICE engines because of adverse collateral environmental impacts.

In summary, the adverse collateral environmental impacts from the use of RICE generators eliminates this option from further consideration. After the elimination of RICE generators from this GHG control technology review, high efficiency simple-cycle gas turbines represent the top control option.

7.7.2 Carbon Capture and Sequestration.

As stated above in Step 2, CCS is not a technically feasible control option for these simple cycle GTs. However, even if the severe technical feasibility issues could be resolved, CCS is not an economically feasible control technology for these GTs. Regarding economic impacts, in its PSD BACT guidance EPA states[22]:

> EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.

For example, even though the U.S. EPA rejected CCS as a technically infeasible GHG emissions control technology option for the Palmdale Hybrid Power Project, the EPA evaluated the costs of CCS in its Response to Public Comments (October, 2011) (this document is available at http://www.epa.gov/region9/air/permit/palmdale/palmdale-response-comments-10-2011.pdf). The Palmdale Hybrid Power Project is a 570 MW power plant based on approximately 520 MW of natural gas-fired combined cycle units, and 50 MW of solar photovoltaic systems. In the EPA's analysis, the estimated capital costs for the Project are $615-$715 million, equal to an annualized cost of about $35 million. In comparison, the estimated annual cost for CCS for this Project is about $78 million, ***or more than twice the value of the facility's annual capital costs***. Based on these very high costs, EPA eliminated CCS as an economically infeasible control option. The EPA's decision to reject CCS based on these very high annual costs was upheld on appeal by the U.S. EPA's Environmental Appeals Board, PSD Appeal No. 11 -07, decided September 17, 2012.

The Palmdale Hybrid Power Project is similar in size to the Ocotillo Modernization Project, and as was the case for Palmdale, the Ocotillo Project site does not have any nearby carbon sequestration sites available. Therefore, the approximate CCS costs and capital costs for both projects would be similar, and the costs for CCS would again be more than twice the facility's annual capital costs. Therefore, even if the severe technical feasibility issues for the application of CCS to the simple cycle GTs could somehow be resolved, the use of CCS for the Ocotillo Modernization Project is not an economically feasible control technology option for the simple cycle GTs.

---

[22] U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases*, (Mar. 2011), page 42.

7.8 STEP 5. Proposed Greenhouse Gas BACT Determination.

Based on this control technology review, the use of efficient, simple-cycle gas turbines combined with good combustion and maintenance practices represents BACT for the control of GHG emissions from the proposed gas turbine generators. Therefore, BACT will be achieved by the GT design, and by the proper operation and maintenance of the GTs.

7.8.1 Gas Turbine Design Limit.

With respect to the turbine design, the proposed LMS100 GTs are among the most efficient, and therefore the lowest CO_2 emitting simple cycle gas turbines which are commercially available at this time. To achieve this high efficiency design requirement, these gas turbines will be designed to achieve an initial heat rate of at least 8,742 Btu per kilowatt hour of gross electric output based on the HHV of natural gas, at a dry bulb temperature of 73 ^{o}F. This heat rate is based on full load operation with inlet chilling.

7.8.2 Gas Turbine Operating Limit.

7.8.2.1 Operating Limit Based on the Worse-Case Operation.

The BACT emission limit must be achievable at all times and across all load ranges for which these turbines are designed to operate. As stated in the Project Description, the new units need the ability to start quickly, change load quickly, and idle at low load. To provide this capability, the gas turbines will be designed to meet the applicable BACT emission limits for CO, NO_x, PM, PM_{10}, $PM_{2.5}$, SO_2, and VOC emissions at steady state loads as low as 25% of the maximum output capability of the turbines, i.e., 25% load. In fact, based on discussions with the manufacturer, these GTs can be operated as low as 17% loads, but below 25% load the BACT emissions limits for CO, NO_x, PM, PM_{10}, $PM_{2.5}$, SO_2, and VOC emissions would need to be adjusted to be higher.

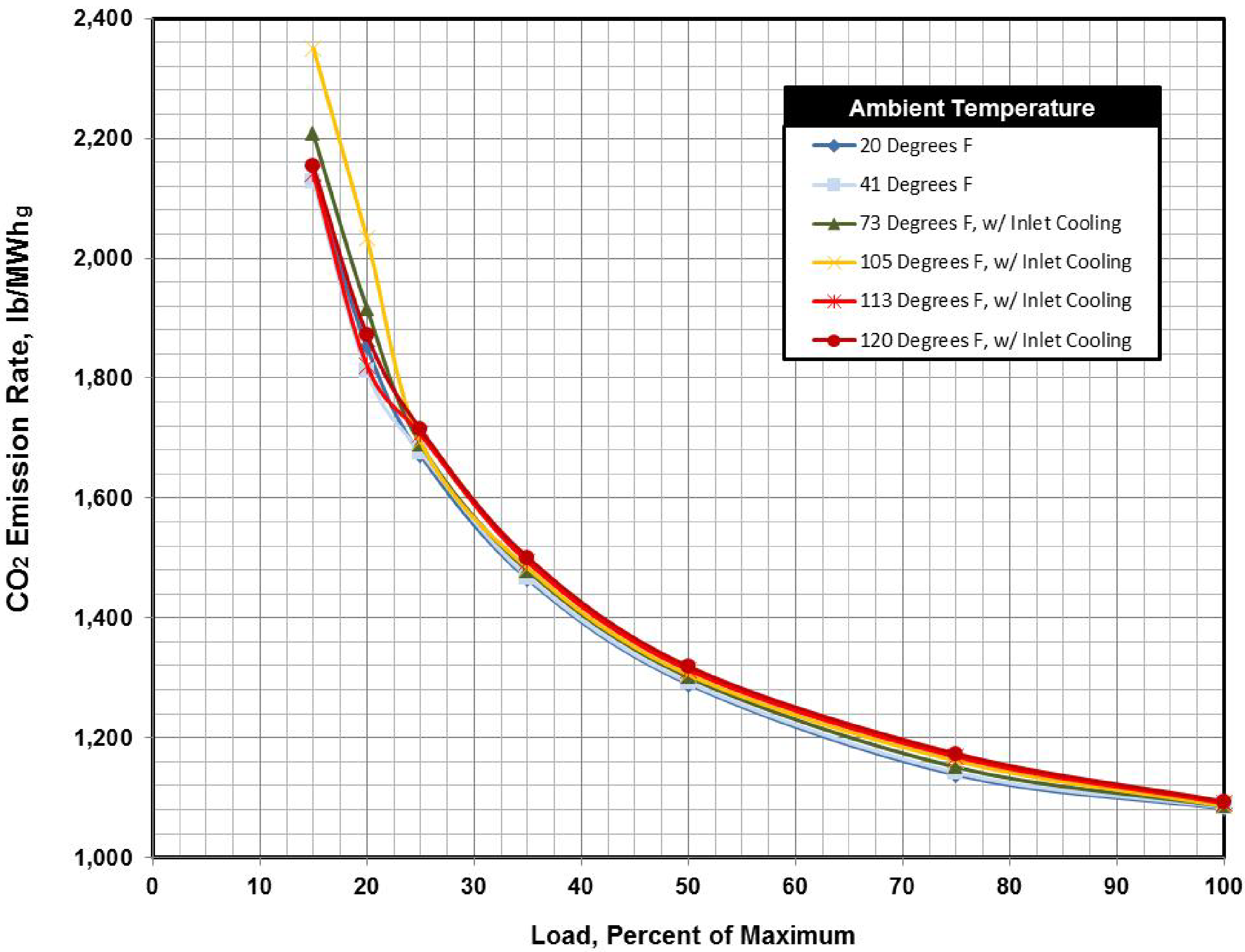
Turbine efficiency decreases and the CO_2 emission rate increases as the turbine load is decreased. In addition, the CO_2 emission rate may vary between gas turbines due to normal variation in the manufacturing process, and even with proper operation and maintenance, the CO_2 emission rate may increase over time due to the normal operation and wear of the GT components. Variation in turbines is expected to about 3%, and degradation in performance due to normal wear is expected to be an additional 3%, which can result in a 6% increase above the design values in Table B6-7.

Table B7-9 is a summary of the expected GT CO_2 emission rate, expressed in pounds of CO_2 per megawatt hour of gross electric output (lb CO_2/MWhg), based on the HHV of natural gas, at five ambient air conditions and across a range of operating loads. The values in Table B7-9 include a 6% increase above the design values. Figure B7-1 shows the relationship of the GT CO_2 emission rate as a function of load at 5 different ambient air temperature conditions. The average annual temperature for Phoenix is approximately 72 ^{o}F. From Table B7-9, at 73 ^{o}F, the CO_2 emission rate increases from 1,086 lb/MWh_g at 100% load, to 1,689 lb/MWh_g at 25% load. The average emission rate at 25% load for all ambient air conditions is 1,690 lb/MWh_g.

TABLE B7-9. Expected CO_2 emission rates for the GE LMS100 GTs at the Ocotillo Power Plant.

Ambient Dry Bulb Temperature	GT Load, % of Maximum Output						
	100%	75%	50%	35%	25%	20%	15%
20 °F	1,082	1,138	1,290	1,465	1,672	1,852	2,130
41 °F	1,084	1,142	1,293	1,468	1,677	1,811	2,128
73 °F, w/ Inlet Cooling	1,086	1,151	1,301	1,479	1,689	1,916	2,207
105 °F, w/ Inlet Cooling	1,086	1,161	1,305	1,483	1,694	2,033	2,350
113 °F, w/ Inlet Cooling	1,091	1,168	1,313	1,493	1,706	1,821	2,140
120 °F, w/ Inlet Cooling	1,094	1,173	1,319	1,501	1,715	1,872	2,153
Average	**1,090**	**1,160**	**1,300**	**1,480**	**1,690**	**1,880**	**2,180**

FIGURE B7-1. Relationship of the GT CO_2 emission rate as a function of load.



EPA Region 9 has provided a framework for addressing the variation of turbine efficiency and resulting GHG emission rate as a function of load in their "Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Pio Pico Energy Center", November 2012. Note that the simple-cycle GTs proposed for the Pio Pico Energy Center are the same units being proposed by APS for this Project. EPA stated that it is not possible to predict the extent of part load operation during every year for the life of the generating facility, and that facilities are designed to meet a range of operating levels. Therefore, EPA stated it is inappropriate to establish a GHG permit limit that prevents the facility from generating electricity as intended. For the Pio Pico PSD permit, EPA determined that the appropriate methodology for setting the GHG BACT emission limit was to set the final BACT limit at a level achievable during the lowest load, "worst-case" normal operating conditions.

7.8.2.2 Operating Limit Based on the Expected Operation.

APS has projected the expected operation of these proposed GTs in the first year of operation (2019) and also in 2023. Using a real-time simulation modeling program (Real Time Simulation), APS projected the expected number of startup and shutdown events per year, and also the expected gross electric generation and load profile. The projected resulting total CO_2 emissions from this analysis for all periods of operation are summarized in Table B7-10. The annual average CO_2 emission rate for the GTs based on the expected operation in 2019 and 2023 and including ALL periods of operation are estimated at 1,460 and 1,450 lb/MWh, respectively. The basis for these emission rates include the following:

1. The CO_2 emission rate at each load level are from Table B7-9. These emission rates are 6% above the design values as described above.
2. The CO_2 emissions for all startup and shutdown (SU/SD) events are based on a 10-minute startup (appropriate for the turbine itself, as compared to the add-on SCR and oxidation catalyst pollution control systems) and a fuel use of 65 mmBtu per SU/SD event. This heat input and the resulting CO_2 emissions are much less than the worse-case emission rate in Table B7-2 which is based on a 30-minute startup time and a total SU/SD heat input of 409 mmBtu.
3. The resulting overall CO_2 emission rate has been increased by 2% to account for potential uncertainties in operating load projections, and to account for startup periods which may exceed 10-minutes in duration.

TABLE B7-10. Expected CO_2 emission rates for the GE LMS100 GTs at the Ocotillo Power Plant based on the projected operation in the Years 2019 and 2023.

Year 2019 Projected Operation[1]	Duaration, % of Total	Emissions, lb/yr	Annual Average Emission Rate, lb/MWh
Startup / Shutdown		1,475,068	
Low Load: ≤ 45%	52%	38,581,804	
Mid Load: >45% ≤ 85%	31%	17,128,839	
High Load: >85% - 100%	17%	8,596,142	
TOTAL	**100%**	**65,781,854**	**1,460**

Year 2023 Projected Operation[1]	Duaration, % of Total	Emissions, lb/yr	Annual Average Emission Rate, lb/MWh
Startup / Shutdown		2,752,447	
Low Load: ≤45%	38%	95,682,509	
Mid Load: >45% ≤85%	30%	42,479,360	
High Load: >85% - 100%	32%	21,318,350	
TOTAL	**100%**	**162,232,666**	**1,450**

Footnotes

1. The projected operation, including the number of startup/shutdown events per year and the gross generation at each load range is from the Real Time (RT) Simulation analysis of expected GT operation.
2. The emission rate for each startup/shutdown event is based on a 10-minute startup event and a fuel use of 43 MMBtu per startup and 22 MMBtu per shutdown for a total of 65 MMBtu per SU/SD event.
3. The CO_2 emission rate at each load level is from Table B7-9.
4. The resulting overall CO_2 emission rate has been increased by 2% to account for potential uncertainties in projecting the worse case operation, and to account for startup periods which may exceed 10-minutes in duration.

7.8.2.3 Proposed Operating Limit.

Based on the above analyses, the operational limit may be based on the level achievable during the lowest load, "worst-case" normal operating conditions. This method was established in the PSD permit for the Pio Pico facility and as upheld by the U.S. EPA EAB. Because the Ocotillo GTs are designed to operate continuously at loads as low as 25% of the maximum load, the lowest achievable BACT emission limit for these GTs based on the average 25% load level is 1,690 lb CO_2/MWh of gross electric output.

The operational limit may also be based on the expected operational loads of the GTs and the resulting expected worse-case emission rate. Based on the above analysis, the expected operation of the GTs would result in an emission rate of 1,460 lb CO_2/MWh of gross electric output including all periods of operation, including periods of startup and shutdown.

Although the operational limit based on the maximum expected operation of the GTs is lower than the limit based on the level achievable during the lowest load, worst-case normal operating conditions, and although APS believes that this higher emission rate is an appropriate BACT limit for these GTs, APS proposes the lower operational limit of 1,460 lb CO_2/MWh of gross electric output as BACT for the control of GHG emissions from these GTs. APS proposes that this limit include all periods of operation, including periods of startup and shutdown.

Because the GHG emission rate varies with ambient air temperatures, and because the operating load will vary not only with the time of day but also the time of year, the averaging period for the GHG BACT limit must be long enough to encompass this variability in operation. A 12-month rolling average basis is consistent with the majority of the CO_2 BACT emission limits, and is also consistent with the final CO_2 emission standard under 40 CFR 60 Subpart TTTT. In the preamble to this proposed rule, EPA stated[23] "This 12-operating-month period is important due the inherent variability in power plant GHG emissions rates." EPA went on to say "a 12-operating month rolling average explicitly accounts for variable operating conditions, allows for a more protective standard and decreased compliance burden, allows EGUs to have and use a consistent basis for calculating compliance (i.e., ensuring that 12 operating months of data would be used to calculate compliance irrespective of the number of long-term outages), and simplifies compliance for state permitting authorities". EPA Region 9 also stated in the Pio Pico response to comments that "EPA believes that annual averaging periods are appropriate for GHG limits in PSD permits because climate change occurs over a period of decades or longer, and because such averaging periods allow facilities some degree of flexibility while still being practically enforceable". For these reasons, APS believes that the operational limit should be based on a 12-month rolling average.

7.8.3 Gas Turbine Maintenance Requirements.

To achieve the proposed BACT emission limits, these gas turbines must be maintained properly to ensure peak performance of the turbines and ensure that good combustion and operating practices are maintained. Therefore, BACT also includes a requirement to prepare and follow a maintenance plan for each turbine. Good gas turbine maintenance practices normally include annual boroscopic inspections of the turbine, generator testing, control system inspections, as well as periodic fuel sampling and analysis. Good gas turbine maintenance practices also includes major GT overhauls conducted as recommended by the manufacturer. The frequency of major overhauls is typically every 25,000 "operating" hours. Because GT startup and shutdowns may consume multiple operating hours for purposes of major overhauls (even though the actual startup or shutdown may only take a fraction of a clock hour), a major overhaul is expected to occur approximately every five years.

[23] Federal Register, Vol. 79, No. 5, January 8, 2014, page 1,481.

7.8.4 Summary of the Proposed GHG BACT Requirements.

Based on this analysis, APS has concluded that the use of efficient simple cycle gas turbines and the use of good combustion practices in combination with low carbon containing fuel (natural gas) represents the best available control technology (BACT) for the control of GHG emissions from the proposed GE LMS100 simple-cycle gas turbines. Based on this analysis, APS proposes the following limits as BACT for the control of GHG emissions from the new GTs:

1. The net electric sales for each LMS100 GT will be limited to no more than the design efficiency times the potential electric output on a 3-year rolling average. The design efficiency and potential electric output will be determined during the initial performance test using the methods referenced in 40 CFR 60 Subpart TTTT.
2. The gas turbines shall achieve an initial heat rate of no more than 8,742 Btu per kilowatt hour of gross electric output at 100% load and a dry bulb temperature of 73 ^{o}F.
3. CO_2 emissions may not exceed 1,460 lb CO_2/MWh of gross electric output for all periods of operation, including periods of startup and shutdown, based on a 12-operating month rolling average.
4. The permittee shall prepare and follow a Maintenance Plan for each GT.

Chapter 8. GT Startup and Shutdown Control Technology Review.

The gas turbine air pollution control systems which represent the best available control technology (BACT) during normal operation, including good combustion practices, water injection, selective catalytic reduction (SCR), and oxidation catalysts, are not operational during the startup and shutdown of the gas turbines.

Water injection is used to reduce NO_x emissions in the diffusion flame combustors of these gas turbines. The earlier that water injection can be initiated during the startup process, the lower NO_x emissions will be during startup. However, if injection is initiated at very low loads, it can impact flame stability and combustion dynamics, and it can increase CO emissions to unacceptable levels. These issues must be carefully balanced when determining when to initiate water injection.

8.1 Startup / Shutdown Event Durations.

The gas turbine air pollution control systems including water injection, selective catalytic reduction (SCR) and oxidation catalysts are not operational during the startup and shutdown of these gas turbines. Water injection is used to reduce NO_x emissions from these GTs before the SCR systems. The earlier that water injection can be initiated during the startup process, the lower NO_x emissions will be during startup. However, if injection is initiated at very low loads, it can impact flame stability and combustion dynamics, and it may increase CO emissions. These concerns must be carefully balanced when determining when to initiate water injection. Oxidation catalysts and SCR pollution control systems are not functional during periods of startup and shutdown because the exhaust gas temperatures are too low for these systems to function as designed.

For simple cycle GTs, the time required for startup is much shorter than gas turbines used in combined cycle applications. The quick startup times for simple cycle GTs help to minimize emissions during startup and shutdown events. For the LMS100 simple cycle GTs, the length of time for a normal startup, that is, the time from initial fuel firing to the time the unit goes on line and water injection begins, is normally about 10 minutes. However, to allow the oxidation catalysts and SCR pollution control systems to become fully operational, and to address complications in startup events, the duration may be up to 30 minutes. The length of time for a normal shutdown, that is, the time from the cessation of water injection to the time when the flame is out, is normally 11 minutes. Therefore, the normal duration for a startup and shutdown cycle or "event" is 41 minutes.

8.2 Proposed Startup and Shutdown Conditions.

Emissions during periods of startup and shutdown may be limited by limiting the duration of each startup and shutdown event, and they may also be limited by limiting the total number of startup and shutdown hours per year. APS has concluded that the following limits represent BACT for the startup and shutdown of these GTs:

1. The duration of a GT startup shall not exceed 30 minutes for each startup event.
2. The duration of a GT shutdown shall not exceed 11 minutes for each shutdown event.
3. "Startup" is defined as the period beginning with the ignition of fuel and ending 30 minutes later.
4. "Shutdown" is defined as the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased.
5. The total number of hours in startup and shutdown mode for all five LMS100 GTs combined shall not exceed 2,490 hours averaged over any consecutive 12-month period.

Chapter 9. Cooling Tower Control Technology Review.

A new mechanical draft cooling tower will be installed as part of the Ocotillo Power Plant Modernization Project. The specifications for the new cooling tower are summarized in Table B9-1. APS is proposing to utilize a hybrid evaporative cooling system with partial dry cooling. Using a hybrid evaporative cooling system with partial dry cooling will reduce the required volume of makeup water and the wastewater discharge volume by approximately 32% as compared to a fully wet cooling system, but will not substantially change the GT output performance as compared to full evaporative cooling. Fully dry cooling systems have significant output penalties as compared to the wet systems.

TABLE B9-1. Specifications for the new mechanical draft cooling tower.

Total Circulating Water Flow to Cooling Tower, gpm	61,500
Number of Cells	6
Maximum Total Dissolved Solids, ppm	8,000
Design Drift Loss, %	0.0005%

9.1 Cooling Tower Emissions.

In a mechanical draft cooling tower, the circulating cooling water is introduced into the top of the tower. As the water falls through the tower, an air flow is induced in a countercurrent flow using an induced draft fan. A portion of the circulating water evaporates, cooling the remaining water. A small amount of the water is entrained in the induced air flow in the form of liquid phase droplets or mist. Demisters are used at the outlet of cooling towers to reduce the amount of water droplets entrained in the air. The water droplets that pass through the demisters and are emitted to the atmosphere are called *drift loss*. When these droplets evaporate, the dissolved solids in the droplet become particulate matter. Therefore, cooling towers are sources of PM, PM_{10}, and $PM_{2.5}$ emissions.

Cooling tower PM emissions are calculated based on the circulating water flow rate, the total dissolved solids (TDS) in the circulating water, and the design drift loss according to the following equation:

$$E = kQ(60\ \text{min/hr})(8.345\ \text{lb water/gal})\left[\frac{C_{TDS}}{10^6}\right]\left[\frac{\%DL}{100}\right] \qquad \textbf{\textit{Equation 1}}$$

Where,

	E	=	Particulate matter emissions, pounds per hour (lb/hr)
	Q	=	Circulating water flow rate, gallons per minute = 61,500 gpm
	C_{TDS}	=	Circulating water total dissolved solids, parts per million = 8,000 ppm
	DL	=	Drift loss, % = 0.0005%
	k	=	particle size multiplier, dimensionless

The particle size multiplier “k” has been added to the basic AP-42 equation to calculate emissions for various PM size ranges, including PM_{10} and $PM_{2.5}$. AP-42 Section 13.4 presents data that suggests the PM_{10} fraction is 1% of the total PM emission rate. There is no information provided on $PM_{2.5}$ emissions.

Maricopa County had developed an emission factor of 31.5% to convert total cooling tower PM emissions to PM_{10} emissions based on tests performed at the Gila Bend Power Plant. During the PSD permitting of the Hydrogen Energy California (HECA) project by the San Joaquin Valley Air Pollution Control District (SJVAPCD), the applicant used an emission factor of 0.6 to convert cooling tower PM_{10} emissions to $PM_{2.5}$ emissions. This factor was based on data contained in the California Emission Inventory Development and Reporting System (CEIDARS) data base, along with further documentation including an analysis of the emission data that formed the basis of the CEIDARS ratio, and discussions with various California Air Resources Board and EPA research staff. This PSD permit was reviewed and commented upon by the California Energy Commission and EPA Region 9, and these agencies accepted this factor for use in cooling tower $PM_{2.5}$ emission estimates.

Table 4 summarizes the PM, PM_{10}, and $PM_{2.5}$ emissions for the cooling tower based on the particle size multipliers of 0.315 for PM_{10} emissions and 0.189 (i.e., 0.315 x 0.6 = 0.189) for $PM_{2.5}$ emissions, based on these multipliers that have been previously approved in PSD permitting actions.

During the PSD permitting of the Hydrogen Energy California (HECA) project by the San Joaquin Valley Air Pollution Control District (SJVAPCD), the applicant used an emission factor of 0.6 to convert cooling tower PM_{10} emissions to $PM_{2.5}$ emissions. This factor was based on data contained in the California Emission Inventory Development and Reporting System (CEIDARS) data base, along with further documentation including an analysis of the emission data that formed the basis of the CEIDARS ratio, and discussions with various California Air Resources Board and EPA research staff. This PSD permit was reviewed and commented upon by the California Energy Commission and EPA Region 9, and these agencies accepted this factor for use in cooling tower $PM_{2.5}$ emission estimates.

Table B9-2 presents the calculated PM, PM_{10}, and $PM_{2.5}$ emissions for the cooling tower, using particle size multipliers of 0.315 for PM_{10} emissions and 0.189 (0.315 * 0.6) for $PM_{2.5}$ emissions, based on these multipliers that have been previously approved in PSD permitting actions.

TABLE B9-2. Potential emissions for the new mechanical draft cooling tower.

POLLUTANT		*Q* Cooling Tower Flowrate	C_{TDS} Blowdown TDS Conc.	%DL Drift Loss	*k* Particle Size Multiplier	Potential to Emit	
		gallon/min	ppm	%		lb/hr	ton/yr
Particulate Matter	PM	61,500	8,000	0.0005%	1.00	1.23	5.39
Particulate Matter	PM_{10}	61,500	8,000	0.0005%	0.315	0.39	1.70
Particulate Matter	$PM_{2.5}$	61,500	8,000	0.0005%	0.189	0.23	1.02

9.2 BACT Baseline.

There are SIP requirements or new source performance standards for this cooling tower.

9.3 Step 1. Identify all available control technologies.

In a review of recently issued permits for new power plants equipped with cooling towers, demisters or mist eliminators are the only identified control technology to limit PM emissions. Demisters can be designed for various levels of drift loss control. The cooling tower drift loss control requirements representing BACT for recently permitted power plants are summarized in Table B9-3. From Table B9-3, the required drift loss control requirements for permits issued since 2007 range from 0.0005% to 0.002%. To reduce drift loss, additional layers of demisters must be installed in the cooling tower. This can make the cooling tower taller and increases the fan horsepower and auxiliary power requirements.

In addition to the use of high efficiency mist eliminators, available plant cooling options include:

1. 100% wet cooling systems which uses only cooling towers or wet surface to air coolers (WSACs),
2. Hybrid evaporative/dry systems using a combination of a cooling tower and air cooled heat exchangers (ACHEs), and
3. 100% dry cooling systems.

All wet systems, including the hybrid systems, have wet cooling towers which are sources of potential PM emissions. Fully dry ACHEs do not use water and can essentially eliminate cooling tower related PM, PM_{10}, and $PM_{2.5}$ emissions. Table B9-4 shows the estimated impacts of the use of 100% wet, hybrid, and 100% dry cooling systems on the performance of the GTs. From Table B9-4, the use of 100% dry cooling would reduce the net plant output at an ambient temperature of 105 ^{o}F by 16.1 MW per GT (a 15% reduction), or a total plant derating of approximately 80 MW. The use of 100% dry cooling would also reduce the GT efficiency and increase GHG emissions per MWh of electric output. At the same temperature, the hybrid system would have a minimal impact on the plant output and efficiency, yet the hybrid system would reduce water consumption by 32%, from 207 gallons per MWh for the 100% evaporative system to 141 gallons per MWh for the hybrid system.

Other possible methods to decrease PM emissions from cooling towers include water treatment methods such as the use of demineralized water. However, demineralizing the makeup water may not significantly change the TDS concentration in the *circulating cooling water*. And because potential PM, PM_{10}, and $PM_{2.5}$ emissions from cooling towers are a function of the circulating water TDS (NOT the makeup water TDS), the use of demineralized makeup cooling water would not affect the maximum potential emissions from the cooling tower. Rather, demineralizing the makeup water would increase the *cycles of concentration* which the cooling tower could operate at, but it would not change the maximum TDS concentration in the circulating cooling water.

TABLE B9-3. Cooling tower BACT requirements for recently permitted power plants.

Facility	Date	State	Drift Loss
Longview Power Plant	Mar. 2014	VA	0.002%
Pio Pico Energy Center	Dec. 2012	CA	0.001%
Consumers Energy Karn Weadock	Dec. 2009	MI	0.0005%
AEP John W. Turk, Jr. Power Plant	Nov. 2008	AR	0.0005%
Santee Cooper - Pee Dee Station	December-07	SC	0.0005%
Seminole Electric - Palatka Unit 3	August-07	FL	0.0005%
Deseret Power Coop - Bonanza	August-07	UT	0.001%
LS Power - Longleaf Energy Center	May-07	GA	0.001%
Southern Montana Electric-Highwood	May-07	MT	0.002%

TABLE B9-4. Estimated GE LMS 100 GT performance at the Ocotillo Power Plant for different types of intercooler cooling systems at 105 oF and with inlet chilling.

Cooling System Design	Gross Output, MW	Net Output, MW	Net Unit Heat Rate, Btu/kWh
100% Dry	92.2	86.2	9,566
100% Wet	107.4	102.4	9,125
Hybrid	107.4	102.2	9,138

9.4 Step 2. Identify the technically feasible control options.

The technically feasible control options include 100% wet, hybrid, and 100% dry cooling systems. However, because the use of 100% wet cooling systems would increase circulating water requirements and PM emissions, they are not considered further in this analysis. As discussed above, 100% dry ACHEs would so dramatically impact the plant output capacity on hot days as to result in redefining the source. Never-the-less, fully dry cooling systems will be considered further in this analysis.

9.5 Step 3. Rank the technically feasible control options.

The only technically feasible control option for wet mechanical draft cooling towers is the use of high efficiency drift eliminators. Therefore, high efficiency drift eliminators are the top ranked control option. The highest level of control commercially available is 0.0005%.

In addition, fully dry ACHEs do not use water and can essentially eliminate cooling tower related PM, PM_{10}, and $PM_{2.5}$ emissions.

9.6 Step 4. Evaluate the most effective controls.

The only feasible control technology for mechanical draft cooling towers is high efficiency drift eliminators. From Table B9-3, the required drift loss control requirements for permits issued in 2007 ranged from 0.0005% to 0.002%. The highest level of control commercially available is 0.0005%.

With respect to the use of 100% dry cooling systems, from Table B9-4, the use of 100% dry cooling would reduce the net plant output at an ambient temperature of 105 ^{o}F by 16.1 MW per GT (a 15% reduction), or a total plant derating of approximately 80 MW. The use of 100% dry cooling would also reduce the GT efficiency and increase GHG emissions per MWh of electric output. This reduction in plant capacity on hot summer days would have a very high cost. The capital and auxiliary power requirements are also much higher for the 100% dry cooling systems. The capital costs for the hybrid system are estimated at $9,888,000 as compared to $13,813,000 for the 100% dry cooling system[24]. To annualize these capital costs, the total capital cost is multiplied by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate
n = control system (project) life, years

For a project life of 25 years and an interest rate of 7%, the CRF is 0.0858 and the annual cost of the additional capital investment is $336,800. If a 100% dry cooling system *eliminated* the hybrid cooling system emissions, the cost effectiveness for the use of 100% dry cooling as a BACT control option – **based only on the additional capital cost -** would be $62,500 per ton of PM controlled, $198,000 per ton of PM_{10} controlled, and $330,000 per ton of $PM_{2.5}$ controlled. These costs do not include the expected much higher lost capacity and energy sales during peak power periods, and these costs do not include the substantially higher auxiliary electric loads required to operate the 100% dry cooling systems. Therefore, the use of 100% dry cooling systems is an economically infeasible BACT control option for the control of PM, PM_{10}, and $PM_{2.5}$ emissions for this Project.

9.7 Step 5. Propose BACT.

Based on this analysis, APS has concluded that the following limits represent BACT for the proposed new cooling tower:

1. The cooling tower drift eliminators shall be designed for a drift loss of no more than 0.0005% of the total circulating water flow.
2. The total dissolved solids (TDS) concentration in wet cooling circulation water may not exceed 8,000 parts per million (ppm) on weight basis.

[24] *Arizona Public Service Company Ocotillo CT 3-7 Expansion Project Cooling System Study*, Kiewit Power Engineers, Project No. 2013-027, Rev 0 – June 6, 2013, page 7-4.

Chapter 10. Emergency Generator Control Technology Review.

The Ocotillo Modernization Project will include the proposed installation of two 2.5 megawatt (MWe) emergency generators powered by diesel (compression ignition) engines. Because these new generators will be used as emergency diesel generators, APS is proposing operational limits for each generator of no more than 100 hours in any 12 consecutive month period. Table B10-1 is a summary of the technical specifications for each emergency generator.

TABLE B10-1. Technical specifications for the proposed new emergency generators.

Generator Standby Rating, kW	2, 500
Engine Type	Diesel (Compression Ingnition)
Engine Power at Standby Output, brake-horsepower	3,750
Engine Displacement, L	78
Engine Cylinders	V-16
Engine Displacement per Cylinder, L	4.88
Maximum Diesel Fuel Consumption Rate, gal/hr	175
Exhaust Gas Flowrate, acfm	15,290
Exhaust Gas Temperature, ^{o}F	752
NOx Emission Controls	None
PM and VOC Emission Controls	None

Footnotes

The maximum generator output rating, fuel consumption rating, emissions, and flowrates are based on the generator standby rating, which is the maximum short term capacity of the generator.

10.1 New Source Performance Standards.

Emissions for the diesel engines are based on the Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60, Subpart IIII, promulgated July, 2006. Under 40 CFR § 60.4202(b)(2), for 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR § 89.112 and 40 CFR § 89.113 for all pollutants:

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

The emission standards under 40 CFR § 89.112 include exhaust emission standards for NOx, CO, hydrocarbons, and particulate matter. The emission standards for engines with a rated power greater than 560 kW (750 hp) in Table 1 for Model Year 2006 and later engines include the following:

Pollutant	Emission Standard		Upper Limit for Engine Family	
	g/kW-hr	g/kW-hr	g/hp-hr	g/hp-hr
NMHC + NO_x	6.4	4.77	10.5	7.83
CO	3.5	2.61	3.5	2.61
PM	0.2	0.15	0.54	0.40

10.2 Emergency Generator Emissions.

With this application, APS is proposing to install diesel generators which comply with the Tier 2 emission standards under 40 CFR § 89.112. These standards are applicable to emergency stationary RICE. Under 40 CFR § 60.4211, an emergency stationary ICE may not operate for more than 100 hours per year, except that there is no limit for emergency operation. Therefore, APS is proposing to limit the operation of each generator to no more than 100 hours per year, based on a 12-month rolling average. The potential emissions for each 2.5 MW diesel-fired emergency electric generator, and for both generators combined, based on these proposed requirements, are summarized in Table B10-2.

TABLE B10-2. Potential emissions for each 2.5 MW generator and for both generators combined.

POLLUTANT		Emission Factor	Power Output	Potential to Emit, Each Generator		Potential to Emit, Both Generators
		g/hp-hr	hp	lb/hr	ton/year	ton/year
Carbon Monoxide	CO	2.61	3,750	21.56	1.08	2.16
Nitrogen Oxides	NO_x	6.90	3,750	56.99	2.85	5.70
Particulate Matter	PM	0.40	3,750	3.30	0.17	0.33
Particulate Matter	PM_{10}	0.40	3,750	3.30	0.17	0.33
Particulate Matter	$PM_{2.5}$	0.40	3,750	3.30	0.17	0.33
Sulfur Dioxide	SO_2	0.0044	3,750	0.037	0.00	0.00
Vol. Org. Cmpds	VOC	0.20	3,750	1.65	0.083	0.17
Sulfuric Acid Mist	H_2SO_4	4.4E-04	3,750	0.0037	0.00	0.00
Fluorides	F	7.9E-04	3,750	0.0065	0.00	0.00
Lead	Pb	2.7E-05	3,750	0.0002	0.00	0.00
Carbon Dioxide	CO_2	476.7	3,750	3,937.7	196.89	393.77
Greenhouse Gases	CO_2e	478.4	3,750	3,951.2	197.56	395.12

Footnotes

1. Potential emissions are based on 100 hours per year of operation for each engine – generator set.
2. The CO, PM, and VOC emission rates are based on the Tier 2 engine standards in 40 CFR §89.112, and a maximum engine rating of 3,750 horsepower. The NO_x emissions are based on the Maricopa Rule 324 emissions limit, which is lower than the Tier 2 family emission limit.
3. All PM emissions are also assumed to be PM_{10} and $PM_{2.5}$ emissions.
4. SO_2 emissions are based on a maximum fuel consumption rate of 175 gal/hr, and a sulfur content of 0.0015%.
5. VOC emissions are based on an estimated NMHC emission rate of 0.2 g/hp-hr.
6. Sulfuric acid mist emissions are based on 10% conversion of SO_2 to SO_3 in the flue gas.
7. Lead and fluoride emissions are based on the emission factor for oil combustion in the *U.S. EPA's Compilation of Air Pollutant Emission Factors, AP-42*, section 1.3, oil combustion, Tables 1.3-10 and 1.3-11., respectively, AND a maximum fuel oil consumption rate of 175 gallons per hour.
8. Emission factors for GHG emissions including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

10.3 Carbon Monoxide (CO) Control Technology Review.

Carbon monoxide (CO) is emitted from diesel engines as a result of incomplete combustion. Therefore, the most direct approach for reducing CO emissions (and also reduce the other related pollutants) is to improve combustion. Incomplete combustion also leads to emissions of diesel particulate matter, volatile organic compounds (VOC) and organic hazardous air pollutants (HAP). CO emissions as well as diesel particulate matter, VOC, and organic HAP emissions may also be reduced using post combustion emission control systems including oxidation catalyst systems. When used on diesel engines, these oxidation catalyst systems are often called diesel oxidation catalysts.

10.3.1 BACT Baseline.

The emergency engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. In accordance with 40 CFR §60.4201, manufacturers of new emergency stationary CI engines must meet the following:

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?
(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.
(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

In addition, in accordance with 40 CFR §60.4207(b), these engines must use diesel fuel that meets the requirements of 40 CFR §80.510(b) for nonroad diesel fuel. The sulfur content requirement for nonroad (NR) diesel fuel in 40 CFR §60.4207(b)(1)(i) is 15 ppm.

The standards are summarized in the table below.

Diesel engine standards under 40 CFR 60, Subpart IIII.

POLLUTANT		Emergency CI Engine Tier 2 Standards	
		g/kWhr	g/hp-hr
Carbon Monoxide	CO	3.5	2.6
Nitrogen Oxides	NO_x	6.4 (10.5)*	4.8 (7.83)*
Particulate Matter	PM	0.20 (0.54)	0.15 (0.40)
Non-Methane Hydrocarbons	NMHC	n/a	n/a

Footnotes

* The NO_x standards for Tier 2 engines are the sum of the NOx and NMHC.
The Tier 2 standards are for engines greater than 750 horsepower (hp). Note that the Tier 2 engine standards also include engine family standards which are indicated in parantheses ().

10.3.2 STEP 1. Identify All Available Control Technologies.

Table B10-3 is a summary of CO emission limits for diesel generators from the U.S. EPA's RACT / BACT / LAER database. From Table B10-3, a total of 10 of the 12 generators identified have the Tier 2 and Tier 4 CO emission limit of 2.6 grams per horsepower hour (g/hp-hr). (The other two units have pound per hour limits. There is insufficient information in the database to determine the equivalent limit expressed in g/hp-hr).

The South Coast Air Quality Management District's LAER/BACT determinations (available at http://www.aqmd.gov/home/permits/bact/guidelines/i---scaqmd-laer-bact) did not have any listed determinations newer than 2003. The Bay Area Air Quality Management District BACT Guideline for diesel-fueled emergency engines with a rating of more than 750 hp, based on the Airborne Toxic Control Measures (ATCMs) promulgated by the California Air Resources Board (CARB) also lists a BACT CO emission limit of 2.6 g/hp-hr. The San Joaquin Valley Air Pollution Control District BACT Guideline, 3.1.1, requires the latest EPA Tier certification level for applicable horsepower range.

Based on this review, Good Combustion Practices (GCP) and Diesel Oxidation Catalysts (DOC) have potential for applicability to these generators.

10.3.3 STEP 2. Identify Technically Feasible Control Technologies.

Good combustion practices and diesel oxidation catalysts are both technically feasible options.

10.3.4 STEP 3. Rank the Technically Feasible Control Technologies.

Based on the above data, the use of Good Combustion Practices (Tier 2) engines, and the use of GCP combined with diesel oxidation catalysts (Tier 4 engines), both can achieve a CO emission rate of 2.6 grams per horsepower hour.

Note that while diesel oxidation catalysts may reduce CO emissions, based on the fact that the Tier 2 and Tier 4 standards have the same CO emission standard, and the fact that engines are designed to meet all emission standards (that is, the engine may have higher uncontrolled CO emissions to reduce uncontrolled NO_x emissions), we cannot conclude that an engine designed to the Tier 4 standard would actually reduce CO emissions from the generator sets as compared to the Tier 2 engine.

TABLE B10-3. Carbon monoxide (CO) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	2.6 g/hp-hr
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	2.6 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		2.6 g/hp-hr
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	2.6 g/hp-hr
CF Industries Nitrogen, LLC - Port Neal	IA	07/12/13	180 gal/hr	2.6 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	17.35 lb/hr
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	2.6 g/hp-hr
Hess Newark Energy Center	NJ	11/01/12	200 hr/yr	11.56 lb/hr
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	2.6 g/hp-hr
Point Thomson Production Facility	AK	08/20/12	1,750 kW	2.6 g/hp-hr
Pyramax Ceramics, LLC	SC	02/08/12	757 hp	2.6 g/hp-hr
Palmdale Hybrid Power Project	CA	10/18/11	2,683 hp	2.6 g/hp-hr

10.3.5 STEP 4. Evaluate the Most Effective Controls.

Because the use of Good Combustion will achieve the required CO emission rate of 2.6 grams per horsepower hour, no further analysis is required.

10.3.6 STEP 5. Proposed Carbon Monoxide (CO) BACT Determination.

Based on this analysis, Arizona Public Service (APS) has concluded that the use of good combustion practices in combination with the use of diesel oxidation catalysts represents the best available control technology (BACT) for the control of CO emissions from the proposed diesel generators. APS proposes the following limits as BACT for the control of CO emissions from the emergency generators:

1. Carbon monoxide (CO) emissions may not exceed the Tier 2 standard under 40 CFR § 89.112 for generator sets manufactured after the 2006 model year of 2.6 g/hp-hr.
2. The operation of each generator may not exceed 100 hours per year.

10.4 Nitrogen Oxides (NO_x) Control Technology Review.

Based on the PSD applicability analysis in Chapter 4 of the construction permit application, the proposed Ocotillo Generation Project will not result in a significant net emissions increase for NO_x emissions. Therefore, the Project is not a major modification for NO_x emissions, and the Project is therefore not subject to the application of BACT under the PSD program. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of nitrogen oxides (NO_x). Therefore, the following BACT analysis is being conducted to comply with Maricopa County Rule 241, Section 301.1.

In accordance with Maricopa County Air Quality Department's memorandum "REQUIREMENTS, PROCEDURES AND GUIDANCE IN SELECTING BACT and RACT", revised July, 2010, section 8, "To streamline the BACT selection process, the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVAPCD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above." The following is an analysis of recent NO_x BACT determinations in California. Arizona Public Service (APS) proposes a BACT level which reflects these NO_x BACT determinations.

10.4.1 BACT Baseline.

These engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. The NO_x emission standard for non-emergency generator sets manufactured after the 2014 model year (Tier 4 standard) is 0.5 g/hp-hr. The NO_x emission standard for emergency engines greater than 750 hp is 4.8 g/hp-hr (Tier 2 standard), or, for the engine family, 7.83 g/hp-hr. Note that the Tier 2 standard is the sum of the NO_x and non-methane hydrocarbons (NMHC). In addition, Maricopa County rule 324 limits NO_x emissions to 6.9 g/hp-hr.

10.4.2 BACT Control Technology Determinations.

Table B10-4 is a summary of NO_x emission limits for similar emergency generators. The limits in Table B10-4 indicate Tier 2 emission limits for the majority of permitted generators. The most stringent limitation is the Tier 4 standard of 0.50 g/hp-hr for the Cronus Chemicals, LLC facility in Illinois.

The Bay Area Air Quality Management District BACT Guideline for diesel-fueled emergency engines with a rating of more than 750 hp, based on the Airborne Toxic Control Measures (ATCMs) promulgated by the California Air Resources Board (CARB) lists a BACT NO_x emission limit of 4.8 g/hp-hr. The San Joaquin Valley Air Pollution Control District BACT Guideline, 3.1.3, requires the latest EPA Tier certification level for the applicable horsepower range; in that reference, equal to 6.9 g/hp-hr.

10.4.3 Available Control Technologies.

The available control technologies for diesel generators includes good combustion practices (engine design), and Selective Catalytic Reduction (SCR). Selective non-catalytic reduction (SNCR) is an available NO_x control technology for boilers and other external combustion sources, but it is not technically feasible for internal combustion engines.

TABLE B10-4. Nitrogen oxides (NO_x) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	0.50 g/hp-hr
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	4.46 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		2.85 g/hp-hr
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	4.46 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	27.8 lb/hr
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	4.8 g/hp-hr
Hess Newark Energy Center	NJ	11/01/12	200 hr/yr	18.53 lb/hr
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	4.47 g/hp-hr
Point Thomson Production Facility	AK	08/20/12	1,750 kW	4.8 g/hp-hr
Pyramax Ceramics, LLC	SC	02/08/12	757 hp	2.98 g/hp-hr
Palmdale Hybrid Power Project	CA	10/18/11	2,683 hp	4.8 g/hp-hr
Highlands Biorefinery and Cogen Plant	FL	09/23/11		4.8 g/hp-hr

10.4.4 SCR Cost Analysis.

The generator sets with Tier 4 engines are equipped with selective catalytic reduction (SCR) systems and are designed to achieve a lower NO_x emission rate of 0.50 g/hp-hr. Based on the operational limit of 100 hours per year for each emergency generator, the potential NO_x emissions, based on the use of Tier 4 engines, would be 4.13 lb/hr and 0.21 tons per year. This would reduce potential NO_x emissions from these generators by 2.64 tons per year for each genset, and 5.29 tons per year for both gensets combined.

The generator sets with Tier 4 engines also have a higher capital cost. The additional total capital cost for each genset equipped with Tier 4 engines is $400,000 per genset, or a total additional capital cost of $800,000 for both gensets. To annualize these capital costs, the total capital cost is multiplied by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate
n = control system (project) life, years

For a project life of 25 years and an interest rate of 7%, the CRF is 0.0858 and the annual cost of the additional capital investment is $34,320 per year. Based on a NOx reduction of 2.64 tons per year per genset, the cost effectiveness for the use of Tier 4 engines as a NO_x BACT control option – <u>based only on the additional capital cost</u> - would be $12,980 per ton of NO_x controlled. The actual Tier 4 engine costs would be higher due to increased operating and maintenance (O&M) costs, including the additional costs for ammonia and additional maintenance costs. This very high cost demonstrates that the use of Tier 4 engines equipped with selective catalytic reduction (SCR) is not an economically feasible control technology option for these emergency generators.

10.4.5 Proposed NO_x BACT Determination.

Based on this analysis, Arizona Public Service (APS) has concluded that the use of good combustion practices and the use of Tier 2 engines represents the best available control technology (BACT) for the control of NO_x emissions from the proposed emergency diesel generators. APS proposes the following limits as BACT for the control of NO_x emissions from the emergency diesel generators:

1. Nitrogen oxide (NO_x) emissions may not exceed 7.83 g/hp-hr.
2. The operation of each emergency generator may not exceed 100 hours per year.

10.5 Particulate Matter (PM) and $PM_{2.5}$ Control Technology Review.

Emissions of particulate matter (PM), including particulate matter with aerodynamic particle sizes less than 10 microns (PM_{10}), and particulate matter with aerodynamic particle sizes less than 2.5 microns ($PM_{2.5}$) from diesel generators result from PM in the combustion air, from ash in the fuel, engine wear, and from products of incomplete combustion. For this analysis, all PM emissions from the diesel generators are also assumed to be PM_{10} and $PM_{2.5}$ emissions. Since ultra-low sulfur diesel fuel has very little ash, fuel ash is not a significant source of PM emissions.

10.5.1 BACT Baseline.

These engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. The PM emission standard for non-emergency generator sets manufactured after the 2014 model year (Tier 4 standard) is 0.022 g/hp-hr. The PM emission standard for emergency engines greater than 750 hp is 0.15 g/hp-hr, or an engine family limit of 0.40 g/hp-hr (Tier 2 standards).

10.5.2 STEP 1. Identify All Available Control Technologies.

Table B10-5 is a summary of PM emission limits for diesel generators from the U.S. EPA's RACT / BACT / LAER database. From Table B10-5, all of the generators identified have the Tier 2 PM emission limit of 0.15 grams per horsepower hour (g/hp-hr) except for the Cronus Chemicals, LLC facility, which has a limit of 0.075 g/hp-hr. That limit is the interim Tier 4 emission standard for generator sets larger than 900 kW manufactured after Year 2010. (Two units have pound per hour limits. There is insufficient information in the database to determine the equivalent limit expressed in g/hp-hr).

The South Coast Air Quality Management District's LAER/BACT determinations (available at http://www.aqmd.gov/home/permits/bact/guidelines/i---scaqmd-laer-bact) did not have any listed determinations newer than 2003. The Bay Area Air Quality Management District BACT Guideline for diesel-fueled emergency engines with a rating of more than 750 hp, based on the Airborne Toxic Control Measures (ATCMs) promulgated by the California Air Resources Board (CARB) also lists a BACT PM emission limit of 0.15 g/hp-hr. The San Joaquin Valley Air Pollution Control District BACT Guideline, 3.1.1, requires the latest EPA Tier certification level for applicable horsepower range.

Based on this review, Good Combustion Practices (GCP) and Diesel Oxidation Catalysts (DOC) have potential for applicability to these generators.

10.5.3 STEP 2. Identify Technically Feasible Control Technologies.

Good combustion practices and diesel oxidation catalysts are both technically feasible options.

10.5.4 STEP 3. Rank the Technically Feasible Control Technologies.

Based on the above data, the use of Good Combustion Practices (Tier 2 engines) can achieve a PM emission rate of 0.15 g/hp-hr. The use of GCP combined with diesel oxidation catalysts (Tier 4 engines) can achieve a PM emission rate of 0.022 g/hp-hr.

TABLE B10-5. Particulate matter (PM) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	0.075 g/hp-hr
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	0.15 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		0.15 g/hp-hr
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	0.15 g/hp-hr
CF Industries Nitrogen, LLC - Port Neal	IA	07/12/13	180 gal/hr	0.15 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	0.99 lb/hr
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	0.15 g/hp-hr
Hess Newark Energy Center	NJ	11/01/12	200 hr/yr	0.59 lb/hr
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	0.15 g/hp-hr
Point Thomson Production Facility	AK	08/20/12	1,750 kW	0.15 g/hp-hr
Palmdale Hybrid Power Project	CA	10/18/11	2,683 hp	0.15 g/hp-hr

10.5.1 STEP 4. Evaluate the Most Effective Controls.

The generator sets with Tier 4 engines are equipped with diesel oxidation catalyst systems and are designed to achieve a lower PM emission rate of 0.022 g/hp-hr. Based on the operational limit of 100 hours per year for each emergency generator, the potential PM and $PM_{2.5}$ emissions, based on the use of Tier 4 engines, would be 0.18 pounds per hour and 0.01 tons per year. This would reduce potential PM and $PM_{2.5}$ emissions from these generatos by 0.16 tons per year for each genset, and 0.31 tons per year for all three gensets combined.

As noted above, the generator sets with Tier 4 engines also have a higher capital cost. The additional capital cost for each genset equipped with Tier 4 engines is $400,000 per genset, or a total additional capital cost of $800,000 for both generators. To annualize these capital costs, the total capital cost is multiplied by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate
n = control system (project) life, years

For a project life of 25 years and an interest rate of 7%, the CRF is 0.0858 and the annual cost of the additional capital investment is $34,320. Based on a PM reduction of 0.16 tons per year per genset, the cost effectiveness for the use of Tier 4 engines as a PM BACT control option – based only on the additional capital cost - would be $220,100 per ton of PM controlled. The actual Tier 4 engine costs would be higher due to increased operating and maintenance (O&M) costs. This very high cost demonstrates that the use of Tier 4 engines equipped with diesel oxidation catalysts is not an economically feasible PM and $PM_{2.5}$ control technology option for these emergency generators.

Based on this cost evaluation, the next most effective PM and $PM_{2.5}$ control option is the use of Tier 2 engines.

10.5.2 STEP 5. Proposed Particulate Matter (PM), and $PM_{2.5}$ BACT Determination.

Based on this analysis, Arizona Public Service (APS) has concluded that the use of good combustion practices and the use of Tier 2 engines represents the best available control technology (BACT) for the control of PM emissions from the proposed diesel generators. APS proposes the following limits as BACT for the control of PM emissions from the emergency generators:

1. Particulate matter (PM) emissions may not exceed 0.40 g/hp-hr.
2. The operation of each generator may not exceed 100 hours per year.

10.6 Volatile Organic Compound (VOC) Control Technology Review.

Based on the PSD applicability analysis in Chapter 4 of the construction permit application, the proposed Ocotillo Generation Project will not result in a significant net emissions increase for volatile organic compound (VOC) emissions. Therefore, the Project is not a major modification for VOC emissions, and the Project is therefore not subject to the application of BACT under the PSD program. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of VOC emissions. Therefore, the following BACT analysis is being conducted to comply with Maricopa County Rule 241, Section 301.1.

In accordance with Maricopa County Air Quality Department's memorandum "REQUIREMENTS, PROCEDURES AND GUIDANCE IN SELECTING BACT and RACT", revised July, 2010, section 8, "To streamline the BACT selection process, the Department will accept a BACT control technology for the same category of industry as listed by the South Coast Air Quality Management District (SCAQMD), SJVACD, or the BAAQMD, or other regulatory agencies accepted by the Department as a viable alternative. Sources who opt to select control technology for the same or similar source category accepted by the air quality management districts in California may forgo the top-down analysis described above." The following is an analysis of recent VOC BACT determinations. Arizona Public Service (APS) proposes a BACT level which reflects these VOC BACT determinations.

Like CO emissions, VOC is emitted from diesel generators as a result of incomplete combustion. Therefore, the most direct approach for reducing VOC emissions (and also reduce the other related pollutants) is to improve combustion. Incomplete combustion also leads to emissions of organic hazardous air pollutants (HAP) such as formaldehyde. VOC and organic HAP emissions may also be reduced using post combustion control systems including diesel oxidation catalyst systems.

10.6.1 BACT Baseline.

These engines will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* in 40 CFR 60, Subpart IIII. The non-methane hydrocarbon (NMHC) emission standard for non-emergency generators manufactured after the 2014 model year (Tier 4) is 0.14 g/hp-hr. The Tier 2 emission standard for NMHC is actually a combined NO_x and NMHC standard for emergency engines greater than 750 hp is 4.8 g/hp-hr or, for the engine family, 7.83 g/hp-hr.

10.6.2 BACT Control Technology Determinations.

Table B10-6 is a summary of VOC emission limits for similar emergency generators. The limits in Table B9-6 indicate VOC or NMHC emission limits ranging from 0.15 to 0.30 g/hp-hr. The Bay Area Air Quality Management District BACT Guideline for diesel-fueled emergency engines with a rating of more than 750 hp, based on the Airborne Toxic Control Measures (ATCMs) promulgated by the California Air Resources Board (CARB) lists a BACT NO_x + NMHC emission limit of 4.8 g/hp-hr, equal to the Tier 2 standard. The San Joaquin Valley Air Pollution Control District BACT Guideline, 3.1.1, requires the latest EPA Tier certification level for the applicable horsepower range.

10.6.3 Available Control Technologies.

The available control technologies for diesel generators includes good combustion practices (engine design), and diesel oxidation catalysts. The reduction potential for VOC emissions for oxidation catalysts is expected to be approximately 50 to 60%. However, the VOC reduction capabilities based on the engine Tier standards is more difficult to estimate for several reasons. First, VOC emissions do not have a specific standard; the standard is for non-methane hydrocarbons (NMHC). The second reason is because the Tier 4 standards have a specific NMHC standard, while the Tier 2 standard includes NO_x and NMHC *combined*.

TABLE B10-6. Volatile organic compound (VOC)) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	0.30 g/hp-hr
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	0.31 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		0.15 g/hp-hr
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	0.31 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	3.93 lb/hr
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	1.04 lb/hr
Hess Newark Energy Center	NJ	11/01/12	200 hr/yr	2.62 lb/hr
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	0.30 g/hp-hr
Pyramax Ceramics, LLC	SC	02/08/12	757 hp	0.30 g/hp-hr

10.6.4 Diesel Oxidation Catalyst Cost Analysis.

The generator sets with Tier 4 engines are equipped with diesel oxidation catalyst systems and are designed to achieve a NMHC emission rate of 0.14 g/hp-hr. Again, the Tier 2 standard includes NO_x and NMHC *combined*. Based on the operational limit of 100 hours per year for each emergency generator, the potential VOC emissions, based on the use of Tier 4 engines, would be 1.17 pounds per hour and 0.06 tons per year. This would reduce potential VOC emissions from these generators by 0.02 tons per year for each genset, and 0.05 tons per year for all three gensets combined.

As noted above, the generator sets with Tier 4 engines also have a higher capital cost. The additional capital cost for each genset equipped with Tier 4 engines is $400,000 per genset, or a total additional capital cost of $800,000 for both generators. To annualize these capital costs, the total capital cost is multiplied by the capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate
n = control system (project) life, years

For a project life of 25 years and an interest rate of 7%, the CRF is 0.0858 and the annual cost of the additional capital investment is $34,320. Based on a VOC reduction of 0.02 tons per year per genset, the cost effectiveness for the use of Tier 4 engines as a VOC BACT control option – based only on the additional capital cost - would be $1,425,000 per ton of VOC controlled. The actual Tier 4 engine costs would be higher due to increased operating and maintenance (O&M) costs. This very high cost demonstrates that the use of Tier 4 engines equipped with diesel oxidation catalysts is not an economically feasible VOC control technology option for these emergency generators.

10.6.5 Proposed VOC BACT Determination.

Based on this analysis, Arizona Public Service (APS) has concluded that the use of good combustion practices and Tier 2 engines represents the best available control technology (BACT) for the control of VOC emissions from the proposed diesel generators. APS proposes the following limits as BACT for the control of VOC emissions from the emergency generators:

1. Volatile organic compound (VOC) emissions may not exceed 0.20 g/hp-hr.
2. The operation of each generator may not exceed 100 hours per year.

10.7 Greenhouse Gas (GHG) Emissions Control Technology Review.

GHG emissions from diesel engine driven electric generators include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The federal *Mandatory Greenhouse Gas Reporting Requirements* under 40 CFR Part 98 requires reporting of greenhouse gas (GHG) emissions from large stationary sources. Under 40 CFR Part 98, facilities that emit 25,000 metric tons or more per year of GHG emissions are required to submit annual reports to EPA. Table C-1 of this rule includes default emission factors for CO_2. The CO_2 emission factor for diesel fuel combustion, based on the combustion of No. 2 distillate fuel oil, is 73.96 kg per mmBtu, equal to 116.6 pounds per million Btu, based on the higher heating value (HHV) of natural gas.

Methane (CH_4) emissions result from incomplete combustion. The federal *Mandatory Greenhouse Gas Reporting rule*, 40 CFR Part 98, Table C-2 lists a methane emission factor for the combustion of No. 2 distillate fuel oil of 0.003 kg/mmBtu (0.0066 lb/mmBtu).

Nitrous oxide (N_2O) emissions from gas turbines result primarily from low temperature combustion. The federal *Mandatory Greenhouse Gas Reporting rule*, 40 CFR Part 98, Table C-2 lists a default N_2O emission factor for the combustion of No. 2 distillate fuel oil of 0.0006 kg/mmBtu (0.0013 lb/mmBtu).

Potential GHG emissions for each generator based on the proposed operating limit of 100 hours per year are summarized in Table B10-7. From Table B10-7, CO_2 emissions account for 99.7% of the total GHG emissions. ***Because CO_2 emissions account for the vast majority of GHG emissions from these generators, this control technology review for GHG emissions will focus on CO_2 emissions.***

TABLE B10-7. Potential greenhouse gas (GHG) emissions for each 2,500 kW diesel generator.

Pollutant		Emission Factor		Total GHG Emission Factor		Heat Input Capacity	Potential to Emit, EACH GENSET	
		kg/mmBtu	lb/mmBtu	CO_2e Factor[4]	lb/mmBtu	mmBtu/hr	lb/hour	tons/yr
Carbon Dioxide	CO_2	73.96	163.05	1	163.05	24.2	3,937.7	196.9
Methane	CH_4	3.0E-03	0.0066	25	0.17	24.2	4.0	0.2
Nitrous Oxide	N_2O	6.0E-04	0.0013	298	0.39	24.2	9.5	0.5
TOTAL GHG EMISSIONS, AS CO_2e					**163.6**		**3,951.2**	**197.6**

Footnotes

1. Potential emissions in tons per year are based on limiting the operation of each emergency generator to 100 hours per year.

2. The emission factors for the greenhouse gases, including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

10.7.1 BACT Baseline.

There are no CO_2 or greenhouse gas emission standards applicable to these diesel generators.

10.7.2 BACT Control Technology Determinations.

Table B10-8 is a summary of CO_2 and/or greenhouse gas emission limits for similar emergency generators. The limits in Table B10-8 indicate CO_2 or GHG emission limits typically expressed as tons per year. These limits appear to all be based on the maximum output of the generator on an hourly basis, and operational limits of 100 to 500 hours per year.

TABLE B10-8. Greenhouse gas (GHG) emission limits for emergency diesel generators from the U.S. EPA's RACT/BACT/LAER database.

FACILITY NAME	STATE	PERMIT DATE	THROUGHPUT	LIMIT
Cronus Chemicals, LLC	IL	09/05/14	3,755 hp	432 ton/year
Midwest Fertilizer Corporation	IN	06/04/14	3,600 hp	526.39 g/hp-hr
Energy Answers Arecibo Puerto Rico	PR	04/10/14		183 ton/year
Ohio Valley Resources, LLC	IN	09/25/13	4,690 hp	526.39 g/hp-hr
Oregon Clean Energy Center	OH	06/18/13	2,250 kW	878 ton/year
St. Joseph Energy Center, LLC	IN	12/03/12	2,012 hp	1,186 ton/year
Iowa Fertilizer Company	IA	10/26/12	142 gal/hr	788.5 ton/year
Hickory Run Energy Station	PA	04/23/13	7.8 mmBtu/hr	80.5 ton/year

10.7.3 STEP 1. Identify All Potential Control Technologies.

CO_2 emissions result from the oxidation of carbon in the fuel. When combusting fuel, this reaction is responsible for much of the heat released in diesel engines and is therefore unavoidable. There are five potential control options for reducing CO_2 emissions from these diesel generators:

1. **The use of low carbon containing or lower emitting primary fuels,**
2. **The use of energy efficient processes and technologies,**
3. **Good combustion, operating, and maintenance practices,**
4. **Low annual capacity factor (applicable to emergency generators),**
5. **Carbon capture and sequestration (CCS) as a post combustion control system.**

10.7.4 STEP 2. Identify Technically Feasible Control Technologies.

The purpose of these generators is to provide a power source during emergencies when the electric grid may be down, during natural disasters, or when natural gas may be curtailed or interrupted and the combustion turbines are unavailable. Liquid fuels which can be stored on site are necessary to ensure that these critical emergency generators will start reliably. Because electricity and natural gas may not be available during these emergencies, natural gas and electricity are not technically feasible control technologies for these emergency generators. And gasoline engines are generally not as efficient as diesel engines and are not available in the large size necessary for these generators.

The use of energy efficient processes and technologies, and the use of good combustion, operating, and maintenance practices are both technically feasible control options. The proposed diesel engines are modern, efficient engines which minimize GHG emissions. The use of good combustion, operating, and maintenance practices will help ensure that the engines operate at or near their design efficiency.

Limiting the operation of any emissions unit will limit emissions. The majority of the operation of these generators will be for maintenance and readiness testing. Because these engines will be used primarily for emergency operation, limiting the operation of these gensets is technically feasible. Therefore, APS proposes to limit the operation of these generators to no more than 100 hours per year.

Chapter 6 of this control technology review includes a detailed discussion of carbon capture and sequestration (CCS). While carbon capture with an MEA absorption process may be technically feasible for combined-cycle gas turbines, it is not feasible for emergency RICE because the exhaust gas temperature is too high for the MEA process and because these engines operate infrequently. Therefore, CCS is also not a technically feasible control option for these emergency generators.

10.7.5 STEP 3. Rank the Technically Feasible Control Technologies.

The use of energy efficient processes and technologies, good combustion, operating, and maintenance practices, and low annual capacity factor are all technically feasible control options and are also proposed for these emergency generators.

10.7.6 STEP 4. Evaluate the Most Effective Controls.

APS proposes the use of energy efficient processes and technologies, good combustion, operating, and maintenance practices, and low annual capacity factor as BACT for these generators. The use of diesel generator sets manufactured to meet the Tier 2 standards will ensure the use of energy efficient processes. This is the highest level of control available for these generators. Therefore, further evaluation is unnecessary.

10.7.7 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, Arizona Public Service (APS) has concluded that the use of energy efficient processes and technologies, good combustion, operating, and maintenance practices, and a low annual capacity factor represents the best available control technology (BACT) for the control of GHG emissions from the proposed diesel generators. APS proposes the following limits as BACT for the control of GHG emissions from the emergency generators:

1. Carbon dioxide (CO_2) emissions from each diesel engine generator may not exceed 197.6 tons per year.
2. The operation of each generator may not exceed 100 hours per year.

Chapter 11. Diesel Fuel Oil Storage Tank Control Technology Review.

The Project will also include two (2) 10,000 gallon diesel fuel oil storage tanks. Based on the operational limits for the diesel generators of 100 hours per year as proposed in this application and a maximum diesel engine fuel consumption rate of 175 gallons per hour, the maximum annual throughput for each tank would be 35,000 gallons per year. Potential VOC emissions based on the U.S. EPA's TANKS program, Version 4.0.9d (which is based on the equations from AP-42, Section 7.1, Organic Storage Tanks), is 5.10 pounds per year for each tank, or total VOC emissions of 0.0051 tons per year for both tanks combined. The emissions are summarized in Table B11-1. Note that under normal generator operation which would be less than 100 hours per year, the working losses would be very small, and the emissions would approach the breathing losses only which are less than 2 pounds per year.

TABLE B11-1. TANKS 4.0.9d annual emissions summary report, individual tank emission totals.

Components	Tank Losses (lbs)		
	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	1.14	1.60	2.74

Based on the PSD applicability analysis in Chapter 4 of the construction permit application, the proposed Ocotillo Generation Project will not result in a significant net emissions increase for volatile organic compound (VOC) emissions. Therefore, the Project is not a major modification for VOC emissions, and the Project is therefore not subject to the application of BACT under the PSD program. However, Maricopa County's Air Pollution Control Regulations, Rule 241, Permits for New Sources and Modifications to Existing Sources, Section 301.1, requires the application of BACT to any new stationary source which emits more than 150 lbs/day or 25 tons/yr of VOC emissions. Therefore, the following BACT analysis is being conducted to comply with Maricopa County Rule 241, Section 301.1.

The proposed diesel fuel oil storage tanks will be equipped with submerged fill pipes which will reduce working losses. Because the vapor pressure of diesel fuel oil is very low, losses from these tanks will be very small. At a cost effectiveness threshold of $10,000 per ton of VOCs controlled ($5.00 per pound), controls which cost more than $25 per tank per year would not be cost effective. Based on the very low potential VOC emissions there are no control technologies available for these tanks which would be economically feasible to reduce the already extremely low level of emissions.

Based on this analysis, APS has concluded that the use of diesel fuel oil storage tanks with submerged fill pipes represents the best available control technology (BACT) for the control of VOC emissions from the proposed diesel fuel oil storage tanks.

Chapter 12. SF_6 Insulated Electrical Equipment Control Technology Review.

The Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21 includes sulfur hexafluoride (SF_6) as a regulated GHG substance or pollutant. The proposed circuit breakers which will be installed with the new LMS 100 GTs and emergency generators will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, inert, and non-toxic gas. SF_6 has a very stable molecular structure and has a very high ionization energy which makes it an excellent electrical insulator. The gas is used for electrical insulation, arc suppression, and current interruption in high-voltage electrical equipment.

The electrical equipment containing SF_6 is designed not to leak, since if too much gas leaked out, the equipment may not operate correctly and could become unsafe. The proposed circuit breakers will have a low pressure alarm and a low pressure lockout system. The alarm will alert personnel of leakage and the lockout would prevent operation of the breaker due to a lack of spark suppression from the SF_6 gas. State-of-the-art circuit breakers are gas-tight and are designed to achieve a leak rate of less than or equal to 0.5% per year (by weight). This is also the International Electrotechnical Commission (IEC) maximum leak rate standard. Table B12-1 summarizes the potential SF_6 emissions for the planned equipment. Note that the potential CO_2e emissions from circuit breaker SF_6 emissions account for 0.01% of the project's total CO_2e emissions.

TABLE B12-1. Potential fugitive sulfur hexafluoride (SF_6) emissions from the planned SF_6 insulated electrical equipment and the equivalent GHG emissions.

Breaker Type	Breaker Count	Total SF_6 per Component pounds	Leak Rate % per year	SF_6 Emissions ton/year	CO_2e Factor[4]	Potential Emissions, ton CO_2e /year
230 kV	9	135	0.50%	0.0030	23,900	72.6
69 kV	11	75	0.50%	0.0021	23,900	49.3
13.8 kV	5	35	0.50%	0.0004	23,900	10.5
TOTAL FUGITIVE EMISSIONS				**0.0046**	**23,900**	**132.3**

Footnotes

Potential emissions are based on the International Electrotechnical Commission (IEC) maximum leak rate standard of 0.5% per year.

12.1 STEP 1. Identify All Potential Control Technologies.

The following technologies are available to control fugitive SF_6 emissions from electrical equipment:

1. State-of-the-art enclosed-pressure SF_6 technology with leak detection.
2. Use of a non-GHG emission dielectric material in the breakers.

12.2 STEP 2. Identify Technically Feasible Control Technologies.

State-of-the-art enclosed-pressure SF_6 technology with leak detection is an available technology used to limit fugitive SF_6 emissions.

In the report *SF_6 Emission Reduction Partnership for Electric Power Systems, 2014 Annual Report*, U.S. EPA, March 2015, (http://www.epa.gov/electricpower-sf6/documents/SF6_AnnRep_2015_v9.pdf), EPA states "Because there is no clear alternative to SF_6, Partners reduce their greenhouse gas emissions through implementing emission reduction strategies such as detecting, repairing, and/or replacing problem equipment, as well as educating gas handlers on proper handling techniques of SF6 gas during equipment installation, servicing, and disposal." Therefore, the use of alternative substances as dielectric materials is not considered a technically feasible control option for these circuit breakers.

12.3 STEP 3. Rank the Technically Feasible Control Technologies.

The use of state-of-the-art enclosed SF_6 technology with leak detection is the highest ranked technically feasible control technology to limit fugitive SF_6 emissions from the proposed electrical equipment.

12.4 STEP 4. Evaluate the Most Effective Controls.

APS proposes the use of state-of-the-art enclosed SF_6 technology with leak detection for the control of SF_6 emissions from the proposed electrical equipment. This is the highest level of control available for the control of SF_6 emissions. Therefore, further evaluation is unnecessary.

12.5 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of state-of-the-art enclosed SF_6 technology with leak detection represents the best available control technology (BACT) for the control of fugitive SF_6 emissions from the proposed electrical equipment. APS proposes the following conditions as BACT:

1. The Permittee shall install, operate, and maintain enclosed-pressure SF_6 circuit breakers with a maximum annual leakage rate of 0.5% by weight.

Chapter 13. Natural Gas Piping Systems Control Technology Review.

The Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21 includes methane (CH_4) as a regulated GHG substance or pollutant. Natural gas piping components including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections can leak and therefore result in small amounts of fugitive natural gas emissions. Since natural gas consists of from 70 to almost 100% methane, leaks in the natural gas piping at the Ocotillo plant can result in small amounts of methane emissions.

The Mandatory Greenhouse Gas Reporting Rules in 40 CFR Part 98, Subpart W include methods for estimating GHG emissions from petroleum and natural gas systems. Table B13-1 summarizes the estimated fugitive methane emissions which are expected to result from a properly operated and maintained natural gas piping system at the Ocotillo Power Plant. Note that these estimated fugitive emissions are less than 0.01% of the total potential GHG emissions from the proposed Project.

TABLE B13-1. Potential fugitive methane emissions from the natural gas piping systems and the equivalent GHG emissions.

Component Type	Component Count	Emission Factor scf / hour / component	Specific Volume scf / lb CH_4	Methane (CH_4) ton/year	CO_2e Factor[4]	Potential Emissions ton CO_2e /year
Valves	150	0.123	24.1	3.35	25	83.9
Connectors	125	0.017	24.1	0.39	25	9.7
Relief Valves	10	0.196	24.1	0.36	25	8.9
TOTAL PIPELINE FUGITIVE EMISSIONS				**4.10**	**25**	**102.4**

Footnotes

1. The emission factors are from 40 CFR Part 98, Table W-1A for onshore natural gas production, Western U.S.
2. The CO_2e factor is from 40 CFR 98, Subpart A, Table A-1.
3. The specific volume of methane at 68 °F is based on a specific volume of 385.5 standard cubic feet per lb-mole of gas, and a methane molecular weight of 16.0 lb/lb-mole.
4. Methane emissions are based on the worst-case assumption that the natural gas is 100% methane by volume.

13.1 STEP 1. Identify All Potential Control Technologies.

The following technologies are available to control fugitive methane emissions from natural gas piping systems.

1. Leakless technology components,
2. Leak detection and repair (LDAR) program,
3. Alternative monitoring using remote sensing technology, and
4. Audio/visual/olfactory (AVO) monitoring program.

13.2 STEP 2. Identify Technically Feasible Control Technologies.

"Leakless" technologies such as bellows or seal valves can reduce fugitive natural gas emissions by eliminating valve gasket and flange leak paths. Other leak paths never-the-less do exist so that this technology does not eliminate fugitive emissions. Leakless technology components are used for highly toxic and hazardous materials. However, leakless technology components are not normally used in natural gas piping systems because of the high cost for these components and the difficulty in maintaining and repairing these components. For example, if a welded or threaded and seal welded bonnet joint valve fails, the failed component cannot be repaired without a unit shutdown, and the repair may result in additional maintenance related natural gas venting. Seal valves have other limitations which limit their use, including cycle life, pressure retention capability, and size limitations. Because these components are not a standard used in natural gas piping systems, the use of leakless valves is not considered a technically feasible control option for the Ocotillo natural gas piping systems.

Leak detection and repair (LDAR) programs, alternative monitoring using remote sensing technology, and audio/visual/olfactory (AVO) monitoring programs are technically feasible control options.

13.3 STEP 3. Rank the Technically Feasible Control Technologies.

Leak detection and repair (LDAR) programs using instrument monitoring are effective for identifying leaking components and is an accepted practice for limiting VOC emissions from gas processing and chemical plants. Quarterly monitoring with an instrument and a leak definition of 500 ppm is considered to have a control efficiency of 97% for valves, flanges, and connectors. Remote sensing using infrared imaging is also effective in detecting leaks, especially for components in difficult to monitor areas and is considered to be equivalent to LDAR.

AVO monitoring is also an effective monitoring method for odorous and low vapor pressure compounds such as natural gas, especially because the observations can be substantially more frequent than for LDAR. Pipeline natural gas is odorized with mercaptan for safety. As a result, natural gas leaks have a discernible odor. Larger leaks can be detected by sound and sight, either directly or as a secondary indicator such as condensation around a leaking source due to the cooling of the expanding gas as it leaves the leaking component. Thus, observations for leaking valves or components can be made when plant personnel make routine walk-downs of the plant. As a result, AVO observation is an effective method for identifying and correcting leaks in natural gas systems, especially larger leaks that can result in increased emissions. The Texas Commission on Environmental Quality (TCEQ) also assigns a 97% control effectiveness for AVO for odorous and low vapor pressure compounds such as natural gas.

13.4 STEP 4. Evaluate the Most Effective Controls.

APS proposes the use of audio/visual/olfactory (AVO) monitoring as an effective monitoring method for the control of fugitive methane emissions from the natural gas piping systems. The proposed project will also utilize high quality components and materials of construction that are compatible with the service in which they are employed. This is the highest level of control available for the control of methane emissions from the piping systems. Therefore, further evaluation is unnecessary.

13.5 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of audio/visual/olfactory (AVO) monitoring represents the best available control technology (BACT) for the control of fugitive methane emissions from the natural gas piping systems. APS proposes the following conditions as BACT:

1. The permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaks in the natural gas piping components.
2. AVO monitoring shall be performed in accordance with a written monitoring program.