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Submitted via e-mail to Nancy Swofford (swofford.nancy@deq.state.or.us)

Nancy Swofford, Permit Coordinator
Oregon Dept. of Environmental Quality
Eastern Region
475 NE Bellevue Dr., Suite 110
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Re: Public Comments Regarding Proposed Air Contaminant Discharge Permit No. 25-0016-ST-02 for Portland General Electric's Carty Generating Station

Dear Ms. Swofford,

Earthrise Law Center (Earthrise) submits the following comments on behalf of Columbia Riverkeeper, Friends of the Columbia Gorge, 350 PDX, Climate Action Coalition, Columbia Gorge Climate Action Network, Greater Hells Canyon Council, Green Energy Institute, Northwest Environmental Defense Center, Oregon Natural Desert Association, Oregon Physicians for Social Responsibility, Sierra Club, and Stop Fracked Gas PDX (collectively, Commenters) in response to Oregon Department of Environmental Quality's (DEQ) solicitation of public comments on a proposed Air Contaminant Discharge Permit (ACDP) No. 25-0016-ST-02 for Portland General Electric's (PGE) Carty Generating Station (Carty).

Commenters have a significant interest in protecting air quality across the State of Oregon and in particular the Columbia River Gorge and National Scenic Area. Commenters represent thousands of members and supporters who recreate, work, visit, and use the areas impacted by the Carty facility. Commenters' members and supporters are adversely impacted by the Carty facility's exponentially-larger-than-advertised emissions, and urge DEQ to reconsider the proposed decision to issue the above-referenced permit.

The pollutants at issue in this permitting decision, carbon monoxide (CO) and volatile organic compounds (VOC), are well known for their adverse effects on public health and environmental quality. *See* U.S. ENVTL. PROT. AGENCY, *Basic Information about Carbon*

Monoxide (CO) Outdoor Air Pollution;[1] U.S. ENVTL. PROT. AGENCY, *Basic Information about Ozone*.[2] In particular VOCs, a precursor to ozone, cause respiratory and other dangerous health effects, even at low levels of exposure. *See* OREGON DEPT. OF ENVTL. QUALITY, *Air Pollution and Health Problems*.[3] That is all the more relevant where those effects are exacerbated by natural weather conditions like stagnated air in the region. *See e.g.* Tony Hernandez, *Air Stagnation Advisories Issued for Northern, Southern Oregon*, THE OREGONIAN, Jan. 27, 2017.[4]

The proposed permitting decision would authorize the Carty facility to increase its VOC emissions by more than 800% and CO emissions by more than 300%. Despite these dramatic increases, and the substantial adverse impacts these pollutants have on Oregonians and the public environment, DEQ is proposing essentially no more stringent controls on emissions while approving all of the excess emissions. For the reasons discussed further herein, Commenters respectfully request that DEQ deny the permit application as proposed.[5]

I. DEQ's BACT Analysis is Fatally Flawed.

Any pollutant regulated under the federal Clean Air Act, 42 U.S.C. § 7401 *et seq.*, emitted from a facility in significant amount above the facility's netting basis must comply with the requirements of the prevention of significant deterioration (PSD) program, including the installation of the best available control technology, or BACT. OAR 340-240-0070(1). BACT is defined as

> an emission limitation based on the maximum degree of reduction of each pollutant . . . 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

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[1] Available at: https://www.epa.gov/co-pollution/basic-information-about-carbon-monoxide-co-outdoor-air-pollution#Effects (last visited Apr. 23, 2018).

[2] Available at: https://www.epa.gov/ozone-pollution/basic-information-about-ozone#effects (last visited Apr. 23, 2018).

[3] Available at: http://www.oregon.gov/deq/aq/Pages/Health.aspx (last visited Apr. 23, 2018).

[4] Available at: http://www.oregonlive.com/weather/index.ssf/2017/01/agencies_issues_air_stagnation.html (last visited Apr. 23, 2018).

[5] Commenters note that their ability to fully analyze the basis for, and to prepare meaningful comments on, the draft PSD permit has been hampered by DEQ's failure to timely respond to their February 16, 2018, public records request (Request No. prrSaul7875). *See* ORS § 192.329(5)(a), (b). Commenters also strongly urge DEQ to follow the lead of other western air quality management agencies and improve the extent to which it automatically provides online access to permit applications and supporting documents. *See, e.g.*, https://ecology.wa.gov/Regulations-Permits/Permits-certifications/Air-Quality-permits/Prevention-of-Significant-Deterioration-PSD; http://www.aqmd.gov/home/permits/psd (last visited Apr. 30, 2018).

cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

42 U.S.C. § 7479(3); *see also* OAR 340-200-0020(17), *codified at* 40 C.F.R. § 52.1970(c) (2018) (adopting federal BACT definition). EPA's Environmental Appeals Board (EAB) has continually stressed that the BACT determination ranks as one of the most critical elements of the PSD Program. *See e.g. In Re: Desert Rock Energy Company, LLC*, 2009 WL 5326323, at *28 (EAB, Sept. 24, 2009); *In re Mississippi Lime Co.*, 15 E.A.D. __, 2011 WL 3557194, at *11 (EAB, Aug. 9, 2011).

BACT is set via five step, "top-down" method. U.S. ENVTL. PROT. AGENCY, NEW SOURCE REVIEW WORKSHOP MANUAL, B.5–B.9 (Draft, 1990) [hereinafter "NSR Manual"].[6] This analysis starts by creating a "comprehensive" list of controls. *Id.* at B.6. This list includes all controls that have "*any* practical *potential* for application to the emissions unit and regulated pollutant under evaluation." *Id.* at B.5 (emphasis added). It includes both processes that reduce the pollutant, and those that "prevent emissions from being generated in the first instance." *In re: Knauf Fiber Glass, GMBH,* 8 E.A.D. 121, __, 1999 WL 64235, at *6 (EAB, Feb. 4, 1999). Potential controls include, but are not limited to, those included in EPA's RACT/BACT/LAER Clearinghouse[7], limits established in other SIPs, and permits issued by other jurisdictions. *Id.* at B.11; *see also Helping Hand Tools v. U.S. Envtl. Prot. Agency*, 848 F.3d 1185, 1190 (9th Cir. 2016) (describing Step 1 of the BACT analysis). From this list created at Step 1, all options that are technically feasible are included as candidates for BACT in Step 2, and ranked based on stringency at Step 3. NSR Manual, at B.6. The ranking takes into account not only differing control technologies, but also more stringent performance levels of a given technology. *Id.* at B.23. The applicant has the burden of eliminating, in order of stringency, controls based on considerations of economics, environmental impacts, or energy considerations. *Id.* at B.6. The top ranked control not so eliminated is adopted as BACT. *Id.*

In the Permit Review Report, DEQ starts from a correct premise – that the VOC and CO emissions from Carty are a significant amount above the netting basis from a federal major source, and thus are subject to limits that reflect BACT. OREGON DEPT. OF ENVTL. QUALITY, STANDARD AIR CONTAMINANT DISCHARGE PERMIT REVIEW REPORT, Permit No. 25-0016-ST-02, 8–9 (Draft, Jan. 4, 2018) [hereinafter "Review Report"]. DEQ also recognizes that BACT is set via the "top-down" method. *Id.*, at 8–10. The following paragraphs discuss how several of the steps were conducted erroneously, or ultimately not conducted at all, leading to fatally flawed BACT limits for both CO and VOC that do not satisfy the minimum requirements. Because the BACT limits are in error, the permit application must be denied.[8]

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[6] Available at: https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf (last visited Apr. 20, 2018).

[7] Available at: https://cfpub.epa.gov/RBLC/ (last visited Apr. 20, 2018).

[8] Because of the serious deficiencies of the BACT analysis, the most crucial element of the PSD permitting process, correcting the errors requires re-opening the public comment period. Absent full and meaningful public comment on a complete and corrected BACT analysis, this permit is not eligible for an administrative amendment to the Facility's Title V permit. *See* OAR 340-218-150(h).

A. PGE Failed to Provide all Required Information.

First, a proper BACT analysis requires the applicant to provide all relevant information. *See generally* OAR 340-224-0070(2); OAR 340-216-0040. Although this is a permit modification, PGE is obligated to provide both complete information about the Facility, and a complete BACT analysis for each pollutant, to allow for review by both DEQ and the public. OAR 340-216-0040(3) (cross referencing OAR 340-216-0040(1)). PGE provided a partial BACT analysis for VOC. *See* PORTLAND GENERAL ELECTRIC, COMPLEX TECHNICAL MODIFICATION APPLICATION (Sept. 30, 2016) [hereinafter "Permit Application"]. This application included a BACT analysis for VOC, but provided no information as to a CO analysis, in contravention of Oregon regulation.[9] OAR 340-216-0040(1)(L). Although the initial burden to conduct the BACT analysis is on the applicant, OAR 340-224-0070, the ultimate responsibility for the BACT determination rests with the permitting authority. *See* 1977 Clean Air Act Amendments to Prevent Significant Deterioration, 43 Fed. Reg. 26,388, 26,397 (Jun. 19, 1978) (*codified at* 40 C.F.R. pt. 52).

DEQ could have required this information from PGE. OAR 340-216-0066(1). Instead, DEQ appears to have simply forgone reliance on anything PGE has submitted and conducted the BACT analysis itself in the Review Report. *See* Review Report, at 13–14. However, if DEQ does not intend to require a full BACT analysis from PGE, it cannot abbreviate its own analysis of CO emission limits to the mere two-paragraph discussion in the Review Report, which is consistently couched in generalities. *See e.g. id.* at 11 (listing "*some* of the more recent determinations" of comparable permit limits) (emphasis added); *id.* at 13 (noting a "review of the status of *many* of the lower emitting plants") (emphasis added). At a minimum, if DEQ is conducting the entire BACT analysis, DEQ should publish the entire search results of the RACT/BACT/LAER Clearinghouse database queried, so as to enable the public to assess any relevant permits that may be missing from the analysis and bring such information to DEQ's attention. *See e.g.* Permit Application, at Attachment 3 (providing full search results for VOC, but not CO BACT analysis).

B. DEQ Failed to Conduct a BACT Analysis on all Emission Limits.

Second, DEQ did not include in its BACT analysis the secondary emission limits or startup and shutdown emission limits set it in the Draft Permit, for either CO or VOC. Secondary emission limits, which apply to all operation of the unit (regardless of load) except startup and shutdown, for both CO and VOC are mentioned only at the end of DEQ's BACT analysis, as a single sentence, noting that the applicant's proposed secondary limit "is also appropriate." Review Report, at 13 (CO); *id.* at 15 (VOC). Nowhere in the previous steps of BACT did DEQ even compile a list of potential secondary emission limits from comparable facilities, or discuss elimination of any more stringent limits. *Id.* at 11–12 (Table of compared emission limits only

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[9] If PGE did submit such a BACT analysis, this should have been provided to Commenters as part of their public record request so as to enable a meaningful public comment period, and withholding of this information has prejudiced Commenter's participation opportunity. *See* discussion *supra*.

listing full load limits). Nor did DEQ provide any factual reasoning or any basis at all to support the setting of secondary emissions limits at the levels chosen. DEQ must provide at least some rational basis for concluding the secondary limits are in fact appropriate. *See Mississippi Lime Co.*, 2011 WL 3557194, at *14–15 (remanding a BACT determination and holding that "the permit issuer must provide a reasoned basis for its decision"). This is so particularly given the fact that the secondary limits for both CO and VOC are in mass-based units (pound per hour, or lb/hr), which has no readily discernable conversion to the concentration-based units (parts per million by volume, or ppmvd) of the primary BACT limit absent variables like flow information that are not provided to the public. *See* Review Report, at 13 (CO); *id.* at 15 (VOC). Although manufacturer estimates may be *part* of a justification, the BACT analysis demands that other alternatives be assessed and "[i]n the absence of a showing of differences between the proposed source and previously permitted sources achieving lower emissions limits, the permit agency should conclude that the lower emissions limit is representative for that control alternative." NSR Manual, at B.24. Absent a BACT analysis that assesses comparable emission limits using the "top-down" method, the limits do not constitute BACT, and the permit application must be denied.

For the startup and shutdown emissions, DEQ seems to, again, start from the correct premise – that startup and shutdown are a "major contribution" to Carty's total CO and VOC emissions. Review Report, at 14 (CO); *id.* at 15 (VOC). Next, DEQ correctly concludes that "it is appropriate to set BACT limits" for startup and shutdown emissions. *Id.* at 14 (CO).[10] Startup and shutdown emissions are routinely subject to a BACT determination, and there is no justification for considering *some* of the emissions from a unit subject to BACT, but not all of them. *See e.g. In Re: Russell City Energy Center, LLC*, 15 E.A.D. 1, __, 2010 WL 5573720, at *15 (EAD Nov. 18, 2010) (reviewing the BACT determination for startup and shutdown emission limits); *Mississippi Lime Co.*, 2011 WL 3557194, at *6 (same). As discussed *infra*, a fully considered range of "good designs" as a control option at Step 1 naturally includes a consideration of startup and shutdown emissions. Yet, DEQ did not conduct any "top-down" analysis for startup and shutdown emissions either separately from the full load BACT limit analysis or as part of setting that limit for CO or VOC. Review Report, at 14 (CO); *id.* at 15 (VOC). Rather, DEQ set hot and cold startup and shutdown limits "in accordance with the manufacturer's estimates." *Id.* (CO); *see also id.* at 15 (VOC startup and shutdown emissions summarily determined, identical to the "vendor supplied average"). For CO, DEQ apparently "review[ed] . . . PSD permits issued by other states[11]" to determine that 50% load is a "common" end point for startup, but did not even do this cursory level of review for the emission limit, let alone rank achievable limits, or adopt the most stringent. *Id.* at 14. For VOC, no comparison of other permits was done. *Id.* at 15. Most puzzlingly, DEQ's BACT analysis for the full load emission limit (although flawed in its own right) expressly footnoted *several* examples of startup

[10] For VOC, the Review Report states "DEQ believes it is appropriate to set limits during startup and shutdown," but does not refer to them as BACT limits. *Id.* at 15. However, as DEQ elsewhere notes, a BACT limit is required for VOC emissions. *Id.* at 8–9.

[11] It is not clear if this was a review of all permits in the RBL Clearinghouse, permits in California's Clearinghouse, or information from other sources. Commenters would like the ability to review DEQ's search, and, if applicable, point DEQ to relevant permits that may not have been considered.

and shutdown emission limits more stringent than the limits adopted for Carty, none of which were ever discussed or compared. *See id.* at 11–12 (footnotes 3, 5, 6 to Table, which all indicate either direct emission limits lower than Carty or other limits, like capped hours that make the total emissions from startup and shutdown lower than Carty). The emissions limits proposed for startup and shutdown periods do not represent BACT, and unless an appropriate BACT limit is applied to all of the Carty unit's CO and VOC emissions, the permit application must be denied.

C. DEQ erred at Step 1 of the BACT Analysis by not Considering all Potential Controls.

For both VOC and CO, DEQ determined at Step 1 of BACT, potential controls included "[t]hermal oxidation, catalytic oxidation, and good design/operation of the combustion unit." Review Report, at 10. DEQ failed to consider alternative processes that could limit either of the pollutants. *See* NSR Manual, at B.11.

1. DEQ must consider energy storage under its VOC and CO BACT analyses

Coupling the Carty unit with battery or other energy storage could eliminate, or at least significantly reduce, emissions from startup and shutdown by avoiding the need to have the Carty unit routinely ramp up and down. While relatively new, such designs are widely available. *See e.g.* Chris Mieckowski, "Battery-Gas Turbine Combination Provides Power Plant Flexibility," POWER MAGAZINE, (Feb. 2, 2018)[12] (discussing use of integrated battery storage to limit natural gas plant ramping); SIEMENS, CO., ENHANCING GAS TURBINE POWER GENERATION WITH BATTERY STORAGE, Article No. EMMS-B10079-00-7600, 2 (2017)[13] (discussing available natural gas plant/battery combination that "can be installed as a retrofit in existing power plants or as added value for new installations"). Such configurations have been employed at comparable gas plants. *See e.g.* Nichola Groom, *Edison, GE Unveil New Battery Systems At California Gas Plants*, REUTERS, (Apr. 17, 2017)[14] (discussing Norwalk, CA, and and Rancho Cucamonga, CA Plants).

Commenters presume that PGE would argue that any use of battery storage would be "redefining the source" and thus need not be considered as BACT. *See* NSR Manual, at B.13. Because PGE has not fully and clearly articulated the basic design of the facility, and neither PGE's application nor DEQ's Review Report considered or discussed the issue, Commenters are unable to meaningfully address how energy storage may be in line with the facility's purpose. *See Helping Hand Tools*, 848 F.3d at 1194 (noting that to assess if prosed alternative "redefines

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[12] Available at: http://www.powermag.com/battery-gas-turbine-combination-provides-power-plant-flexibility/ (last visited Apr. 20, 2018) [Attachment 1].

[13] Available at: https://www.siemens.com/content/dam/webassetpool/mam/tag-siemens-com/smdb/energy-management/medium-voltage-power-distribution/medium-voltage-solutions/flyer/sistart/emms-b10079-00-7600-db-siestart-siestorage-en-gen-lowres.pdf (last visited Apr. 20, 2018) [Attachment 2].

[14] Available at: https://uk.reuters.com/article/uk-edison-intl-ge-batteries/edison-ge-unveil-new-battery-systems-at-california-gas-plants-idUKKBN17J1TD (last visited Apr. 23, 2018) [Attachment 3].

the source," the applicant must have "objectively discernable" purpose, which "cannot be motivated by cost savings or avoidance of risks"); *see also* OAR 340-216-0040 (requiring applicant to submit all necessary information). However, energy storage may not be categorically determined to be "redefining the source" without a fully reasoned analysis of the facility's fundamental purpose. *See In Re: La Paloma Energy Center*, 2014 WL 1066556 at *16 (EAB Mar. 14, 2014) ("[P]ermitting authorities should not simply dismiss alternative control options, such as cleaner fuels, as constituting redesign, thereby creating an 'automatic BACT off-ramp' from further consideration of the option."); *Helping Hand Tools*, 848 F.3d at 1194 (permitting authority must take "hard look" at facility's fundamental design to discern if an alternative design constituted "redefining the source). Requiring energy storage would neither affect PGE's fundamental purpose, nor require use of a different fuel source. Indeed, PGE has itself proposed renewable energy sources (like solar) as part of its larger designs for the site. *See* PORTLAND GENERAL ELECTRIC, REQUEST FOR AMENDMENT NO. 1 OF THE SITE CERTIFICATE FOR THE CARTY GENERATING STATION, 1-1 (Aug. 2016). It is unlikely that deploying on-site energy storage along side the gas turbine as a means of reducing startup and shutdown emisssions [offsetting some natural gas usage] would somehow undermine PGE's basic purpose. Thus, energy storage should not be considered a redefinition of the source, but instead must be considered in the BACT analysis, and failing to consider it renders the BACT analysis incomplete. As such, the permit application must be denied.

2. *DEQ must consider combustion unit optimization during periods of startup and shutdown as part of its VOC and CO BACT analyses.*

Additionally, although DEQ nominally cited "good design" as a potential control method, DEQ did not actually consider or discuss *any* other possible design of the combustion unit, despite several potential designs that may have lowered the emissions. *See* Review Report, at 10. At this step, designs that allowed for optimization of startup to reduce emissions should have been considered. For example, combined cycle plants can be designed to optimize the startup time and operate fully compliant with oxidation catalysts in as few as 30 minutes, and at as low a load as 20%. *See* RUCHTI, C., ET AL., COMBINED CYCLE POWER PLANTS AS IDEAL SOLUTION TO BALANCE GRID FLUCTUATIONS, 2 (2011).[15] Such a design is particularly relevant here, where, as DEQ acknowledges, startup and shutdown makes "a major contribution to the total amount" of CO and VOC emissions. Review Report, at 14 (CO); *id.* at 15 (VOC).

3. *DEQ must consider limiting the frequency and duration of both hot and cold startups as part of its VOC and CO BACT analyses.*

Also as part of "good design" DEQ should have considered options to optimize the many combustion unit parameters around startup and shutdown. For example, a design/operation parameter that enabled hot-startup level emission efficiencies (rather than cold) after the unit had been down for more than 12 hours (as the Draft Permit defines) would reduce startup emissions. *Compare e.g.* Review Report, at 12, Table, fn. 5 (defining any "cold" startup as only after ≥ 72

[15] Available at: http://gastopowerjournal.com/documents/110918_kraftwerkstechnisches_kolloquium_ccpp_as_ideal_so2.pdf (last visited Apr. 23, 2018) [Attachment 4].

hours down time) *with* OR. DEPT. ENVTL. QUALITY, STANDARD AIR CONTAMINANT DISCHARGE PERMIT, Permit No. 25-0016-ST-02, 6, Cond. 3.4(c); Cond. 3.5(c) (Draft, Jan. 1, 2018) [hereinafter "Draft Permit"] (defining "cold" startup after only 12 hours downtime). Such designs often employ a "warm" startup, which has more stringent emission limits than "cold," a design parameter not considered or even mentioned by DEQ. Review Report, at 12–13, fn. 5, 7. Other available design parameters allow for a stringent time-based limit on startup. *Id.* at 12, fn. 1. Although DEQ's own compilation of comparable source permit limits employ several combinations of these parameters, DEQ never considered any of them as possible methods to reduce emissions of either CO or VOC, nor did it ever discuss any justification for excluding these from the BACT analysis. But startup and shutdown are part of the BACT analysis.[16] *See* discussion *supra; see also* NSR Manual, at B.69 (example BACT analysis for gas turbine considering startup and shutdown in the analysis); *Russell City Energy Center, LLC*, 2010 WL 5573720, at *15 (BACT limit set for startup and shutdown); *Mississippi Lime Co.*, 2011 WL 3557194, at *6 (remanding improper BACT limit for startup).

Any of these designs – energy storage, optimized low-load units, design/operation parameters – could lower both CO and VOC emissions, particularly by controlling the startup and shutdown emissions DEQ expressed particular concern with. Each of these design possibilities must be part of the "comprehensive" list BACT requires assembled at Step 1. NSR Manual, at B.6.

4. DEQ must consider "good design" separately from "good combustion practices" as part of its VOC and CO BACT analyses

DEQ itself listed "good design" as a possible control method, but just as soon dismissed any possible options summarily only two paragraphs later. Review Report, at 10. DEQ conflated "good design" with "good combustion practices" and then concluded that catalytic oxidation removes more CO and VOC emissions "than good combustion practices alone," and that "[t]herefore, catalytic oxidation" is considered BACT. *Id.* This conclusion contains two errors. First, "good design" should not be conflated with "good combustion practices." Following manufacturer recommendations to properly *run the unit as designed* is inherently different than *optimizing the design* of the unit to be the least polluting unit possible. Second, good design of a combustion unit is a control method to be considered *in addition to* a pollution control like a catalytic oxidizer. Rather, these designs are about optimizing the unit in conjunction with an add-on control. *See e.g.* RUCHTI, C., ET AL., COMBINED CYCLE POWER PLANTS AS IDEAL SOLUTION TO BALANCE GRID FLUCTUATIONS, 4 (2011) (noting that that unit is designed to fully be fully emission compliant at low loads). Step 1 of BACT includes options that are a combination of add-on control (like an oxidizer) and designs that are inherently lower emitting. NSR Manual, at B.10. Thus, DEQ's summarily announced conclusion is in error.

[16] EPA has long considered startup and shutdown part of the normal operation of a source, and not exempted from the BACT analysis. *See In Re: Indeck-Elwood, LLC*, 13 E.A.D. 126, __, 2006 WL 3361087, at *33 (EAB Sept. 27, 2006) (compiling EPA statements).

5. DEQ cannot lawfully constrain its BACT analysis to just the existing technology at the Carty plant.

DEQ's approach to Step 1 of the BACT analysis seems to assume that whatever unit in whichever configuration PGE had already installed must be sufficient for BACT. Indeed, DEQ's ultimate "selection" of BACT turns out to be no different design and no more stringent operation parameter than PGE had already employed prior to this modification. *See* Review Report, at 5 (noting the unit already has a catalytic oxidizer); Draft Permit, Cond. 3.4–3.5 (setting emission limits for VOC and CO). The BACT analysis is not meant to merely accept what was already done. BACT is normally *pre-construction*, precisely to allow the permitting authority the fullest range of lower polluting alternatives. *See* 42 U.S.C. § 7475(a). However, the BACT analysis may not be rendered meaningless merely because PGE erred in calculating emissions for CO and VOC, which are well above the significance threshold, and failed to submit to a BACT analysis prior to constructing the unit.

To the extent that DEQ is implicitly considering the costs of retrofitting the Carty unit to rule out more efficient designs, it is wrong for two reasons. First, the costs to retrofit are not relevant here because PGE made the change (constructing the Carty unit) requiring NSR before the current Major NSR application, and the current application seeks to relax an emission limit that was previously relied on to avoid NSR. OAR 340-224-0070(2)(c)(B). PGE previously relied on a 99 ton per year CO emissions limit, which because it is one ton per year below the significance threshold, allowed them to avoid NSR for CO in the previous permitting action. *See* OR. DEPT. OF ENVTL. QUAL., OR. TITLE V AND ACID RAIN PERMIT TITLE V PERMIT, Permit No. 25-0016-TV-01, 19, Cond. 66 (Aug. 9, 2016) [hereinafter "Title V Permit"] (cross referencing ACDP 25-0016-ST-02 (12/29/10) Condition 3.4). PGE here seeks to dramatically relax its CO emissions limit, and thus any costs of retrofitting may not be considered in the BACT analysis. OAR 340-224-0070(2)(c)(B). Second, even if costs could be considered, they are properly counted at Step 3 of BACT. *See* NSR Manual, at B.8. Such considerations may not be used to artificially narrow the range of emissions control options at Step 1. *Id.* at B.5 ("*all* potential options are to be included) (emphasis added). And if costs are considered at Step 3, it may not be an implicit consideration. Rather, the applicant must produce relevant information discussing the cost effectiveness of the top ranked option(s), and the permitting authority may only select an alternative on a "reasoned basis" which is "well documented in the administrative record." *Mississippi Lime Co.*, 2011 WL 3557194, at *13, 11.

Because DEQ failed to consider all potential available options in Step 1, the BACT analysis is flawed, and the emissions limits set based on such analysis do not represent BACT limits. Accordingly, the permit application must be denied.

D. DEQ Erred at Step 2 of the BACT Analysis by Eliminating Technically Feasible Alternatives.

DEQ also erred at Step 2 of the BACT analysis, by eliminating every more stringent permitted limit for both CO and VOC on a flawed basis. *See* Review Report, at 13 (CO); *id.* at 14 (VOC). At Step 2 of the BACT analysis, a control option or emission limit gathered at Step 1 may be eliminated where it is technically infeasible. NSR Manual, at B.7. "A demonstration of

technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option." *Id.* Further, "a permit requiring the application of a certain technology or emission limit to be achieved for such technology usually is sufficient justification to assume the technical feasibility of that technology or emission limit*." Id.; see also In Re: Prairie State Generating Co.*, 13 E.A.D. 1, ___, 2006 WL 2847225, at *97, n. 85 (EAB Aug. 24, 2006). Where a permitted limit has not yet been demonstrated in operation, the limit is still considered feasible if the technology is both "available" and "applicable." NSR Manual, at B.17–B.21; *see also In Re: Maui Electric Company*, 8 E.A.D. 1, __, 1998 WL 666709, at *9–11 (EAB Sept. 10, 1998) (reviewing permitting authority determination of feasibility on available and applicable grounds). Technology used to reach the lower emission limit is "available" if it can be obtained through commercial channels, and is "applicable" if it can "reasonably be installed and operated on the source under consideration." NSR Manual, at B.17; *see also In Re: Pennsauken County, New Jersey, Resource Recovery Facility*, 2 E.A.D. 667, ___, 1988 WL 249035, at *3 (EAB Nov. 10, 1988) ("The question of availability for purposes of BACT is a practical, factual determination, using conventional notions of whether the technology can be put into use").

DEQ did not follow this process, but instead summarily eliminated *every* potential emissions limit more stringent that the limit proposed by PGE for both CO and VOC in a single paragraph devoid of analysis. Review Report, at 13 (CO); *id.* at 14 (VOC). DEQ, for both pollutants, noted that "many"[17] of the lowest permitted plants had not yet begun operation and concluded that the "level of control permitted for [the lower emitting plants previously permitted] will not be considered since the limits have not be demonstrated." *Id.* at 13 (CO); *id.* at 14 (VOC). This single sentence is the *only* analysis for why CO emission limits as low as 1.0 to 1.6 ppmvd (less than half of what Carty's proposed limit is), and VOC limits as low as 0.7 to 1.4 ppmvd (40% lower than Carty's proposed limit) were not considered. *Id.* at 12 (Limits for Greenville Power Station, VA). DEQ did not assess any factual demonstration of infeasibility for any of these (and PGE provided no such factual basis).

Looking only to limits actually demonstrated in practice fundamentally misunderstands BACT. BACT is inherently forward looking; the standard requires "the maximum degree of reduction of each pollutant" which "is *achievable* for such facility," not merely what has been achieved in the past. 42 U.S.C. 7479(3) (emphasis added); OAR 340-200-0020(17) (emphasis added); *see also Prairie State*, 2006 WL 2847225, at *41 ("the word "achievable," as used in the statute and regulations, mandates a forward-looking analysis of what the facility can achieve in the future"). Accordingly, the standard is a *presumption* of feasibility, unless the applicant *demonstrates* that the technology is infeasible. NSR Manual, at B.7 (noting requirement to demonstrate infeasibility and presumption of feasibility). DEQ's few-sentence rejection of nearly a dozen different, more stringent permitted limits puts this presumption backwards and so fails

[17] In addition to not actually conducting a technical feasibility analysis, Commenters also object to DEQ's selective inclusion of only a partial list of the more stringent limits possible, and then a universal conclusion to discount every other limit. *See* Review Report, at 11 (listing "*some* of the more recent determinations") (emphasis added); *id.* at 13 (citing "*many* of the lower emitting plants" to summarily discount all more stringent limits and conclude "the remaining facilities" are all less stringent that PGE's proposed limit) (emphasis added).

the evidentiary burden required in a BACT analysis. *See Mississippi Lime Co.*, 2011 WL 3557194, at *15 (remanding permit where "administrative record is devoid of any analysis of why another design fuel with [lowered emissions potential] was not available and thus, not technically feasible"); *Knauf Fiber Glass,* 1999 WL 64235, at *7 ("The technical feasibility analysis requires application of technical judgment on the part of the permitting authority"). Absent a reasoned, fact-based rationale for eliminating *each* of these limits, the presumption of technical feasibility requires these to be included in the remaining steps of the BACT analysis. *See* NSR Manual, at B.19. Accordingly, the permit application must be denied.

E. DEQ Erred at Step 3 of the BACT Analysis by Ignoring the Most Stringent Limits in Setting BACT.

Further, even if every single permitted limit not yet in operation were determined technically infeasible, DEQ still erred in declining to consider more stringent limits from permits that are currently in commercial operation, and thus are "demonstrated." *See id.* at B.17; *see also Indeck-Elwood, LLC*, 2006 WL 3361087, at *37 ("[T]he existence of a similar facility with a lower emissions limit creates an obligation for [the applicant] (and [permitting authority]) to consider and document whether that same emission level can be achieved at [the] proposed facility.").

At Step 3 of the BACT analysis, controls must be ranked by their stringency. NSR Manual, at B.7. For a fully transparent analysis, "a list should be prepared for each pollutant" which includes relevant information like control effectiveness,[18] emission rate, and economic impact. *Id.* at B.7–B.8. That is particularly true here, where at Step 2 several potential limits were eliminated on a vague and cursory basis. *See supra*, Note 17. DEQ did not prepare a list to allow meaningful comparison between emission limits, or conduct any form of comparison, suggesting that it believes every control more stringent than the ones proposed by PGE were eliminated at Step 2. *See* NSR Manual, at B.8 ("An applicant proposing the top control alternative need not provide cost and other detailed information"). However, at Step 2, DEQ's only justification for eliminating several more stringent limits was that the permitted facilities were not yet in operation. *See* discussion, *supra*; Review Report, at 13 (CO); *id.* at 14 (VOC). This justification (even if valid) does not apply to all more stringent permitted limits. PGE's own application noted some of facilities with more stringent permitted limits that are currently in commercial operation. *See* PGE Application, at 7–9, Table 7 (Row 9 [LS Power, West Depford[19]], Row 10 [Chouteau

[18] Commenters also note that ranking emission limits by control effectiveness, i.e. as a percent of emissions removed, is particularly necessary here where DEQ intends to set the primary emission limit as concentration-based but other emission limits as mass-based, and not all comparable permitted limits normalize to the same oxygen level for concentration-based limits. This makes comparable permitted limits more difficult to directly compare absent additional metrics like flow rate. Thus, the list at Step 3 would provide additional information to allow for public input.

[19] In operation since 2014. http://www.perennialpower.net/Portfolio/West-Deptford-Power-Station/ (last visited Apr. 21, 2018).

Power Plant[20]], Row 12 [So. Co. Georgia Power, McDonough[21]], Row 13 [Progress Energy Florida, Bartow[22]], Row 14 [Florida Power and Light, West County[23]]). None of these were considered or even mentioned by DEQ.

PGE's application notes that some of these more stringent limits were set as the result of LAER demonstrations, apparently as a justification to discount their consideration here. *See* PGE Application, at 7–9, Table 7. However, LAER-based permit limits must be considered in a BACT analysis and in fact are often the presumptively best control. NSR Manual, at B.5 ("Technologies required under [LAER] determinations are available for BACT purposes and *must* also be included as control alternatives and usually represent the top alternative.") (emphasis added); *see also Pennsauken County*, 1988 WL 249035, at *3 (the "fact that these projects were undertaken to comply with allegedly different legal requirements (LAER or California rules) and different control strategies is not especially material" to issue of availability of a BACT analysis). Although Commenters note that the commercial operation of the facility is not required before a more stringent permitted limit can be considered in the BACT analysis, *see* discussion *supra*, facilities in current commercial operation have emissions limits as low as 1.8[24] ppmvd for CO and either 0.3[25] or 0.7[26] ppmvd for VOC, both far more stringent than the limits proposed for Carty. *See* Draft Permit, at 6, Cond. 3.4–3.5 (limits for CO and VOC for Carty). At a *minimum*, these limits must be part of the Step 3 analysis. Where DEQ did not conduct a Step 3 analysis, it may not adopt less than the top control alternatives. Because the proposed CO and VOC emission limits for Carty are nowhere close to the most stringent control alternatives, these limits are not BACT, and DEQ must deny the permit application.

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[20] In operation since 2012. https://www.aeci.org/resources/natural-gas/chouteau/ (last visited Apr. 21, 2018).

[21] In operation since 2012. https://www.georgiapower.com/company/energy-industry/generating-plants/mcdonough-atkinson.html (last visited Apr. 21, 2018).

[22] In operation since 2009. https://www.progress-energy.com/assets/www/docs/company/plantbrochure.pdf (at p. 12) (last visited Apr. 21, 2018).

[23] Operation started 2009, fully operational since 2011. https://www.fpl.com/clean-energy/natural-gas/west-county.html (last visited Apr. 21, 2018).

[24] Georgia Power – McDonough, operational since 2012. *See* Attachment 5.

[25] Chouteau Power Plant, operational since 2012. *See* Attachment 6. PGE suggests this emission limit is not consistent with its permit. PGE Application, at 8, Table 7. However, PGE must factually support such assertion, and DEQ, as the permitting agency, is obligated to investigate the applicability of such facility. *See Mississippi Lime Co.*, 2011 WL 3557194, at *15 (reminding State that "its role as permit issuer requires the agency to investigate and examine recent regulatory determinations, especially if one is brought to the permit issuer's attention").

[26] Brunswick County Power Station, operational since 2016. https://www.dominionenergy.com/about-us/making-energy/natural-gas/brunswick-county-power-station (last visited Apr. 21, 2018). *See* Attachment 7.

F. DEQ erred in Setting Emissions Limits for CO and VOC.

1. DEQ did not account for all operating scenarios in setting emissions limits.

As a result of not conducting any comparison at Step 3 of the BACT analysis, DEQ failed to consider a number of options that would reduce emissions in setting the BACT limits for both CO and VOC. For example, DEQ did not consider setting different emission limits for when the duct burners are not firing. PGE and DEQ contemplated operation scenarios with and without duct burners operating, *see e.g.* Review Report, at 18. DEQ and PGE both noted that permits often set more stringent limits for operation without duct burners. *See e.g. id.* at 12, n.4; PGE Application, at 8, Table 7. Yet, DEQ did not consider or adopt emission limits that actually account for all operating scenarios. By setting an emission limit for each operating scenario (with duct burners and without) the limit is both more accurate and more stringent. *Compare e.g.* Attachment 3, at 11 (setting CO emission limit 62% lower when duct burner not operating and VOC emission limit 44% lower when duct burner not operating). Because DEQ did not assess alternative emission limits at Step 3 of the BACT analysis, and did not consider setting a limit for when duct burners are not operating, DEQ adopted less stringent emissions than other comparable facilities. Absent a reasoned, factual record-based rationale for why more stringent emissions cannot be set for the Carty facility, these emission limits are in error and the permit application must be denied. *See e.g. Mississippi Lime, Co.*, 2011 WL 3557194, at *11 (permitting authority must provided reasonable basis supported by administrative record for BACT determination).

2. DEQ did not assess requiring more stringent monitoring for VOC.

Further, in adopting the VOC emission limit, DEQ correctly noted that setting the emissions limit averaging time as a three hour rolling average would only be appropriate if the unit had a continuous emissions monitoring system (CEMS) for VOC. Review Report, at 14–15. However, rather than actually considering the more stringent monitoring of the emissions limit, DEQ simply adopted a 3-hour averaging time. *Id.* at 15. Although DEQ noted that CO emissions are "often a surrogate" for VOC emissions, *id.*, DEQ did not discuss or assess whether a CEMS for VOC would be rejected for cost, energy or other impacts that are employed to reject more stringent control options at Step 3 of the BACT analysis.[27] *See* NSR Manual, at B.7–B.8. Because a CEMS is a direct measure of the emissions, rather than an indirect surrogate that 'often' is comparable, and because it implicates the emission limit itself, and the stringency with which the emissions are monitored, this control must be considered as part of the BACT analysis. *See generally id.* at B.56 (monitoring and enforceability of BACT limit is part of BACT analysis).

In the alternative, DEQ could employ CO, which is monitored by a CEMS, as a surrogate to measure emissions of VOC. DEQ seems to prefer this route, stating "[s]ince CO emissions are

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[27] Such a control is available and employed on other comparable facilities, as noted in PGE's application. *See* PGE Application, at Attachment 7, pg. 2, Row 1 (noting VOC employing rolling average because monitored by CEMS). Thus, such control is to be considered at Step 3 of the BACT analysis. NSR Manual, at B.22.

often a surrogate for organic emissions . . . and since CO emissions are monitored with a CEMS, the CO emissions provide confidence that VOC emissions are well controlled[.]" Review Report, at 15. Commenters agree that CO *can* be a surrogate for VOC. U.S. Envtl. Prot. Agency, *Basic Information About Air Emissions Monitoring*.[28] However, DEQ cannot conclude that "the CO CEMS should provide confidence that VOC emissions are well controlled on an on-going basis" on the mere *assumed* correlation between CO and VOC. Review Report, at 15. If DEQ intends to rely on the correlation between CO and VOC to reflect VOC emissions on an "on-going basis," *id.*, DEQ must establish a variable adequately reflecting the surrogate relationship between the two pollutants to enable a determination of compliance with VOC emissions based on CO data. *See e.g.* SAN DIEGO AIR POLLUTION CTRL. DIST., ENGINEERING EVALUATION AUTHORITY TO CONSTRUCT, SDG&E PALOMAR ENERGY CENTER, ID No. APCD2001-SITE-04276, Att. 2 at 2–3, Cond. 7 (Apr. 14, 2016)[29] (compliance with VOC emissions assessed using "the District approved VOC/CO surrogate relationship, the CO CEMS data, and a 3-clock hour average" and requiring that "[t]he VOC/CO surrogate relationship shall be verified and/or modified, if necessary, based on source testing"). DEQ must require *actual* and accurate data – typically a source test as the San Diego Air District requires – in order to establish a site-specific relationship between CO and VOC emissions. DEQ may not rely on the general proposition that "often" CO and VOC emissions are correlated to satisfy the requirement that emission limits be enforceable and monitored. *See* OAR 340-216-0066(3)(c); NSR Manual, at B.56.

II. The Draft Permit Lacks Sufficient Monitoring Requirements for VOC

As a result of not incorporating a CEMS, or actual CO/VOC surrogate variable for VOC, the draft permit is devoid of *any* specific monitoring of VOC at Carty after the initial stack test. *See* Draft Permit, at 8–15, Cond. 5 (listing Carty-specific VOC monitoring only during an initial stack test). Even if DEQ determines that CEMS is not required for VOC, DEQ must require regular verification of compliance with the VOC emission limits. OAR 340-216-0066(3)(c); *see also* NSR Manual, at B.56 (Emission limit for BACT must require compliance verification). As written in the Draft Permit, after the initial stack test, only the PSEL limit requires annual compliance demonstration. Draft Permit, at 14–15, Cond. 5.6. The PSEL limit includes VOC from all of the facility, which comprises multiple separate units, including the Boardman coal boiler, and auxiliary boilers for both Carty and Boardman, all of which emit VOCs. Thus, compliance with the annual PSEL limit (and the facility-wide calculations used to verify compliance) does not ensure compliance with Carty's VOC limit.

If DEQ declines to require a CEMS, or to establish a verifiable CO/VOC surrogacy variable to reliably assess VOC emissions based on CO emissions–the means often employed by other comparable facilities to monitor emissions–DEQ must at least require annual verifications of the Carty unit's VOC emissions via stack tests to comply with OAR 340-216-0066(3)(c) and to ensure the BACT limit is enforceable. Although OAR 340-216-0066(3)(c) allows for DEQ

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[28] Available at: https://www.epa.gov/air-emissions-monitoring-knowledge-base/basic-information-about-air-emissions-monitoring#continuous (last visited Apr. 27, 2018).

[29] Available at: https://www.sdapcd.org/content/dam/sdc/apcd/notices/APCD_PEC_ATC_Evaluation.pdf (last visited Apr. 25, 2018) [Attachment 8].

discretion in requiring emissions monitoring, that discretion is curtailed here by OAR 340 Div. 212. Because Carty is required to obtain an Oregon Title V permit,[30] the unit is subject to Div. 212. OAR 340-212-0200(1). Thus, the Carty unit must have emissions monitoring that meets the requirements of OAR 340-212-0210. Such monitoring must be sufficiently designed to provide "a reasonable assurance of ongoing compliance with [the] emission limitation." *Id.* at 340-212-0210(1)(b). As currently drafted, DEQ does not have any verification that Carty's operation will comply with VOC emissions on an "ongoing" basis, and as such, this proposed emission limit is deficient under Oregon regulations.

The BACT analysis is among the most critical elements of any PSD permitting process. *Mississippi Lime, Co.*, 2011 WL 3557194, at *11. Here, not all emissions limits were even made part of the BACT analysis; the BACT analysis did not comprehensively include all possible control options at Step 1; the analysis eliminated without adequate justification multiple controls at Step 2, and did not perform Step 3, ignoring multiple more control options, failing to account for all operation scenarios, and declining to require compliance verifications for limits set. All of the proposed permit limits for both CO and VOC are thus in error, and require a rejection of the permit application.

III. PGE has Failed to Comply with the PSD requirements Triggered by its Greenhouse Gas Emissions.

According to DEQ's Review Report, the combined PGE facility's "proposed" netting basis for greenhouse gases (GHG) emissions is 5,670,300 tpy while the "proposed" plant site emission limit (PSEL) for those same emissions is 6,796,000 tpy. Review Report, at 6. That is a difference in 1,125,700 tpy of pollution;[31] such an increase is well above the relevant significant emission rate (SER) for GHG emissions, which is set at 75,000 tpy. *See* Review Report, at 9; OAR 340-200-0020(161)(a). DEQ regulations state that facilities that are subject to PSD for pollutant emissions from sources other than GHGs, are also subject to PSD for GHG emissions under certain circumstances. OAR 340-224-0010(1)(c). In fact, in the 2010 ACDP Review Report (for Carty's initial construction) DEQ admits:

> The existing Boardman Plant is a major source of GHG emissions. The proposed Carty Plant will increase GHG emissions by more than 75,000 tons per year. The

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[30] The facility has a current Title V permit, which includes Carty, and DEQ acknowledges that the current ACDP permit modification must be incorporated into the facility's existing Title V Permit via amendment. *See* Draft Permit, at 3, Cond. 1.3.

[31] The value provided here is 200 tpy higher than the value provided in the SER Analysis section of the Review Report, where DEQ calculated the "Requested Increase Over Previous Netting Basis." *See* Review Report, at 9. For determining SERs for purposes of PSD applicability, it seems only logical to calculate the difference between the PSEL and netting basis by using the "proposed" values for both, rather than measuring the "previous" netting basis against the "proposed" PSEL, which it appears is what DEQ did here. *See id.* at 8, 9. Nevertheless, the difference of 200 tpy is not particularly relevant since either value constitutes an increase in GHG emissions well above the 75,000 tpy SER threshold for GHGs.

> proposed Carty Plant is subject to PSD for PM10 and NOx. Therefore, under EPA's tailoring rule, the Carty Plant would be subject to PSD for GHG after January 2, 2011.

OREGON DEPT. OF ENVTL. QUALITY, STANDARD AIR CONTAMINANT DISCHARGE PERMIT REVIEW REPORT, No. 25-0016-ST-02, Application No. 23919 (2010), at 7. [hereinafter "2010 Review Report"]. In issuing the original permit in 2010, DEQ noted it would not have authority to fully regulate GHGs until Jan. 2, 2011. *Id.* Neither DEQ nor PGE disputes that DEQ must subject all significant GHG emissions to a BACT analysis for sources already subject to New Source Review (NSR) for permits today. *Id.*; OAR 340-224-0010(1)(c).

With its 2018 application, PGE is voluntarily reopening that initial 2010 permit for modification. Thus, where PGE is also seeking a modification in its GHG PSEL as part of re-opening the 2010 permitting, the current regulations apply to subject PGE's facility – either Boardman or Carty – to PSD for its GHG emissions, as explained below.

A. DEQ regulations preclude PGE from setting its proposed PSEL for GHG emissions at its chosen level.

Under the relevant regulations, DEQ may set a PSEL "equal to the source's potential to emit, netting basis or a level requested by the applicant, *whichever is less, except as provided in section (3) or (4)*." OAR 340-222-0041(2) (emphasis added). That is to say, unless PGE meets the criteria provided in OAR 340-222-0041 sections (3) or (4) it cannot set its PSEL for GHG emissions above its netting basis, which it has here. Section (3) deals only with PM2.5 and is therefore inapplicable to GHGs. Section (4) states:

> *If an applicant wants an annual PSEL at a rate greater than the netting basis, the applicant must*, consistent with OAR 340-222-0035:
> (a) Demonstrate that the requested increase over the netting basis is less than the SER; or
> (b) For increases equal to or greater than the SER over the netting basis, *demonstrate that the applicable Major NSR or State NSR requirements in OAR 340 division 224 have been satisfied, except that an increase in the PSEL for GHGs is subject to the requirements of NSR specified in 340-224-0010(1)(c) only if the criteria in 340-224-0010(1)(c) are met*.

OAR 340-222-0041(4) (emphasis added). In line with PGE's request, DEQ proposed to set the annual PSEL for GHG emissions at a level above the netting basis that exceeds the SER for GHGs. *See* Review Report, at 6, 8.

To increase the GHG PSEL as requested, PGE must demonstrate, and DEQ must ensure, that the Major NSR requirements of "OAR 340 division 224" have been satisfied. GHGs are subject to PSD, *inter alia*, where the source is a new source that will emit GHGs at a rate equal to or greater than the SER. OAR 340-224-0010(1)(c)(A). As DEQ acknowledged in the 2010 Review Report, the Carty plant would have been subject to PSD—and thus NSR—for its GHG

emissions following its implementation of EPA's tailoring rule.[32] *See* 2010 Review Report, at 7. Nevertheless, DEQ explicitly declined to require a BACT limit primarily because, as explained above, it did not yet have authority and had not established the relevant regulations to regulate GHG emissions. *Id.* Thus, the facility never had to satisfy the relevant NSR or PSD requirements for GHG emissions as mandated by OAR 340-22-0041(4) above in order to justify setting its annual PSEL for GHG emissions above the netting basis in this case.[33]

Thus, because PGE has not demonstrated that the "applicable Major NSR requirements" for GHGs in Division 224 have been satisfied for the Carty Plant, DEQ may not authorize an increase in the GHG PSEL "equal to or greater than the SER over the netting basis." OAR 340-222-0041(4)(b).

B. DEQ's 'existing capacity' Rationale is not Supported, and Violates DEQ Regulations to Allow a PSEL Increase Well in Excess of the Relevant SER for GHG emissions.

PGE asserts that the increase in GHG emissions—i.e., the difference between the netting basis and PSEL—"is greater than [the] SER but is due to use of the coal-fired boiler capacity that existed during the baseline period." Review Report, at 8. DEQ does not provide any support from the regulations for this justification. Further, DEQ fails to actually explain or break down the calculation for determining that existing capacity and how it measured it against the proposed PSEL. Commenters, following DEQ's regulations, calculate that number as follows.

DEQ provides in the 2018 Review Report an overall baseline emission rate of 5,670,500 tpy. *Id.* at 6. DEQ also simplifies the regulations on how to calculate the appropriate netting basis, explaining that "[t]he netting basis is defined as the baseline emission rate minus any emission reductions required by rule, order or permit condition, minus any unassigned PSEL emission reductions, minus any emission credit transfers, plus any emission increases through

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[32] Although EPA's tailoring rule was impacted by the Supreme Court ruling in *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427, 2448–49 (2014), GHG emissions may still be subject to PSD if the relevant source is already a major source, and therefore subject to PSD, for any other regulated pollutant. Oregon regulations reflect this change. OAR 340-224-0010(1)(c).

[33] Although minor, it is also worth noting an error made by DEQ in the 2018 Review Report. DEQ asserts that the "previous PSEL" value provided is the PSEL contained in the current Title V permit issued on August 9, 2016. Review Report, at 8. The PSEL value provided in the Title V permit is 6,795,900 tpy. Title V Permit, at 29. However, the value DEQ provided as the "previous PSEL" in the 2018 Report is 6,796,100 tpy, and comparing this value to PGE's "proposed PSEL" of 6,796,000 tpy yields an apparent 100 tpy decrease in the PSEL requested. Review Report at 6. But beginning with the "previous PSEL" value from the Title V permit instead—6,795,900 tpy—and comparing it to the "proposed PSEL" in the 2018 Review Report and draft permit—6,796,000 tpy—it instead reveals an apparent increase of 100 tpy between the previous and proposed PSELs. This unexplained difference in the values is not relevant to any of the NSR calculations, but that DEQ claims to have approved a decrease in the requested PSEL when there will instead in fact be a small increase illustrates a lack of accuracy, clarity, and perhaps even candor, on behalf of DEQ.

NSR/PSD approvals. [OAR 340-222-0046(3)]." *Id.* However, without actually explaining these adjustments for which the regulations allow, a slightly different netting basis is proposed—5,670,300 tpy—that is 200 tpy less than the baseline emissions rate. *Id.* Of that value, 4,351,900 tpy comes from the Boardman coal boiler, the implication being that the remaining 1,318,400 tpy of GHG pollution is attributable to the Carty Plant, which is supported by another table provided in the 2018 Report which lists a netting basis of 1,318,400 tpy in 2021—the year after PGE agreed "to cease burning coal" at the Boardman Plant *See id.* at 6–7. Subtracting the proposed netting basis—5,670,300 tpy—from the proposed PSEL—6,796,000 tpy—yields 1,125,700 tpy. *See* OAR 340-222-0041.[34] Commenters assume that this value is what DEQ asserts is the existing capacity from the Boardman coal boiler.[35]

DEQ regulations define capacity as: "the maximum regulated pollutant emissions from a stationary source under its physical and operational design" OAR 340-200-0020(19). Based on the above, Commenters assume that the claimed coal boiler "capacity" that existed during the baseline period did not get calculated into the baseline emission rate—and thus the netting basis—or else PGE would not be trying to justify a difference between its netting basis and proposed PSEL based on this capacity. This suggests that the baseline emission rate during the selected 2010 baseline period for the coal boiler was based on actual emissions.[36] However, it appears that the baseline emission rate for the Carty Plant was based on the potential to emit during that baseline period. *See* Review Report, at 6. Ostensibly, this is the cause of the discrepancy between PGE's proposed netting basis and PSEL: PGE set the Boardman unit's baseline rate for GHGs at actual emissions during the baseline period, while setting its proposed PSEL based on the Boardman unit's potential to emit. DEQ's explanation then that the difference in these values represents Boardman's existing capacity during the 2010 baseline

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[34] Commenters are confident that this is the correct calculation to make for multiple reasons. First, DEQ itself compares the proposed PSEL to the netting basis in its SER analysis. *See* Review Report, at 8. Second, as explained above, in the DEQ regulations that instruct facilities how to calculate a source specific annual PSEL, DEQ provides that "[i]f an applicant wants an annual PSEL at a rate greater than the netting basis," the applicant must meet certain requirements. OAR 340-222-0041(4). Thus, the calculation pertinent to this analysis is the difference between the netting basis and the PSEL, and logically one must compare the "proposed" values of each of these numbers as opposed to their "previous" values since what is being proposed is what naturally appears in the 2018 draft permit. *See* Draft Permit, at 8 (providing a PSEL for GHGs that matches the "proposed" PSEL value from the 2018 Review Report).

[35] This value differs slightly from that which appears in the 2018 Review Report. *See* Review Report, at 9. An explanation for the apparent difference is provided above. *See supra* note 31.

[36] Commenters note that the regulations do not explicitly permit or prohibit this approach. The regulations say only that pollutants that became regulated *after* May 1, 2011 are set at actual emissions during the baseline period. OAR 340-222-0048(5). There does not appear to be any comparable provision covering how to set the baseline rate for pollutants that became regulated *before* that May 1, 2011 date. Nevertheless, the math above suggests that PGE set the Boardman unit's baseline rate at the level of actual emissions during the 2010 baseline period.

period is obvious, but as concluded above, PGE has not met the regulatory criteria that would allow DEQ to approve a PSEL that exceeds the netting basis as it does here. Principally, those criteria would require compliance with division 224 NSR standards, which under PSD would require a BACT analysis. *See* OAR 340-222-0041(4); 340-224-0070(2).

C. PGE is attempting to game the regulations, allowing the Carty Plant to escape PSD by using the Boardman Plant as a scapegoat.

The baseline period chosen by PGE for all of its GHG emissions—at both Boardman and Carty—is 2010. Review Report, at 6. Because PGE first obtained a permit to construct the Carty Plant in 2010—*during* this baseline period—DEQ asserts that the gas plant's potential to emit may be used to calculate the "baseline PSEL," and thus the Plant essentially escapes PSD regulation for its GHG emissions. *See id.* It is not clear what DEQ means by "baseline PSEL,"[37] but assuming DEQ means "baseline emissions rate," this is PGE attempting to negate the tradeoff it knowingly made earlier. PGE patently choose 2010 as its baseline year intentionally so that all of the Carty Plant's potential to emit would continue to escape PSD regulation as it explicitly did in the 2010 permit. *See* 2010 Review Report, at 7. However, having to use that same 2010 baseline period for all of its GHG emissions—including those from its Boardman coal boiler—PGE's calculations yielded a netting basis and PSEL that would appear to subject the Boardman Plant to PSD requirements if it plans to operate at its actual highest capacity. DEQ now seeks to justify allowing PGE to substantially increase its GHG emissions above the purposely chosen netting basis using its existing "capacity" rationale, suggesting that the large difference between the netting basis and the proposed PSEL does not trigger PSD.

D. To comply with DEQ regulations, PGE must either reduce its GHG PSEL, or subject the facility to PSD review, including a BACT analysis, for GHGs.

As noted above, PGE chose 2010 as its baseline period, presumably to avoid subjecting the Carty Plant to more stringent GHG emissions restrictions, but now is trying to avoid the consequences of that decision. Ultimately, DEQ and PGE have two options for how to address the discrepancy between the proposed PSEL and netting basis noted above. First, PGE could stay the course and rely on a 2010 baseline for its GHG emissions, but then DEQ must impose, and

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[37] DEQ states in the 2018 Review Report that the Carty Plant's potential to emit was "included in the baseline PSEL," but that statement conflates two distinct terms with different meanings: "baseline emission rate" and "PSEL." *See* Review Report, at 6. Based on the context, Commenters assume that DEQ meant to say that the Plant's potential to emit was included in the "baseline emission rate," but there are two potential alternate meanings—neither of which would support DEQ's permitting decision here. First, if DEQ used "baseline PSEL" to mean "*previous* PSEL," it would have no bearing on the proposed PSEL because (a) this is a voluntary reopening of the old 2010 permit which at the time of issuance was clearly not yet incorporated into the Title V permit issued in 2016; and (b) the regulations establishing the method for setting a source specific annual PSEL do not authorize reliance on any previous PSEL. *See* OAR 340-222-0041(4). Second, if DEQ used "baseline PSEL" to mean "*proposed* PSEL," the permit would be contrary to OAR 340-22-0041(2), which allows the potential to emit to be chosen as the proposed PSEL *only* if that emissions level does not exceed the netting basis.

PGE would have to accept, a reduced PSEL—likely equal to its netting basis—in accordance with DEQ regulations. *See* OAR 340-222-0041(2).[38]

Alternately, PGE may select an alternative baseline year, which would set the netting basis for the Carty Plant at zero, thereby subjecting the plant to PSD requirements and a BACT analysis for its GHG emissions. For GHG emissions specifically, DEQ regulations permit PGE to choose as its baseline period "any consecutive 12 calendar month period during the calendar years 2000 through 2010." OAR 340-22-048(1)(b). The regulations then dictate that a source's netting basis is zero for "[a]ny regulated pollutant emitted from a source that first obtained permits to construct and operate after the applicable baseline period for that regulated pollutant, and has not undergone NSR for that regulated pollutant." OAR 340-222-0046(1)(c)(A). In other words, choosing any permissible baseline period *other than* the year in which the Carty Plant obtained its permit—e.g., anytime between 2000 and 2009 that is representative of Boardman's actual capacity—would set the netting basis for the Carty Plant at zero; thus, the large difference between zero and PGE's proposed PSEL for GHG emissions would subject those GHG emissions from Carty to PSD, and therefore would require a BACT analysis.

In sum, the amount by which PGE's proposed PSEL for GHG emissions exceeds its proposed netting basis—1,125,700 tpy—is well above the relevant SER for GHGs—75,000 tpy. However, neither the Boardman Plant nor the Carty Plant have ever been subject to NSR/PSD requirements for GHG emissions as mandated by OAR 340-222-0041(4) in order to justify approval of such a high PSEL. DEQ does not support its existing capacity justification for approving that PSEL with any regulatory authority. It is in fact contrary to the most natural reading of DEQ's regulations. Accordingly, DEQ may not increase PGE's PSEL for GHGs on this rationale. Since PGE is voluntarily reopening its 2010 permit to increase emission levels even though updated GHG regulations are in place, PGE may either maintain a 2010 baseline period, and reduce its proposed PSEL to a permissible level, or it may choose a different allowable baseline period, excluding Carty from the netting basis, and meet all the NSR requirements for GHG emissions from the Carty unit. However, DEQ cannot rely on unexplained calculations and ignore its regulations to avoid imposing NSR requirements while allowing a drastic increase in GHG emissions.

IV. Because PGE has Failed to Submit Multiple Required Air Impact Analyses, DEQ Must Either Ensure the Required Analyses are Submitted Prior to a Decision, or Must Deny the Application.

[38] The only way to retain the increased PSEL having selected 2010 as its baseline period, would be to subject the Boardman Plant to BACT for those existing capacity emissions. Commenters agree that it makes little sense to subject the Boardman Plant to such requirements, especially when the regional haze regulations mandate that the "boiler at the source must permanently cease burning coal by no later than December 31, 2020." OAR 340-223-0030(1)(e). However, this is PGE's own doing and until Boardman is shutdown entirely, all of its emissions, including GHGs, *must* comply with DEQ regulations.

A. PGE has Failed to Submit the Required Analysis of Potential Impacts to Visibility in the Columbia River Gorge National Scenic Area.

DEQ is required to "carry out [its] respective functions and responsibilities in accordance with . . . the Columbia River Gorge National Scenic Area Act." ORS § 196.155. As applied here, this statutory mandate means DEQ must ensure that PGE's proposal complies with the requirement that "[a]ir quality [in the National Scenic Area] shall be protected and enhanced, consistent with the purposes[39] of the Scenic Area Act." Management Plan for the Columbia River Gorge National Scenic Area at I-3-32. Furthermore, in order to ensure compliance with these mandates, state law requires an applicant for a DEQ air pollution permit to submit an analysis of potential impacts to visibility in the Columbia River Gorge National Scenic Area. Unfortunately, PGE has failed to submit the required analysis, making it impossible for DEQ, the National Scenic Area agencies, and the public to evaluate the potential impacts of the proposal on the National Scenic Area.

Pursuant to OAR 340-224-0070(3)(a)(B), "the owner or operator of a federal major source must comply with OAR . . . 340-225-0070." Carty Unit 1 is a federal major source, as previously acknowledged by DEQ. OREGON DEPT. OF ENVTL. QUALITY, TITLE V REVIEW REPORT, No. 25-0016-TV-01, Application No. 27773, at 1; DEQ, Review Report, at 12. Thus, 340-224-0070(3)(a)(B) is triggered, and the proposal must comply with OAR 340-225-0070. PGE expressly acknowledges this requirement in its application. Permit Application, at 11 & n. 1 ("PGE must provide an air quality impacts analysis in accordance with OAR . . . 340-225-0070 for each pollutant subject to major NSR.") (*citing* OAR 340-224-0070(3)).

OAR 340-225-0070(4)(b) and (c), in turn, require PGE to "conduct a visibility analysis on the Columbia River Gorge National Scenic Area if it is affected by the source" and to "submit all information necessary to perform any analysis or demonstration required by these rules." PGE previously admitted that the National Scenic Area is affected by Carty and submitted a visibility analysis for the National Scenic Area in its application for Carty Unit 1. *See, e.g.*, PORTLAND GENERAL ELECTRIC, CARTY POWER PLANT PREVENTION OF SIGNIFICANT DETERIORATION APPLICATION (Dec. 2009), at 40. Now, although PGE is proposing significant increases in emissions of VOCs at Carty, and despite the fact that VOCs are a known contributor to visibility impairment, PGE has completely failed to provide *any* analysis of visibility impacts within the National Scenic Area.

Pursuant to the above-cited authorities, PGE must prepare and submit an analysis of the proposal's impacts to air quality, including visibility impacts, in the National Scenic Area. The analysis should use actual emissions data from Carty now that it is already in operation, and

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[39] The first and primary purpose of the Scenic Area Act is "to establish a national scenic area to protect and provide for the enhancement of the scenic, cultural, recreational, and natural resources of the Columbia River Gorge." 16 U.S.C. § 544a(1). The second purpose of the Scenic Area Act is to "protect and support the economy of the Columbia River Gorge area," but only in a manner consistent with the first purpose. 16 U.S.C. § 544a(2). The Act's second purpose is subordinate to the first purpose. *Id.*

should also factor in the proposed increases in VOC emissions into modeling of potential impacts. If PGE fails to submit the required analysis, its application must be denied.

B. PGE has Failed to Submit the Required Analysis of Potential Impacts to Visibility and Other Air Quality Related Values in Class I areas.

As discussed above, PGE's proposal "must comply with OAR . . . 340-225-0070." OAR 340-224-0070(3)(a)(B). OAR 340-225-0070, in turn, requires PGE to "demonstrate that the potential to emit any regulated pollutant at a [significant emission rate] in conjunction with all other applicable emission increases or decreases, including secondary emissions, permitted since January 1, 1984 and other increases or decreases in emissions, will not cause or contribute to significant impairment of visibility [in] any Class I area," and to "submit all information necessary to perform any analysis or demonstration required by these rules," "including analysis of anticipated impacts on Class I area air quality related values." OAR 340-225-0070(3)(a), (4)(a), (4)(c).

Despite the requirements cited above, PGE's application for proposed increases in VOC emissions contains no discussion—let alone analysis—of impacts to visibility and other air quality related values in Class I areas. Without the required analysis, it is impossible for DEQ, the Federal Land Managers, and the public to evaluate the impacts of this proposal. Pursuant to the above-cited authorities, PGE must prepare and submit an analysis of the proposal's impacts to air quality related values, including visibility, within Class I areas. The analysis should use actual emissions data from Carty now that it is already in operation and should factor in the proposed increases in VOC emissions into modeling of potential impacts. Once PGE submits the required analysis, it must be shared with the Federal Land Managers. OAR 340-225-0070(3), (4)(d), (5), (6)(b), (10). If PGE fails to submit the required analysis, its application must be denied.

C. PGE has failed to submit the required deposition modeling for receptors in Class I areas and the Columbia River Gorge National Scenic Area.

Pursuant to OAR 340-225-0070(7), "[d]eposition modeling is required for receptors in PSD Class I areas and the Columbia River Gorge National Scenic Area where visibility modeling is required." As discussed above, visibility modeling is required for these areas. Thus, deposition modeling is also required. Despite these requirements, PGE has failed to submit the required deposition modeling. Without the required analysis, it is impossible for DEQ, the Federal Land Managers, the National Scenic Area agencies, and the public to evaluate the impacts of this proposal.

PGE must prepare and submit deposition modeling for Class I areas and the National Scenic Area. The analysis should use actual emissions data from Carty now that it is already in operation and should factor in the proposed increases in VOC emissions into modeling of potential impacts. Once PGE submits the required analysis, it must be shared with the Federal Land Managers. OAR 340-225-0070(3), (7), (10). If PGE fails to submit the required analysis, its application must be denied.

D. PGE has failed to submit the required analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the proposal.

Pursuant to OAR 340-224-0070(3)(a)(B), "the owner or operator of a federal major source must comply with OAR 340-225-0050[(3)[40]] and 340-225-0070." Those rules, in turn, mandate that "[t]he owner or operator of a source or modification must . . . provide an analysis of . . . the impairment to visibility, soils and vegetation that would occur as a result of the source or modification, and general commercial, residential, industrial and other growth associated with the source or modification," OAR 340-225-0050(3)(a), and, similarly, that "[t]he owner or operator subject to OAR . . . 340-224-0070(3) must provide an analysis of the impact to visibility that would occur as a result of the proposed source and general commercial, residential, industrial, and other growth associated with the source," OAR 340-225-0070(9). These required analyses are not limited to Class I areas nor the Columbia River Gorge National Scenic Area, but rather require analysis of impacts to visibility, soils, and vegetation in all areas, including Class II and Class III areas. *See, e.g.*, OAR 340-225-0050 ("Requirements for Analysis in PSD Class II and Class III Areas).

Despite these requirements, PGE's application does not appear to contain any discussion—let alone analysis—of the potential impairment to visibility, soils and vegetation that would result in Class II areas as a result of PGE's proposed emissions increases. Without the required analysis, it is impossible for DEQ, the Federal Land Managers, and the public to evaluate the impacts of this proposal. Pursuant to the above-cited authorities, PGE must prepare and submit an analysis of the proposal's impacts to visibility, soils, and vegetation. The analysis should use actual emissions data from Carty now that it is already in operation and should factor in the proposed increases in emissions into modeling of potential impacts. If PGE fails to submit the required analysis, its application must be denied.

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[40] In OAR 340-224-0050(2)(a) and 340-224-0070(3)(a)(B), the cross-references to OAR 340-225-0050(4) are scrivener's errors; the intended references are to OAR 340-225-0050(3). These scrivener's errors are evident upon review of the language of OAR 340-225-0050(4) (which contains no substantive requirements), as well as prior regulations and rulemaking documents. *See, e.g.*, OAR 340-222-0041(4)(b)(D) (2014) ("For federal major sources, the applicant must demonstrate compliance with AQRV protection in accordance with *OAR 340-225-0050(3)* and 340-225-0070.") (emphasis added); OAR 340-222-0041(4) (2014) ("Additional Requirements for Federal Major Sources: The owner or operator of a federal major source subject to this rule must provide an analysis of the air quality impacts for the proposed source or modification in accordance with *OAR 340-225-0050(3)* and 340-225-0070.") (emphasis added); DEQ, Crosswalk of proposed revisions to air quality permitting, Heat Smart, and gasoline dispensing facility rules (June 16, 2014), http://www.oregon.gov/deq/Rulemaking%20Docs/AQpermCwalk.pdf, at 114–15, 122–23 (rulemaking document discussing the cross-references to OAR 340-225-0050(3) and indicating no intent to change those cross-references to OAR 340-225-0050(4)).

E. DEQ Erred in Waiving the Requirement for Monitoring of VOCs for the Ambient Air Quality Analysis.

DEQ additionally erred in not requiring an adequate analysis to ensure VOC emissions from Carty do not cause a violation of the ozone standards. As DEQ notes, Oregon regulations specifically require an ambient impact analysis, including ambient ozone monitoring data, for any increase of 100 tpy or more of VOCs. OAR 340-224-0070(1)(a)(B)(vi); *see also* Review Report, at 19. Despite this specific requirement, DEQ purports to use the general authority of relying solely on background data in lieu of monitoring. Review Report, at 19 (*citing* OAR 340-224-0070(1)(a)(A)(vii)). DEQ further states that it considers background data collected 45 kilometers away from the Carty plant from no more recently than four years ago to be "representative and conservative" and thus "[n]o additional ozone monitoring" will be required. *Id.*

This 'analysis' is deficient for two reasons. First, this data cannot be considered representative because Oregon regulation specifies parameters for sufficient representative monitoring data for ozone. OAR 340-224-0070(1)(a)(B)(vi). That regulation, specific to VOC, permits representative data in lieu of specific monitoring only where "the existing representative monitoring data shows maximum ozone concentrations are less than 50 percent of the ozone ambient air quality standards based on a full season of monitoring." *Id.* The representative data DEQ purports to rely on neither shows maximum concentrations are less than 50% of the standard, nor does it break down data to show concentration variations by season. DEQ notes that the standard is 75 parts per billion (ppb). Review Report, at 19. The most recent ambient monitoring, in 2014, shows a concentration of 64 ppb, well above 50% of the standard. *Id.* Further, all data supplied is only a single concentration for an entire year, and does not make any distinction based on seasonal variation. *Id.* This data does not meet the parameters DEQ regulation requires for waiving monitoring for VOC. OAR 340-224-0070(1)(a)(B)(vi). Thus, this data cannot be considered representative by DEQ, and is not sufficient to waive the requirement to submit an analysis of the ambient air quality of the area. OAR 340-224-0070(1)(a).

Second, even if this data could be used, DEQ has not provided any rationale as to why this data is sufficient given both the distance from the Carty facility and the age of the data. Even if DEQ could avoid the VOC specific regulation and rely on the general authority to waive the increment analysis requirement – which it cannot – DEQ must provide a rational explanation of why four to nine year old data collected 45 kilometers away from the source is sufficiently representative and conservative. Absent a reasoned explanation, this data is not sufficient to justify waiver of the requirement to ensure PSD increments and the NAAQS are not exceeded. Absent a full and reasoned analysis, that comports with Oregon regulation which demonstrates that the Carty VOC increase will not exceed the ozone standards, DEQ must deny the permit application.

Conclusion

For the forgoing reasons, Commenters respectfully request that DEQ deny the permit application. Short of denying the permit application, DEQ must address all of the omissions and errors identified above. Particularly, DEQ must redo the BACT analysis to conform to legal

requirements, including for CO, VOC, and GHGs, and set emission limits based on the most stringent controls achievable, rather than the applicant's recommendations. Additionally, DEQ must require PGE to conduct an adequate air impact analysis prior to approval of the permit. Proper analysis and regulation of Carty's emissions that is consistent with the federal Clean Air Act and Oregon's regulations implementing the Act is essential to protecting Oregon's air quality.

Sincerely,

Kathryn Roberts
Legal Fellow
Earthrise Law Center

James Saul
Staff Attorney and Clinical Professor
Earthrise Law Center

On Behalf of:

Columbia Riverkeeper
Friends of the Columbia Gorge
350 PDX
Climate Action Coalition
Columbia Gorge Climate Action Network
Greater Hells Canyon Council
Green Energy Institute
Northwest Environmental Defense Center
Oregon Natural Desert Association
Oregon Physicians for Social Responsibility
Sierra Club
Stop Fracked Gas PDX

Attachments:

Attachment 1	Chris Mieckowski, "Battery-Gas Turbine Combination Provides Power Plant Flexibility," POWER MAGAZINE
Attachment 2	Siemens, Co., Enhancing Gas Turbine Power Generation with Battery Storage, Article No. EMMS-B10079-00-7600
Attachment 3	Nichola Groom, *Edison, GE Unveil New Battery Systems At California Gas Plants*, REUTERS
Attachment 4	Ruchti, C., et al., Combined Cycle Power Plants as Ideal Solution to Balance Grid Fluctuations

Attachment 5	Part 70 Operating Permit, McDonough-Atkinson Combined Cycle Facility (Permit No. 4911-067-0003-V-04-0)
Attachment 6	Oklahoma Dept. of Envtl. Quality, Air Quality Div., Evaluation of Permit Application (Chouteau Power Plant) (Permit App. No. 2007-115-C)
Attachment 7	PSD Permit, Brunswick County Power Station (Registration No. 52404)
Attachment 8	San Diego Air Pollution Ctrl. Dist., Engineering Evaluation Authority to Construct, SDG&E Palomar Energy Center, ID No. APCD2001-SITE-04276

Attachment 1

Battery-Gas Turbine Combination Provides Power Plant Flexibility

02/01/2018 | Chris Mieckowski

With a broadening portfolio of generation technologies and rapidly changing demands, effectively combining and integrating diverse technologies is important to a reliable power grid. Siemens' SIESTART solution—a combination of battery technology and a simple or combined cycle Flex-Plant—results in an integrated power plant that reacts instantaneously to complement weather-dependent renewable generation.

The energy landscape has changed dramatically over the past several years. Renewable generation plays a larger role in today's market, and that role continues to expand. In an ideal world, renewables would produce exactly the amount of power demanded at exactly the time it was needed, but that turns out to be the exception rather than the rule. Thus, the weather and time of day is more influential than ever in the power generation industry.

On a typical day, solar generation is highest around midday (http://www.powermag.com/duck-hunting-california-independent-system-operator/), but it can vary dramatically based on conditions. Wind power is often highest in the evening or overnight, but it too is highly dependent on location and conditions. In most markets, the highest power demand is often in the afternoon and evening timeframe. In other words, power demand typically peaks when solar power is coming offline and wind power hasn't ramped up yet.

High solar production or strong winds at night can (and often do) generate more power than the grid demands, leading to low or negative power pricing during certain times of the day or night. This time shift between power production and grid loading means other generation has to be used to match the supply with the demand so that exactly the right amount of electricity is delivered when needed.

There are a number of solutions available in the market to address undersupply of electricity. Rapid demand increases can be addressed efficiently by today's fast-start and fast-ramp technologies like Siemens' Flex-Plant combined cycle units. Siemens' SIESTORAGE (https://www.siemens.com/global/en/home/products/energy/medium-voltage/solutions/siestorage.html) battery storage system addresses the challenge of over generation, taking surplus power and storing that energy in a battery. SIESTART (https://www.siemens.com/content/dam/webassetpool/mam/tag-siemens-com/smdb/energy-management/medium-voltage-power-distribution/medium-voltage-solutions/flyer/sistart/emms-b10079-00-7600-db-siestart-siestorage-en-gen-lowres.pdf) integrates these two technologies, resulting in a solution that is more capable and flexible than either technology on its own.

Flex-Plant Gas-Powered Generation

All power generation technologies have associated strengths and weaknesses. In the case of gas turbine power plants, strengths include:

■ *Dispatchability.* Both simple and combined cycle plants can be called upon by grid operators or plant owners to run at any time.

■ *Reliability.* Gas turbines are dependable machines, with reliabilities frequently measured to be greater than 98%.

■ *Continuity.* Gas turbine power plants can be started and run for extended periods of time either as baseload or peaking units.

Finding the right technology to couple with gas turbine power plants requires improving or eliminating the major weaknesses of the technology, namely:

■ *Instantaneous.* Gas turbine power plants can start very fast—some Flex-Plants can reach baseload in less than 30 minutes and simple cycle plants in under 10 minutes—but they cannot achieve an instantaneous start to full power.

■ *Blackstart.* Gas turbines require power for initial startup. This can come from the grid or from an on-site blackstart generator, which is typically a lower efficiency and less environmentally friendly technology like a reciprocating engine.

■ *Power balancing.* Gas turbines can ramp up and down very quickly, but can't take full advantage of negative power pricing, demand response, or power consumption.

SIESTORAGE

The concept of an energy storage system is simple; store power when there is a surplus, and then provide power to the grid when there is a demand. There are a few different technologies available in the market that operate in this capacity, but one of the most common is a battery storage system like Siemens' SIESTORAGE.

Some of the strengths associated with a SIESTORAGE system are:

■ *Instantaneous.* Power can be supplied to the grid (or load) in less than one second.

■ *Power balancing.* Batteries are bidirectional, providing power to the grid when needed and absorbing power from the grid when it's not.

■ *Emissions.* Batteries discharge electricity with zero emissions.

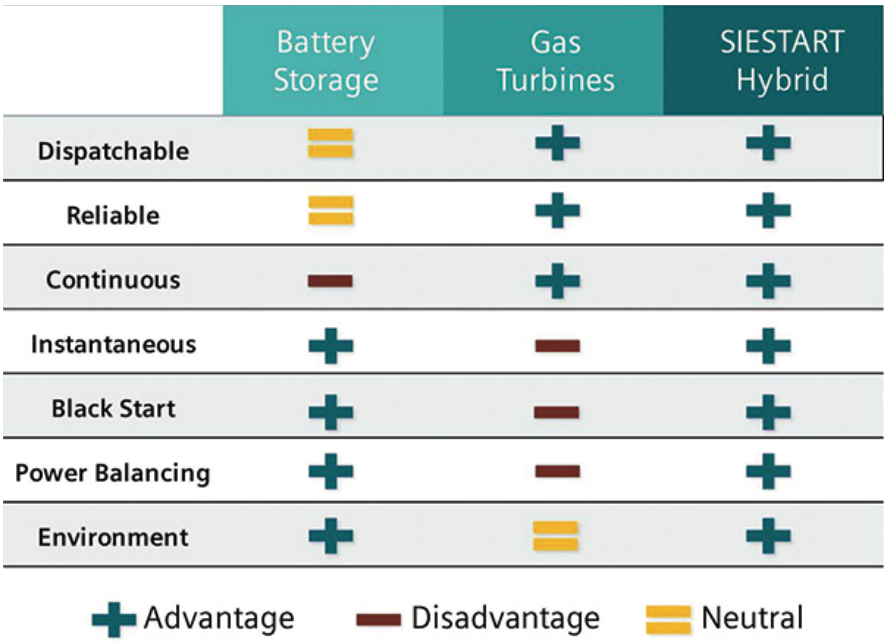
While it is becoming more common to co-locate battery storage solutions at renewable sites to help alleviate the intermittency issue, the resulting power plant is still unreliable. The batteries can store surplus power, but when the batteries are depleted and the source (sun or wind) is still absent the power plant production drops to zero.

SIESTART

An opportunity for innovation arises when you can combine multiple technologies and mitigate or eliminate one's weakness with another's strength. SIESTART combines the strengths of a gas turbine power plant with the strengths of a battery storage system.

Comparing the system characteristics side-by-side (Figure 1) shows the complementary relationship of battery storage systems and gas turbine power plants. SIESTART delivers the best of both technologies in one facility—and enhances the strengths when they are combined.

(http://www.powermag.com/proposed-power-plant-sparks-debate-in-new-jersey/)
- Advanced Boiler and HRSG Designs Offer Improved Performance (http://www.powermag.com/advanced-boiler-and-hrsg-designs-offer-improved-performance/)



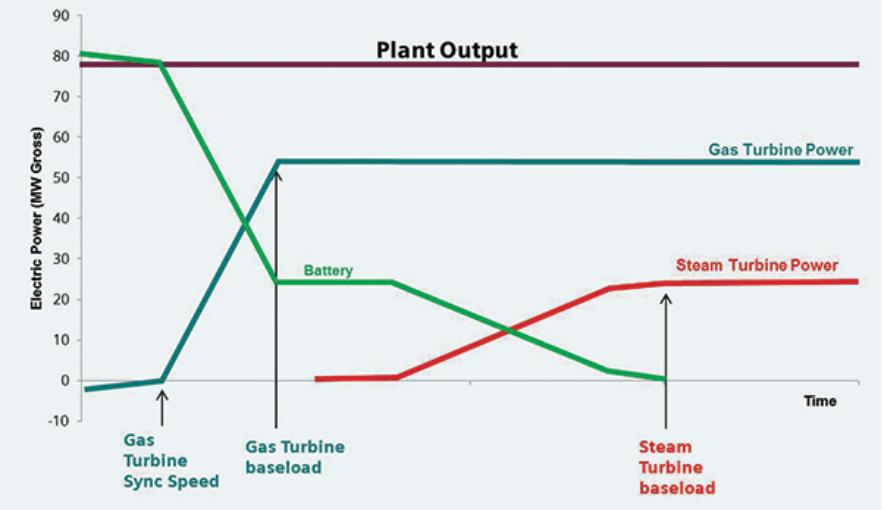
(http://www.powermag.com/wp-content/uploads/2018/02/fig-1-siestart-hybrid.jpg)

1. SIESTART advantages. The operational benefits of a hybrid system that combines battery storage with gas turbine technology are substantial. *Courtesy: Siemens*

To demonstrate the full potential of a SIESTART system, consider the following example. A 1 x 1 combined cycle power plant with a nominal 80-MW output is fully deenergized. A grid that relies on wind and solar power suddenly sees an unpredicted loss in renewable production. This creates a situation where electrical load is constant, but supply is rapidly decreasing.

To prevent brownouts and subsequent blackouts, the grid operator calls on the SIESTART plant for full output. In less than one second the full 80-MW supply is on the grid, stabilizing grid power. From the grid's perspective, 80 MW is delivered and the crisis is averted.

Inside the power plant's fence, the SIESTORAGE battery storage system immediately delivered 80 MW to the grid and provided the operators with time to analyze the situation. If renewable generation were to come rapidly back online, the batteries could be ramped down and deenergized, avoiding an unnecessary gas turbine startup. If the renewable generation didn't return quickly, the batteries would continue to provide 80 MW to the grid, as well as power to startup the gas turbine. The gas turbine would then be started normally and ramped up to full output. As the gas turbine ramped up, battery output would decrease to keep a constant 80-MW delivery to the grid. As the steam turbine went through a normal startup and ramp to full load, the battery output would further be curtailed until the full 80 MW was delivered by the combined cycle plant (Figure 2). The plant could then operate in combined cycle mode until renewable supply increased or the demand subsided.



(http://www.powermag.com/wp-content/uploads/2018/02/fig-2-battery-ramping.jpg)

2. Sequence of events. Initially, the battery system supplies the necessary plant output, providing the gas turbine with the time it needs to get up to full load and bring the steam turbine online in combined cycle mode. *Courtesy: Siemens*

SIESTART Value Generation

In addition to the intrinsic benefits noted previously, SIESTART delivers additional benefits that are not possible with two separate solutions. These can often be monetized in different energy markets. For instance:

■ *Spinning reserve.* SIESTART can deliver the capacity of the batteries instantaneously, and that power can continue until the gas turbine power plant is up to full output. In other words, with proper sizing, full plant output can be delivered in less than one second, so full plant output can be offered as spinning reserve.

■ *Arbitrage.* SIESTART gives a plant the ability to consume power if the grid is in surplus, potentially making money off the energy consumption, then selling the energy back to the grid when demand increases and power prices become more lucrative.

■ *Energy storage.* Many localities offer credits, or even mandates, for energy storage systems. SIESTART (on a new unit or retrofit basis) can allow realization of those credits or satisfy storage requirements.

■ *Blackstart.* A SIESTART gas turbine plant can be designated as a full blackstart plant, allowing additional revenue and offsetting potentially inefficient reciprocating engine operations.

■ *Peaking demand.* Adding SIESTART to a gas turbine provides an extra "boost" of output from the batteries when the grid (or load) needs it the most, enabling the plant to take full advantage of high-value peak power.

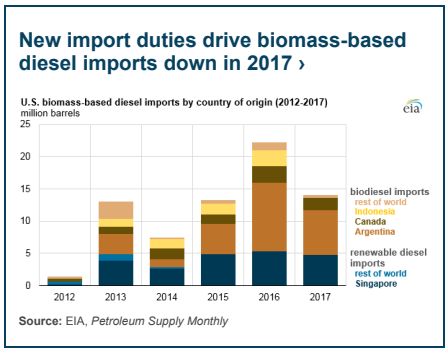
■ *Day-ahead market.* SIESTART batteries can be used to provide additional power output on top of the gas turbine production. This power can be sold in the same manner as any other megawatts.

Everlasting Valve Co.'s self-lapping, rotating disc valve was on display during the ELECTRIC POWER Conference and Exhibition, held in Nashville, Tennessee, March 19–22, 2018. While other metal-sealed valves wear out over time, the seal in the Everlasting Valve gets tighter and stronger as it wears in. As the valve opens and closes, the disc rotates incrementally, uniformly polishing away scratches and creating an ever-tightening seal.

For more, see "Novel Technology Featured at ELECTRIC POWER Event (http://www.powermag.com/novel-technology-featured-at-electric-power-event/)."

Visit our video archive (/power-video-archive/)

April 30, 2018



INDUSTRY NEWS

INDUSTRY PRESS

- NuScale Power's Small Modular Nuclear Reactor Becomes First Ever to Complete Nuclear Regulatory Commission's Phase 1 Review (http://www.powermag.com/press-releases/nuscale-powers-small-modular-nuclear-reactor-becomes-first-ever-to-complete-nuclear-regulatory-commissions-phase-1-review/)
- OSIsoft announces partnership with Kansai Electric Power to enhance power plant operation (http://www.powermag.com/press-releases/osisoft-announces-partnership-with-kansai-electric-power-to-enhance-power-plant-operation/)
- Siemens Gamesa secures its largest ever wind turbine order of 300 MW in India (http://www.powermag.com/press-releases/siemens-gamesa-secures-its-

■ *Real-time market.* The output from a SIESTART power plant can be ramped up and down instantly to follow load or market prices.

■ *Capacity market.* SIESTART plant output (gas turbine power plant plus batteries) can be fully committed at any time, as the battery output is not time or weather dependent.

Market applicability is shown in Figure 3.

	Battery Storage	Gas Turbine	SIESTART Hybrid
Spinning Reserve	✓	✓	✓+
Arbitrage	✓		✓
Energy Storage	✓		✓
Black Start	✓		✓
Peaking Demand		✓	✓+
Real Time Market		✓	✓+
Capacity / DA Market	✓	✓	✓+

(http://www.powermag.com/wp-content/uploads/2018/02/fig-3-siestart-hybrid.jpg)

3. Taking advantage of the system. By combining battery storage with gas turbine technology, the SIESTART hybrid captures enhanced benefits. *Courtesy: Siemens*

Beyond the Energy Market

Energy storage technologies have seen considerable advancements across the board, including thermal storage with chilling systems, mechanical storage with flywheels, pumped hydro, compressed air, and electrical storage with batteries. However, of all these technologies, the SIESTART solution could have the most profound impact on the industry.

SIESTART has applications far beyond the energy market, especially in places where responsiveness is measured in seconds rather than minutes. For critical loads, such as hospitals and data centers, SIESTART can deliver the instantaneous response of a battery with the reliability and durability of a gas turbine. Any size power plant (combined cycle or simple cycle), any model gas turbine, and any energy market (or power demand) could recognize the benefits of this solution.

As the price of resources change, environmental requirements evolve, and new technologies enter the market, the diversity of power generation supply and demand can be expected to broaden. The only constant throughout this change is that generators need to be as flexible as possible.

To enable the reliable, stable power generation grid that loads and customers require, solutions that effectively integrate diverse technologies and demands are critical. Siemens' SIESTART portfolio, combining SIESTORAGE with a simple or combined cycle Flex-Plant, results in a power plant that is more capable and flexible than either solution alone. This allows owners to recognize benefits that have not been achievable with a single solution in the past, while capi-

largest-ever-wind-turbine-order-of-300-mw-in-india/)
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- 2018 Deloitte Energy Conference, 05/15 - 05/16 (https://www2.deloitte.com/us/en/pages/energy-and-resources/events/energy-conference.html)
- Eurelectric - Watt's Next - Power Summit, 06/04 - 06/05 (https://wattsnext.eurelectric.org)
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talizing on value over a full range of demands for the future. With high baseload efficiency, fast load-change capability, and instantaneous response, SIESTART has redefined power plant flexibility. ■

—***Chris Mieckowski*** *is product line manager for North America with Siemens (https://www.siemens.com/global/en/home.html).*

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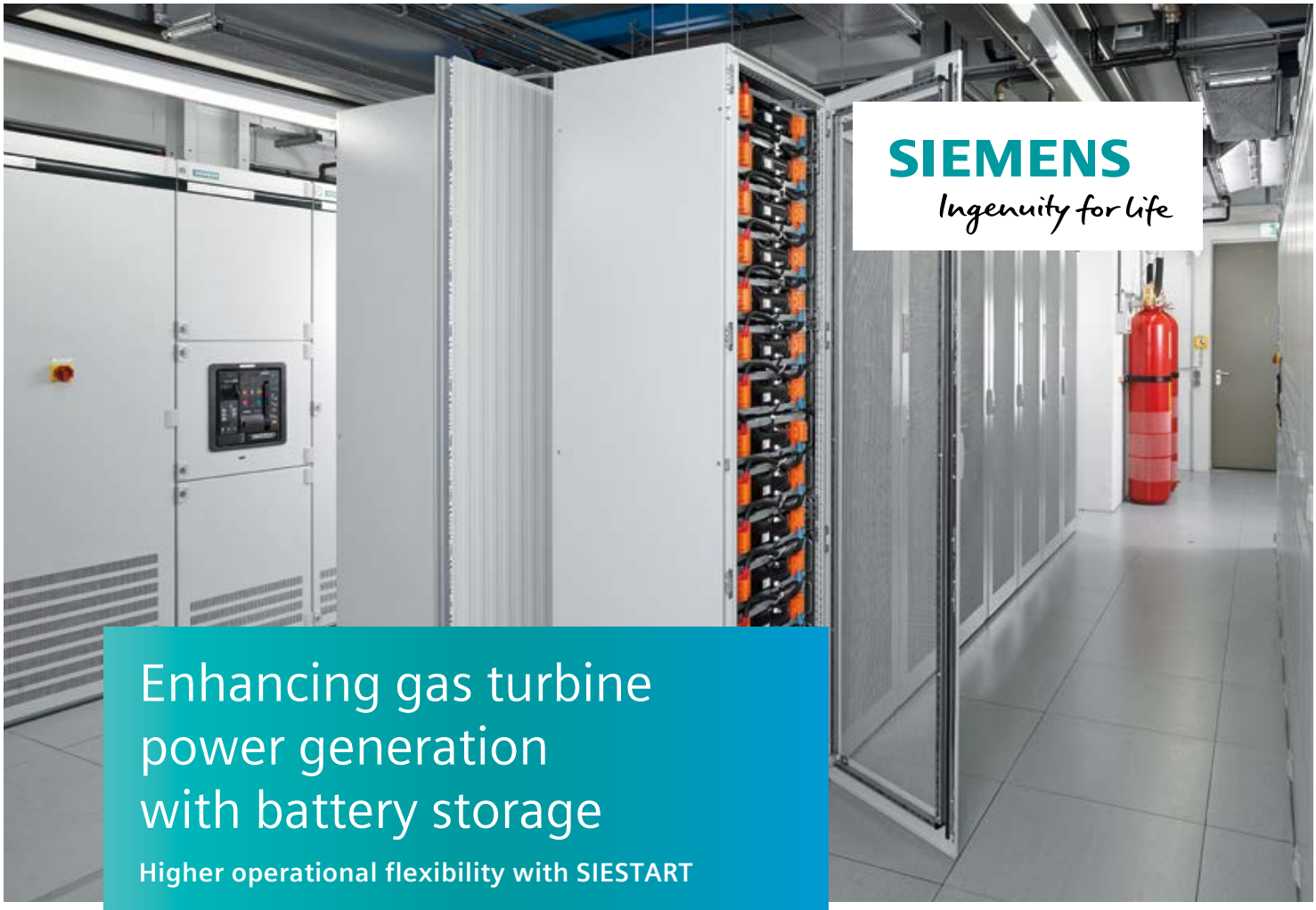
Attachment 2

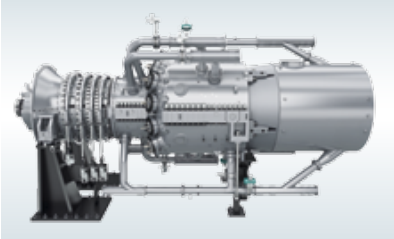


SIEMENS
Ingenuity for life

Enhancing gas turbine power generation with battery storage

Higher operational flexibility with SIESTART

Conventional power plants (heavy-duty as well as industrial-scale) need to ensure grid stability

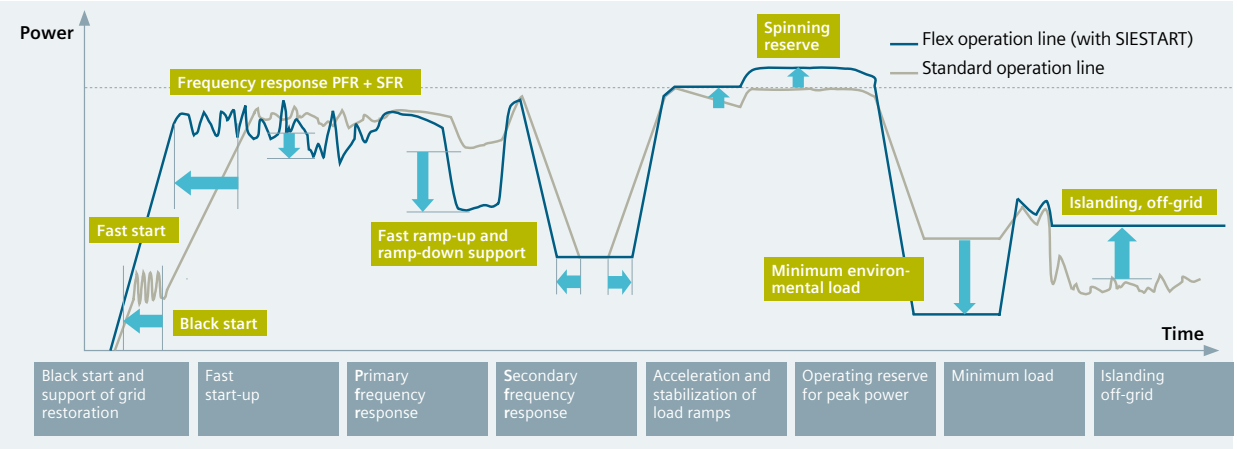


Gas turbine SGT6-8000H

Today's challenges in the grid
The energy transition puts grid systems under growing pressure, because greater utilization of renewable sources doesn't provide sufficient inertia to support stabilizing the grid frequency. To ensure grid stabilization, large centralized fossil power plants that were originally designed for baseload operation now need to ramp much faster and more frequently, and provide highly flexible spinning reserve. Traditionally, maintaining frequency and voltage stability relies on gas turbine power generation. However, sometimes the power generated is not sufficient to allow the gas turbine to reconnect, resulting in a partial or total blackout.

Stability of the grid and secure supply of power
Power producers need to broaden their capabilities to ensure grid stability when power system operation is under threat. They must:

- Accelerate load ramping for fast compensation of imbalances in the grid
- Provide spinning reserve as an additional power reserve to stabilize the grid
- Provide islanding and off-grid services (especially for industrial power plants)
- Provide black start capability in the event of a grid failure



SIESTART: optimized performance and new opportunities – for grid services and gas turbine operation

The solution: SIESTART
The solution combines the performance of a gas turbine with a battery energy storage system (BESS) like Siemens' SIESTORAGE. The system comprises very fast and reliably responding Lithium-ion battery technology combined with cutting-edge power electronics and control for the fast and accurate response required by ancillary services. Because it is designed with both active and reactive power components, it can offer reliable black start functionality in the event of grid collapse. This collocation of gas turbine and batteries can also be used for ramping up and down faster, which ensures flexible operation to provide and sell ancillary services.

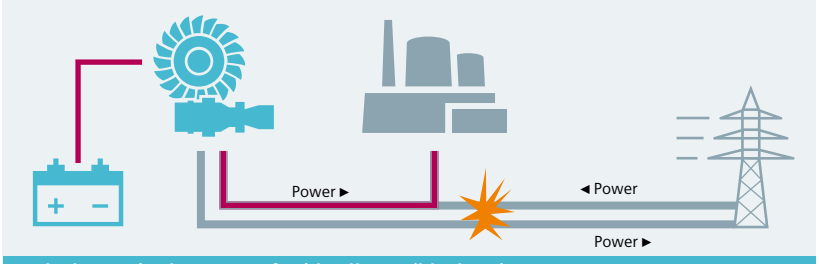
Optimized OPEX
The SIESTART solution can be installed as a retrofit in existing power plants or as added value for new installations. SIESTART is also a reliable power supply alternative to gensets, as it's both eco-friendly and resource-efficient.

Cutting-edge technological portfolio
- Gas turbines from 4 to 425 MW
- Steam turbines from 2 to 1,900 MW
- Generators
- Electrical components
- Instrumentation and control solutions for all types of plants
- Modular battery storage system
- Turnkey industrial or heavy-duty power plant solutions (simple cycle, combined cycle, cogeneration) from 14 to 1,250 MW

Comprehensive portfolio of experience and expertise
- Consulting
- Project development
- Financing
- Engineering
- Procurement
- Construction
- Commissioning
- Operation and maintenance
- Optimization

SIESTART combines the performance of a gas turbine with the Li-ion battery energy storage system SIESTORAGE

Use cases
- Black start
- Grid restoration
- Frequency control
- Stabilization of voltage – critical power
- Stabilization of electrical island mode
- Ramping control and acceleration
- Decrease GT minimum load by time shifting
- Spinning reserve



Black start in the event of grid collapse (blackout)

Enhancing gas turbine operation with SIESTORAGE battery storage system

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Attachment 3

BUSINESS NEWS APRIL 17, 2017 / 4:16 PM / A YEAR AGO

Edison, GE unveil new battery systems at California gas plants

Reuters Staff

3 MIN READ

(Reuters) - A major California utility and General Electric Co (GE.N) on Monday unveiled a first-of-its-kind battery storage system that will enable instant power output from a natural gas peaking plant to accommodate the state's changing electricity needs while decreasing greenhouse gas emissions.

The system, which was installed at two separate Southern California Edison "peaker" plants this month, will give the utility increased flexibility as the large amounts of renewable wind and solar power required by state mandates have made energy generation cleaner but far less predictable.

Peaker plants are small power plants designed to come online quickly when power demand is high, such as on a hot summer day. But they are also among the least efficient resources available to the utility.

The 10 megawatt batteries, which contain cells made by Samsung SDI (006400.KS), are capable of providing power immediately, eliminating the need for the plant to burn fuel in "standby" mode. Prior to integrating the batteries, the 50 megawatt plant would take about 10 minutes to ramp up to a desired capacity.

General Electric Co
GE.N NEW YORK STOCK EXCHANGE
14.07
-0.31 (-2.16%)

Southern California Edison's president, Ron Nichols, said at an event to unveil the hybrid electric gas turbine in Norwalk, California that the new system would cut plant startups in half and reduce total run hours by 60 percent.

The systems will work particularly well as solar power drops off at the end of the day, just at the time when demand starts to rise as utility customers get home from work and begin running air conditioners or turning on appliances.

California is requiring its utilities to source half of their electricity needs from renewable sources by 2030. At the same time, the state has required procurement of energy storage wables. Southern California Edison has brought several energy arge Tesla Inc (TSLA.O) battery earlier this year.

akers in Norwalk and Rancho Cucamonga. The utility is ıree other peaker plants in its territory, Nichols said.

Reporting by Nichola Groom; Editing by Bill Rigby

Our Standards: The Thomson Reuters Trust Principles.

BUSINESS NEWS APRIL 29, 2018 / 11:38 PM / UPDATED 11 HOURS AGO

Interserve's 2017 loss widens, calls performance 'extremely poor'

Reuters Staff

2 MIN READ

(Reuters) - British business support and construction services provider Interserve Plc (IRV.L) said on Monday its financial performance was “extremely poor” last year, and reported a wider full-year pretax loss.

Attachment 4

Combined Cycle Power Plants as ideal solution to balance grid fluctuations

Fast Start-up Capabilities

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Wesley Bauver
Alstom Power, Windsor (CT), USA

Summary

The traditional patterns of power demand and generation are subject to change due to the increasing intermittent generation from renewable sources such as wind and solar. Large load variation in the grid must be balanced. Gas fired combined cycle power plants with a maximum of operational flexibility are ideally suited for this purpose.

Alstom does not believe that specialized power plant designs for peaking and for base load are the right approach in a rapidly changing market. Nobody can predict which will be the requirements for a power plant 10 or 20 years in the future. For this reason, Alstom is designing combined cycle power plants, such that they suit every scenario, from daily start-stop to base load operation, from part load with high efficiency to parking mode below 20% plant load.

Sequential combustion is a unique feature of the GT26 gas turbine, which makes it possible to 'park' the entire KA26 combined cycle power plant at very low load with only one of the two GT26 combustors in operation, fully complying with the emission limits. This provides reliable and rapid reserve power of about 350 MW within less than 15 minutes.

In order to further improve the flexibility of the plant, Alstom has optimized the operation concept of the KA26-1 single-shaft combined cycle power plant for fast start-up. Thermal and mechanical stress in the steam turbine and in the heat recovery steam generator have been carefully analyzed and included in the simulation of the dynamic behavior of the plant to achieve an optimum balance between fast start and minimum life time impact of the equipment.

Zusammenfassung

In Zeiten steigender Stromproduktion durch intermittierende erneuerbare Quellen, wie Wind und Sonne, lösen sich die gewohnten zeitlichen und kapazitiven Zusammenhänge von Stromnachfrage und Stromproduktion mehr und mehr auf. Starke Lastschwankungen müssen ausgeglichen werden. Gasgefeuerte Kombikraftwerke sind eine ideale Ergänzung, vorausgesetzt sie sind so ausgelegt, dass sie ein Maximum an Betriebsflexibilität mitbringen.

Alstom glaubt nicht daran, dass speziell für Spitzenlastabdeckung ausgelegte Kraftwerke oder nur für Grundlastbetrieb ausgelegte Kraftwerke die richtige Lösung in einem sich schnell ändernden Marktumfeld sind. Kein Betreiber oder Investor kann heute vorhersagen, welche Anforderungen an ein Kraftwerk in 10 oder 20 Jahren gestellt werden. Deshalb legt Alstom Kombikraftwerke so aus, dass sie jeden Bedarfsfall abdecken: Vom täglichen An- und Abfahren bis zum Grundlastbetrieb, vom Teillastbetrieb mit hohen Wirkungsgraden bis zum mit dem Netz synchronisierten „Parken“ des gesamten Kombikraftwerks bei Niedrigstlast (<20% Gesamt-Kraftwerksleistung).

Aufgrund der spezifischen Bauart der GT26 Gasturbine mit sequentieller Verbrennung, d.h. zwei hintereinander geschalteten Brennkammern, können die entsprechenden Kombikraftwerke KA26-1 während einer niedrigen Stromnachfrage bei sehr tiefen Lastpunkten unter Einhaltung der Emissionswerte „geparkt“ werden. Hiermit ist eine permanente Leistungsreserve (Minutenreserve) von ca. 350 MW auf Knopfdruck innerhalb von 15 Minuten sicher und zu jeder Zeit verfügbar.

Um die Betriebsflexibilität weiter zu erhöhen hat Alstom das Betriebskonzept des KA26-1 Einwellen-Kombikraftwerks optimiert, um schnellste Startzeiten zu erreichen. Der Aufbau und der Verlauf der Spannungen in Dampfturbine und Dampferzeuger werden in einem dynamischen Simulationsmodell des gesamten Kraftwerks berechnet. Dies dient zur Ermittlung der optimalen Betriebsführung und zur Sicherstellung der maximalen Lebensdauer aller Bauteile. In dem Vortrag wird das mit Hilfe des dynamischen Simulationsmodells ermittelte Betriebskonzept erläutert.

1 Introduction

The growth of power generation from renewable sources leads to new challenges as all the consumers and generators connected to a grid need to be in balance. Since the generation from renewable sources is subject to natural fluctuations, the requirements for the other generators regarding operational flexibility get inevitably more demanding. They need to balance out not only the fluctuating demand from the consumers, but also the fluctuating generation from renewable sources. Combined cycle power plants are best-suited candidates to satisfy this fluctuating demand:

- The fuel supply with natural gas is well buffered.
- The fixed costs constitute a relatively low fraction of the total cost of electricity.
- They provide highest efficiency and lowest CO2 emissions among conventional power plants.

That is why aspects of flexibility receive more and more attention in the design and operation of combined cycle power plants. This paper reports about two features enhancing the operational flexibility of Alstom combined cycle power plants:

- The Low Load Operation Capability, a unique feature of the GT26 gas turbine to park the entire plant below 20% load, ready to ramp up rapidly any time
- The ability for fast hot start, an operation concept developed based on a careful analysis of thermal and mechanical stress in the most affected plant components, which allows to reduce the start-up time below 30 minutes without adverse impact on the number of cycles in a lifetime

2 Alstom Combined Cycle Power Plants

The fleet of KA24 combined cycle power plants for the 60 Hz market and KA26 for the 50 Hz market comprises more than 100 units throughout the world. These plants have accumulated more than 4.2 million operating hours. There are two typical configurations:

- The ‘one on one’ single-shaft configuration with one gas turbine and one steam turbine (see Figure 1)
- The ‘two on one’ multi-shaft configuration with two gas turbines and one steam turbine.

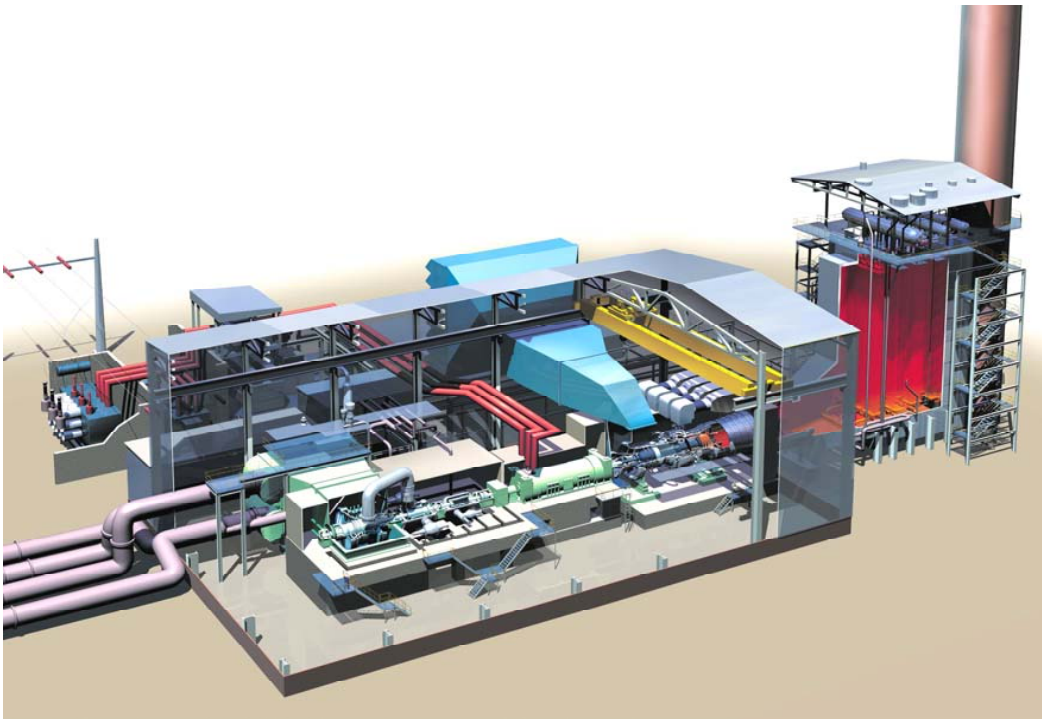

Figure 1: KA26-1 single-shaft combined cycle power plant

These plants are driven by GT26 gas turbines (see Figure 2) applying the unique sequential combustion principle. The hot gas from the first combustor (EV = EnVironmental) is expanded only partially in the high-pressure section of the gas turbine. Then the gas is reheated in the second combustion chamber (SEV = Sequential EV) before it is completely expanded in the low-pressure section of the gas turbine. Gas turbine and steam turbine share the common shaft. There is a clutch for disengagement of the steam turbine during start-up. The water steam cycle is a triple-pressure-reheat cycle. The heat recovery steam generator is an Alstom boiler with suspended single row harps and drums at all pressure levels. This plant type is described further in [1] and [2].

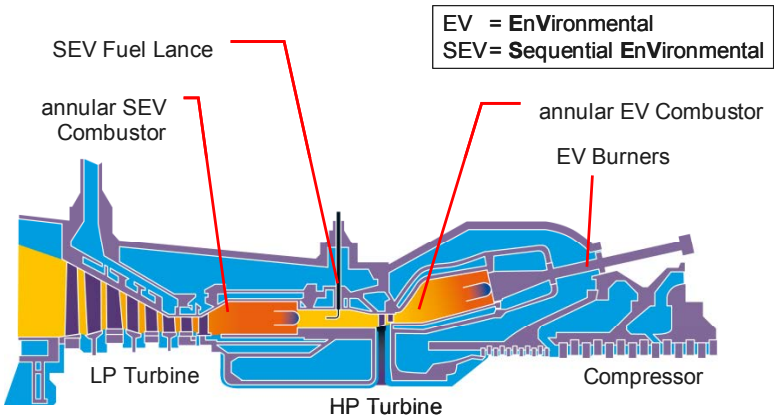

Figure 2: Schematic drawing of a GT26 gas turbine

Due to the sequential combustion the GT26 has excellent properties at part load. The minimum combined cycle power plant load complying with emission limits can achieve 40% or even below with a comparatively low loss of efficiency as compared to base load. And the GT26 has the optional Low

Load Operation Capability. It is possible to run the machine with only the EV combustor and reach an operation point below 20% plant load complying with the emission limits.

At daytimes with weak power demand and low electricity price, conventional gas power plants have only two options:

- Either operate the plant at the relatively high minimum environmental load of around 50% or even higher for some combined cycle power plant models,
- Or shut down the plant completely.

The GT26 with sequential combustion offers a third option:

- The plant can be operated below 20% plant load without SEV combustor in operation.

The Low Load Operating Capability is elaborated further in [3].

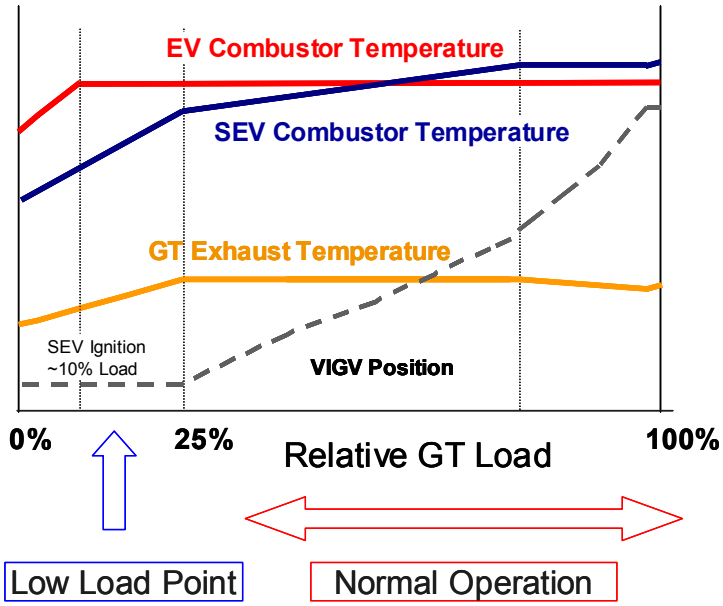

Figure 3: Operation concept of the GT26 gas turbine

3 Requirements for Start-up

3.1 The value of fast start-up capability

It is generally accepted that the capability for fast start-up is a potential differentiator, which is gaining importance. But how should someone evaluate this fast start capability? There are two fundamentally different approaches for the comparison of start-up procedures:

- Fixed begin of start:
  In this consideration, start-up time has the nature of a reaction time. It is the time a plant at standstill needs to react to an opportunity on the market. In order to participate in such scenarios, the start-up time should be shorter than the bidding interval on the power market. Payments for non-spinning reserve can play a major role in this scenario.
- Fixed end of start:
  In this scenario power is allocated several hours or even a full day ahead of time. The plant has to reach the dispatched power level at a certain agreed point in time. Slow plants can compensate by starting earlier.

Although the first scenario may gain importance, we feel that the second scenario will continue to dominate. The scenario with fixed end of a start is therefore in the focus of this analysis. There are two ways of determining the cost of a hot start, which are believed to cover the full spectrum seen on the market:

- 'Full Revenue': The electric power generated between beginning and end of start-up can be sold at the same tariff as during normal operation.
- 'Zero Revenue': The electric power generated between beginning and end of start-up does not generate any revenue for the power plant operator at all.

Reality is bound to be somewhere between these two extremes. In both scenarios we compare two operation concepts for hot starts:

- 'Normal': The standard hot start-up procedure of the KA26-1 with loading gradient of 15 MW per minute and duration of about 50 minutes.
- 'Fast': The new FX30 concept with GT loading gradient of 30 MW per minute and duration of less than 30 minutes as explained later.

This is applied to the KA26-1 single-shaft combined cycle plant as described above.

		Normal	Fast	Delta
Electric Energy Output	MWh(el)	111	47	64
Fuel Gas Heat Input	MWh(th)	267	152	118
CO emissions	kg	953	818	135
NOx emissions	kg	32	20	12
Fuel cost for one start in scenario 'Zero Revenue'	k€	4.8	2.7	2.1
Incremental fuel cost for one start in scenario 'Full Revenue'	k€	1.4	1.3	0.1

Table 1: Comparison of operation concepts for hot start after typically 8 hours standstill ('Normal' refers to the conventional operation concept about 50 minutes start-up time, 'Fast' refers to the improved FX30 start-up; fuel price of 5 €/GJ)

CO emissions pre-dominantly occur at operation between idle and about 40% GT load. Since the fast loading gradient is effective only in the last phase of the start-up, the relative change in CO emission is small.

The NOx emissions show a different pattern. The short peak at very low load amounts to a minor fraction of the total emission. Therefore the shorter duration of the start-up is directly impacting the total start-up emissions.

In the scenario 'zero revenue' the cost for start-up is simply the cost for the fuel consumed in the course of the start-up. The reduced start-up time leads directly to a significant reduction of fuel consumption during start-up, which amounts to a saving of about 2.1 k€ per start.

In the scenario 'full revenue' we ask, how much fuel would have been burned, if the electric output generated during start-up would have been generated with base load efficiency. Only the additional heat input due to operation at part load with reduced efficiency is considered as start-up cost. This consideration leads of course too much smaller start-up costs. There is still a small benefit for the new concept amounting to 0.1 k€ per start because the total amount of electricity generated during start-up is considerably smaller. Typically the 'Full Revenue' scenario is much closer to the market reality.

The comparison between the two scenarios clearly illustrates the dilemma of the development engineer. A standard plant design for truly flexible operation must be competitive in both scenarios. It is therefore decided that the improved start-up must be realized without major investment in additional or improved hardware. We cannot afford to penalize the competitiveness of the plant in the scenario

'full revenue'. Additional first costs for an option for fast start are only acceptable within narrow limits, e.g. for some additional measurements.

3.2 Definition of Start-up Time

The preferred definition of start-up time also used in this paper is as follows: Start-up begins with ignition of the burners in the GT. Start-up is completed, when the GT has reached base load and when all the steam produced in the HRSG is used for power generation, i.e. the ST admission valves are fully opened and the HP and IP bypass valves are fully closed. This definition provides unambiguously clear criteria and avoids taking unnecessary margins such as would be necessary, if we would link the end of start to the reaching of a certain power output.

Table 2 below gives the expected durations of start-up. The categorization is made based on the approximate duration of standstill. In reality, however, we differentiate between start-up types based on ST rotor temperatures. The applicable limits depend on the turbine configuration. Technical specifications will be based on these rotor temperatures to avoid any ambiguity and to minimize the need for margins.

The project for improvement of start-up described in this paper was limited to hot and warm start. These are the start types, which happen frequently and with reproducible initial conditions. Cold starts tend to occur after a shutdown for maintenance or repair and often do not run according to the theoretical screenplay. Cold starts are also excluded from most contractual guarantees, mostly because the required tuning and testing would lead to unacceptably prolonged commissioning time, caused by the long waiting times for cold initial conditions.

	Duration of standstill	Start-up time
Hot start	< 8h	28 minutes
Warm start	> 8h ; < 60h	100 minutes
Cold start	> 60 h	135 minutes

Table 2: Expected start-up times for KA26-1 combined cycle power plants with water cooled condenser

3.3 Number of Cycles

Start-up exposes the equipment to considerable stress. The challenge in designing an optimized start-up procedure is associated with a proper balance of speed and consumption of lifetime. Any specification of a start-up time should therefore refer to the underlying number of such starts possible in a lifetime. The lifetime assessment performed to verify the operation concept considers three operation scenarios. The plant lifetime is confirmed against any of these scenarios for a commercial operation of the plant of 20 years. This provides the plant operator with an envelope of possible operation modes. He is free to switch between the formulated scenarios throughout the plant life and he is still assured to remain within the creep / fatigue limits of the components.

	cycling	intermediate	base load
Cold starts	200	250	200
Warm starts	900	900	160
Hot starts	4100	1100	300
Operating hours	100'000	125'000	200'000

Table 3: The Alstom standard lifetime requirement for a combined cycle power plant

4 The Concept of Fast Hot Start

The technical solution is presented in this section for a hot start after 8 h standstill as an example. Figure 4 to Figure 6 show the results from optimization by plant dynamic simulation.

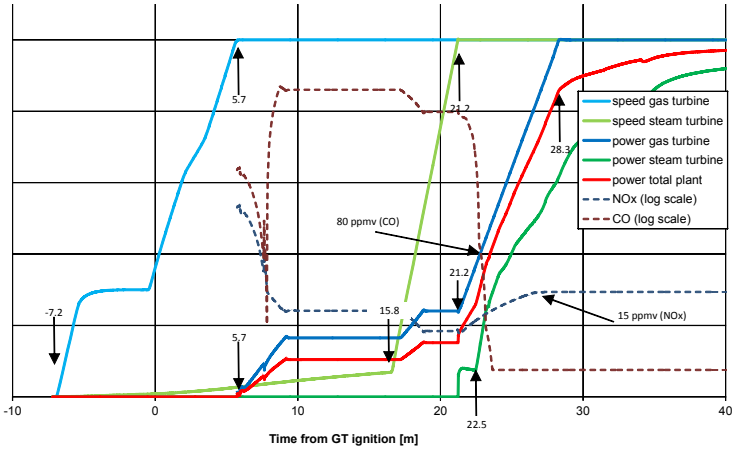

Figure 4: Fast hot start, basic overview

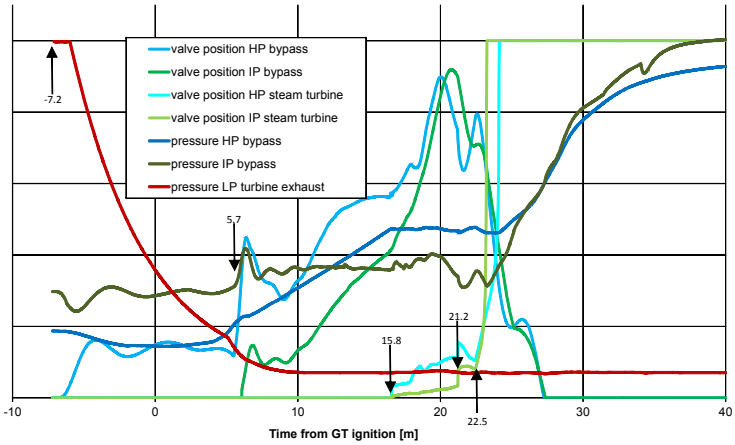

Figure 5: Fast hot start, pressures and valves

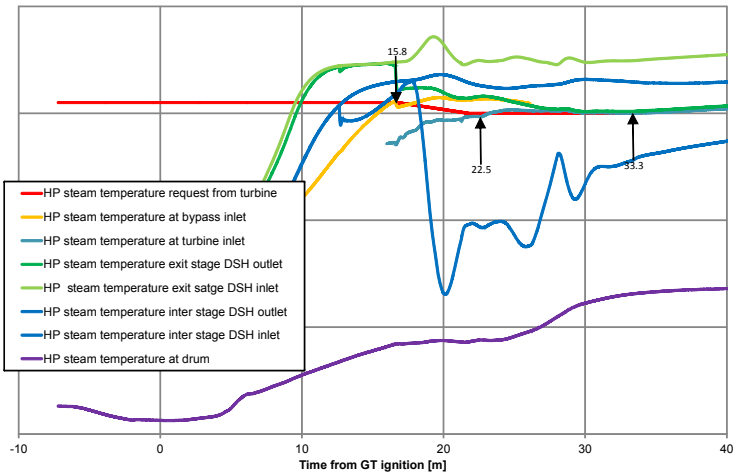

Figure 6: Fast hot start, temperatures

4.1 Sequence of Events

(-7.2) Start of acceleration of GT up to purge speed and subsequent purge of the HRSG, which leads to some pressure decay in the HRSG. Resume acceleration of the GT after completion of the HRSG purge. Simultaneously with the start of acceleration of the GT, the sequencer for the start of the hogging ejector is launched. The HP bypass opens to secure steam supply for RH system. The pressure reduction in the HRSG due to steam consumption of the ejector is minimal.

(0.0) Begin of startup: Ignition of the EV combustor and continued acceleration up to full speed. The vacuum required in the condenser for admission of steam is reached before the GT reaches full speed.

(5.7) The GT is at full speed. Synchronization and further load increase to the selected hold point. Load and operation point of GT are selected to reach the desired steam temperature with acceptable stress in the SH outlet manifold. The target steam temperature is selected to match the ST rotor temperature. The desuperheat stations work in a cascade control scheme to control the steam temperature at the HP bypass. Almost simultaneously with the GT reaching full speed the rate of increase of HP steam pressure triggers a rapid opening of the bypass. Now the HP bypass is ramping up the HP steam pressure at a pre-defined rate.

(15.8) The steam temperature at the HP bypass is reaching the requested level for admission to turbine. The ST admission valves open to ramp up the ST speed at a pre-determined rate. The requested steam temperature is gradually reduced with increasing ST speed. The desuperheat stations now work as cascade to control the steam temperature at the turbine inlet. About simultaneously with the steam temperature reaching the value for admission to turbine, the HP steam pressure is reaching the fixed pressure level. From then onwards, The HP bypass valve keeps the pressure constant. The IP bypass controls the IP pressure such as to avoid ventilation of the HP steam turbine. The GT is loading up to the next hold point, increasing the exhaust temperature to the full value. The GT hold point is selected, such the available capacity of the bypass valves is sufficient to control the pressures.

(21.2) The full ST speed is reached. The GT starts to ramp up the load at the constant load gradient of 30MW per minute.

(22.5) The additional heat input from the GT exhaust becomes effective and the steam temperature at the ST is within the acceptable window for loading up the ST. The ST admission valves open fully. The HP bypass now limits the rate of increase of live steam pressure in accordance with the permissible loading gradient for the ST. The total power output is increasing at about 40MW per minute in this phase.

(28.3) The GT reaches base load. The bypass valves have completely closed before. The criteria for 'End of Start-up' are fulfilled. Plant load is at about 86% at this point in time. The plant is switched to plant load control mode at this time. It is free to perform any load change or to go into frequency sensitive mode.

(33.3) The stress at the ST rotor has stabilized, such that steam temperature can increase now. The steam temperature requested at the steam turbine inlet starts to increase at about 0.75 degrees per minute.

(80.0) The inter stage desuperheat valve closes.

(140.) The set value for life steam temperature has reached nominal conditions.

4.2 Heat Recovery Steam Generator

The configuration of the KA26-1 combined cycle power plant includes a triple pressure reheat cycle. The heat recovery steam generator has a horizontal gas path with suspended vertical tubes arranged in single row harps. The steam is flowing in parallel through all the harps belonging to the same heat exchange surface. The steam is guided from the headers of individual harps to the common superheat outlet manifold. This design is very flexible in that it follows the principle of stepped component wall thickness. In spite of this very flexible design principle, the final SH outlet manifolds remain the limiting elements for a fast hot start compatible with the overall lifetime requirement of the plant.

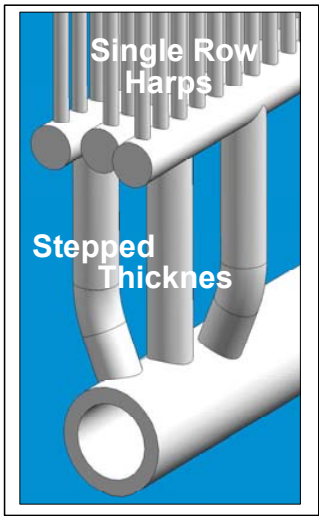

Figure 7: The principle of stepped component wall thickness

It took a special collaborative effort between HRSG, GT and ST to realize a plant operation concept, which achieves the steam temperature for admission to ST fast and with acceptable stress values in the HRSG. Figure 5 illustrates the progress of one optimization step.

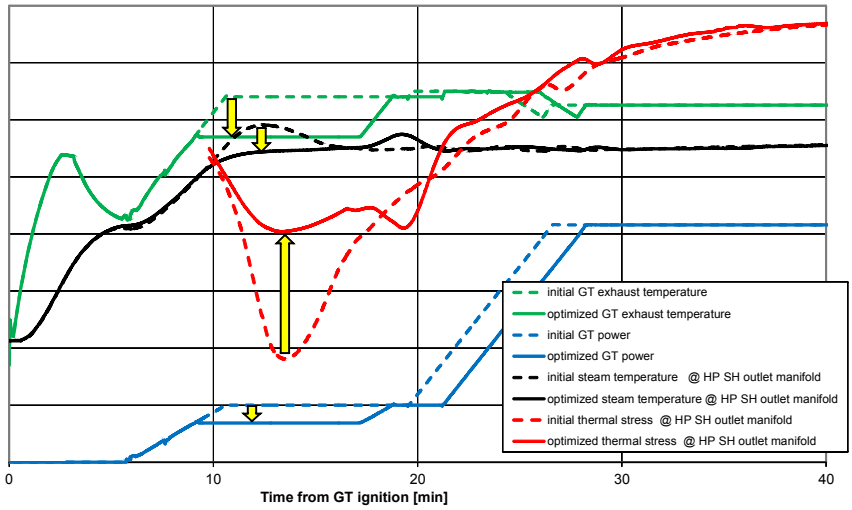

Figure 8: Modified GT operation concept to save HRSG lifetime

Initially, the GT was operated in this early phase of the start-up with the normal operation concept for part load, i.e. the GT exhaust temperature went quickly up to 650°C. Such maximized GT exhaust temperatures at part load are beneficial for steady state performance at part load, but they create disadvantages during the start of the combined cycle plant. The steam temperature at the final SH outlet manifold was overshooting with this operation concept. The internal desuperheater was not capable to control it, because spraying down into the 2-phase domain would have been required. The result was a marked peak of the thermal stress, such that the required 4100 hot start cycles would have eaten up more than 70% of the cyclic life. It was then decided to modify the control concept:

- Depending on the ST rotor temperature prior to start, the steam turbine controller issues a steam temperature request.
- Based on this steam temperature request, the overall plant controller generates a set value for the GT exhaust temperature, which is communicated to the GT controller.
- With this set value the GT then realized a modified operation concept where the internal machine settings depend on the actual plant conditions.

The result was striking: the overshoot of steam temperature at the final SH outlet manifold disappeared and the thermal stress was reduced significantly. In fact, 4100 hot start cycles are now eating up less than 30% of the total available cyclic life of the final SH outlet manifold.

We have not encountered any limitation imposed by the drums in the course of the optimization of the fast hot and warm start.

4.3 Gas Turbine

The GT26 with sequential combustion chambers allows for an optimization of the GT exhaust temperatures by keeping the combustion at low loads stable at low emissions. As shown in Figure 3 the EV combustion chamber is operating in stable conditions at constant temperature, while the GT exhaust temperature can be adjusted by variation of VIGV position and of the SEV fuel flow to the needs of the steam cycle. An exhaust temperature variation up to 100°C with maximum temperatures of 650°C can be realized at low part load below 25% GT load. Furthermore, loading gradients of the GT can be adapted for an optimized combined cycle start-up. GT loading gradients up to 30 MW per minute are possible during start-up without additional impact to the GT lifetime. Higher loading gradients over a wide range of part load have been demonstrated to be reliable, particular for participation in primary and secondary frequency response.

4.4 Steam Turbine

Steam turbines are operated at high pressures and temperatures. They are exposed to creep loading during continuous operation at high temperatures. Additional high fatigue loading occurs due to thermal stress appearing during transient events such as start-up, shut down and load changes. Thermal stresses are pronounced in thick-walled components, such as rotors, valves, casings, etc. The bigger the temperature change, the higher the fatigue loading becomes. The combination of creep and cycling fatigue eventually may lead to crack initiation and growth, which limits the life of the affected steam turbine component.

The limitations of start-up capability coming from the steam turbine are related to thermal stress in thick-walled components in direct contact with hot steam, such as the turbine rotor. The number of required cycles in a lifetime determines a maximum permissible peak stress for the affected turbine component. The actually observed stress is associated with the heating-up of the component. As such it is dictated by heat transfer from the steam to the component.

$$Q = \alpha \times (T_{steam} - T_{rotor}) \qquad Q = \kappa \times \frac{\partial T}{\partial r}$$

The stress in the rotor is determined by temperature differences within the metal. It is thus associated with heat flux within the rotor, which arises from heat transfer to the rotor. This heat transfer is first of all proportional to the temperature difference between steam and rotor surface. Secondly it is proportional to the heat transfer coefficient, which in turn depends mainly on the steam velocity. The higher the steam velocity, the more effective is the heat transfer. All other parameters influencing the heat transfer coefficient are material properties of the steam and do not change significantly during a start-up. So rotor stress during start-up has two main root causes:

- Temperature difference between steam and rotor,
- The increasing steam flow.

Note that pressure as such is not a root cause for rotor stress. This is a fundamental difference as compared to pressure parts, where the internal pressure is one of the main drivers of stress. For example, pressure may have a significant influence on turbine and valve casings.

A set of tools has been developed, which allows the determination of the optimum evolution of steam parameters and minimizes the resulting stress as calculated by finite element methods in three dimensions [4]. In addition, a simplified one dimensional stress evaluation has been implemented in the overall plant dynamic simulation, such that the qualitative impact of any modification in the operation on component life can be directly estimated.

Conventional Steam Turbine Stress Control

Conventional turbine stress controllers do measure temperatures and other process variables and calculate the resulting stress. If the calculated stress exceeds a given limit, they throttle the turbine admission valves and reduce the steam flow. This approach has two fundamental draw-backs:

A feedback controller by definition works with a snapshot, i.e. it is processing state variables at one instant in time. This works well for small ramp-rates where the duration of the ramp is small compared with the time delay associated with the build-up of stress. But the start-up of a combined cycle is in this regard a fast process. Due to the relatively large time constants of stress response, thermal stress peaks are normally reached after completion of the causing ramp-up. So feedback stress controllers face a fundamental challenge: they risk reacting too late.

The second draw back lies in the very nature of the limiting action. Throttling of the turbine admission valves not only reduces the steam flow. The increased pressure drop also leads to change in temperature at the rotor.

A Paradigm Change in Steam Turbine Stress Control

The start-up of a combined cycle power plant is a predictable and repeatable process. Dynamic simulations provide reliable forecast of the plant behavior. It is therefore possible to generate set-

points and to design a start-up process, which relies to very large extent on feed-forward control alone. The steam turbine stress controller as implemented in the Alstom FX30 concept is just a back-up, which becomes effective only in cases where the plant is operated clearly outside the design band of normal operation, such that damage would result.

In addition, the start-up process is guided in such a way that – once we start loading the ST – the rest of the plant is capable to maintain the required steam parameters throughout the entire loading process and deliver enough steam even with the ST admission valves opening rapidly to wide open position. The steam turbine controller monitors this at several release points throughout the start-up process. If the parameters as provided by the boiler are not with a design band, the steam turbine start-up is put on hold until the required parameters are achieved.

Having recognized the two root causes of steam turbine rotor stress (flow and temperature of steam) it is a straight-forward strategy of stress reduction to design the start-up process in such a way that the impacts of the two root causes do not cumulate. This is achieved through the definition of the signal 'HP steam temperature request from turbine':

- The initial value is selected based on the ST rotor temperature at begin of the start-up.
- During acceleration of the ST the value is gradually reduced.
- It remains constant again until the ST rotor stress caused by the ramp-up of the GT to base load has decayed below a selected level.
- Finally it is increased at a constant rate to the design value of 585°C.

We strive to separate the main contributions to thermal stress. In the first phase we focus on quick loading with the main cause for thermal stress being the increased steam velocity.

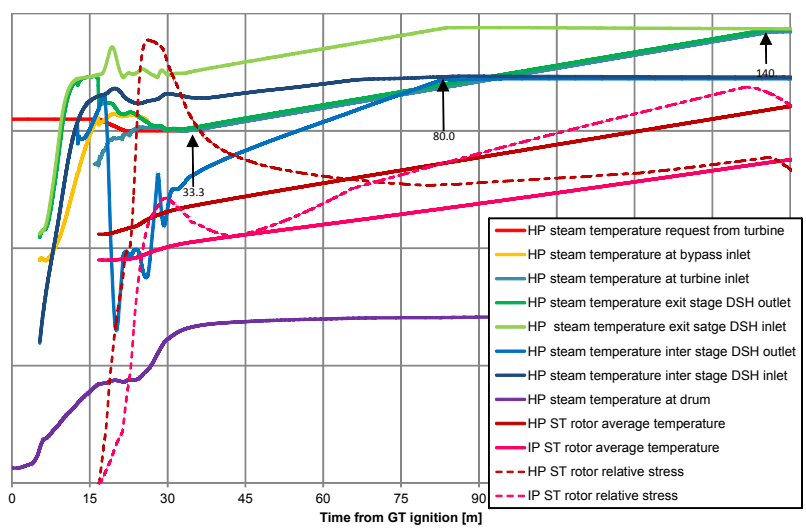

Figure 9: Separation of steam turbine rotor stress arising from increase of steam flow and temperature

5 Field Test

Figure 10 below illustrates the result from a field test on an existing KA26-1 single shaft power plant. It is actually a hot re-start after a standstill of 2 hours. Under these boundary conditions, the steam temperature as requested by the ST is increased to 545°C. It is a key feature of the FX30 concept that all set-point values are generated depending in a smooth manner on the conditions prior to start-up.

The concept as designed by computer simulation has been validated successfully. It will be part of future offering.

Category	Name	Description	Range	Unit	Min	Max	Avg	21:23:46.988	21:51:23.855
00	78LBF10AA001_FBMV	CV HP BYP	0/100	%	0.000	59.080	21.496	31.853	0.000
01	78MAN40AA002_FBMV	CV IP BYP	0/100	%	0.000	54.546	14.705	0.000	0.000
02	78MAA11CG011_XQ60	POS MAIN CTRL VALVE	0/100	%	-0.875	101.215	27.781	-0.696	101.095
03	78MAB11CG011_XQ60	POS ICV1 CV	0/100	%	-0.668	101.111	27.250	-0.590	101.042
04	71MBA82CG011_XQ60	GUIDE VANE POS ROW1	-85/15	Deg	-77.451	0.667	-39.921	-65.000	0.330
05	78LBA50CT001_XQ60	T HP STM BFR ST	0/600	degC	476.125	550.266	520.887	514.313	549.758
06	78MAC10CP931_XQ61	P LPT EXHAUST 2o3	0/1200	mbara	65.395	1013.556	311.032	632.828	72.508
07	71MKA10CE601_XQ60	GEN ACTIVE POWER CH1	-20/580	MW	-16.344	438.438	138.197	-0.500	379.596
08	78MAD20CS901_XQ60	ST SPEED 2o3	0/3600	rpm	7.049	3009.667	1236.012	7.896	3000.229
	71MBA30CS001_XQ60	GT SPEED CH1	0/3750	rpm	23.906	3009.141	2481.740	1126.641	2999.766

Figure 10: Hot re-start of a KA26-1 after 2 hours standstill based on the operation concept described in this paper; end of start-up has been reached in less than 28 minutes.

6 Conclusions

The time for a hot start could be reduced to less than 30 minutes without significant investment for additional or increased equipment. Key requirement for success is the close cooperation of all equipment designers in true Plant Integrator spirit. In fact, detailed computation methods for stress calculation of critical components has been openly shared and implemented in the dynamic simulation of the overall behavior. This made it possible to assess the benefit of operation concept modifications on each simulation run, without the need to request a lifetime assessment report from the component designer. Further improvement of plant flexibility may be expected through such collaborative approach.

7 References

[1] "The Next Generation Alstom GT26, The Pioneer in Operational Flexibility", M.Hiddemann et al, Paper presented at the Power-Gen Europe, 07-09 June 2011, Milan, Italy

[2] "Alstom's KA26 Advanced Combined Cycle Power Plant – Optimised for Base Load and Cycling Duty", M.Stevens et al, Paper presented at Power-Gen Europe 08-10 June 2010, Amsterdam, The Netherlands

[3] "Erste Betriebserfahrungen mit dem Niedrigstlastmodus der KA26 Kombianlagen", Ch. Ruchti et al, VDI Gasturbinenkonferenz, 24.-25. Nov. 2010

[4] "Steam Turbine Start-up Optimisation Tool based on ABACUS and Python Scripting", A. Ehrsam et al, 2009, Simulia Customer Conference

Attachment 5

PERMIT NO. 4911-067-0003-V-04-0
ISSUANCE DATE: March 17, 2017

GEORGIA
DEPARTMENT OF NATURAL RESOURCES

ENVIRONMENTAL PROTECTION DIVISION

Air Quality - Part 70 Operating Permit

Facility Name:	**McDonough-Atkinson Combined-Cycle Facility**
Facility Address:	**5551 South Cobb Drive** **Smyrna, Georgia 30080, Cobb County**
Mailing Address:	**241 Ralph McGill Blvd. NE, Bin 10221** **Atlanta, Georgia 30308**
Parent/Holding Company:	**Southern Company/Georgia Power**
Facility AIRS Number:	**04-13-067-00003**

In accordance with the provisions of the Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq and the Georgia Rules for Air Quality Control, Chapter 391-3-1, adopted pursuant to and in effect under the Act, the Permittee described above is issued a Part 70 Permit for:

The operation of an electric utility plant including four simple cycle combustion turbines, and three natural-gas-fired combined-cycle power blocks with associated support equipment.

This Permit is conditioned upon compliance with all provisions of The Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq, the Rules, Chapter 391-3-1, adopted and in effect under that Act, or any other condition of this Permit. Unless modified or revoked, this Permit expires five years after the issuance date indicated above.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above, for any misrepresentation made in Title V Application TV-23280 signed on May 22, 2015, any other applications upon which this Permit is based, supporting data entered therein or attached thereto, or any subsequent submittal of supporting data, or for any alterations affecting the emissions from this source.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached 61 pages.

[Signed]

Richard E. Dunn, Director
Environmental Protection Division

Table of Contents

PART 1.0 FACILITY DESCRIPTION

1.1 Site Determination

Plant McDonough-Atkinson is currently contracting with an ash processing facility located on site to process and sell some of the coal ash produced from the electric generating process at Plant McDonough-Atkinson. Even though the ash processing facility and Plant McDonough-Atkinson are located on contiguous property, they are deemed to be separate sources for purposes of Title V permitting due to the fact that there is no common control between Georgia Power Company and the ash processing facility. Therefore, the Title V permit for Plant McDonough-Atkinson covers only those operations controlled solely by Georgia Power. The ash processing facility, which is itself a minor source under 40 CFR Part 70, will continue to operate under its minor source SIP permit.

1.2 Previous and/or Other Names

This facility has been referred to as either Plant McDonough or Plant Atkinson, depending upon which emission units were being considered, since historically these were considered to be two separate facilities. The old Plant Atkinson and its emissions units have since been retired. The new combined cycle emissions units were previously permitted as McDonough Combined Cycle Generating Units in Permit Amendment No. 4911-067-0003-V-02-2 or as McDonough-Atkinson Steam Electric Generating Plant. For purposes of this permit, the plant will be referred to as McDonough-Atkinson Combined-Cycle Facility.

1.3 Overall Facility Process Description

Plant McDonough-Atkinson burns fossil fuel to generate electricity. This facility includes three combined-cycle power blocks and four simple cycle combustion turbines which primarily burn natural gas. Each power block is nominally rated at 840 MW and consists of two combustion turbines, two heat recovery steam generators with duct-burners, and one steam turbine. The combustion turbines and duct burners are primarily fired with natural gas. Two of the combustion turbines, CT4A and CT5A, also have the capability to burn ultra-low sulfur diesel as a back-up fuel and are served by two above-ground oil storage tanks. Each combustion turbine and its paired duct burner share a common stack which is 160 feet tall. Two of the three power blocks, 4 and 5, share a common auxiliary boiler for pre-heating the combustion turbine subsystems and the steam turbines, as well as cooling the combustion system during startup. Power block 6 has its own auxiliary boiler. Each auxiliary boiler stack is 50 feet tall. The four simple cycle turbines work (two two-on-one configurations) to drive two generators with a nominal capacity of 39 MW each. Each simple cycle combustion turbine has its own exhaust which is 33 to 36 feet tall. Three mechanical-draft cooling towers will provide cooling water to the combined cycle units.

PART 2.0 REQUIREMENTS PERTAINING TO THE ENTIRE FACILITY

2.1 Facility Wide Emission Caps and Operating Limits

None applicable.

2.2 Facility Wide Federal Rule Standards

None applicable.

2.3 Facility Wide SIP Rule Standards

None applicable.

2.4 Facility Wide Standards Not Covered by a Federal or SIP Rule and Not Instituted as an Emission Cap or Operating Limit

None applicable.

PART 3.0 REQUIREMENTS FOR EMISSION UNITS

Note: Except where an applicable requirement specifically states otherwise, the averaging times of any of the Emissions Limitations or Standards included in this permit are tied to or based on the run time(s) specified for the applicable reference test method(s) or procedures required for demonstrating compliance.

3.1 Emission Units

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	**Description**	**Applicable Requirements/Standards**	**Corresponding Permit Conditions**	**ID No.**	**Description**
CT5M	Combustion Turbine 3AA (McDonough)	391-3-1-.02(2)(b), (g), (nnn)	3.2.1, 3.4.2, 3.4.3, 4.1.3, 6.2.1, 6.2.3, 6.2.18, 7.15.2	none	n/a
CT6M	Combustion Turbine 3AB (McDonough)	391-3-1-.02(2)(b), (g), (nnn)	See CT5M	none	n/a
CT7M	Combustion Turbine 3BA (McDonough)	391-3-1-.02(2)(b), (g), (nnn)	See CT5M	none	n/a
CT8M	Combustion Turbine 3BB (McDonough)	391-3-1-.02(2)(b), (g), (nnn)	See CT5M	none	n/a
CT4A	Combustion Turbine Unit 4A, Block 4	391-3-1-.02(2)(b), (d), (g), (nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, 40 CFR 63 Subpart A, 40 CFR 63 Subpart YYYY, Acid Rain, CSAPR	3.3.1, 3.3.4 to 3.3.7, 3.3.8 to 3.3.15, 4.1.3, 4.2.1, 4.2.2, 4.2.4, 5.2.7, 5.2.10 to 5.2.13, 6.1.7, 6.1.8, 6.2.5, 6.2.6, 6.2.8 to 6.2.15, 6.2.17 to 6.2.20, 6.2.21, 6.2.22, 6.2.25 to 6.2.28	SC4A OC4A LC4A WI4A	SCR Catalytic Oxidation Dry Low NO_x Combustor Water Injection
DB4A	HRSG, for combustion turbine CT4A, supplemental Duct Burner Unit 4A, Block 4	391-3-1-.02(2)(b), (d), (g), (yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSAPR	3.3.3, 3.3.4, 3.3.7, 3.3.8, 3.3.9, 4.1.3, 4.2.1, 5.2.4 to 5.2.6, 5.2.8, 6.1.7, 6.1.8, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20, 6.2.28	SC4A OC4A LD4A	SCR Catalytic Oxidation Dry Low NO_x Combustor
CT4B	Combustion Turbine Unit 4B, Block 4	391-3-1-.02(2)(b), (d), (g), (nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSAPR	3.3.1, 3.3.2, 3.3.5 to 3.3.7,3.3.8, 3.3.9, 4.1.3, 4.2.4, 5.2.10 to 5.2.13, 6.1.7, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20, 6.2.21, 6.2.26, 6.2.27	SC4B OC4B LC4B	SCR Catalytic Oxidation Dry Low NO_x Combustor
DB4B	HRSG, for combustion turbine CT4B, supplemental Duct Burner Unit 4B, Block 4	391-3-1-.02(2)(b), (d), (g), (yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSAPR	3.3.3, 3.3.8, 3.3.9, 4.1.3, 5.2.4 to 5.2.6, 5.2.8, 6.1.7, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20	SC4B OC4B LD4B	SCR Catalytic Oxidation Low NO_x Burners
CT5A	Combustion Turbine Unit 5A, Block 5	391-3-1-.02(2)(b), (d), (g), (nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, 40 CFR 63 Subpart A, 40 CFR 63 Subpart YYYY, Acid Rain, CSAPR	3.3.1, 3.3.5 to 3.3.7, 3.3.8 to 3.3.15, 4.1.3, 4.2.1, 4.2.2, 4.2.4, 5.2.7, 5.2.10 to 5.2.13, 6.1.7, 6.1.8, 6.2.5, 6.2.6, 6.2.8 to 6.2.15, 6.2.17 to 6.2.20, 6.2.21, 6.2.22, 6.2.25 to 6.2.28	SC5A OC5A LC5A WI5A	SCR Catalytic Oxidation Dry Low NO_x Combustor Water Injection

Emission Units		Specific Limitations/Requirements		Air Pollution Control Devices	
ID No.	**Description**	**Applicable Requirements/Standards**	**Corresponding Permit Conditions**	**ID No.**	**Description**
DB5A	HRSG, for combustion turbine CT5A, supplemental Duct Burner Unit 5A, Block 5	391-3-1-.02(2)(b), (d), (g), (yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSAPR	3.3.3, 3.3.4, 3.3.8, 3.3.9, 4.1.3, 4.2.1, 5.2.4 to 5.2.6, 5.2.8, 6.1.7, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20, 6.2.28	SC5A OC5A LD5A	SCR Catalytic Oxidation Low NO_x Burners
CT5B	Combustion Turbine Unit 5B, Block 5	391-3-1-.02(2)(b), (d), (g), (nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSAPR	3.3.1, 3.3.2, 3.3.5 to 3.3.7, 3.3.8, 3.3.9, 4.1.3, 4.2.1, 4.2.4, 5.2.10 to 5.2.13, 6.1.7, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20, 6.2.21, 6.2.26, 6.2.27	SC5B OC5B LC5B	SCR Catalytic Oxidation Dry Low NO_x Combustor
DB5B	HRSG, for combustion turbine CT5B, supplemental Duct Burner Unit 5B, Block 5	391-3-1-.02(2)(b), (d), (g), (yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSAPR	3.3.3, 3.3.8, 3.3.9, 4.1.3, 4.2.1, 5.2.4 to 5.2.6, 5.2.8, 6.1.7, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20	SC5B OC5B LD5B	SCR Catalytic Oxidation Low NO_x Burners
CT6A	Combustion Turbine Unit 6A, Block 6	391-3-1-.02(2)(b), (d), (g), (nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSAPR	3.3.2, 3.3.5 to 3.3.7, 3.3.8, 3.3.9, 4.1.3, 4.2.2, 4.2.4, 5.2.10 to 5.2.13, 6.1.7, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20, 6.2.21, 6.2.26, 6.2.27	SC6A OC6A LC6A	SCR Catalytic Oxidation Dry Low NO_x Combustor
DB6A	HRSG, for combustion turbine CT6A, supplemental Duct Burner Unit 6A, Block 6	391-3-1-.02(2)(b), (d), (g), (yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSAPR	3.3.3, 3.3.8, 3.3.9, 4.1.3, 4.2.1, 5.2.4 to 5.2.6, 5.2.8, 6.1.7, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20	SC6A OC6A LD6A	SCR Catalytic Oxidation Low NO_x Burners
CT6B	Combustion Turbine Unit 6B, Block 6	391-3-1-.02(2)(b), (d), (g), (nnn), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSPAR	3.3.2, 3.3.5 to 3.3.7, 3.3.8, 3.3.9, 4.1.3, 4.2.1, 4.2.4, 5.2.10 to 5.2.13, 6.1.7, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20, 6.2.21, 6.2.26, 6.2.27	SC6B OC6B LC6B	SCR Catalytic Oxidation Dry Low NO_x Combustor
DB6B	HRSG, for combustion turbine CT6B, supplemental Duct Burner Unit 6B, Block 6	391-3-1-.02(2)(b), (d), (g), (yy), 40 CFR 60 Subpart A, 40 CFR 60 Subpart KKKK, Acid Rain, CSAPR	3.3.3, 3.3.8, 3.3.9, 4.1.3, 4.2.1, 5.2.4 to 5.2.6, 5.2.8, 6.1.7, 6.2.5, 6.2.8 to 6.2.15, 6.2.19, 6.2.20	SC6B OC6B LD6B	SCR Catalytic Oxidation Low NO_x Burners
AB05	Auxiliary Boiler Unit 05	391-3-1-.02(2)(b), (d), (g), (lll), 40 CFR 60 Subpart A, 40 CFR 60 Subpart Db, 40 CFR 63 Subpart A, 40 CFR 63 Subpart DDDDD	3.3.6, 3.3.16 to 3.3.18, 4.1.3, 4.2.3, 5.2.5, 5.2.14, 6.1.7, 6.2.16, 6.2.19, 6.2.20	LA05 FR05	Low NO_x Burners Flue Gas Recirculation
AB06	Auxiliary Boiler Unit 06	391-3-1-.02(2)(b), (d), (g), (lll), 40 CFR 60 Subpart A, 40 CFR 60 Subpart Db, 40 CFR 63 Subpart A, 40 CFR Subpart 63 DDDDD	See AB05	LA06 FR06	Low NO_x Burners Flue Gas Recirculation
PH01	Propane Heater Unit 1	391-3-1-.02(2)(b), (d), (g), 40 CFR 63 Subpart A, 40 CFR 63 Subpart DDDDD	None	None	

* Generally applicable requirements contained in this permit may also apply to emission units listed above. The lists of applicable requirements/standards and corresponding permit conditions are intended as a compliance tool and may not be definitive.

3.2 Equipment Emission Caps and Operating Limits

3.2.1 The Permittee shall not fire any fuel other than natural gas, No. 2 fuel oil, biodiesel, or biodiesel blends in the combustion turbines (emission unit IDs CT5M, CT6M, CT7M, and CT8M).
[391-3-1-.03(2)(c)]

3.3 Equipment Federal Rule Standards

General Requirements

3.3.1 The Permittee shall fire only pipeline quality natural gas, ultra low sulfur diesel fuel, biodiesel, or biodiesel blends in combustion turbines with emission unit ID Nos. CT4A and CT5A.
[40 CFR 60 Subpart KKKK and 391-3-1-.02(2)(g)]

3.3.2 The Permittee shall fire only pipeline quality natural gas in combustion turbines with emission unit ID Nos. CT4B, CT5B, CT6A, and CT6B.
[40 CFR 60 Subpart KKKK and 391-3-1-.02(2)(g)]

3.3.3 The Permittee shall fire only pipeline quality natural gas or landfill gas in the duct burners (emission unit ID Nos. DB4A, DB4B, DB5A, DB5B, DB6A, and DB6B).
[40 CFR 60 Subpart KKKK and 391-3-1-.02(2)(g)]

3.3.4 Ultra low sulfur fuel oil, biodiesel, or biodiesel blends fired in combustion turbines with emission unit ID Nos. CT4A and CT5A shall not contain more than 0.0015 percent sulfur by weight [equivalent to 15 ppm].
[40 CFR 60 Subpart KKKK and 391-3-1-.02(2)(g)]

3.3.5 The Permittee shall install and operate catalytic oxidation add-on control equipment on the combined exhaust from each combined cycle combustion turbine and its paired duct burner as Best Available Control Technology (BACT) for carbon monoxide (CO) and as Lowest Achievable Emission Rate (LAER) for volatile organic compounds (VOC).
[40 CFR 52.21(j)(2) and 391-3-1-.03(8)(c)2.]

3.3.6 The Permittee shall not discharge, or cause the discharge, into the atmosphere as follows:

a. Carbon monoxide emissions, including emissions occurring during startup and shutdown, in excess of 259 tons each for Blocks 4 & 5 and 238 tons for Block 6, during any twelve consecutive months. A block consists of the correspondingly numbered combustion turbines and duct burners.
[40 CFR 52.21(j)(2)]

b. VOC emissions, including emissions occurring during startup and shutdown, in excess of 135 tons each for Blocks 4 & 5 and 132 tons for Block 6, during any twelve consecutive months. A block consists of the correspondingly numbered combustion turbines and duct burners.
[391-3-1-.03(8)(c)2.]

c. NO_x emissions, including emissions occurring during startup and shutdown, in excess of 217 tons from Block 4; 217 tons from Block 5 and Auxiliary Boiler 5; and 200 tons from Block 6 and Auxiliary Boiler 6, during any twelve consecutive months. A block consists of the correspondingly numbered combustion turbines and duct burners.
[391-3-1-.03(13)(b)1]

3.3.7 The following definitions of startup and shutdown, as used in this Permit, shall apply:
[40 CFR 52.21(j)(2)]

a. Startup is defined as the period of time from when the combustion turbine is first fired until the time for reception of 60 percent output signal from the combustion turbine or the time to achieve an output level less than 60 percent at which it has been demonstrated by a CEMS or during compliance testing that the normal steady state operating emission limits can be met.

b. Cold startup is defined as a startup to combined-cycle operation following a complete shutdown lasting more than forty-eight hours. Time allocated to a cold startup is not to exceed three hundred minutes or the time for reception of 60 percent output signal from the combustion turbine or the time to achieve an output level less than 60 percent at which it has been demonstrated by a CEMS or during compliance testing that the normal steady state operating emission limits can be met, whichever time is less.

c. Warm startup is defined as a startup to combined-cycle operation following a complete shutdown lasting eight hours or more, but less than or equal to forty-eight hours. Time allocated to a warm startup is not to exceed one-hundred eighty minutes or the time for reception of 60 percent output signal from the combustion turbine or the time to achieve an output level less than 60 percent at which it has been demonstrated by a CEMS or during compliance testing that the normal steady state operating emission limits can be met, whichever time is less.

d. Hot startup is defined as a startup to combined-cycle operation following a complete shutdown lasting less than eight hours. Time allocated to a hot startup is zero to one-hundred fifteen minutes or the time for reception of 60 percent output signal from the combustion turbine or the time to achieve an output level less than 60 percent at which it has been demonstrated by a CEMS or during compliance testing that the normal steady state operating emission limits can be met, whichever time is less.

e. Unit shutdown is defined as the period of time from steady state operation to cessation of combustion turbine firing. Time allocated to a shutdown is not to exceed sixty minutes.

3.3.8 The Permittee shall comply with all applicable provisions of the New Source Performance Standards (NSPS) as found in 40 CFR 60 Subpart A – "General Provisions" as it relates to the combined-cycle systems (emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, and CT6B/DB6B).
[40 CFR 60 Subpart A]

Natural Gas Combustion – Combined-Cycle System

3.3.9 The Permittee shall not discharge, or cause the discharge, into the atmosphere from the combined exhaust of each combined cycle combustion turbine and its paired duct burner, excluding periods of startup and shutdown, when the combustion turbine is fired with pipeline quality natural gas, and the duct burner is fired with either natural gas and/or landfill gas, any gases which:

a. Contain nitrogen oxides in excess of 15 ppmvd, corrected to 15% oxygen, on a 30-day rolling average.
[40 CFR 60 Subpart KKKK]

b. Contain nitrogen oxides in excess of 6.0 ppmvd, corrected to 15% oxygen, on a 30-day rolling average, during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(nnn)]

c. Contain carbon monoxide in excess of 1.8 ppmvd, corrected to 15% oxygen, on a 3-hour average.
[40 CFR 52.21(j)(2)]

d. Contain volatile organic compounds in excess of 1.8 ppmvd, corrected to 15% oxygen, as methane, on a 3-hour average, while the duct burner is being fired.
[391-3-1-.03(8)(c)2.]

e. Contain volatile organic compounds in excess of 1.0 ppmvd, corrected to 15% oxygen, as methane, on a 3-hour average, while the duct burner is not being fired.
[391-3-1-.03(8)(c)2.]

f. Contain particulate matter in amounts equal to or exceeding 0.10 pound per million Btu, HHV basis, on a 3-hour average.
[391-3-1-.02(2)(d)(2)(iii)]

g. Exhibit greater than or equal to 20% opacity except for one 6-minute period in any hour of no more than 27% opacity.
[391-3-1-.02(2)(d)3]

Fuel Oil Combustion – Combined-Cycle System

3.3.10 The Permittee shall not operate any combustion turbine with emission unit ID Nos. CT4A or CT5A for more than 1,000 hours each on ultra low sulfur diesel fuel, biodiesel, or biodiesel blends during any twelve consecutive months.
[40 CFR 52.21]

3.3.11 The Permittee shall not discharge, or cause the discharge, into the atmosphere from the combined exhaust of each combustion turbine and its paired duct burner, excluding periods of startup and shutdown, when the combustion turbine is fired with ultra low sulfur diesel fuel, biodiesel, or biodiesel blend and the duct burner is fired with either natural gas and/or landfill gas, any gases which:

a. Contain nitrogen oxides in excess of 42 ppmvd, corrected to 15% oxygen, on a 30-day rolling average.
[40 CFR 60 Subpart KKKK]

b. Contain nitrogen oxides in excess of 6.0 ppmvd, corrected to 15% oxygen, on a 30-day rolling average, during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(nnn)]

c. Contain carbon monoxide in excess of 9.0 ppmvd, corrected to 15% oxygen, on a 3-hour average.
[40 CFR 52.21(j)(2)]

d. Contain volatile organic compounds in excess of 4.0 ppmvd, corrected to 15% oxygen, as methane, on a 3-hour average.
[391-3-1-.03(8)(c)2.]

e. Contain particulate matter in amounts equal to or exceeding 0.10 pound per million Btu, HHV basis, on a 3-hour average.
[391-3-1-.02(2)(d)(2)(iii)]

f. Exhibit greater than 20% opacity except for one 6-minute period in any hour of no more than 27% opacity.
[391-3-1-.02(2)(d)3]

3.3.12 The Permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants (NESHAP) as found in 40 CFR 63 Subpart A – "General Provisions" as it relates to emission unit ID Nos. CT4A and CT5A.
[40 CFR 63 Subpart A]

3.3.13 Except for startup, shutdown or malfunction, or during periods of gas-fired operation, the Permittee shall limit the concentration of formaldehyde from any lean premix oil-fired stationary combustion turbine with emission unit ID Nos. CT4A or CT5A to no greater than 91 parts per billion on a dry volume basis (ppb) at 15% oxygen.
[40 CFR 63.6100 and Table 1 of 40 CFR 63 Subpart YYYY]

3.3.14 Except for startup, shutdown or malfunction, or during periods of gas-fired operation, compliance with the emission limit established by Condition 3.3.13 shall be demonstrated by maintaining the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer.
[40 CFR 63.6100 and Table 2 of 40 CFR 63 Subpart YYYY]

3.3.15 Upon startup of any combustion turbine with emission unit ID Nos. CT4A or CT5A, the Permittee shall operate such units in compliance with applicable emission limits and operating standards prescribed by Subpart YYYY of 40 CFR 63, except for startup, shutdown, or malfunction. The Permittee shall operate and maintain such units, their associated catalytic oxidation emission control devices, and their related monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including periods of startup, shutdown, or malfunction.
[40 CFR 63.6095(a)(2), 40 CFR 63.6105(a), 40 CFR 63.6105(b), and 40 CFR 63.6165]

Auxiliary Boilers

3.3.16 The Permittee shall fire only pipeline quality natural gas or propane-air in each auxiliary boiler with emission unit ID Nos. AB05 and AB06.
[391-3-1-.02(2)(d)2, 391-3-1-.02(2)(d)3, and 391-3-1-.02(2)(g)]

3.3.17 The Permittee shall limit the annual heat input to each auxiliary boiler (emission unit ID Nos. AB05 and AB06) to no more than 175,200 MMBtu during any twelve consecutive months (equivalent to an annual capacity factor equal to or less than 10%). The Permittee shall use a standard fuel heat content value of 1020 Btu/scf for natural gas and 1380 Btu/scf for propane-air to calculate compliance with this limit.
[40 CFR 52.21, 40 CFR 63 Subpart DDDDD]

3.3.18 The Permittee shall not discharge, or cause the discharge, into the atmosphere from any auxiliary boiler with emission unit ID Nos. AB05 and AB06 any gases which:

a. Contain carbon monoxide in excess of 0.037 lb/MMBtu, on a 3-hour average.
[40 CFR 52.21(j)(2)]

b. Contain volatile organic compounds in excess of 0.0051 lb/MMBtu, on a 3-hour average.
[391-3-1-.03(8)(c)2.]

c. Contain nitrogen oxides in excess of 30 ppmvd, corrected to 3% oxygen, on dry basis, during the period May 1 through September 30 of each year.
[391-3-1-.02(2)(lll)]

d. Contain particulate matter in amounts equal to or exceeding

$$P = 0.5(10/R)^{0.5}$$

Where P = particulate matter in pounds per million Btu and R = heat input of fuel-burning equipment in million Btu per hour.
[391-3-1-.02(d)(2)(ii)]

e. Exhibit greater than or equal to 20% opacity except for one 6-minute period in any hour of no more than 27% opacity.
[391-3-1-.02(2)(d)3]

3.3.19 The Permittee shall not discharge, or cause the discharge, into the atmosphere from the propane heater (Emission Unit ID PH01) any gases which:

a. Contain particulate matter in amounts equal to or exceeding 0.5 pounds per million BTU heat input.
[391-3-1-.02(2)(d)2(i)]

b. Exhibit greater than or equal to 20% opacity except for one 6-minute period in any hour of no more than 27% opacity.
[391-3-1-.02(2)(d)3, 391-3-1-.02(2)(b) subsumed]

3.3.20 The Permittee shall not burn fuel containing more than 2.5 percent sulfur, by weight, in the propane heater (Emission Unit ID PH01).
[391-3-1-.02(2)(g)2]

3.3.21 The Permittee shall comply with all applicable provisions of 40 CFR 63 Subpart A – "General Provisions" and 40 CFR 63 Subpart DDDDD – "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters" for the operation of the Auxiliary Boilers 5 and 6 (Emission Unit IDs AB05 and AB06), as limited use boilers from compliance with Condition 3.3.17, and Propane Heater 1 (Emission Unit ID PH01) beginning on January 31, 2016.
[40 CFR 63 Subpart A and DDDDD]

3.4 Equipment SIP Rule Standards

3.4.1 The Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine (emission unit ID Nos. CT5M, CT6M, CT7M, or CT8M) any gases which exhibit opacity equal to or greater than 40 percent.
[391-3-1-.02(2)(b)]

3.4.2 The Permittee shall not fire any fuel in any combustion turbine (emission unit ID Nos. CT5M, CT6M, CT7M, or CT8M) that contains greater than 3.0 percent sulfur, by weight.
[391-3-1-.02(2)(g)2]

NO_x Emission Exemption Per Georgia Rule (nnn)7

3.4.3 The Permittee shall only operate combustion turbines CT5M, CT6M, CT7M, and CT8M under the following conditions from May 1 through September 30 of each year.
[391-3-1-.02(2)(nnn)7]

a. For purposes of routine testing, to maintain operability, not to exceed three (3) hours per month.

b. For the purposes of restarting the following units: (emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, and CT6B/DB6B) when all generating units at a facility are down and off-site power is not available (also known as a "Black Start"). Or, when power problems on the grid would necessitate implementing manual load shedding procedures for retail customers (Note: This does not apply to special rate structure conditions).

3.5 Equipment Standards Not Covered by a Federal or SIP Rule and Not Instituted as an Emission Cap or Operating Limit

None Applicable.

PART 4.0 REQUIREMENTS FOR TESTING

4.1 General Testing Requirements

4.1.1 The Permittee shall cause to be conducted a performance test at any specified emission unit when so directed by the Environmental Protection Division ("Division"). The test results shall be submitted to the Division within 60 days of the completion of the testing. Any tests shall be performed and conducted using methods and procedures that have been previously specified or approved by the Division.
[391-3-1-.02(6)(b)1(i)]

4.1.2 The Permittee shall provide the Division thirty (30) days (or sixty (60) days for tests required by 40 CFR Part 63 unless otherwise listed in an applicable NESHAP) prior written notice of the date of any performance test(s) to afford the Division the opportunity to witness and/or audit the test, and shall provide with the notification a test plan in accordance with Division guidelines.
[391-3-1-.02(3)(a) and 40 CFR 63.7(b)(1)]

4.1.3 Performance and compliance tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division's Procedures for Testing and Monitoring Sources of Air Pollutants. The methods for the determination of compliance with emission limits listed under Sections 3.2, 3.3, 3.4 and 3.5 are as follows:

a. Method 1 or 1A, as applicable, for the determination of sample point locations.

b. Method 2 for the determination of stack gas flow rate.

c. Method 3 or 3A for the determination of stack gas molecular weight.

d. Method 3A or 3B for the determination of the emissions rate correction factor or excess air.

e. Method 4 for the determination of stack gas moisture.

f. Method 5 or Method 17, as applicable, for the determination of particulate matter concentration from all emission units except stacks serving a combustion turbine and its paired duct burner.

g. Method 5T for the determination of particulate matter concentration in any stack serving a combustion turbine and its paired duct burner.

h. Method 6 or 6C for the determination of sulfur dioxide concentration.

i. Method 7E and the procedures contained in Section 2.121 of the above-referenced document for the determination of nitrogen oxide emissions from any stack serving a combustion turbine and its paired duct burner.

j. Method 7 or 7E for the determination of nitrogen oxide concentration for any purposes other than the purposes listed in Condition 4.1.3 i.

k. Method 9 and the procedures contained in Section 1.3 of the above-referenced document for the determination of opacity.

l. Method 10 for the determination of carbon monoxide concentration.

m. Method 19, when applicable, to convert particulate matter, carbon monoxide, sulfur dioxide, and nitrogen oxides concentrations (i.e., grains/dscf for PM, ppm for gaseous pollutants), as determined using other methods specified in this section, to emission rates (i.e., lb/MMBtu).

n. Method 25A for the determination of concentrations of volatile organic compounds. The concentration of formaldehyde measured using Method 320 shall be added to the results of Method 25A to determine the VOC concentration. If data from Method 320 is not available, a value of 0.091 ppm for formaldehyde may be used.

o. ASTM Test Method D3120, or alternatively D129, D1266, D1552, D2622, D4294, or D5453, for the determination of sulfur content in liquid fuels.

p. Test Method 320 of 40 CFR 63, Appendix A; or other methods approved by the Division for the determination of formaldehyde concentrations for combustion turbines with emission unit IDs CT4A and CT5A for 40 CFR 63, Subpart YYYY purposes only.

Minor changes in methodology may be specified or approved by the Director or his designee when necessitated by process variables, changes in facility design, or improvement or corrections that, in his opinion, render those methods or procedures, or portions thereof, more reliable.
[391-3-1-.02(3)(a)]

4.1.4 The Permittee shall submit performance test results to the US EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI) in accordance with any applicable NSPS or NESHAP standards (40 CFR 60 or 40 CFR 63) that contain Electronic Data Reporting Requirements. This Condition is only applicable if required by an applicable standard and for the pollutant(s) subject to said standard.
[391-3-1-.02(8)(a) and 391-3-1-.02(9)(a)]

4.2 Specific Testing Requirements

4.2.1 If the aggregate total hours of operation when firing fuel oil by all stationary combustion turbines at the site equal or exceed 1000 hours in a calendar year, the Permittee shall conduct a performance test for formaldehyde emissions on emission units ID No. CT4A and/or No. CT5A, for each unit that burned oil during that calendar year. Each such performance test shall be conducted, while burning ultra low sulfur diesel fuel, within 90 days after the end of that calendar year.
[40 CFR 63.6175]

4.2.2 For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, the Permittee must submit the Notification of Compliance Status required by Condition 6.2.22, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.
[40 CFR 63.6145(f)]

4.2.3 Within 60 days after achieving the maximum production rate at which the first auxiliary boiler (emission unit ID No. AB05) will be operated, but not later than 180 days after the initial startup of that auxiliary boiler, the Permittee shall conduct the following performance tests on emission unit ID No. AB05:

a. Performance tests on the first auxiliary boiler (emission unit ID No. AB05) at 50% load and 100% load for carbon monoxide emissions to verify compliance with Condition 3.3.18a.
[391-3-1-.02(6)(b)1.(i) and 40 CFR 52.21]

b. Performance tests on the first auxiliary boiler (emission unit ID No. AB05) at 50% load and 100% load for volatile organic compounds to verify compliance with Condition 3.3.18b.
[391-3-1-.02(6)(b)1.(i) and 391-3-1-.03(8)(c)2]

4.2.4 Following the initial performance test on each combustion turbine and its paired duct burner, the Permittee shall conduct emission testing for VOC from each combustion turbine (emission unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A, and CT6B) at 5 year intervals. The tests shall be conducted at base load with the duct burner not firing. The CO emissions during each tests, determined using the device required by Condition 5.2.4b., shall be included with the test report.
[391-3-1-02(6)(b)1.(i)]

4.2.5 The Permittee shall demonstrate initial compliance with NO_x emission limits in Condition 3.3.11b using the NO_x CEMS and the following procedures:
[391-3-1-.02(3), 391-3-1-.03(2)(c), PTM Section 2.121, and 40 CFR 60.4400]

a. For the initial compliance test, nitrogen oxides from the turbine are monitored for 30 successive operating days and the 30-day average emission rate is used to determine compliance with the nitrogen oxides emission standard in Condition 3.3.11b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

b. Following the date on which the initial performance test is completed, the Permittee shall determine compliance with the nitrogen oxides emissions standards under Condition 3.3.11b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each operating day as the average of all of the hourly nitrogen oxides emission data for the preceding 30 operating days.

c. In the event there are less than 30 operating days by the end of the period from May 1 to September 30, then the performance test or monitoring averaging period shall include all the operating days for that period.

d. For the purposes of this section, an operating day shall be defined as a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the turbine. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

PART 5.0 REQUIREMENTS FOR MONITORING (Related to Data Collection)

5.1 General Monitoring Requirements

5.1.1 Any continuous monitoring system required by the Division and installed by the Permittee shall be in continuous operation and data recorded during all periods of operation of the affected facility except for continuous monitoring system breakdowns and repairs. Monitoring system response, relating only to calibration checks and zero and span adjustments, shall be measured and recorded during such periods. Maintenance or repair shall be conducted in the most expedient manner to minimize the period during which the system is out of service.
[391-3-1-.02(6)(b)1]

5.2 Specific Monitoring Requirements

5.2.1 The Permittee shall install, calibrate, maintain, and operate a system to continuously monitor and record the indicated pollutants on the following equipment. Data shall be recorded at the frequency specified below. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.

a. A Continuous Emissions Monitoring System (CEMS) for measuring NO_x concentration and diluent concentration (either oxygen or carbon dioxide) of the discharge to the atmosphere from each combined cycle combustion turbine and its paired duct burner with emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, and CT6B/DB6B. The one-hour average NO_x emissions rates shall be recorded in ppm corrected to 15 percent oxygen on a dry basis, and also in pound per million Btu heat input. The diluent concentration shall be expressed in percent. For purposes of this condition, each one-hour average shall be calculated from at least four data points, each representing a different quadrant of the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For hours that quality assurance and maintenance to the CEMS is performed, a valid hour must have at least two valid data points (one in each of two quadrants of the hour). For the purposes of this condition, each clock hour begins a new one-hour period. The quadrants of the hour begin at 0, 15, 30, and 45 minutes past the hour.
[391-3-1-.02(6)(b)1, 40 CFR 60.4335(b)(1), and 40 CFR 60.4340(b)(1)]

b. A Continuous Emissions Monitoring System (CEMS) for measuring CO concentration and diluent concentration (either oxygen or carbon dioxide) discharged to the atmosphere from each combined cycle combustion turbine and its paired duct burner with emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, and CT6B/DB6B. The one-hour average CO emission rates shall be recorded in ppm corrected to 15 percent oxygen on a dry basis. The diluent concentration shall be expressed in percent. In addition to the applicable provisions of Section 1.4 of the Division's PTM, each CO CEMS must be installed and certified in accordance with Performance Specification 4A of, Appendix B of the Division's PTM, except (1) the 7-day calibration drift shall be based on unit operating

days, not calendar days, (2) the high-level value on the low-range scale shall be 10 ppm, and (3) the high-level value on the high-range scale shall be 1000 ppm. For purposes of this condition, each one-hour average shall be calculated from at least four data points, each representing a different quadrant of the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For hours that quality assurance and maintenance to the CEMS is performed, a valid hour must have at least two valid data points (one in each of two quadrants of the hour). For the purposes of this condition, each clock hour begins a new one-hour period. The quadrants of the hour begin at 0, 15, 30, and 45 minutes past the hour.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

5.2.2 The Permittee shall install, calibrate, maintain, and operate monitoring devices for the measurement of the indicated parameters on the following equipment. Data shall be recorded at the frequency specified below. Where such performance specification(s) exist, each system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

a. The quantity of natural gas, in cubic feet, burned in each combustion turbine (emission unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A, and CT6B). Data shall be recorded continuously.
[391-3-1-.02(6)(b)1, 40 CFR 52.21, and 40 CFR 60, Subpart KKKK (subsumed)]

b. The quantity of natural gas and/or landfill gas, in cubic feet, burned in each duct burner (emission unit ID Nos. DB4A, DB4B, DB5A, DB5B, DB6A, and DB6B). Data shall be recorded continuously.
[391-3-1-.02(6)(b)1, 40 CFR 52.21, and 40 CFR 60, Subpart KKKK (subsumed)]

c. The quantity of ultra low sulfur diesel fuel, biodiesel, or biodiesel blends, in gallons, burned in each combustion turbine with emission unit ID Nos. CT4A or CT5A. Data shall be recorded continuously.
[391-3-1-.02(6)(b)1, 40 CFR 52.21, and 40 CFR 60, Subpart KKKK (subsumed)]

d. The quantity of natural gas and the quantity of propane-air, in cubic feet, burned in each auxiliary boiler with emission unit ID Nos. AB05 and AB06. Data shall be recorded monthly.
[391-3-1-.02(6)(b)1, 40 CFR 52.21, and 40 CFR 63.7525(k)]

e. The monthly oil-fired operating time, in hours, for each combustion turbine with emission unit ID Nos. CT4A and CT5A while burning ultra low sulfur diesel fuel, biodiesel, or biodiesel blends, shall be measured.
[391-3-1-.02(6)(b)1, 40 CFR 52.21, and 40 CFR 63.6125(d)]

f. The monthly oil-fired operating time, in hours, for each existing combustion turbine with emission unit ID Nos. CT5M, CT6M, CT7M, and CT8M at the site while burning distillate oil shall be measured.
[40 CFR 63.6125(d)]

g. A Continuous Parameter Monitoring System (CPMS) for measuring the inlet temperature to the oxidation catalyst on each combustion turbine with emission unit ID Nos. CT4A and CT5A, whenever that unit is firing ultra low sulfur diesel fuel, biodiesel, or biodiesel blends. Data shall be recorded continuously.
[391-3-1-.02(6)(b)1 and 40 CFR 63.6135(a) & (b)]

5.2.3 The sulfur content of the pipeline quality natural gas burned in the combustion turbines (emission unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A and CT6B) and in the duct burners (DB4A, DB4B, DB5A, DB5B, DB6A, DB6B) shall be monitored by submittal of a semiannual analysis of the gas by supplier or by the Permittee.
[391-3-1-.02(6)(b)1]

5.2.4 The sulfur content of the ultra low sulfur diesel fuel, biodiesel, or biodiesel blends burned in the combustion turbines with emission unit ID Nos. CT4A and CT5A shall be monitored by verifying that each shipment of such fuel received complies with the specifications for Grade No. 1-D S15 or No. 2-D S15 as defined in ASTM D975 for ultra low sulfur diesel fuel or ASTM D6751 for biodiesel or biodiesel blends. Supplier certifications shall contain the name of the supplier and a statement from the supplier indicating the grade of the fuel as defined in ASTM D975 or ASTM D6751.
[40 CFR 60.4360 and 40 CFR 60.4365]

5.2.5 The sulfur content of the landfill gas burned in the duct burners with emission unit ID Nos. DB4A, DB4B, DB5A, DB5B, DB6A, and DB6B shall be monitored by submittal of a semiannual analysis of the gas by the Permittee.
[40 CFR 60.4360]

5.2.6 Using the procedures of Appendix F, Procedure 1 (Quality Assurance Requirements for Gas Continuous Emissions Monitoring Systems Used for Compliance Determination) contained in the Division's "Procedures for Testing and Monitoring Sources of Air Pollutants," the Permittee shall assess the quality and accuracy of the data acquired by the carbon monoxide CEMS required by Condition 5.2.4.b. The following exceptions to Appendix F, Procedure 1 are allowed:
[391-3-1-.02(6)(b)1]

a. The cylinder gas audit (CGA) is only required to be conducted in a calendar quarter if the turbine is operated during the quarter.

b. A Relative Accuracy Test Audit (RATA) shall be conducted annually or every four operating quarters (not to exceed eight calendar quarters) which ever is greater. For the purpose of this condition an operating quarter is defined as any calendar quarter during which the turbine is operated.

c. The CGA is only required on the high-range scale of a dual-range analyzer. The zero and high-level calibration drift results for the low-range scale conducted on the day of the CGA shall be submitted in lieu of the low-range scale CGA.

5.2.7 The Permittee shall obtain CO emissions data for at least 75 percent of the operating hours in at least 22 out of 30 successive turbine operating days for each combustion turbine and its paired duct burner with emissions unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, and CT6B/DB6B. If this minimum data requirement is not met using the CO CEMS required by condition 5.2.4, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Director or the test methods and procedures as described in Condition 4.1.3.
[391-3-1-.02(6)(b)1 and PTM Section 2.121]

5.2.8 The following pollutant specific emission unit(s) (PSEU) is/are subject to the Compliance Assurance Monitoring (CAM) Rule in 40 CFR 64.

Emission Unit	Pollutant
Combustion Turbine Unit 4A	NO_x, CO, and VOC
Combustion Turbine Unit 4B	NO_x, CO, and VOC
Combustion Turbine Unit 5A	NO_x, CO, and VOC
Combustion Turbine Unit 5B	NO_x, CO, and VOC
Combustion Turbine Unit 6A	NO_x, CO, and VOC
Combustion Turbine Unit 6B	NO_x, CO, and VOC
Duct Burner Unit 4A	NO_x, CO, and VOC
Duct Burner Unit 4B	NO_x, CO, and VOC
Duct Burner Unit 5A	NO_x, CO, and VOC
Duct Burner Unit 5B	NO_x, CO, and VOC
Duct Burner Unit 6A	NO_x, CO, and VOC
Duct Burner Unit 6B	NO_x, CO, and VOC

Permit conditions in this permit for the PSEU(s) listed above with regulatory citation 40 CFR 70.6(a)(3)(i) are included for the purpose of complying with 40 CFR 64. In addition, the Permittee shall meet the requirements, as applicable, of 40 CFR 64.7, 64.8, and 64.9.
[40 CFR 64]

5.2.9 The Permittee shall comply with the performance criteria listed in the table below for the nitrogen oxides (NO_x) emissions from combustion turbines and paired duct burners with emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, and CT6B/DB6B.
[40 CFR 64.6(c)(1)(iii)]

Performance Criteria [64.4(a)(3)]	**Indicator NO_x CEMS**
A. Data Representativeness [64.3(b)(1)]	NO_x and O_2 are measured continuously in the exhaust to the atmosphere.
B. Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	The CEMS is certified under 40 CFR Part 75, Appendix A

Performance Criteria [64.4(a)(3)]	**Indicator** **NO_x CEMS**
C. QA/QC Practices and Criteria [64.3(b)(3)]	NO_x and O_2 analyzers are calibrated daily. They are maintained according to the QA/QC program developed specifically for the plant.
D. Monitoring Frequency [64.3(b)(4)]	NO_x and O_2 are monitored continuously except during calibration and maintenance.
Data Collection Procedures [64.3(b)(4)]	A Data Acquisition System (DAS) retains all hourly average NO_x and O_2 data.
Averaging Period [64.3(b)(4)]	The 1-minute data is used to calculate 1-hour averages.

5.2.10 The Permittee shall comply with the performance criteria listed in the table below for the carbon monoxide (CO) and volatile organic compound (VOC) emissions from combustion turbines and paired duct burners with emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, and CT6B/DB6B.
[40 CFR 64.6(c)(1)(iii)]

Performance Criteria [64.4(a)(3)]	**Indicator** **CO CEMS**
A. Data Representativeness [64.3(b)(1)]	CO and O_2 are measured continuously in the exhaust to the atmosphere.
B. Verification of Operational Status (new/modified monitoring equipment only) [64.3(b)(2)]	The CO analyzer is certified under the Division's, Appendix B, Performance Specification 4A and the O2 analyzer is certified under 40 CFR Part 75, Appendix A.
C. QA/QC Practices and Criteria [64.3(b)(3)]	CO and O_2 analyzers are calibrated daily. They are maintained according to the QA/QC program developed specifically for the plant.
D. Monitoring Frequency [64.3(b)(4)]	CO and O_2 are monitored continuously except during calibration and maintenance.
Data Collection Procedures [64.3(b)(4)]	A Data Acquisition System (DAS) retains all hourly average CO and O_2 data.
Averaging Period [64.3(b)(4)]	The 1-minute data is used to calculate 1-hour averages.

5.2.11 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The Permittee shall use all the data collected during all other periods in assessing the operation of the control device and associated control

system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.
[40 CFR 64.7(c)]

5.2.12 Upon detecting an excursion or exceedance as defined in Condition 6.1.7, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable. Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.
[40 CFR 64.7(d)(1) and (2)]

5.2.13 If the Permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the permitting authority and, if necessary, submit a proposed modification to the part 70 or 71 permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.
[40 CFR 64.7(e)]

5.2.14 The Permittee shall, each calendar year, monitor emissions of nitrogen oxides (NO_x) from Auxiliary Boilers AB05 and AB06 by performing tune-ups and keeping records as described below:
[391-3-1-.02(2)(lll)]

a. The tune-up shall be performed at the normal maximum operating load during the periods of May 1 to September 30 each year, and no earlier than March 1 and no later than May 1 of each calendar year, with the following exception. In the case of startups that occur after May 1 but before September 30 , tune-ups shall be performed no later than 120 hours after startup.

b. The tune-up shall be performed by using the manufacturer-recommended equipment settings for reduced NO_x emissions or by using a NO_x analyzer. Adjustments shall be made, as needed, so that NO_x emissions are reduced in a manner consistent with good combustion practices and safe fuel-burning equipment operation.

c. Following the adjustments, or determination that adjustments are not required, the Permittee shall perform a minimum of three emissions test runs to demonstrate that the emissions are less than or equal to the NO_x concentration limit of Condition No. 3.3.18c. Each test run shall be a minimum of 30 minutes of operational data in length and shall measure the average NO_x concentration over the test duration. Following any test run which results in an average NO_x concentration that exceeds the NO_x limit of Condition No. 3.3.18c, the Permittee shall make adjustments to the boiler and conduct a new set of test runs within one day. Subsequent adjustments followed by test runs shall be continued until the results of 3 consecutive test runs are less than or equal to the NO_x concentration limit of Condition No. 3.3.18c.

d. All measurements of NO_x and oxygen concentrations in paragraphs b. and c. of this condition shall be conducted using procedures of the American Society for Testing and Materials (ASTM) Standard Test Method for Determination of NO_x, Carbon Monoxide (CO), and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, ASTM D 6522; procedures of Gas Research Institute Method GRI-96/0008, EPA/EMC Conditional Test Method (CTM-30) Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers and Process Heaters Using Portable Analyzers; or procedures of EPA Reference Method 7E and 3A.

e. The Permittee shall maintain records of all tune-ups performed in accordance with this condition. These records shall include the following:

   i. date and time the tune-up was performed
   ii. the boiler settings for each test run
   iii. the average NO_x concentration (in ppm at 3% O_2, dry basis) for each test run
   iv. what operating parameters were adjusted to minimize NO_x emissions
   v. an explanation of how the final (compliant) settings were determined

f. Following the tune-up, from the period May 1 through September 30 of each year, the Permittee shall operate each affected boiler using the settings determined during the annual tune-up. If no parameters can be monitored to indicate the performance of a specific boiler, the Permittee shall certify that no adjustments have been made to the boiler by the Permittee and/or any third party since the most recent successful tune-up was completed. This certification shall be made in writing no later than October 15 of each year and shall be maintained with the records required by paragraph e. of this condition.

g. As an alternative to complying with the annual tune-up requirement described above, the owner or operator may conduct measurements of NO_x at a reduced frequency following a tune-up and verification demonstrating that the affected facility is capable

of NO_x emissions of less than or equal to 15 ppm at 3 percent oxygen. The Permittee may conduct subsequent tune-ups at 48 calendar month intervals as long as the 15 ppm capability can be demonstrated. Performance of tests and tune-ups, maintenance of records, and subsequent boiler operation shall otherwise be conducted as described in paragraphs a through f of this condition. The Permittee shall continue to make annual certifications of no adjustments since the previous tune-up.

h. As an alternative to complying with the requirements in this condition, the Permittee shall submit documentation no later than April 30 of each year confirming that an affected unit will not operate during the months of May through September. As a minimum, the documentation shall include the identification of the facility, the permit number, and the specific affected units that will not be operated.

5.2.15 For each one-hour period of operation of each combustion turbine with emissions unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A, CT6B, the Permittee shall record the one-hour average NO_x concentration and the percent oxygen (O_2) (in ppm, corrected to 15% O_2, dry basis). For an hour to be included in the calculation, the one-hour average concentration must be based upon a minimum of 30 minutes of turbine operation and must include a minimum of two data points, with each data point representing a 15-minute period. This condition applies during the period May 1 through September 30 of each year.
[391-3-1-.02(6)(b)1, PTM Section 2.121, and 40 CFR 60.4400]

5.2.16 The procedures of Section 1.4 of the Division's **Procedures for Testing and Monitoring of Air Pollutants** shall be followed for the installation, evaluation, and operation of the continuous monitoring systems (CMS).
[391-3-1-.02(6)(b)1 and PTM Section 2.121]

a. All CMS shall be operated in accordance with the applicable procedures under Performance Specifications 2 or 3 (Appendix B).

b. Quarterly accuracy determinations and calibration drift assessments shall be performed in accordance with Procedure 1, Appendix F during the period of May 1 through September 30 each year.

c. The span for the Nitrogen Oxides monitor shall be set at 30 parts per million (ppm).

5.2.17 Auxiliary Boilers 5 and 6 (Emission Unit IDs AB05 and AB06) and Propane Heater 1 (Emission Unit ID PH01) must conduct a tune-up every 5 years to demonstrate compliance with the following paragraphs (a)-(g) below. Each 5-year tune-up must be conducted no more than 61 months after the previous tune-up.
[40 CFR 63.7500(c), (e), and 40 CFR 63.7540(a)(10), (a)(12), and (a)(13)]

a. As applicable, inspect the burner, and clean or replace any components of the burner as necessary. The Permittee may delay the burner inspection until the next scheduled unit shutdown. The Permittee must inspect each burner of the Auxiliary Boilers (Emission Unit IDs AB05 and AB06) at least once every 72 months. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up

inspections, inspections are required only during planned entries into the storage vessel or process equipment.

b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.

c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly. The inspection may be delayed until the next scheduled unit shutdown.

d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any nitrogen oxide requirement to which the unit is subject.

e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

f. Maintain on-site and submit, if requested by the Division, a report containing the following:

    i. The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler.

    ii. A description of any corrective actions taken as a part of the tune-up of the boiler.

    iii. The type and amount of fuel used over the 12 months prior to the tune-up of the boiler, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

g. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

PART 6.0 RECORD KEEPING AND REPORTING REQUIREMENTS

6.1 General Record Keeping and Reporting Requirements

6.1.1 Unless otherwise specified, all records required to be maintained by this Permit shall be recorded in a permanent form suitable for inspection and submission to the Division and to the EPA. The records shall be retained for at least five (5) years following the date of entry.
[391-3-1-.02(6)(b)1(i) and 40 CFR 70.6(a)(3)]

6.1.2 In addition to any other reporting requirements of this Permit, the Permittee shall report to the Division in writing, within seven (7) days, any deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning, or emissions control equipment for a period of four hours or more which results in excessive emissions.

The Permittee shall submit a written report that shall contain the probable cause of the deviation(s), duration of the deviation(s), and any corrective actions or preventive measures taken.
[391-3-1-.02(6)(b)1(iv), 391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(iii)(B)]

6.1.3 The Permittee shall submit written reports of any failure to meet an applicable emission limitation or standard contained in this permit and/or any failure to comply with or complete a work practice standard or requirement contained in this permit which are not otherwise reported in accordance with Conditions 6.1.4 or 6.1.2. Such failures shall be determined through observation, data from any monitoring protocol, or by any other monitoring which is required by this permit. The reports shall cover each semiannual period ending June 30 and December 31 of each year, shall be postmarked by August 29 and February 28, respectively following each reporting period, and shall contain the probable cause of the failure(s), duration of the failure(s), and any corrective actions or preventive measures taken.
[391-3-1-.03(10)(d)1.(i) and 40 CFR 70.6(a)(3)(iii)(B)]

6.1.4 The Permittee shall submit a written report containing any excess emissions, exceedances, and/or excursions as described in this permit and any monitor malfunctions for each quarterly period ending March 31, June 30, September 30, and December 31. All reports shall be postmarked by May 30, August 29, November 29, and February 28, respectively following each reporting period. In the event that there have not been any excess emissions, exceedances, excursions or malfunctions during a reporting period, the report should so state. Otherwise, the contents of each report shall be as specified by the Division's Procedures for Testing and Monitoring Sources of Air Pollutants and shall contain the following:
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(iii)(A)]

a. A summary report of excess emissions, exceedances and excursions, and monitor downtime, in accordance with Section 1.5(c) and (d) of the above referenced document, including any failure to follow required work practice procedures.

b. Total process operating time during each reporting period.

c. The magnitude of all excess emissions, exceedances and excursions computed in accordance with the applicable definitions as determined by the Director, and any conversion factors used, and the date and time of the commencement and completion of each time period of occurrence.

d. Specific identification of each period of such excess emissions, exceedances, and excursions that occur during startups, shutdowns, or malfunctions of the affected facility. Include the nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

e. The date and time identifying each period during which any required monitoring system or device was inoperative (including periods of malfunction) except for zero and span checks, and the nature of the repairs, adjustments, or replacement. When the monitoring system or device has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

f. Certification by a Responsible Official that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.

6.1.5 Where applicable, the Permittee shall keep the following records:
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(3)(ii)(A)]

a. The date, place, and time of sampling or measurement;

b. The date(s) analyses were performed;

c. The company or entity that performed the analyses;

d. The analytical techniques or methods used;

e. The results of such analyses; and

f. The operating conditions as existing at the time of sampling or measurement.

6.1.6 The Permittee shall maintain files of all required measurements, including continuous monitoring systems, monitoring devices, and performance testing measurements; all continuous monitoring system or monitoring device calibration checks; and adjustments and maintenance performed on these systems or devices. These files shall be kept in a permanent form suitable for inspection and shall be maintained for a period of at least five (5) years following the date of such measurements, reports, maintenance and records.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6 (a)(3)(ii)(B)]

6.1.7 For the purpose of reporting excess emissions, exceedances or excursions in the report required in Condition 6.1.4, the following excess emissions, exceedances, and excursions shall be reported:
[391-3-1-.02(6)(b)1, 40 CFR 70.6(a)(3)(iii), 40 CFR 60.4380)]

a. Excess emissions: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping which is specifically defined, or stated to be, excess emissions by an applicable requirement)

   i. Any operating period in which the 30-day rolling average NO_x emissions rate from a combustion turbine and its paired duct burner exceeds the applicable emissions limit in Condition 3.3.9a. or 3.3.11a.

b. Exceedances: (means for the purpose of this Condition and Condition 6.1.4, any condition that is detected by monitoring or record keeping that provides data in terms of an emission limitation or standard and that indicates that emissions (or opacity) do not meet the applicable emission limitation or standard consistent with the averaging period specified for averaging the results of the monitoring)

   i. Any three-hour rolling average CO emission rate, determined in accordance with Condition 6.2.12, which exceeds 1.8 ppmvd at 15% oxygen for a combustion turbine and its paired duct burner with emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, CT6B/DB6B, when the combustion turbine is fired with natural gas. For purposes of this condition, each clock hour begins a new one-hour average.

   ii. Any three-hour rolling average CO emission rate, determined in accordance with Condition 6.2.12, which exceeds 9.0 ppmvd at 15% oxygen for a combined cycle combustion turbine and its paired duct burner with emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, CT6B/DB6B, when the combustion turbine is fired with ultra low sulfur diesel fuel, biodiesel, or biodiesel blends. For purposes of this condition, each clock hour begins a new one-hour average.

   iii. Any twelve consecutive month total CO emissions from Combined Cycle Combustion Turbine Blocks 4, 5, or 6, including emissions resulting from startup and shutdown, in excess of 259 tons, for Blocks 4 or 5, or 238 tons for Block 6. Each block consists of the correspondingly numbered combustion turbines and duct burners.

   iv. Any twelve consecutive month total NO_x emissions from Combined Cycle Combustion Turbine Blocks 4, 5, or 6, along with their auxiliary boilers, including emissions resulting from startup and shutdown, in excess of the limits in Condition 3.3.6c, which are 217 tons, for Blocks 4 or 5, or 200 tons for Block 6. Each block consists of the correspondingly numbered combustion turbines and duct burners.

   v. Any 30-day rolling average NO_x emissions from a combined cycle combustion turbine and its paired duct burner with emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, CT6B/DB6B, that exceeds 6 ppmvd, corrected to 15% oxygen, during the ozone season (May 1 through September 30 of each year).

c. Excursions: (means for the purpose of this Condition and Condition 6.1.4, any departure from an indicator range or value established for monitoring consistent with any averaging period specified for averaging the results of the monitoring)

i. Any semiannual analysis of the natural gas combusted in any combustion turbine or duct burner with emission unit ID Nos. CT4A/DB4A, CT4B/DB4B, CT5A/DB5A, CT5B/DB5B, CT6A/DB6A, CT6B/DB6B, whose sulfur content exceeds 0.5 grains per 100 standard cubic feet.

ii. For combustion turbines with emission unit ID Nos. CT4A and CT5A, any 4-hour rolling average of the oxidation catalyst inlet temperature outside the range suggested by the catalyst manufacturer while burning ultra low sulfur diesel fuel, biodiesel, or biodiesel blends.

iii. Any twelve consecutive month total hours of operation from burning ultra low sulfur diesel fuel, biodiesel, or biodiesel blends, for a combustion turbine with emission unit ID Nos. CT4A or CT5A, which exceeds 1,000 hours.

iv. Any time ultra low sulfur diesel fuel, biodiesel, or biodiesel blends, combusted in a combustion turbine, with emission unit ID Nos. CT4A or CT5A, exceeds 0.0015 percent sulfur by weight.

v. Any twelve consecutive month total fuel consumption for an auxiliary boiler (emission unit ID Nos. AB05 or AB06) equals or exceeds 175,200 MMBtu.

6.1.8 In addition to the excess emissions, exceedances and excursions specified in Condition 6.1.7, the quarterly compliance report for each combustion turbine with emission unit ID Nos. CT4A and CT5A should also be included with the report required in Condition 6.1.4, which must contain the following:
[391-3-1-.02(6)(b)1, 40 CFR 61.6150(a), 40 CFR 61.6150(b)(5), and Table 6 of 40 CFR 63 Subpart YYYY]

a. Company name and address.

b. Statement by a responsible official, with that official's name, title and signature, certifying the accuracy of the content of the report.

c. Date of report and beginning and ending dates of the reporting period.

d. For each deviation from an emission limitation, the compliance report must contain:

i. The total operating time of each stationary combustion turbine during the reporting period.

ii. Information on the number, duration and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action.

iii. Information on the number, duration and cause for monitor downtime incidents (including unknown cause, if applicable) other than downtime associated with zero and span and other daily calibration checks.

6.1.9 The Permittee shall provide the Division with a statement, in such form as the Director may prescribe, showing the actual emissions of nitrogen oxides and volatile organic compounds from the entire facility. These statements shall be submitted every year by the date specified in 391-3-1-.02(6)(a)4 and shall show the actual emissions of the previous calendar year.
[391-3-1-.02(6)(b)1(i)]

6.2 Specific Record Keeping and Reporting Requirements

6.2.1 The Permittee shall retain monthly records of all fuel burned in the combustion turbines (emission unit IDs CT5M, CT6M, CT7M, or CT8M) for five years after the date and year of record. The records shall be available for inspection or submittal to the Division, upon request, and contain the following:
[391-3-1-.02(6)(b)1(i)]

a. Quantity (million cubic feet) of natural gas burned.

b. Quantity (gallons) of distillate oil, No. 2 fuel oil, biodiesel, biodiesel blends, very low sulfur oil burned, or ultra low sulfur oil burned.

6.2.2 For each shipment of No. 2 fuel oil received, the Permittee shall obtain from the supplier of the fuel oil, a statement certifying that the oil complies with the specifications of No. 2 fuel oil contained in ASTM D396, or ASTM D975. As an alternative to the procedure described above, the Permittee may, for each shipment of No. 2 fuel oil received, obtain a sample for analysis of the sulfur content. The procedures of ASTM D4057 shall be used to acquire the sample. Sulfur content shall be determined using the procedures listed in Condition 4.1.3o, or by some other test method approved by the US EPA and acceptable to the Division.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.3 The Permittee shall maintain records specifying the hours per month of operation of each combustion turbine (emission unit IDs CT5M, CT6M, CT7M, and CT8M). In addition, these records should include documentation of the purpose of turbine operation (i.e., routine testing, maintenance, etc). This condition applies May 1 through September 30 of each year. These records shall be in a format suitable and available for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

Reporting Requirements

6.2.4 The Permittee may submit, via electronic media, any report required by Part 6.0 of this permit provided such format has been approved by the Division.

6.2.5 The Permittee shall retain monthly records of natural gas usage in each combustion turbine (emission unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A, and CT6B) and in each duct burner (emission unit ID Nos. DB4A, DB4B, DB5A, DB5B, DB6A, and DB6B).
[391-3-1-.02(6)(b)1 and 40 CFR 60, Subpart KKKK]

6.2.6 The Permittee shall retain monthly records of ultra low sulfur diesel fuel, biodiesel, or biodiesel blend usage in each combustion turbine with emission unit ID Nos. CT4A and CT5A.
[391-3-1-.02(6)(b)1 and 40 CFR 60, Subpart KKKK]

6.2.7 The Permittee shall maintain the following daily records as they relate to the startup and shutdown of each combustion turbine with emission unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A, and CT6B: the type of startup initiated, the minutes attributed to the startup, and the minutes attributed to shutdown. If the turbine was not in operation on any given day, the records shall so note.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

Verification of Compliance with NO_x Emission Limits

6.2.8 The Permittee shall calculate a 30-day rolling average NO_x emission rate (in ppm at 15 percent oxygen) for each combined cycle combustion turbine and its paired duct burner, using the NO_x emission hourly emission rate determined in accordance with Condition 5.2.4.a.
[40 CFR 60.4350 and 40 CFR 60.4380]

6.2.9 The Permittee shall determine and record the mass emission rate (pound per hour) of NO_x from each combined cycle combustion turbine and its paired duct burner for each hour or portion of each hour of operation. This emission rate must include emissions from all periods of operation. The hourly mass emission rate shall be calculated by multiplying the total NO_x emissions in units of pound per million Btu, determined in accordance with the procedures of 40 CFR Part 75, Section 3 of Appendix F, by the total heat input for that hour determined in accordance with the procedures of 40 CFR Part 75, Section 5.5 of Appendix F. These records (including calculations) shall be maintained in a form suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.10 The Permittee shall use the records required by Condition 6.2.9 to determine and record the monthly mass emission rate, in tons per month, of NO_x from each combined cycle combustion turbine and its paired duct burner. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

6.2.11 The Permittee shall use the records required by Condition 6.2.10 to determine and record the twelve consecutive month total emission rate, in tons, of NO_x emissions from each combined cycle combustion turbine and its paired duct burner. A twelve consecutive month total shall be the total for a month in the reporting period plus the totals for the previous eleven consecutive months. These records (including calculations) shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

Verification of Compliance with CO Emission Limits

6.2.12 The Permittee shall calculate a three-hour average CO emission rate (in ppm at 15% oxygen) for each combined cycle combustion turbine and its paired duct burner using the CO emission rate determined in accordance with Condition 5.2.4.b.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.13 The Permittee shall, using the hourly heat input rate (million Btu per hour) determined in accordance with the procedures of Appendix F, 40 CFR Part 75, and the one-hour average CO emission rate in pounds per million Btu, calculate the hourly CO mass emission rate (pound per hour) for each hour or portion of each hour of operation of each combined cycle combustion turbine and its paired duct burner. Only the one-hour average CO emission rates (pound per million Btu) that have been determined to be valid hourly emission rates, shall be used to calculate hourly mass emission rates.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.14 The Permittee shall use the valid hourly CO mass emission rates (pound per hour), determined in accordance with the requirements of Condition 6.2.13, and all hourly CO mass emissions rates acquired in order to meet the minimum data requirement of Condition 5.2.10, to determine the monthly CO mass emissions, in tons, from each combined cycle combustion turbine and its paired duct burner. This emission rate must include emissions during all periods of operation. The monthly CO mass emissions from each combustion turbine and its paired duct burner shall be calculated as follows:

CO emissions (tons) = ECO*(TOT/TGD)/2000

where, ECO equals the total CO mass emissions (sum of the valid hours of CO mass emissions including all hourly CO mass emissions data acquired to meet the minimum data requirement) for the month, TOT equals the total operating time of the combustion turbine during the month, and TGD equals the number of hours of valid emissions data including all hourly emissions data acquired to meet the minimum data requirement contained in Condition 5.2.10. These records shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.15 For each combined cycle combustion turbine and its paired duct burner at the end of each month, the twelve consecutive month CO mass emissions shall be the sum of its monthly CO mass emissions for that month plus its monthly CO mass emissions for the previous eleven consecutive months. These records shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

Verification of Compliance with Operational Limits

6.2.16 For each auxiliary boiler with emission unit ID Nos. AB05, and AB06, its monthly heat input for each month (in MMBtu) shall be calculated as the product of the monthly quantity of natural gas and propane-air burned in that boiler (in cubic feet), as recorded in Condition 5.2.5d, times the applicable heat content of each of those fuels (1020 Btu/scf for natural gas and 1380 Btu/scf for propane-air). For each auxiliary boiler at the end of each month, a

twelve consecutive month total heat input shall be the sum of the monthly heat input for that month plus the monthly heat inputs for the previous eleven consecutive months. These records shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.17 For each combustion turbine with emission unit ID Nos. CT4A and CT5A at the end of each month, the Permittee shall calculate the twelve consecutive month oil-fired operating time, which shall be the sum of its monthly oil-fired operating time for that month plus its monthly oil-fired operating time for the previous eleven consecutive months. These records shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.18 For each combustion turbine at the site firing distillate oil, the Permittee shall calculate the calendar-year, oil-fired operating time, which shall be the sum of the monthly oil-fired operating times recorded for that turbine as required by Condition 5.2.5e or 5.2.5f, as applicable, as of January of the calendar year in question. The aggregate calendar-year, oil-fired operating time for all combustion turbines at the site shall be the sum of each such unit's calendar-year oil-fired operating time. These records shall be maintained as part of the monthly record suitable for inspection or submittal.
[391-3-1-.02(6)(b)1 and 40 CFR 63, Subpart YYYY]

Reporting Requirements

6.2.19 The Permittee shall submit a report of the following information for each quarterly period ending March 31, June 30, September 30, and December 31 of each year. All reports shall be postmarked by May 30, August 29, November 29, and February 28, respectively following each reporting period.
[40 CFR 52.21 and 40 CFR 60.7]

a. Heat input to each auxiliary boiler (emission unit ID Nos. AB05 and AB06), for each month during the reporting period, using a heat content of 1020 Btu/scf for natural gas and a heat content of 1380 Btu/scf for propane-air.

b. The twelve consecutive month total heat input to each auxiliary boiler (emission unit ID Nos. AB05 and AB06), for each twelve consecutive month period ending during the reporting period, using a heat content of 1020 Btu/scf for natural gas and a heat content of 1380 Btu/scf for propane-air.

c. Monthly oil-fired operating time with ultra low sulfur diesel fuel by each combustion turbine with emission unit ID Nos. CT4A and CT5A for each month during the reporting period.

d. The twelve consecutive month oil-fired operating time with ultra low sulfur diesel fuel by each combustion turbine with emission unit ID Nos. CT4A and CT5A for each twelve consecutive month period ending during the reporting period.

e. The twelve consecutive month CO mass emissions from each combustion turbine and its paired duct burner for each twelve consecutive month period ending during the reporting period.

f. Identification of each calendar month for which CO emissions data have not been obtained for 75 percent of the combustion turbine operating hours during the months in the reporting period, including reasons for not obtaining sufficient data and a description of corrective actions taken.

g. Identification of the Out-of-Control Periods (as defined in Appendix F, Procedure 1) for the CO CEMS during the quarterly reporting period.

h. Results of any failed daily CO CEMS drift tests and subsequent passed tests and quarterly accuracy assessments under Appendix F, Procedure 1, during the reporting period.

6.2.20 The Permittee shall submit to the Division the results of the Relative Accuracy Test Audits (RATA), required by Condition 5.2.9 for the CO CEMS, within sixty (60) days of the completion of the RATA.
[391-3-1-.02(6)(b)1 and 40 CFR 52.21]

6.2.21 For each combustion turbine with emission unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A, or CT6B, the Permittee must submit any applicable notification required in 40 CFR 63.8(f)(4) by the date specified. For each combustion turbine with emission unit ID Nos. CT4A or CT5A, if the Permittee requests to use an alternative monitoring procedure under 40 CFR 63, Subpart YYYY, the Permittee must submit written notification of intent. The notification of intent may be submitted at any time, provided that the alternative monitoring procedure is not the performance test method used to demonstrate compliance with a relevant standard or other requirement. If the alternative monitoring procedure will serve as the performance test method that is to be used to demonstrate compliance, the notification of intent must be submitted at least 60 days before the performance evaluation is scheduled to begin and must meet the requirements for an alternative test method under 40 CFR 63.7(f). That submittal shall include:
[40 CFR 63.6145(a)]

a. A description of the proposed alternative monitoring system which addresses the four elements contained in the definition of monitoring: (1) indicator(s) of performance, (2) measurement techniques, (3) monitoring frequency and (4) averaging time.

b. A performance evaluation test plan, if required.

c. Information justifying the Permittee's request for the alternative monitoring procedure, such as the technical or economic infeasibility, or the impracticality, of the affected source using the required method.

d. Results of the Method 301 (40 CFR 63, Appendix A) validation process for the alternative test method.

6.2.22 The Permittee must submit a Notification of Compliance Status according to 40 CFR 63.9(h)(2)(ii) for each combustion turbine with emission unit ID Nos. CT4A and CT5A before the close of business on the 60th day following the completion of any performance test for formaldehyde emissions from that unit, including the following:
[40 CFR 63.6145(f)]

a. The methods that were used to determine compliance.

b. The results of any performance tests, opacity or visible emission observations, continuous monitoring system (CMS) performance evaluations, and/or other monitoring procedures or methods that were conducted.

c. The methods that will be used for determining continuing compliance, including description of monitoring and reporting requirements and test methods.

d. The type and quantity of hazardous air pollutants emitted by the source (or surrogate pollutants if specified in the relevant standard), reported in units and averaging times and in accordance with the test methods specified in the relevant standard.

e. If the relevant standard applies to both major and area sources, an analysis demonstrating whether the affected source is a major source (using the emissions data generated for this notification).

f, A description of the air pollution control equipment (or method) for each emission point, including each control device (or method) for each hazardous air pollutant and the control efficiency (percent) for each control device (or method).

g. A statement by the owner or operator of the affected existing, new, or reconstructed source as to whether the source has complied with the relevant standard or other requirements.

6.2.23 The Permittee must keep the following records:
[40 CFR 63.6155(a)]

a. A copy of each notification and report that was submitted to comply with 40 CFR 63, Subpart YYYY, including all documentation supporting any Initial Notification or Notification of Compliance Status that was submitted.

b. Records of performance tests and performance evaluations.

c. Records of occurrence and duration of each startup, shutdown or malfunction.

d. Records of the occurrence and duration of each malfunction of the catalytic oxidation control equipment, if applicable.

e. Records of all maintenance on the catalytic oxidation control equipment.

6.2.24 The Permittee shall maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection according to 40 CFR 63.10(b)(1). As specified in 40 CFR 63.10(b)(1), the Permittee shall keep records for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report or record. The Permittee shall retain these records for the most recent 2 years onsite. The records for the remaining 3 years may be retained offsite.
[391-3-1-.03(10)(d)1(i), 40 CFR 70.6 (a)(3)(ii)(B), 40 CFR 63.6160(a), (b), and (c), and 40 CFR 63.7560]

6.2.25 The Permittee shall, in accordance with 40 CFR 63.6(f)(2)(iv), maintain records of the catalyst inlet temperature range suggested by the catalyst manufacturer, in such a manner that they can be readily accessed and are suitable for inspection. The Permittee shall submit the inlet temperature range suggested by the catalyst manufacturer as part of the Notification of Compliance Status required by Permit Condition 6.2.22, in accordance with 40 CFR 63.9(h)(2)(i).
[40 CFR 63.6(f)(2)(iv) and 40 CFR 63.9(h)(2)(i)]

6.2.26 The Permittee shall for each combined cycle combustion turbine with emission unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A, and CT6B maintain records of the following information for each operating day:
[391-3-1-.02(6)(b)1 and PTM Section 2.121]

a. Calendar date

b. The average hourly nitrogen oxides emission rates (expressed as ppm corrected to 15 percent oxygen), unless the affected facility was not in operation for the day.

c. The 30-day average nitrogen oxides emission rates (expressed as ppm corrected to 15 percent oxygen) calculated at the end of each operating day from the measured hourly nitrogen oxide emission rates for the preceding 30 operating days.

d. Identification of any operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions limits with the reasons for such excess emissions as well as a description of corrective actions taken.

e. Identification of any operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

f. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.

g. Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

h. Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.

i. Results of daily CMS drift tests and quarterly accuracy assessments as required under Appendix F, Procedure 1.

6.2.27 The Permittee shall for each combined cycle combustion turbine with emission unit ID Nos. CT4A, CT4B, CT5A, CT5B, CT6A, and CT6B submit a quarterly report containing the information required by Condition 6.2.26 with the exception of item 6.2.26b. All reports shall be postmarked by May 30, August 29, November 29, and February 28, respectively following each reporting period.
[391-3-1-.02(6)(b)1 and PTM Section 2.121]

6.2.28 When burning ultra low sulfur diesel fuel, biodiesel, or biodiesel blends, the Permittee shall calculate a four-hour average catalyst inlet temperature for each combined cycle combustion turbine and its paired duct burner with emission unit ID Nos. CT4A/DB4A and CT5A/DB5A, using the catalyst inlet temperature determined in accordance with Condition 5.2.5g. After the first 4-hour average, a new 4-hour rolling average shall be calculated after each operating hour.
[391-3-1-.02(6)(b)1 and 40 CFR 63. 6135(a) & (b)]

6.2.29 Every 5 years beginning January 31, 2021, the Permittee shall prepare and submit to the Division by January 31, a compliance report covering the 5-year period, January 1 – December 31, since the previous reporting period, containing the information specified below for AB05, AB06, and PH01. The first reporting period shall cover from January 31, 2016 to December 31, 2020 and shall be submitted by January 31, 2021.
[40 CFR 63.7550(b) and (c)(1)]

a. Company and Facility name and address.

b. Process unit information.

c. Date of report and beginning and end dates of the reporting period.

d. The total operating time during the reporting period for limited use units.

e. The date of the most recent tune-up for each unit, including the date of the most recent burner inspection if delayed from the 5-year schedule.

f. A statement by a responsible official with official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

6.2.30 The Permittee shall maintain the following records for the auxiliary boilers (Emission Unit IDs AB05 and AB06) and the process heater (PH01):
[40 CFR 63.7555(a)]

a. A copy of each notification and report that the Permittee submitted to comply with 40 CFR 63 Subpart DDDDD, including all documentation supporting any Initial Notification, Notification of Compliance Status, or 5-year compliance report that was submitted.

b. A copy of the boiler tune-up reports required by 5.2.17.

c. A copy of the one-time energy assessment report required for PH01.

d. A copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent for AB05 and AB06.

e. Monthly records of fuel use for the days AB05 and AB06 was operating.

PART 7.0 OTHER SPECIFIC REQUIREMENTS

7.1 Operational Flexibility

7.1.1 The Permittee may make Section 502(b)(10) changes as defined in 40 CFR 70.2 without requiring a Permit revision, if the changes are not modifications under any provisions of Title I of the Federal Act and the changes do not exceed the emissions allowable under the Permit (whether expressed therein as a rate of emissions or in terms of total emissions). For each such change, the Permittee shall provide the Division and the EPA with written notification as required below in advance of the proposed changes and shall obtain any Permits required under Rules 391-3-1-.03(1) and (2). The Permittee and the Division shall attach each such notice to their copy of this Permit.
[391-3-1-.03(10)(b)5 and 40 CFR 70.4(b)(12)(i)]

a. For each such change, the Permittee's written notification and application for a construction Permit shall be submitted well in advance of any critical date (typically at least 3 months in advance of any commencement of construction, Permit issuance date, etc.) involved in the change, but no less than seven (7) days in advance of such change and shall include a brief description of the change within the Permitted facility, the date on which the change is proposed to occur, any change in emissions, and any Permit term or condition that is no longer applicable as a result of the change.

b. The Permit shield described in Condition 8.16.1 shall not apply to any change made pursuant to this condition.

7.2 Off-Permit Changes

7.2.1 The Permittee may make changes that are not addressed or prohibited by this Permit, other than those described in Condition 7.2.2 below, without a Permit revision, provided the following requirements are met:
[391-3-1-.03(10)(b)6 and 40 CFR 70.4(b)(14)]

a. Each such change shall meet all applicable requirements and shall not violate any existing Permit term or condition.

b. The Permittee must provide contemporaneous written notice to the Division and to the EPA of each such change, except for changes that qualify as insignificant under Rule 391-3-1-.03(10)(g). Such written notice shall describe each such change, including the date, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result of the change.

c. The change shall not qualify for the Permit shield in Condition 8.16.1.

d. The Permittee shall keep a record describing changes made at the source that result in emissions of a regulated air pollutant subject to an applicable requirement, but not otherwise regulated under the Permit, and the emissions resulting from those changes.

7.2.2 The Permittee shall not make, without a Permit revision, any changes that are not addressed or prohibited by this Permit, if such changes are subject to any requirements under Title IV of the Federal Act or are modifications under any provision of Title I of the Federal Act. [Rule 391-3-1-.03(10)(b)7 and 40 CFR 70.4(b)(15)]

7.3 Alternative Requirements
[White Paper #2]

Not Applicable.

7.4 Insignificant Activities
(see Attachment B for the list of Insignificant Activities in existence at the facility at the time of permit issuance)

7.5 Temporary Sources
[391-3-1-.03(10)(d)5 and 40 CFR 70.6(e)]

Not Applicable.

7.6 Short-term Activities
(see Form D5 "Short Term Activities" of the Permit application and White Paper #1)

7.6.1 The Permittee shall maintain records of the duration and frequency of the following Short-term Activities:

a. Sand blasting for maintenance purposes in accordance with Georgia Rule 391-3-1-.02(2)(n).

b. Asbestos removal in accordance with Georgia Rule 391-3-1-.02(9)(b)7.

7.7 Compliance Schedule/Progress Reports
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(4)]

None applicable.

7.8 Emissions Trading
[391-3-1-.03(10)(d)1(ii) and 40 CFR 70.6(a)(10)]

Not Applicable.

7.9 Acid Rain Requirements

Facility ORIS code: 710 (Plant McDonough)
Effective: January 1, 2015 through December 31, 2019

7.9.1 Emissions which exceed any allowances that the permittee lawfully holds under Title IV of the 1990 CAAA, or the regulations promulgated thereunder, are expressly prohibited. [40 CFR 70.6(a)(4)]

7.9.2 Permit revisions are not required for increases in emissions that are authorized by allowances acquired pursuant to the State's Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement.
[40 CFR 70.6(a)(4)(i)]

7.9.3 This permit does not place limits on the number of allowances the permittee may hold. However, the permittee may not use allowances as a defense to noncompliance with any other applicable requirement.
[40 CFR 70.6(a)(4)(ii)]

7.9.4 Any allowances held by the permittee shall be accounted for according to the procedures established in regulations promulgated under Title IV of the 1990 CAAA.
[40 CFR 70.6(a)(4)(iii)]

7.9.5 Each affected unit, with the exceptions specified in 40 CFR 72.9(g)(6), operated in accordance with the Acid Rain portion of this permit shall be deemed to be operating in compliance with the Acid Rain Program.
[40 CFR 70.6(f)(3)(iii)]

7.9.6 Where an applicable requirement is more stringent than an applicable requirement of regulations promulgated under Title IV of the 1990 CAAA, both provisions shall be incorporated into the permit and shall be enforceable.
[40 CFR 70.6(a)(1)(ii)]

7.9.7 SO_2 Allowance Allocations and NO_x Requirements for each affected unit
[40 CFR 73 (SO_2) and 40 CFR 76 (NO_x)]

			2015	2016	2017	2018	2019
EMISSION UNIT ID	EPA ID	SO_2 Allowances	0	0	0	0	0
CT4A/DB4A	4A	NO_x Limit	This affected unit is not subject to the NOx requirements in 40 CFR Part 76				

			2015	2016	2017	2018	2019
EMISSION UNIT ID	EPA ID	SO_2 Allowances	0	0	0	0	0
CT4B/D4B4B	4B	NO_x Limit	This affected unit is not subject to the NOx requirements in 40 CFR Part 76				

			2015	2016	2017	2018	2019
EMISSION UNIT ID	EPA ID	SO_2 Allowances	0	0	0	0	0
CT5A/DB5A	5A	NO_x Limit	This affected unit is not subject to the NOx requirements in 40 CFR Part 76				

			2015	2016	2017	2018	2019
EMISSION UNIT ID	EPA ID	SO_2 Allowances	0	0	0	0	0
CT5B/DB5B	5B	NO_x Limit	This affected unit is not subject to the NOx requirements in 40 CFR Part 76				

			2015	2016	2017	2018	2019
EMISSION UNIT ID	EPA ID	SO_2 Allowances	0	0	0	0	0
CT6A/DB6A	6A	NO_x Limit	This affected unit is not subject to the NOx requirements in 40 CFR Part 76				

			2015	2016	2017	2018	2019
EMISSION UNIT ID	EPA ID	SO_2 Allowances	0	0	0	0	0
CT6B/DB6B	6B	NO_x Limit	This affected unit is not subject to the NOx requirements in 40 CFR Part 76				

7.9.8 Permit Application: The Phase II Acid Rain Permit Application, Compliance Plan, and NO_x Averaging Plan submitted for this source, as corrected by the State of Georgia, is attached as part of this Permit. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.
[40 CFR 72.50(a)(1)]

7.10 Prevention of Accidental Releases (Section 112(r) of the 1990 CAAA)
[391-3-1-.02(10)]

7.10.1 When and if the requirements of 40 CFR Part 68 become applicable, the Permittee shall comply with all applicable requirements of 40 CFR Part 68, including the following.

a. The Permittee shall submit a Risk Management Plan (RMP) as provided in 40 CFR 68.150 through 68.185. The RMP shall include a registration that reflects all covered processes.

b. For processes eligible for Program 1, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a. and the following additional requirements:

i. Analyze the worst-case release scenario for the process(es), as provided in 40 CFR 68.25; document that the nearest public receptor is beyond the distance to a toxic or flammable endpoint defined in 40 CFR 68.22(a); and submit in the RMP the worst-case release scenario as provided in 40 CFR 68.165.
ii. Complete the five-year accident history for the process as provided in 40 CFR 68.42 and submit in the RMP as provided in 40 CFR 68.168
iii. Ensure that response actions have been coordinated with local emergency planning and response agencies
iv. Include a certification in the RMP as specified in 40 CFR 68.12(b)(4)

c. For processes subject to Program 2, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a., 7.10.1.b. and the following additional requirements:

i. Develop and implement a management system as provided in 40 CFR 68.15
ii. Conduct a hazard assessment as provided in 40 CFR 68.20 through 68.42
iii. Implement the Program 2 prevention steps provided in 40 CFR 68.48 through 68.60 or implement the Program 3 prevention steps provided in 40 CFR 68.65 through 68.87
iv. Develop and implement an emergency response program as provided in 40 CFR 68.90 through 68.95
v. Submit as part of the RMP the data on prevention program elements for Program 2 processes as provided in 40 CFR 68.170

d. For processes subject to Program 3, as provided in 40 CFR 68.10, the Permittee shall comply with 7.10.1.a., 7.10.1.b. and the following additional requirements:

i. Develop and implement a management system as provided in 40 CFR 68.15
ii. Conduct a hazard assessment as provided in 40 CFR 68.20 through 68.42
iii. Implement the prevention requirements of 40 CFR 68.65 through 68.87
iv. Develop and implement an emergency response program as provided in 40 CFR 68.90 through 68.95
v. Submit as part of the RMP the data on prevention program elements for Program 3 as provided in 40 CFR 68.175

e. All reports and notification required by 40 CFR Part 68 must be submitted electronically using RMP*eSubmit (information for establishing an account can be found at www.epa.gov/rmp/rmpesubmit). Electronic Signature Agreements should be mailed to:

MAIL

Risk Management Program (RMP) Reporting Center
P.O. Box 10162
Fairfax, VA 22038

COURIER & FEDEX

Risk Management Program (RMP) Reporting Center
CGI Federal
12601 Fair Lakes Circle
Fairfax, VA 22033

Compliance with all requirements of this condition, including the registration and submission of the RMP, shall be included as part of the compliance certification submitted in accordance with Condition 8.14.1.

7.11 Stratospheric Ozone Protection Requirements (Title VI of the CAAA of 1990)

7.11.1 If the Permittee performs any of the activities described below or as otherwise defined in 40 CFR Part 82, the Permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B:

a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.

b. Equipment used during the maintenance, service, repair, or disposal of appliance must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.

c. Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.

d. Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record keeping requirements pursuant to 40 CFR 82.166.
[Note: "MVAC-like appliance" is defined in 40 CFR 82.152.]

e. Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to 40 CFR 82.156.

f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

7.11.2 If the Permittee performs a service on motor (fleet) vehicles and if this service involves an ozone-depleting substance (refrigerant) in the MVAC, the Permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include air-tight sealed refrigeration systems used for refrigerated cargo, or air conditioning systems on passenger buses using HCFC-22 refrigerant.

7.12 Revocation of Existing Permits and Amendments

The following Air Quality Permits, Amendments, and 502(b)10 are subsumed by this permit and are hereby revoked:

Air Quality Permit and Amendment Number(s)	Dates of Original Permit or Amendment Issuance
4911-067-0003-V-03-0	November 23, 2010
4911-067-0003-V-03-1	May 19, 2011
4911-067-0003-V-03-2	March 2, 2012
4911-067-0003-V-03-3	October 1, 2013
4911-067-0003-V-03-4	November 7, 2014

7.13 Pollution Prevention

None applicable.

7.14 Specific Conditions

None applicable.

7.15 Cross State Air Pollution Rule (CSAPR) Allowance Trading Program Requirements
[40 CFR 97]

7.15.1 CSAPR Units and Applicable CSAPR Programs.

Unit ID#	NOx Annual	SO2	NOx Ozone Season
CT5M	X	X	X
CT6M	X	X	X
CT7M	X	X	X
CT8M	X	X	X
CT4A/DB4A	X	X	X
CT4B/DB4B	X	X	X
CT5A/DB5A	X	X	X
CT5B/DB5B	X	X	X
CT6A/DB6A	X	X	X
CT6B/DB6B	X	X	X

7.15.2 Annual NOx, SO_2 and Ozone Season NOx emissions requirements.
The owners and operators and the CSAPR designated representative of each CSAPR Annual NOx source, CSAPR SO_2 source and CSAPR Ozone Season NOx source and each CSAPR Annual NOx unit, CSAPR SO_2 unit, and CSAPR Ozone Season NOx unit at the source shall comply with the applicable requirements of the Annual NOx, SO_2, and Ozone Season NOx Allowance Trading Programs as set forth in 40 CFR Part 97.

7.15.3 Monitoring, reporting, and recordkeeping requirements.
The owners and operators and the CSAPR designated representative of each CSAPR Annual NOx source, CSAPR SO_2 source and CSAPR Ozone Season NOx source and each CSAPR Annual NOx unit, CSAPR SO_2 unit, and CSAPR Ozone Season NOx unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430-97.435 (Annual NOx), 40 CFR 97.530-97.535 (Ozone Season NOx) and 40 CFR 97.730-97.735 (Annual SO_2).

PART 8.0 GENERAL PROVISIONS

8.1 Terms and References

8.1.1 Terms not otherwise defined in the Permit shall have the meaning assigned to such terms in the referenced regulation.

8.1.2 Where more than one condition in this Permit applies to an emission unit and/or the entire facility, each condition shall apply and the most stringent condition shall take precedence. [391-3-1-.02(2)(a)2]

8.2 EPA Authorities

8.2.1 Except as identified as "State-only enforceable" requirements in this Permit, all terms and conditions contained herein shall be enforceable by the EPA and citizens under the Clean Air Act, as amended, 42 U.S.C. 7401, et seq.
[40 CFR 70.6(b)(1)]

8.2.2 Nothing in this Permit shall alter or affect the authority of the EPA to obtain information pursuant to 42 U.S.C. 7414, "Inspections, Monitoring, and Entry."
[40 CFR 70.6(f)(3)(iv)]

8.2.3 Nothing in this Permit shall alter or affect the authority of the EPA to impose emergency orders pursuant to 42 U.S.C. 7603, "Emergency Powers."
[40 CFR 70.6(f)(3)(i)]

8.3 Duty to Comply

8.3.1 The Permittee shall comply with all conditions of this operating Permit. Any Permit noncompliance constitutes a violation of the Federal Clean Air Act and the Georgia Air Quality Act and/or State rules and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a Permit renewal application. Any noncompliance with a Permit condition specifically designated as enforceable only by the State constitutes a violation of the Georgia Air Quality Act and/or State rules only and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a Permit renewal application.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(i)]

8.3.2 The Permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the Permitted activity in order to maintain compliance with the conditions of this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(ii)]

8.3.3 Nothing in this Permit shall alter or affect the liability of the Permittee for any violation of applicable requirements prior to or at the time of Permit issuance.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(f)(3)(ii)]

8.3.4 Issuance of this Permit does not relieve the Permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Director or any other federal, state, or local agency.
[391-3-1-.03(10)(e)1(iv) and 40 CFR 70.7(a)(6)]

8.4 Fee Assessment and Payment

8.4.1 The Permittee shall calculate and pay an annual Permit fee to the Division. The amount of fee shall be determined each year in accordance with the "Procedures for Calculating Air Permit Fees."
[391-3-1-.03(9)]

8.5 Permit Renewal and Expiration

8.5.1 This Permit shall remain in effect for five (5) years from the issuance date. The Permit shall become null and void after the expiration date unless a timely and complete renewal application has been submitted to the Division at least six (6) months, but no more than eighteen (18) months prior to the expiration date of the Permit.
[391-3-1-.03(10)(d)1(i), (e)2, and (e)3(ii) and 40 CFR 70.5(a)(1)(iii)]

8.5.2 Permits being renewed are subject to the same procedural requirements, including those for public participation and affected State and EPA review, that apply to initial Permit issuance.
[391-3-1-.03(10)(e)3(i)]

8.5.3 Notwithstanding the provisions in 8.5.1 above, if the Division has received a timely and complete application for renewal, deemed it administratively complete, and failed to reissue the Permit for reasons other than cause, authorization to operate shall continue beyond the expiration date to the point of Permit modification, reissuance, or revocation.
[391-3-1-.03(10)(e)3(iii)]

8.6 Transfer of Ownership or Operation

8.6.1 This Permit is not transferable by the Permittee. Future owners and operators shall obtain a new Permit from the Director. The new Permit may be processed as an administrative amendment if no other change in this Permit is necessary, and provided that a written agreement containing a specific date for transfer of Permit responsibility coverage and liability between the current and new Permittee has been submitted to the Division at least thirty (30) days in advance of the transfer.
[391-3-1-.03(4)]

8.7 Property Rights

8.7.1 This Permit shall not convey property rights of any sort, or any exclusive privileges.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(iv)]

8.8 Submissions

8.8.1 Reports, test data, monitoring data, notifications, annual certifications, and requests for revision and renewal shall be submitted to:

Georgia Department of Natural Resources
Environmental Protection Division
Air Protection Branch
Atlanta Tradeport, Suite 120
4244 International Parkway
Atlanta, Georgia 30354-3908

8.8.2 Any records, compliance certifications, and monitoring data required by the provisions in this Permit to be submitted to the EPA shall be sent to:

Air and EPCRA Enforcement Branch – U. S. EPA Region 4
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW
Atlanta, Georgia 30303-3104

8.8.3 Any application form, report, or compliance certification submitted pursuant to this Permit shall contain a certification by a responsible official of its truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
[391-3-1-.03(10)(c)2, 40 CFR 70.5(d) and 40 CFR 70.6(c)(1)]

8.8.4 Unless otherwise specified, all submissions under this permit shall be submitted to the Division only.

8.9 Duty to Provide Information

8.9.1 The Permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the Permit application, shall promptly submit such supplementary facts or corrected information to the Division.
[391-3-1-.03(10)(c)5]

8.9.2 The Permittee shall furnish to the Division, in writing, information that the Division may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the Permit, or to determine compliance with the Permit. Upon request, the Permittee shall also furnish to the Division copies of records that the Permittee is required to keep by this Permit or, for information claimed to be confidential, the Permittee may furnish such records directly to the EPA, if necessary, along with a claim of confidentiality.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(v)]

8.10 Modifications

8.10.1 Prior to any source commencing a modification as defined in 391-3-1-.01(pp) that may result in air pollution and not exempted by 391-3-1-.03(6), the Permittee shall submit a Permit application to the Division. The application shall be submitted sufficiently in advance of any critical date involved to allow adequate time for review, discussion, or revision of plans, if necessary. Such application shall include, but not be limited to, information describing the precise nature of the change, modifications to any emission control system, production capacity of the plant before and after the change, and the anticipated completion date of the change. The application shall be in the form of a Georgia air quality Permit application to construct or modify (otherwise known as a SIP application) and shall be submitted on forms supplied by the Division, unless otherwise notified by the Division.
[391-3-1-.03(1) through (8)]

8.11 Permit Revision, Revocation, Reopening and Termination

8.11.1 This Permit may be revised, revoked, reopened and reissued, or terminated for cause by the Director. The Permit will be reopened for cause and revised accordingly under the following circumstances:
[391-3-1-.03(10)(d)1(i)]

a. If additional applicable requirements become applicable to the source and the remaining Permit term is three (3) or more years. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if the effective date of the requirement is later than the date on which the Permit is due to expire, unless the original permit or any of its terms and conditions has been extended under Condition 8.5.3;
[391-3-1-.03(10)(e)6(i)(I)]

b. If any additional applicable requirements of the Acid Rain Program become applicable to the source;
[391-3-1-.03(10)(e)6(i)(II)] (Acid Rain sources only)

c. The Director determines that the Permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of the Permit; or
[391-3-1-.03(10)(e)6(i)(III) and 40 CFR 70.7(f)(1)(iii)]

d. The Director determines that the Permit must be revised or revoked to assure compliance with the applicable requirements.
[391-3-1-.03(10)(e)6(i)(IV) and 40 CFR 70.7(f)(1)(iv)]

8.11.2 Proceedings to reopen and reissue a Permit shall follow the same procedures as applicable to initial Permit issuance and shall affect only those parts of the Permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable.
[391-3-1-.03(10)(e)6(ii)]

8.11.3 Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Director at least thirty (30) days in advance of the date the Permit is to be reopened, except that the Director may provide a shorter time period in the case of an emergency.
[391-3-1-.03(10)(e)6(iii)]

8.11.4 All Permit conditions remain in effect until such time as the Director takes final action. The filing of a request by the Permittee for any Permit revision, revocation, reissuance, or termination, or of a notification of planned changes or anticipated noncompliance, shall not stay any Permit condition.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(6)(iii)]

8.11.5 A Permit revision shall not be required for changes that are explicitly authorized by the conditions of this Permit.

8.11.6 A Permit revision shall not be required for changes that are part of an approved economic incentive, marketable Permit, emission trading, or other similar program or process for change which is specifically provided for in this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(8)]

8.12 Severability

8.12.1 Any condition or portion of this Permit which is challenged, becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this Permit.
[391-3-1-.03(10)(d)1(i) and 40 CFR 70.6(a)(5)]

8.13 Excess Emissions Due to an Emergency

8.13.1 An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the Permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(1)]

8.13.2 An emergency shall constitute an affirmative defense to an action brought for noncompliance with the technology-based emission limitations if the Permittee demonstrates, through properly signed contemporaneous operating logs or other relevant evidence, that:
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(2) and (3)]

a. An emergency occurred and the Permittee can identify the cause(s) of the emergency;

b. The Permitted facility was at the time of the emergency being properly operated;

c. During the period of the emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in the Permit; and

d. The Permittee promptly notified the Division and submitted written notice of the emergency to the Division within two (2) working days of the time when emission limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

8.13.3 In an enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency shall have the burden of proof.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(4)]

8.13.4 The emergency conditions listed above are in addition to any emergency or upset provisions contained in any applicable requirement.
[391-3-1-.03(10)(d)7 and 40 CFR 70.6(g)(5)]

8.14 Compliance Requirements

8.14.1 Compliance Certification

The Permittee shall provide written certification to the Division and to the EPA, at least annually, of compliance with the conditions of this Permit. The annual written certification shall be postmarked no later than February 28 of each year and shall be submitted to the Division and to the EPA. The certification shall include, but not be limited to, the following elements:
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(5)]

a. The identification of each term or condition of the Permit that is the basis of the certification;

b. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent, based on the method or means designated in paragraph c below. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred;

c. The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period;

d. Any other information that must be included to comply with section 113(c)(2) of the Act, which prohibits knowingly making a false certification or omitting material information; and

e. Any additional requirements specified by the Division.

8.14.2 Inspection and Entry

a. Upon presentation of credentials and other documents as may be required by law, the Permittee shall allow authorized representatives of the Division to perform the following:
[391-3-1-.03(10)(d)3 and 40 CFR 70.6(c)(2)]

i. Enter upon the Permittee's premises where a Part 70 source is located or an emissions-related activity is conducted, or where records must be kept under the conditions of this Permit;
ii. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;
iii. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this Permit; and
iv. Sample or monitor any substances or parameters at any location during operating hours for the purpose of assuring Permit compliance or compliance with applicable requirements as authorized by the Georgia Air Quality Act.

b. No person shall obstruct, hamper, or interfere with any such authorized representative while in the process of carrying out his official duties. Refusal of entry or access may constitute grounds for Permit revocation and assessment of civil penalties.
[391-3-1-.07 and 40 CFR 70.11(a)(3)(i)]

8.14.3 Schedule of Compliance

a. For applicable requirements with which the Permittee is in compliance, the Permittee shall continue to comply with those requirements.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(A)]

b. For applicable requirements that become effective during the Permit term, the Permittee shall meet such requirements on a timely basis unless a more detailed schedule is expressly required by the applicable requirement.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(B)]

c. Any schedule of compliance for applicable requirements with which the source is not in compliance at the time of Permit issuance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.
[391-3-1-.03(10)(c)2 and 40 CFR 70.5(c)(8)(iii)(C)]

8.14.4 Excess Emissions

a. Excess emissions resulting from startup, shutdown, or malfunction of any source which occur though ordinary diligence is employed shall be allowed provided that: [391-3-1-.02(2)(a)7(i)]

i. The best operational practices to minimize emissions are adhered to;

ii. All associated air pollution control equipment is operated in a manner consistent with good air pollution control practice for minimizing emissions; and

iii. The duration of excess emissions is minimized.

b. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction are prohibited and are violations of Chapter 391-3-1 of the Georgia Rules for Air Quality Control. [391-3-1-.02(2)(a)7(ii)]

c. The provisions of this condition and Georgia Rule 391-3-1-.02(2)(a)7 shall apply only to those sources which are not subject to any requirement under Georgia Rule 391-3-1-.02(8) – New Source Performance Standards or any requirement of 40 CFR, Part 60, as amended concerning New Source Performance Standards. [391-3-1-.02(2)(a)7(iii)]

8.15 Circumvention

State Only Enforceable Condition.

8.15.1 The Permittee shall not build, erect, install, or use any article, machine, equipment or process the use of which conceals an emission which would otherwise constitute a violation of an applicable emission standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of the pollutants in the gases discharged into the atmosphere. [391-3-1-.03(2)(c)]

8.16 Permit Shield

8.16.1 Compliance with the terms of this Permit shall be deemed compliance with all applicable requirements as of the date of Permit issuance provided that all applicable requirements are included and specifically identified in the Permit. [391-3-1-.03(10)(d)6]

8.16.2 Any Permit condition identified as “State only enforceable” does not have a Permit shield.

8.17 Operational Practices

.8.17.1 At all times, including periods of startup, shutdown, and malfunction, the Permittee shall maintain and operate the source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on any information available to the Division that may include, but is not limited to, monitoring results, observations of the opacity or other characteristics of emissions, review of operating and maintenance procedures or records, and inspection or surveillance of the source.
[391-3-1-.02(2)(a)10]

State Only Enforceable Condition.

8.17.2 No person owning, leasing, or controlling, the operation of any air contaminant sources shall willfully, negligently or through failure to provide necessary equipment or facilities or to take necessary precautions, cause, permit, or allow the emission from said air contamination source or sources, of such quantities of air contaminants as will cause, or tend to cause, by themselves, or in conjunction with other air contaminants, a condition of air pollution in quantities or characteristics or of a duration which is injurious or which unreasonably interferes with the enjoyment of life or use of property in such area of the State as is affected thereby. Complying with Georgia's Rules for Air Quality Control Chapter 391-3-1 and Conditions in this Permit, shall in no way exempt a person from this provision.
[391-3-1-.02(2)(a)1]

8.18 Visible Emissions

8.18.1 Except as may be provided in other provisions of this Permit, the Permittee shall not cause, let, suffer, permit or allow emissions from any air contaminant source the opacity of which is equal to or greater than forty (40) percent.
[391-3-1-.02(2)(b)1]

8.19 Fuel-burning Equipment

8.19.1 The Permittee shall not cause, let, suffer, permit, or allow the emission of fly ash and/or other particulate matter from any fuel-burning equipment with rated heat input capacity of less than 10 million Btu per hour, in operation or under construction on or before January 1, 1972 in amounts equal to or exceeding 0.7 pounds per million BTU heat input.
[391-3-1-.02(2)(d)]

8.19.2 The Permittee shall not cause, let, suffer, permit, or allow the emission of fly ash and/or other particulate matter from any fuel-burning equipment with rated heat input capacity of less than 10 million Btu per hour, constructed after January 1, 1972 in amounts equal to or exceeding 0.5 pounds per million BTU heat input.
[391-3-1-.02(2)(d)]

8.19.3 The Permittee shall not cause, let, suffer, permit, or allow the emission from any fuel-burning equipment constructed or extensively modified after January 1, 1972, visible

emissions the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.
[391-3-1-.02(2)(d)]

8.20 Sulfur Dioxide

8.20.1 Except as may be specified in other provisions of this Permit, the Permittee shall not burn fuel containing more than 2.5 percent sulfur, by weight, in any fuel burning source that has a heat input capacity below 100 million Btu's per hour.
[391-3-1-.02(2)(g)]

8.21 Particulate Emissions

8.21.1 Except as may be specified in other provisions of this Permit, the Permittee shall not cause, let, permit, suffer, or allow the rate of emission from any source, particulate matter in total quantities equal to or exceeding the allowable rates shown below. Equipment in operation, or under construction contract, on or before July 2, 1968, shall be considered existing equipment. All other equipment put in operation or extensively altered after said date is to be considered new equipment.
[391-3-1-.02(2)(e)]

a. The following equations shall be used to calculate the allowable rates of emission from new equipment:

$E = 4.1P^{0.67}$; for process input weight rate up to and including 30 tons per hour.
$E = 55P^{0.11} - 40$; for process input weight rate above 30 tons per hour.

b. The following equation shall be used to calculate the allowable rates of emission from existing equipment:

$E = 4.1P^{0.67}$

In the above equations, E = emission rate in pounds per hour, and
P = process input weight rate in tons per hour.

8.22 Fugitive Dust
[391-3-1-.02(2)(n)]

8.22.1 Except as may be specified in other provisions of this Permit, the Permittee shall take all reasonable precautions to prevent dust from any operation, process, handling, transportation or storage facility from becoming airborne. Reasonable precautions that could be taken to prevent dust from becoming airborne include, but are not limited to, the following:

a. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;

b. Application of asphalt, water, or suitable chemicals on dirt roads, materials, stockpiles, and other surfaces that can give rise to airborne dusts;

c. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate containment methods can be employed during sandblasting or other similar operations;

d. Covering, at all times when in motion, open bodied trucks transporting materials likely to give rise to airborne dusts; and

e. The prompt removal of earth or other material from paved streets onto which earth or other material has been deposited.

8.22.2 The opacity from any fugitive dust source shall not equal or exceed 20 percent.

8.23 Solvent Metal Cleaning

8.23.1 Except as may be specified in other provisions of this Permit, the Permittee shall not cause, suffer, allow, or permit the operation of a cold cleaner degreaser subject to the requirements of Georgia Rule 391-3-1-.02(2)(ff) "Solvent Metal Cleaning" unless the following requirements for control of emissions of the volatile organic compounds are satisfied: [391-3-1-.02(2)(ff)1]

a. The degreaser shall be equipped with a cover to prevent escape of VOC during periods of non-use,

b. The degreaser shall be equipped with a device to drain cleaned parts before removal from the unit,

c. If the solvent volatility is 0.60 psi or greater measured at 100 ºF, or if the solvent is heated above 120 ºF, then one of the following control devices must be used:

i. The degreaser shall be equipped with a freeboard that gives a freeboard ratio of 0.7 or greater, or

ii. The degreaser shall be equipped with a water cover (solvent must be insoluble in and heavier than water), or

iii. The degreaser shall be equipped with a system of equivalent control, including but not limited to, a refrigerated chiller or carbon adsorption system.

d. Any solvent spray utilized by the degreaser must be in the form of a solid, fluid stream (not a fine, atomized or shower type spray) and at a pressure which will not cause excessive splashing, and

e. All waste solvent from the degreaser shall be stored in covered containers and shall not be disposed of by such a method as to allow excessive evaporation into the atmosphere.

8.24 Incinerators

8.24.1 Except as specified in the section dealing with conical burners, no person shall cause, let, suffer, permit, or allow the emissions of fly ash and/or other particulate matter from any incinerator subject to the requirements of Georgia Rule 391-3-1-.02(2)(c) "Incinerators", in amounts equal to or exceeding the following:
[391-3-1-.02(2)(c)1-4]

a. Units with charging rates of 500 pounds per hour or less of combustible waste, including water, shall not emit fly ash and/or particulate matter in quantities exceeding 1.0 pound per hour.

b. Units with charging rates in excess of 500 pounds per hour of combustible waste, including water, shall not emit fly ash and/or particulate matter in excess of 0.20 pounds per 100 pounds of charge.

8.24.2 No person shall cause, let, suffer, permit, or allow from any incinerator subject to the requirements of Georgia Rule 391-3-1-.02(2)(c) "Incinerators", visible emissions the opacity of which is equal to or greater than twenty (20) percent except for one six minute period per hour of not more than twenty-seven (27) percent opacity.

8.24.3 No person shall cause or allow particles to be emitted from an incinerator subject to the requirements of Georgia Rule 391-3-1-.02(2)(c) "Incinerators" which are individually large enough to be visible to the unaided eye.

8.24.4 No person shall operate an existing incinerator subject to the requirements of Georgia Rule 391-3-1-.02(2)(c) "Incinerators" unless:

a. It is a multiple chamber incinerator;

b. It is equipped with an auxiliary burner in the primary chamber for the purpose of creating a pre-ignition temperature of 800°F; and

c. It has a secondary burner to control smoke and/or odors and maintain a temperature of at least 1500°F in the secondary chamber.

8.25 Volatile Organic Liquid Handling and Storage

8.25.1 The Permittee shall ensure that each storage tank subject to the requirements of Georgia Rule 391-3-1-.02(2)(vv) "Volatile Organic Liquid Handling and Storage" is equipped with submerged fill pipes. For the purposes of this condition and the permit, a submerged fill pipe is defined as any fill pipe with a discharge opening which is within six inches of the tank bottom.
[391-3-1-.02(2)(vv)(1)]

8.26 Use of Any Credible Evidence or Information

8.26.1 Notwithstanding any other provisions of any applicable rule or regulation or requirement of this permit, for the purpose of submission of compliance certifications or establishing whether or not a person has violated or is in violation of any emissions limitation or standard, nothing in this permit or any Emission Limitation or Standard to which it pertains, shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.
[391-3-1-.02(3)(a)]

8.27 Internal Combustion Engines

8.27.1 For diesel-fired internal combustion engine(s) manufactured after April 1, 2006 or modified/reconstructed after July 11, 2005, the Permittee shall comply with all applicable provisions of New Source Performance Standards (NSPS) as found in 40 CFR 60 Subpart A - "General Provisions" and 40 CFR 60 Subpart IIII – "Standard of Performance for Stationary Compression Ignition Internal Combustion Engines." Such requirements include but are not limited to:
[40 CFR 60.4200]

a. Equip all emergency engines with non-resettable hour meters in accordance with Subpart IIII.

b. Purchase only diesel fuel with a maximum sulfur content of 15 ppm unless otherwise specified by the Division in accordance with Subpart IIII.

c. Conduct engine maintenance prescribed by the engine manufacturer in accordance with Subpart IIII.

d. Limit maintenance checks and readiness testing operation of each engine to 100 hours per year in accordance with 40 CFR 60.4211(f)(2). 50 hours of the 100 total hours allowed for maintenance checks and readiness testing operation per year may be used for non-emergency operation as allowed by 40 CFR 60.4211(f)(3).

e. Maintain any records in accordance with Subpart IIII

f. Maintain a list of engines subject to 40 CFR 60 Subpart IIII, including the date of manufacture.[391-3-1-.02(6)(b)]

8.27.2 The Permittee shall comply with all applicable provisions of New Source Performance Standards (NSPS) as found in 40 CFR 60 Subpart A - "General Provisions" and 40 CFR 60 Subpart JJJJ - "Standard of Performance for Stationary Spark Ignition Internal Combustion Engines," for spark ignition internal combustion engines(s) (gasoline, natural gas, liquefied petroleum gas or propane-fired) manufactured after July 1, 2007 or modified/reconstructed after June 12, 2006.
[40 CFR 60.4230]

8.27.3 The Permittee shall comply with all applicable provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) as found in 40 CFR 63 Subpart A - "General Provisions" and 40 CFR 63 Subpart ZZZZ - "National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

For diesel-fired emergency engines defined as "existing" in 40 CFR 63 Subpart ZZZZ (constructed prior to June 12, 2006 for area sources of HAP, constructed prior to June 12, 2006 for ≤500hp engines at major sources, and constructed prior to December 19, 2002 for >500hp engines at major sources of HAP), such requirements (if applicable) include but are not limited to:
[40 CFR 63.6580]

a. Equip all emergency engines with non-resettable hour meters in accordance with Subpart ZZZZ.

b. Purchase only diesel fuel with a maximum sulfur content of 15 ppm unless otherwise specified by the Division in accordance with Subpart ZZZZ.

c. For engines less than or equal to 500 hp, conduct the following in accordance with Subpart ZZZZ.

   i. Change oil and filter every 500 hours of operation or annually, whichever comes first

   ii. Inspect air cleaner every 1000 hours of operation or annually, whichever comes first and replace as necessary

   iii. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first and replace as necessary.

d. Limit maintenance checks and readiness testing operation of each engine to 100 hours per year in accordance with 40 CFR 63.6640(f)(2). 50 hours of the 100 total hours allowed for maintenance checks and readiness testing operation per year may be used for non-emergency operation as allowed by 40 CFR 63.6640(f)(3).

e. Maintain any records in accordance with Subpart ZZZZ.

f. Maintain a list of engines subject to 40 CFR 63 Subpart ZZZZ, including the date of manufacture.[391-3-1-.02(6)(b)]

8.27.4 For stationary gas turbines, stationary gas engines used to generate electricity whose nameplate capacity is greater than or equal to 100 kilowatt (KWe) and is less than or equal to 25 megawatts (MWe), the Permittee shall not discharge, cause the discharge, into the atmosphere Nitrogen Oxides (NOx) from the following engines during each ozone season (May 1 through September 30):

a. For stationary engines in operation before April 1, 2000: 160 ppm @ 15% O2, dry basis;

b. For stationary engines installed or modified on or after April 1, 2000: 80 ppm @ 15% O2, dry basis;

c. For stationary gas turbines in operation on or after January 1, 1999 and before October 1999: 42 ppm @ 15% O2, dry basis;

d. For stationary gas turbines installed or modified on or after October 1, 1999: 30 ppm @ 15% O2, dry basis

e. Emergency standby stationary gas turbines and stationary engines are not subject to the emission limitations in a through d. Non-emergency operation is allowed for these engines as prescribed in 40 CFR 60 Subpart IIII, 40 CFR 60 Subpart JJJJ, and 40 CFR 63 Subpart ZZZZ.

f. The requirements shall apply to all applicable sources located in the counties of Banks, Barrow, Bartow, Butts, Carroll, Chattooga, Cherokee, Clarke, Clayton, Cobb, Coweta, Dawson, DeKalb, Douglas, Fayette, Floyd, Forsyth, Fulton, Gordon, Gwinnett, Hall, Haralson, Heard, Henry, Jackson, Jasper, Jones, Lamar, Lumpkin, Madison, Meriwether, Monroe, Morgan, Newton, Oconee, Paulding, Pickens, Pike, Polk, Putnam, Rockdale, Spalding, Troup, Upson, and Walton.

8.28 Boilers and Process Heaters

8.28.1 If the facility/site is an area source of Hazardous Air Pollutants, the Permittee shall comply with all applicable provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR Part 63 Subpart A - "General Provisions" and 40 CFR 63 Subpart JJJJJJ - "National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers."
[40 CFR 63.11193]

8.28.2 If the facility/site is a major source of Hazardous Air Pollutants, the Permittee shall comply with all applicable provisions of National Emission Standards for Hazardous Air Pollutants (NESHAP) 40 CFR Part 63 Subpart A - "General Provisions" and 40 CFR 63 Subpart DDDDD - "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters."
[40 CFR 63.7480]

Attachments

A. List of Standard Abbreviations and List of Permit Specific Abbreviations
B. Insignificant Activities Checklist, Insignificant Activities Based on Emission Levels and Generic Emission Groups
C. List of References

ATTACHMENT A

List Of Standard Abbreviations

AIRS	Aerometric Information Retrieval System
APCD	Air Pollution Control Device
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BTU	British Thermal Unit
CAAA	Clean Air Act Amendments
CEMS	Continuous Emission Monitoring System
CERMS	Continuous Emission Rate Monitoring System
CFR	Code of Federal Regulations
CMS	Continuous Monitoring System(s)
CO	Carbon Monoxide
COMS	Continuous Opacity Monitoring System
dscf/dscm	Dry Standard Cubic Foot / Dry Standard Cubic Meter
EPA	United States Environmental Protection Agency
EPCRA	Emergency Planning and Community Right to Know Act
gr	Grain(s)
GPM (gpm)	Gallons per minute
H_2O (H2O)	Water
HAP	Hazardous Air Pollutant
HCFC	Hydro-chloro-fluorocarbon
MACT	Maximum Achievable Control Technology
MMBtu	Million British Thermal Units
MMBtu/hr	Million British Thermal Units per hour
MVAC	Motor Vehicle Air Conditioner
MW	Megawatt
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_x (NOx)	Nitrogen Oxides
NSPS	New Source Performance Standards
OCGA	Official Code of Georgia Annotated

PM	Particulate Matter
PM_{10} (PM10)	Particulate Matter less than 10 micrometers in diameter
PPM (ppm)	Parts per Million
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RMP	Risk Management Plan
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2 (SO2)	Sulfur Dioxide
USC	United States Code
VE	Visible Emissions
VOC	Volatile Organic Compound

List of Permit Specific Abbreviations

ATTACHMENT B

NOTE: Attachment B contains information regarding insignificant emission units/activities and groups of generic emission units/activities in existence at the facility at the time of Permit issuance. Future modifications or additions of insignificant emission units/activities and equipment that are part of generic emissions groups may not necessarily cause this attachment to be updated.

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Mobile Sources	1. Cleaning and sweeping of streets and paved surfaces	1
Combustion Equipment	1. Fire fighting and similar safety equipment used to train fire fighters or other emergency personnel.	1
	2. Small incinerators that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act and are not considered a "designated facility" as specified in 40 CFR 60.32e of the Federal emissions guidelines for Hospital/Medical/Infectious Waste Incinerators, that are operating as follows: i) Less than 8 million BTU/hr heat input, firing types 0, 1, 2, and/or 3 waste.	0
	ii) Less than 8 million BTU/hr heat input with no more than 10% pathological (type 4) waste by weight combined with types 0, 1, 2, and/or 3 waste.	0
	iii) Less than 4 million BTU/hr heat input firing type 4 waste. (Refer to 391-3-1-.03(10)(g)2.(ii) for descriptions of waste types)	0
	3. Open burning in compliance with Georgia Rule 391-3-1-.02 (5).	1
	4. Stationary engines burning: i) Natural gas, LPG, gasoline, dual fuel, or diesel fuel which are used exclusively as emergency generators shall not exceed 500 hours per year or 200 hours per year if subject to Georgia Rule 391-3-1-.02(2)(mmm).7	0
	ii) Natural gas, LPG, and/or diesel fueled generators used for emergency, peaking, and/or standby power generation, where the combined peaking and standby power generation do not exceed 200 hours per year.	0
	iii) Natural gas, LPG, and/or diesel fuel used for other purposes, provided that the output of each engine does not exceed 400 horsepower and that no individual engine operates for more than 2,000 hours per year.	3
	iv) Gasoline used for other purposes, provided that the output of each engine does not exceed 100 horsepower and that no individual engine operates for more than 500 hours per year.	0
Trade Operations	1. Brazing, soldering, and welding equipment, and cutting torches related to manufacturing and construction activities whose emissions of hazardous air pollutants (HAPs) fall below 1,000 pounds per year.	1
Maintenance, Cleaning, and Housekeeping	1. Blast-cleaning equipment using a suspension of abrasive in water and any exhaust system (or collector) serving them exclusively.	1
	2. Portable blast-cleaning equipment.	1
	3. Non-Perchloroethylene Dry-cleaning equipment with a capacity of 100 pounds per hour or less of clothes.	0
	4. Cold cleaners having an air/vapor interface of not more than 10 square feet and that do not use a halogenated solvent.	1
	5. Non-routine clean out of tanks and equipment for the purposes of worker entry or in preparation for maintenance or decommissioning.	1
	6. Devices used exclusively for cleaning metal parts or surfaces by burning off residual amounts of paint, varnish, or other foreign material, provided that such devices are equipped with afterburners.	0
	7. Cleaning operations: Alkaline phosphate cleaners and associated cleaners and burners.	0

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Laboratories and Testing	1. Laboratory fume hoods and vents associated with bench-scale laboratory equipment used for physical or chemical analysis.	2
	2. Research and development facilities, quality control testing facilities and/or small pilot projects, where combined daily emissions from all operations are not individually major or are support facilities not making significant contributions to the product of a collocated major manufacturing facility.	0
Pollution Control	1. Sanitary waste water collection and treatment systems, except incineration equipment or equipment subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	2. On site soil or groundwater decontamination units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	3. Bioremediation operations units that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
	4. Landfills that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	0
Industrial Operations	1. Concrete block and brick plants, concrete products plants, and ready mix concrete plants producing less than 125,000 tons per year.	0
	2. Any of the following processes or process equipment which are electrically heated or which fire natural gas, LPG or distillate fuel oil at a maximum total heat input rate of not more than 5 million BTU's per hour: i) Furnaces for heat treating glass or metals, the use of which do not involve molten materials or oil-coated parts.	0
	ii) Porcelain enameling furnaces or porcelain enameling drying ovens.	0
	iii) Kilns for firing ceramic ware.	0
	iv) Crucible furnaces, pot furnaces, or induction melting and holding furnaces with a capacity of 1,000 pounds or less each, in which sweating or distilling is not conducted and in which fluxing is not conducted utilizing free chlorine, chloride or fluoride derivatives, or ammonium compounds.	0
	v) Bakery ovens and confection cookers.	0
	vi) Feed mill ovens.	0
	vii) Surface coating drying ovens	0
	3. Carving, cutting, routing, turning, drilling, machining, sawing, surface grinding, sanding, planing, buffing, shot blasting, shot peening, or polishing; ceramics, glass, leather, metals, plastics, rubber, concrete, paper stock or wood, also including roll grinding and ground wood pulping stone sharpening, provided that: i) Activity is performed indoors; & ii) No significant fugitive particulate emissions enter the environment; & iii) No visible emissions enter the outdoor atmosphere.	1
	4. Photographic process equipment by which an image is reproduced upon material sensitized to radiant energy (e.g., blueprint activity, photographic developing and microfiche).	0
	5. Grain, food, or mineral extrusion processes	0
	6. Equipment used exclusively for sintering of glass or metals, but not including equipment used for sintering metal-bearing ores, metal scale, clay, fly ash, or metal compounds.	0
	7. Equipment for the mining and screening of uncrushed native sand and gravel.	0
	8. Ozonization process or process equipment.	0
	9. Electrostatic powder coating booths with an appropriately designed and operated particulate control system.	0
	10. Activities involving the application of hot melt adhesives where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	0
	11. Equipment used exclusively for the mixing and blending water-based adhesives and coatings at ambient temperatures.	0
	12. Equipment used for compression, molding and injection of plastics where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	0
	13. Ultraviolet curing processes where VOC emissions are less than 5 tons per year and HAP emissions are less than 1,000 pounds per year.	0

INSIGNIFICANT ACTIVITIES CHECKLIST

Category	Description of Insignificant Activity/Unit	Quantity
Storage Tanks and Equipment	1. All petroleum liquid storage tanks storing a liquid with a true vapor pressure of equal to or less than 0.50 psia as stored.	6
	2. All petroleum liquid storage tanks with a capacity of less than 40,000 gallons storing a liquid with a true vapor pressure of equal to or less than 2.0 psia as stored that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	9
	3. All petroleum liquid storage tanks with a capacity of less than 10,000 gallons storing a petroleum liquid.	7
	4. All pressurized vessels designed to operate in excess of 30 psig storing petroleum fuels that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	1
	5. Gasoline storage and handling equipment at loading facilities handling less than 20,000 gallons per day or at vehicle dispensing facilities that are not subject to any standard, limitation or other requirement under Section 111 or 112 (excluding 112(r)) of the Federal Act.	1
	6. Portable drums, barrels, and totes provided that the volume of each container does not exceed 550 gallons.	<100
	7. All chemical storage tanks used to store a chemical with a true vapor pressure of less than or equal to 10 millimeters of mercury (0.19 psia).	0

INSIGNIFICANT ACTIVITIES BASED ON EMISSION LEVELS

Description of Emission Units / Activities	Quantity
Cooling towers with drift eliminators and plume abatement	3

ATTACHMENT B (continued)

GENERIC EMISSION GROUPS

Emission units/activities appearing in the following table are subject only to one or more of Georgia Rules 391-3-1-.02 (2) (b), (e) &/or (n). Potential emissions of particulate matter, from these sources based on TSP, are less than 25 tons per year per process line or unit in each group. Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Emissions Units / Activities	Number of Units (if appropriate)	Applicable Rules		
		Opacity Rule (b)	PM from Mfg Process Rule (e)	Fugitive Dust Rule (n)
n/a				

The following table includes groups of fuel burning equipment subject only to Georgia Rules 391-3-1-.02 (2) (b) & (d).Any emissions unit subject to a NESHAP, NSPS, or any specific Air Quality Permit Condition(s) are not included in this table.

Description of Fuel Burning Equipment	Number of Units
Fuel burning equipment with a rated heat input capacity of less than 10 million BTU/hr burning only natural gas and/or LPG.	0
Fuel burning equipment with a rated heat input capacity of less than 5 million BTU/hr, burning only distillate fuel oil, natural gas and/or LPG.	0
Any fuel burning equipment with a rated heat input capacity of 1 million BTU/hr or less.	0

ATTACHMENT C

LIST OF REFERENCES

1. The Georgia Rules for Air Quality Control Chapter 391-3-1. All Rules cited herein which begin with 391-3-1 are State Air Quality Rules.

2. Title 40 of the Code of Federal Regulations; specifically 40 CFR Parts 50, 51, 52, 60, 61, 63, 64, 68, 70, 72, 73, 75, 76 and 82. All rules cited with these parts are Federal Air Quality Rules.

3. ***Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Procedures for Testing and Monitoring Sources of Air Pollutants.***

4. ***Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, Procedures for Calculating Air Permit Fees***.

5. Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources. This information may be obtained from EPA's TTN web site at *www.epa.gov/ttn/chief/ap42/index.html*.

6. The latest properly functioning version of EPA's **TANKS** emission estimation software. The software may be obtained from EPA's TTN web site at *www.epa.gov/ttn/chief/software/tanks/index.html*.

7. The Clean Air Act (42 U.S.C. 7401 et seq).

8. White Paper for Streamlined Development of Part 70 Permit Applications, July 10, 1995 (White Paper #1).

9. White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program, March 5, 1996 (White Paper #2).

Attachment 6

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

MEMORANDUM **January 20, 2009**

TO: Phillip Fielder, P.E., Permits and Engineering Group Manager
Air Quality Division

THROUGH: Kendal Stegmann, Senior Environmental Manager
Compliance and Enforcement

THROUGH: Phil Martin, P.E., Engineering Section

THROUGH: Peer Review

FROM: Eric L. Milligan, P.E., Engineering Section

SUBJECT: Evaluation of Permit Application No. **2007-115-C (M-1) PSD**
Associated Electric Cooperative, Inc.
Chouteau Power Plant
Mid America Industrial Park, Mayes County
SW/4, SW/4 of Section 10, T20N, R19E
Latitude: 36.2225N; Longitude: 95.2778W
Directions: From the Mid America Industrial Park east off of State Highway 412B and North on Robertson Street

SECTION I. INTRODUCTION

Associated Electric Cooperative, Inc. (AECI) has submitted an application for construction of a natural gas-fired combined cycle (two-on-one) electricity generating facility located next to the existing Chouteau Power Plant in Mayes County, Oklahoma. The major components of the new facility will include the following:

1) Two Combustion Turbines, each mated to a nominal 178 MW generator
2) Two Heat Recovery Steam Generating Units (HRSGs) with Duct Burners that supply steam to a single 182 MW generator
3) Two Selective Catalytic Reduction units to control NO_X emissions from each combustion turbine and the duct burners
4) One Cooling Tower with nine (9) individual cells equipped with drift eliminators
5) One Auxiliary Boiler to maintain the system in hot/ready standby
6) One Fuel Gas Water Bath Heater to heat incoming gas to the combustion turbines
7) Two pressurized 10,000 gallon anhydrous ammonia tanks
8) One Emergency Diesel Generator limited to 500 hours
9) One Emergency Fire Water Pump limited to 500 hours

The new facility's emissions are in excess of the Prevention of Significant Deterioration (PSD) threshold levels. The existing facility is currently operating as authorized by Permit No. 2007-115-TVR, issued on April 23, 2008.

SECTION II. FACILITY DESCRIPTION

A. Proposed Equipment

The main emission sources from the new equipment are the two combustion turbines. The combustion turbine equipment will be supplied by Siemens-Westinghouse, and is nearly identical to the existing units. As with the existing combustion turbine units, these will also be operated with a single steam turbine in combined-cycle mode. These combustion turbines will be limited to using natural gas as a fuel, which will be obtained from a local pipeline.

The V84.3A model combustion turbines incorporate lean pre-mix dry low NO_X combustors as well as the add-on Selective Catalytic Reduction (SCR) to minimize NO_X formation. In addition, these units will utilize a new Siemens technology that will allow the combustion turbines to operate in the pre-mix mode throughout the load range. In the pre-mix mode, fuel combustion is more efficient and results in lower NO_X emissions. In contrast, the existing units must reach approximately 60% of the rated turbine load before pre-mix operation is permissible.

Each turbine's exhaust gas will duct through a natural gas fired heat recovery steam generator (HRSG) where steam will be produced and used by a steam turbine to generate additional electricity. Each HRSG is specifically designed to match the operating characteristics of the combustion turbines to provide optimum performance for the total power cycle. Each HRSG is a three-pressure, superheat and reheat, duct fired, natural circulation unit with a horizontal gas turbine exhaust flow receiver containing vertical heat tube transfer sections. Both HRSGs may utilize duct firing at 100 percent load. Duct firing generates additional heat (99 MMBTUH each) to the exhaust gases of the combustion turbines by burning natural gas. This heat energy is then converted to steam and electricity.

The primary consumer of the steam is a reheat, condensing steam turbine. It consists of a high pressure section, which receives high-pressure superheated steam from the HRSGs and exhausts to the reheat section of the HRSG. The steam from the reheat section is then supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure section of the steam turbine also receives excess low-pressure superheated steam from the HRSGs and exhausts to the condenser unit. Emissions from the combustion gas turbine generator and the duct fired HRSG system will be exhausted through two stacks 130 feet above the ground surface. The combustion gas turbine generators will be shut down as necessary for scheduled maintenance, or as dictated by economic or electrical demand.

Similar to the existing facility, the system will include a 9-cell mechanical draft cooling tower with up to seven cycles of concentration. Drift (water loss) from the tower is estimated at 0.0005% of total water flow. Water treatment chemicals will be non-chromium chemicals including sodium hypochlorite and sulfuric acid. The facility may also use scale inhibitor/corrosion inhibitor, non-oxidizing biocides, and liquid dispersants similar to those currently employed on the existing system.

The new equipment will also include an auxiliary boiler (natural gas), a fuel gas heater (natural gas), and emergency fire water pump (diesel), an emergency generator (diesel), and two pressurized 10,000-gallon (anhydrous) ammonia tanks. Since this equipment is yet to be purchased, AECI will permit these new emission sources as identical to the existing auxiliary boiler, fire water pump, gas heaters, and emergency diesel generator. The equipment that is eventually purchased for the installation will meet or exceed the emission rates and have heat input capability at or below the assumed capacities. The fire water pump and emergency generator will be limited to 500 hours and are not considered in the air quality impact analysis included in this permit application.

B. Existing Facility – Title V Permit 2007-115-TVR

The existing facility will contain a "two-on-one" combined cycle gas turbine (CCGT) plant firing exclusively natural gas. Hot exhaust gases from the gas turbines are passed through two separate drum-type heat recovery steam generators (HRSG) where the heat is converted to steam which drives a single conventional steam turbine that adds about 182 MW to the plant's capacity. Waste heat is rejected through a condenser and mechanical draft-cooling tower.

Each of the two gas turbines are Siemens KWU, Model V84.3A, advanced gas turbine design with a rated output of 176 MW (1,783 MMBTUH) at IS0 conditions. This model utilizes Siemens hybrid burner ring combustor designed for pre-mix firing above 60 percent output. This machine has a 15-stage compressor and 4-stage turbine. Advanced design features, in addition to the low-NO_X hybrid burner ring combustor, include single crystal blade castings and extensive use of film cooling. Film cooling ensures high cooling efficiency in the first two turbine stages. The design allows slightly higher firing temperatures, higher exhaust temperatures, and improved heat rates, in both simple and combined cycle modes.

The HRSGs are three-pressure level boilers (low, intermediate, and high) with superheat and reheat sections. The gas turbines exhaust gases at about 1,050 °F that contact the boiler surfaces and transfer heat to the feed water and steam. This arrangement enables higher efficiencies of the combined cycle power plant by using the exhaust gas energy. Each HRSG produces about 375,000 pounds of steam per hour at 1,566 psia and 1,016 °F. The HRSGs house a selective catalytic reduction (SCR) system for each unit to reduce NO_X emissions.

The steam turbine is a Siemens K36-16/N36-2 x 6.9 two-cylinder tandem compound flow machine. The three electrical generators used to produce the nominal 530 MW are Siemens, Model TLRI-108146-36, designed for dual drive from both the steam and gas turbines.

The cooling tower is a nine cell mechanical draft tower with up to seven cycles of concentration. Drift (water loss) from the tower is about 15,000-18,000 gallons (i.e., 0.0005% of total water flow) per day at full load. Water treatment chemicals are non-chromium chemicals including sodium hypochlorite (14 lbs/day) and sulfuric acid (5,000 gallons/year). The facility may also use NALCO 1333T, a scale inhibitor/corrosion inhibitor (300-310 lbs/day) and/or NALCO 7330 a non-oxidizing biocide (1,200 lbs/year). In addition, a liquid dispersant, NALCO 8301 D is used at an approximate rate of 6.8 lbs/day.

The facility also includes an auxiliary boiler and a fuel gas heater that fire natural gas only and two pressurized 10,000-gallon anhydrous ammonia tanks. The auxiliary boiler is a Donlee boiler with a maximum design capacity of 33.5 MMBTUH. The design features include a low NO_X burner control. The boiler is utilized to maintain the turbine system in hot-ready standby. This helps minimize the duration of the startup period for each turbine, which lowers the overall emissions and the amount of time spent in the diffusion mode (high emission levels) of operation. The boiler was originally not expected to operate more than 3,000 hours in a given year. However, the boiler is permitted for continuous operation and will normally be used only when the turbines are not in operation or during startup. The fuel gas heater, rated at 18.8 MMBTUH, is used predominantly during winter months to heat a glycol/water solution that will circulate in a small heat exchanger preheating the supply of gas to prevent icing.

The plant is designed for base load operation, but has the ability to cycle. Other than specified maintenance periods, the plant is designed to have an availability of over 90 percent. However, emissions estimates for this permit were based on continuous operation and 100% load.

Other than startup, shutdown, and malfunctions, both combustion turbines are operated at approximately 60 percent rated turbine load and above to assure operations in the "pre-mix" mode. Pre-mix is the operating mode for the burner that optimizes combustion efficiency and produces the lowest NO_X emissions. However, elevated levels of NO_X and CO can result during cold startups and/or in the diffusion mode for periods up to four hours. Although the permit does limit the diffusion mode of operation to four hours, the auxiliary boiler may shorten this time to three hours, under normal operating conditions. (i.e outside startup, shutdown, and malfunctions).

SECTION III. EQUIPMENT

A. Proposed Equipment

EUG 1. Electric Generating Units

EU	Name & Make	Heat Capacity (MMBTUH)	Serial #	Installed Date
1-03	Siemens V84.3A w/Duct Burner	1,882	800451	2009
1-04	Siemens V84.3A w/Duct Burner	1,882	800461	2009

TBD – To Be Determined

EUG 2. Auxiliary Boiler

EU	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
2-02	TBD	33.5	TBD	2009

TBD – To Be Determined

EUG 3. Fuel Gas Water Bath Heater

EU	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
3-02	TBD	18.8	TBD	2009

TBD – To Be Determined

EUG 4B. Emergency Diesel Generator

EU	Make/Model	hp	Serial #	Installed Date
4-02	TBD	2,200	TBD	2009

TBD – To Be Determined

EUG 5B. Emergency Fire Pump (Diesel)

EU	Make/Model	hp	Serial #	Installed Date
5-02	TBD	267	TBD	2009

TBD – To Be Determined

EUG 6. Cooling Towers

EU	Make/Model	No. of Towers	Installed Date
6-01	TBD	9	2009

TBD – To Be Determined

B. Existing Equipment

EUG 1. Electric Generating Units

EU	Name & Make	Heat Capacity (MMBTUH)	Serial #	Installed Date
1-01	Siemens V84.3A	1,783	800390	1999
1-02	Siemens V84.3A	1,783	800394	1999

EUG 2. Auxiliary Boiler

EU	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
2-01	Donlee	33.5	9920891	1999

EUG 3. Fuel Gas Water Bath Heater

EU	Make/Model	Heat Capacity (MMBTUH)	Serial #	Installed Date
3-01	ThermoFlux/CryoFlux	18.8	9105	1999

EUG 4A. Emergency Diesel Generator

EU	Make/Model	hp	Serial #	Installed Date
4-01	Detroit Diesel/T1237K36	2,200	5262000436	2000

EUG 5A. Emergency Fire Pump (Diesel)

EU	Make/Model	hp	Serial #	Installed Date
5-01	Caterpillar/3306- A552598	267	64Z29015	1999

EUG 6. Cooling Towers

EU	Make/Model	No. of Towers	Installed Date
6-01	Psychometrics, Inc	9	1999

SECTION III. SCOPE OF REVIEW AND EMISSIONS

Since the project will increase emissions by more than the PSD significance thresholds for NO_X, CO, and PM_{10} the project is subject to full PSD review. The project is also subject to NSPS, Subpart GG for combustion turbines. Numerous Oklahoma Air Quality rules affect the new turbines, duct burners, backup diesel generator, diesel fire water pump engine, and auxiliary boiler as fuel-burning equipment, rules including Subchapters 19, 25, 31, 33, and 37. Pollutants emitted in minor quantities are evaluated for all pollutant-specific rules, regulations and guidelines.

This project involves a number of emission points. Emissions are generated by combustion at the turbines, at the duct burners, at the auxiliary boiler and fuel gas water bath heater, and to a much smaller extent at the backup diesel generator and fire water pump. Each HRSG stack exhausts combustion emissions from the duct burner and related turbine. Very small emissions of VOC are expected from the diesel storage tanks. Ammonia is supplied to the SCR process in amounts slightly above the stoichiometric requirement, so there will be some emissions of ammonia, called “ammonia slip,” in the exhaust.

A. Criteria Pollutants - Proposed Equipment

Turbine emissions are based on continuous operation of the turbines, use of SCR, and the manufacturer's data as listed below:

Pollutant	Units	Concentration
NO_X	ppmvd @ 15% O_2	2.0
CO	ppmvd @ 15% O_2	8.0
VOC	ppmvd @ 15% O_2	0.3
Ammonia	ppmvd @ 15% O_2	10.0

Although the plant is expected to operate at a 70 to 75% capacity factor, short and long term emissions for the turbines were based on 100% load since this resulted in the highest emissions. VOC emissions, from the turbines with duct burners firing, are estimated at 0.0028 lb/MMBTU for the turbines with duct burners. SO_2 emissions, from the turbines with duct burners firing, are estimated at 0.00056 lb/MMBTU based on usage of natural gas with a sulfur content of 0.25 grains/100 SCF. PM_{10} emissions, from the turbines with duct burners firing, are estimated at 0.0035 lb/MMBTUH based on stack testing of a similar unit.

Since market forces and other factors may force the facility to experience many startups and shutdowns during the course of a year an analysis of annual emissions for NO_X and CO based on the historical number of startups and shutdowns was used to determine annual emissions. Startup and shutdown are not expected to affect emissions of VOC, SO_2, and PM_{10}.

Estimated NO_X Emissions (Per Unit) Combustion Turbine with Duct Burner

Operating Mode	Event Duration (hr)	Number of Events	Total Hours	lb/event	lb/hr	TPY
Cold Startup	4	20	120	568	142.00	5.68
Warm Startup	3	120	360	426	142.00	25.56
Hot Startup	2.5	100	250	355	142.00	17.75
Shutdown	1	240	240	142	142.00	17.04
Normal	----	----	7,790	N/A	15.25	59.42
Total						**125.45**

Estimated CO Emissions (Per Unit) Combustion Turbine with Duct Burner

Operating Mode	Event Duration (hr)	Number of Events	Total Hours	lb/event	lb/hr	TPY
Cold Startup	4	20	120	1,596.00	399.00	15.96
Warm Startup	3	120	360	1,197.00	399.00	71.82
Hot Startup	2.5	100	250	997.50	399.00	49.88
Shutdown	1	240	240	399.00	399.00	47.88
Normal	----	----	7,790	N/A	51.32	199.89
Total						**385.43**

Emissions from the auxiliary boiler and fuel gas water bath heater are based on manufacturer's data and 8,760 hours/year of operation. Emissions from the backup diesel generator are based on NSPS, Subpart IIII emission limits and 500 hours/year of planned operation. Emissions from the diesel fire water pump are based on NSPS, Subpart IIII emission limits and 500 hours/year of planned operation except for SO_2 emissions which are based on AP-42 (10/96), Section 3.4. SO_2 emissions from the backup diesel generator and diesel fire water pump are based on a fuel sulfur content of 0.05 % sulfur by weight. Emissions from the cooling tower were based on a conservative estimate of 10,920-ppmw of Total Dissolved Solids (TDS) in the cooling tower drift and a total circulating water flow of 130,000 gallons per minute. The expected drift is approximately 0.0005% of the circulating water flow.

Emissions from the Electrical Generating Units

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr[1]	TPY[2]	lb/hr[1]	TPY[2]	lb/hr[1]	TPY	lb/hr[1]	TPY	lb/hr[1]	TPY
1-03	15.25	125.45	51.32	385.43	5.27	23.08	1.06	4.62	6.59	28.86
1-04	15.25	125.45	51.32	385.43	5.27	23.08	1.06	4.62	6.59	28.86
Subtotal	**30.50**	**250.90**	**102.64**	**770.86**	**10.54**	**46.16**	**2.12**	**9.24**	**13.18**	**57.72**

[1] - lb/hr emissions are based on the worst case scenarios for the turbines with the duct burners firing.

[2] - TPY values include startup emissions based on a representative sample of data from the existing units and 8,760 hours of operation.

Emissions from the Auxiliary Boiler

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
2-02	2.36	10.34	5.02	21.99	0.54	2.37	0.03	0.14	0.34	1.49

Emissions from the Fuel Gas Water Bath Heater

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
3-02	2.70	11.83	0.39	1.71	0.10	0.44	0.01	0.04	0.10	0.44

Emissions from the Emergency Diesel Generator[1]

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
4-02	23.15	5.79	12.66	3.16	1.55	0.39	0.89	0.22	0.72	0.18

[1] – Based on standards from § 89.112; NO_X is inclusive of NMHC. VOC emissions are estimated based on the AP-42 (10/96), Section 3.4 TOC factor.

Emissions from the Emergency Fire Pump (Diesel)

EU	NO_X		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
5-02	4.59	1.15	1.53	0.38	0.66	0.16	0.11	0.03	0.24	0.06

[1] – Based on standards from NSPS, Subpart IIII, Table 4 (2008 & earlier factors); NO_X is inclusive of NMHC. VOC emissions are estimated based on the AP-42 (10/96), Section 3.3 TOC factor.

Emissions from the Cooling Tower

EU	NOx		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
6-02	--	--	--	--	--	--	--	--	3.55	15.56

B. Criteria Pollutants - Existing Facility

Turbine emissions are based on continuous operation of the turbines, use of SCR, and the manufacturer's data as listed below:

Pollutant	Units	Concentration
NO_X	ppmvd @ 15% O_2	12.0
CO	ppmvd @ 15% O_2	10.0
VOC	ppmvd @ 15% O_2	0.3
Ammonia	ppmvd @ 15% O_2	10.0

Although the plant is expected to operate at a 70 to 75% capacity factor, short and long term emissions for the turbines were based on 100% load since this resulted in the highest emissions. VOC emissions, from the turbines with duct burners firing, are estimated at 0.0028 lb/MMBTU for the turbines with duct burners. SO_2 emissions, from the turbines with duct burners firing, are estimated at 0.00056 lb/MMBTU based on usage of natural gas with a sulfur content of 0.25 grains/100 SCF. PM_{10} emissions, from the turbines with duct burners firing, are estimated at 0.0035 lb/MMBTUH based on stack testing of a similar unit. Emissions from the auxiliary boiler and fuel gas water bath heater are based on manufacturer's data and 8,760 hours/year of

operation. Emissions from the backup diesel generator are based on AP-42 (10/96), Section 3.4 and 500 hours/year of planned operation. Emissions from the diesel fire water pump are based on AP-42 (10/96), Section 3.3 and 500 hours/year of planned operation except for SO_2 emissions which are based on AP-42 (10/96), Section 3.4. SO_2 emissions from the backup diesel generator and diesel fire water pump are based on a fuel sulfur content of 0.05 % sulfur by weight. Emissions from the cooling tower were based on a conservative estimate of 10,920-ppmw of Total Dissolved Solids (TDS) in the cooling tower drift and a total circulating water flow of 130,000 gallons per minute. The expected drift is approximately 0.0005% of the circulating water flow.

Emissions from the Electrical Generating Units

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**
1-01	86.70	379.75	59.00	258.42	4.99	21.87	1.00	4.38	6.24	27.33
1-02	86.70	379.75	59.00	258.42	4.99	21.87	1.00	4.38	6.24	27.33
Subtotal	**173.40**	**759.50**	**118.00**	**516.84**	**9.98**	**43.74**	**2.00**	**8.76**	**12.48**	**54.66**

[1] - lb/hr emissions are based on the worst case scenarios for the turbines.

Emissions from the Auxiliary Boiler

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
2-01	2.36	10.34	5.02	21.99	0.54	2.37	0.03	0.14	0.34	1.49

Emissions from the Fuel Gas Water Bath Heater

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
3-01	2.70	11.83	0.39	1.71	0.10	0.44	0.01	0.04	0.10	0.44

Emissions from the Emergency Diesel Generator

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
4-01	52.80	13.20	12.10	3.03	1.41	0.35	0.89	0.22	1.54	0.39

Emissions from the Emergency Fire Pump (Diesel)

	NO_X		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
5-01	8.28	2.07	1.78	0.45	0.66	0.17	0.11	0.03	0.59	0.15

Emissions from the Cooling Tower

	NOx		CO		VOC		SO_2		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
6-01	--	--	--	--	--	--	--	--	3.55	15.56

Facility Wide Criteria Pollutant Emissions from the Facility

EUs	NOx		CO		VOC		SO_2		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Proposed										
1-03 & 04	30.50	250.90	102.64	770.86	10.54	46.16	2.12	9.24	13.18	57.72
2-02	2.36	10.34	5.02	21.99	0.54	2.37	0.03	0.14	0.34	1.49
3-02	2.70	11.83	0.39	1.71	0.10	0.44	0.01	0.04	0.10	0.44
4-02	23.15	5.79	12.66	3.16	1.55	0.39	0.89	0.22	0.72	0.18
5-02	4.59	1.15	1.53	0.38	0.66	0.16	0.11	0.03	0.24	0.06
6-02	--	--	--	--	--	--	--	--	3.55	15.56
Subtotals	**63.30**	**280.01**	**122.24**	**798.10**	**13.39**	**49.52**	**3.16**	**9.67**	**18.13**	**75.45**
Existing										
1-01 & 02	173.40	759.50	118.00	516.84	9.98	43.74	2.00	8.76	12.48	54.66
2-01	2.36	10.34	5.02	21.99	0.54	2.37	0.03	0.14	0.34	1.49
3-01	2.70	11.83	0.39	1.71	0.10	0.44	0.01	0.04	0.10	0.44
4-01	52.80	13.20	12.10	3.03	1.41	0.35	0.89	0.22	1.54	0.39
5-01	8.28	2.07	1.78	0.45	0.66	0.17	0.11	0.03	0.59	0.15
6-01	--	--	--	--	--	--	--	--	3.55	15.56
Subtotals	**239.54**	**796.94**	**137.29**	**544.02**	**12.69**	**47.07**	**3.04**	**9.19**	**18.60**	**72.69**
Total	**302.84**	**1,077.0**	**259.53**	**1,342.1**	**26.08**	**96.59**	**6.20**	**18.86**	**36.73**	**148.14**

C. Hazardous Air Pollutants (HAPs) - Proposed Equipment

HAP emissions from the turbines are based on AP-42, Section 3.1 (4/2000). HAP emissions from the auxiliary boiler and heater are based on AP-42, Section 1.4 (7/98). HAP emissions from the emergency generator and fire water pump are based on AP-42, Sections 3.4 and 3.3 (10/96), respectively. Only emissions greater than 1.0E-3 (lb/hr and TPY) are listed.

HAP Emissions
(Turbines, Aux. Boiler, Emg. Generator, and FW Pump)

		Emissions	
HAP	**CAS #**	**lb/hr**	**TPY**
1,3-Butadiene	106990	0.002	0.008
Acetaldehyde	75070	0.151	0.660
Acrolein	107028	0.024	0.105
Arsenic	7440382	0.000	0.001
Barium	7440393	0.055	0.191
Benzene	71432	0.139	0.610

HAP Emissions (Continued)
(Turbines, Aux. Boiler, Emg. Generator, and FW Pump)

		Emissions	
Ethylbenzene	100414	0.121	0.528
Formaldehyde	50000	2.638	11.556
Hexane	110543	0.081	0.354
Naphthalene	91203	0.005	0.022
POM	N/A	0.011	0.035
Propylene Oxide	75569	0.109	0.478
Toluene	108883	0.490	2.144
Xylene	1330207	0.241	1.055

D. Hazardous Air Pollutants (HAPs) – Existing Facility

HAP emissions from the turbines are based on AP-42, Section 3.1 (4/2000). HAP emissions from the auxiliary boiler and heater are based on AP-42, Section 1.4 (7/98). HAP emissions from the emergency generator and fire water pump are based on AP-42, Sections 3.4 and 3.3 (10/96), respectively. Only emissions greater than 1.0E-3 (lb/hr and TPY) are listed.

HAP Emissions
(Turbines, Aux. Boiler, Emg. Generator, and FW Pump)

		Emissions	
HAP	**CAS #**	**lb/hr**	**TPY**
1,3-Butadiene	106990	0.002	0.007
Acetaldehyde	75070	0.144	0.625
Acrolein	107028	0.025	0.100
Arsenic	7440382	0.000	0.001
Barium	7440393	0.055	0.191
Benzene	71432	0.139	0.610
Ethylbenzene	100414	0.114	0.500
Formaldehyde	50000	2.539	11.105
Hexane	110543	0.081	0.354
Naphthalene	91203	0.007	0.021
POM	N/A	0.011	0.035
Propylene Oxide	75569	0.007	0.021
Toluene	108883	0.468	2.032
Xylene	1330207	0.231	1.000

SECTION IV. PSD REVIEW

As shown in the emission summary below, the previously permitted and proposed facility will have potential emissions above the PSD significance levels for NO_X, CO, VOC, and PM_{10} and are reviewed below.

EMISSIONS INCREASES COMPARED TO PSD LEVELS OF SIGNIFICANCE

Pollutant	Emissions (TPY)	PSD Levels of Significance (TPY)	PSD Review Required?
NO_X	280	40	Yes
CO	798	100	Yes
VOC	50	40	Yes
SO_2	10	40	No
PM/PM_{10}	64	25/15	Yes
H_2SO_4	1	7	No

Full PSD review of emissions consists of the following:

A. Determination of best available control technology (BACT)
B. Air Quality Impacts
C. Evaluation of source-related impacts on growth, soils, vegetation, visibility
D. Evaluation of Class I area impacts

A. Best Available Control Technology (BACT)

Methodology

A BACT analysis is required for each new or physically modified emissions unit for each pollutant which exceeds an applicable PSD Significant Emission Rate (SER). The pollutants subject to review under the PSD regulations include nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and particulates less than or equal to 10 microns in diameter (PM_{10}). The BACT review follows the "top-down" approach recommended by the EPA.

BACT must be at least as stringent as any NSPS applicable to the emissions source. After determining whether any NSPS is applicable, the first step in this approach is to determine for the emission unit in question the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically infeasible for the unit in question, the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical or environmental concerns. The remaining technologies are evaluated on the basis of operational and economic effectiveness. The EPA-required top-down BACT approach must look not only at the most stringent emission control technology previously approved, but it also must evaluate all demonstrated and potentially applicable technologies, including innovative controls, lower polluting processes, etc.

Presented below are the five basic steps of a top-down BACT review procedure as identified by the U.S. EPA in the March 15, 1990, Draft BACT Guidelines:

Step 1. Identification of all control technologies
Step 2. Determination of technical feasibility of control options
Step 3. Ranking of remaining control technologies by control effectiveness
Step 4. Evaluation of most effective controls and document results
Step 5. Selection of BACT

Control technologies and related emissions data were identified through a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC), as well as EPA's NSR and CTC websites, recent DEQ BACT determinations for similar facilities, and vendor-supplied information.

The BACT analysis for this project includes two gas combustion turbines an auxiliary boiler, a fuel gas heater, a cooling tower, and auxiliary equipment as listed below.

Emission Sources included in the BACT Analysis

EU ID	Source Description
EU 1-03	Siemens V84.3A Turbine
EU 1-04	Siemens V84.3A Turbine
EU 2-02	Auxiliary Boiler
EU 6-02	Cooling Tower
EU 3-02, 4-02, 5-02	Auxiliary Equipment

BACT Evaluation for Gas Turbines (Normal Operations)

Step 1 – Identification of all control technologies

The first step in the BACT analysis is to identify all control technologies for each pollutant. Search of the RBLC database was performed in April 2008 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for emission sources similar to those at the proposed Facility. Research of emerging air-pollution control technologies for turbines and cooling towers was also performed. Summary of the control technologies identified for each of the applicable pollutants are presented on the following page.

Possible Control Technologies

Emission Unit	Pollutant	Control Technology
Combined Cycle Gas Turbines (>50MW)	NO_X	$SCONO_X$
		Catalytic Combustion (XONON[tm])
		Selective Catalytic Reduction (SCR)
		Lean-Premix (Dry Low-NO_X Combustors)
		Steam / Water Injection
		Selective Non-Catalytic Reduction (SNCR)
		Good Combustion Practices
	CO	Catalytic Oxidation
		Good Combustion Practices
	VOC	Catalytic Oxidation
		Good Combustion Practices
	PM/PM_{10}	Good Combustion Practices
		Fuel Specification: Clean-Burning Fuels
Auxiliary Boiler	NO_X	Dry Low-NO_X Combustors
	Other criteria pollutants	Natural Gas with Good Combustion Practices
Cooling Tower	PM/PM_{10}	Drift Eliminators
Auxiliary Equipment	NO_X, CO, VOC, PM/PM_{10}	Good Combustion Practices, Fuel Specification: Clean-Burning Fuels

<u>Step 2 – Determination of Technical Feasibility of Identified Control Options</u>

The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those which are clearly technically infeasible are identified and not considered further.

NO_X Control Technologies

NO_X are formed during the fuel combustion process. There are three types of NO_X formations: thermal NO_X, fuel-bound NO_X, and prompt NO_X. Thermal NO_X is created by the high temperature reaction in the combustion chamber between atmospheric nitrogen and oxygen. The amount that is formed is a function of time, turbulence, temperature, and fuel to air ratios within the combustion flame zone. Fuel-bound NO_X is created by the gas-phase oxidation of the elemental nitrogen contained within the fuel. Its formation is a function of the fuel nitrogen content and the amount of oxygen in the combustion chamber. Fuel NO_X is temperature-dependent to a lesser degree; at lower temperatures, the fuel-bound nitrogen will form N_2 rather than NO_X. The fuel specification for these turbines, natural gas, has inherently low elemental nitrogen, so the effects of fuel NO_X are insignificant in comparison to thermal NO_X. Prompt NO_X occurs primarily in combustion sources that use fuel rich combustion techniques. The formation of prompt NO_X occurs through several early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. The reactions primarily take place within fuel rich

flame zones and are usually negligible when compared to the formation of NO_X by the thermal NO_X process. Combustion turbines generally have high mixing efficiencies with excess air, rich combustion zones rarely exist, and the formation of prompt NO_X is not deemed a significant contributing factor towards NO_X formation.

Since the formation of NO_X is largely dependent on thermal NO_X, several control technologies are used to reduce the precursors of NO_X formation or use catalysts to treat the post-combustion emissions. There are three types of emission controls for natural gas-fired turbines. The least effective are wet controls, which use steam or water injected into the combustion zone to reduce the ambient flame temperature, thus limiting NO_X formation. Intermediate are dry controls that use advanced combustor design to suppress NO_X formation. Most effective are post-combustion catalytic controls that selectively or non-selectively reduce NO_X.

$SCONO_X$™

$SCONO_X$™, is an emerging catalytic and absorption technology that has shown some promise for turbine applications. SCONOx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce CO and NO_X emissions from natural gas fired turbines. The catalyst oxidizes carbon-monoxide (CO) to carbon-dioxide (CO_2), and nitric oxide (NO) to nitrogen-dioxide (NO_2). The CO_2 is exhausted while the NO_2 absorbs onto the catalyst to form potassium nitrites (KNO_2) and potassium nitrates (KNO_3). This technology does not involve injection of ammonium, as most SCR technologies, and therefore it is not associated with ammonium slip emissions.

In 1998, the CA EPA Environmental Technology Certification Program reviewed the $SCONO_X$ technology and validated the claims of the manufacturer Emera Chem. However, the largest turbine at which the $SCONO_X$™ system has been installed is a 43 MW turbine in the City of Redding, CA. In recent years Emera Chem has come up with a new generation of the $SCONO_X$™ technology, marketed under the name EM_X. According to the manufacturer, currently the largest application of the EM_X technology is at a 6 MW turbine.

Since the $SCONO_X$™ and EM_X technologies have not been applied at a turbine with size comparable to the size of the proposed installations, they are not considered further.

Catalytic (Flameless) Combustion (XONON™)

While several companies have been reported to be working on this technology, it was first introduced commercially by Catalytica, Inc., and is being marketed under the name XONON™. The XONON™ technology replaces traditional flame combustion with flameless catalytic combustion. NO_X control is accomplished through the combustion process using a catalyst to limit the temperature in the combustor below the temperature where NO_X is formed. The XONON™ combustion system consists of four sections: 1) the preburner, for start-up, acceleration of the turbine engine, and adjusting catalyst inlet temperature if needed; 2) the fuel injection and fuel-air mixing system, which achieves a uniform fuel-air mixture to the catalyst; 3) the flameless catalyst module, where a portion

of the fuel is combusted flamelessly; and 4) the burnout zone, where the remainder of the fuel is combusted.

The XONON™ technology has been successfully implemented in a field trial at Silicon Valley Power, a municipal power company in Santa Clara, California. The NO_X emissions were well below 2.5 ppmvd on 1.5 MW Kawasaki M1A-13A gas turbines. Catalytica Combustion Systems (manufacturer of XONON™) had a collaborative commercialization agreement with General Electric Power Systems for the development of XONON™ systems for large scale gas turbines. However, in the last few years only one facility nationwide, a 750 MW natural gas-fired Pastoria Energy Facility, near Bakersfield, California, has attempted to employ the XONON™ system. According to a decision by the California Energy Commission (December 2000), XONON™ system was selected as the primary NO_X BACT pollution control technology for the Pastoria Energy Facility but the facility was given the option to use SCR if XONON™ system proved to be not feasible for scale up. The facility has employed SCR upon construction. The lack of large-scale operating experience and the lack of commercial availability preclude the use of XONON™ for gas turbine NO_X reduction for this project. Thus, the XONON™ catalytic combustion system is not considered further.

Selective Catalytic Reduction (SCR)

SCR systems selectively reduce NO_X by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. NO_X, ammonia, and oxygen react on the surface to form molecular nitrogen (N_2) and water. The overall chemical reaction can be expressed as:

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

The catalyst, comprised of parallel plates or honeycomb structures, is installed in the form of rectangular modules into the HRSG portion of the combined-cycle gas turbine downstream of the superheater. Ammonia is injected into the exhaust gases prior to passage through the catalyst bed. Even under normal operation of a SCR system, a portion of the injected ammonia passes unreacted through the catalyst and gets emitted out of the stack. These ammonia emissions are called ammonia slip.

The turbine exhaust gas must contain a minimum amount of oxygen and be within a particular temperature range in order for the selective catalytic reduction system to operate properly. The temperature range is dictated by the catalyst, which is typically made from noble metals, base metal oxides, or zeolite-based material. The typical temperature range for base-metal catalysts is 450 to 800 °F. If the temperature drops below 600 °F, the reaction efficiency becomes too low and increased amounts of NO_X and ammonia will be released out the stack. If the reaction temperature becomes too high, the catalyst may begin to decompose and NH_3 is oxidized to NO_X. Turbine exhaust gas is generally in excess of 1,000 °F but the HRSG cools the exhaust gases before they reach the catalyst by extracting energy from the hot turbine exhaust gases and creating steam. Selective catalytic reduction can typically achieve NO_X emission reductions in the range of 50 - 95 % control efficiency.

SCR is the most widely applied post-combustion control technology in turbine applications, and is currently accepted as LAER for new facilities located in ozone non-attainment regions. When combining with Dry-Low NO_X combustor, it can reduce NO_X emissions to as low as 2 ppmvd at 15% O_2 for standard combustion turbines with and without duct burner firing.

As mentioned previously, a possible side effect of this NO_X control system is ammonia slip. Ammonia slip occurs because the exhaust temperature falls outside the optimum catalyst reaction range or because the catalyst itself becomes prematurely fouled or exceeds its life expectancy. When the units meet the minimum temperature at the HRSG to activate the catalyst and employ the SCR, the units require only enough ammonia to control NO_X emissions to permitted levels. Negligible levels of ammonia slip should occur on these units since it is not in the interest of the facility to allow excess emissions of ammonia. Gas turbines using SCR typically have been limited to 5-10 ppmvd ammonia slip at 15 % O_2.

Lean-Premix Technology (Dry-Low NO_X)

Turbine manufacturers have developed processes that use air as a diluent to reduce combustion flame temperatures, and have achieved reduced NO_X by premixing the fuel and air before they enter the combustor. This type of process is called lean-premix combustion, and goes by a variety of names, including the Dry-Low NO_X (DLN) process of General Electric, the Dry-Low Emissions (DLE) process of Rolls-Royce and the $SoLoNO_X$ process of Solar Turbines.

The burner, or combustor, is the space inside the gas turbine where fuel and compressed air are burned. The combustion chamber can take the shape of a long can, an axially-centered ring of long cans (can-annular combustor), an annulus located behind the compressor and in front of the gas turbine (annular combustor), or a vertical silo.

Conventional combustors are diffusion controlled. This means fuel and air are injected into the combustor separately and mix in small, localized zones. The zones burn hot and produce more NO_X. In contrast, lean-premix combustors minimize combustion temperatures by providing a lean-premixed air/fuel mixture, where air and fuel are mixed before entering the combustor. This minimizes fuel-rich pockets and allows the excess air to act as a heat sink. The lower temperatures reduce NO_X formation. However, because the mix is so lean, the flame must be stabilized with a pilot flame.

To achieve low NO_X emission levels, the air/fuel ratio must be maintained near the lean flammability limit of the mixture. In the standard burner technology, such as is employed in EU 1-01 and 1-02, lean-premix combustors are designed to maintain this air/fuel ratio at around 60% of the rated load and above. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emission that occur as the air/fuel ratio reaches the lean flammability limit, standard lean-premix combustors switch to diffusion combustion mode at reduced load conditions. This

operation in diffusion mode means that the NO_X emissions in this mode are essentially uncontrolled. Lean-premix technology is the most widely applied pre-combustion control technology in natural gas turbine applications. It has been demonstrated to achieve emissions as low as 9 ppmvd NO_X at 15% O_2, with removal efficiency in the range of 40-95%.

The proposed combustion turbine units will be equipped with new burner technology that allows for operation in the pre-mix mode throughout the load range. This means that the higher emitting diffusion mode is no longer required at lower loads, and the resulting pollutant concentrations are lower during startup and shutdown compared to the standard design. In August of 2005, the Air Quality Division of ODEQ approved an equipment modification of EU 1-01 to operate in the same manner as described here. Ultimately, the combustion system of EU 1-01 was never modified to the new design. Based on the experience with the new units, AECI may revisit these modifications to EU 1-01 and 1-02 in the future.

Steam/Water Injection

Higher combustion temperatures result in greater thermodynamic efficiency. In turn, more work is generated by the gas turbine at a lower cost. Conversely, more NO_X is produced as the gas turbine inlet temperature is increased. Diluent injection, or wet controls, can be used to reduce NO_X emissions from gas turbines. Diluent injection involves the injection of a small amount of water or steam via a nozzle into the immediate vicinity of the combustor burner flame. NO_X emissions are reduced by instantaneous cooling of combustion temperatures from the injection of water or steam into the combustion zone. The effect of the water or steam injection is to increase the thermal mass by mass dilution and thereby reduce the peak flame temperature in the NO_X forming regions of the combustor.

Combustor geometry, injection nozzle design, and the fuel nitrogen content can affect diluent injection performance. Water or steam must be injected into the combustor so that a homogeneous mixture is created. Non-uniform mixing of water and fuel creates localized "hot spots" in the combustor that generate NO_X emissions. Increased NO_X emissions require more diluent injection to meet a specified level of emission. When diluent injection is increased, dynamic pressure oscillations in the combustor increase. Dynamic pressure oscillations can create noise and increase the wear and tear and required maintenance on the equipment. Continued increase of diluent injection will eventually lead to combustor flame instability and emission increases of CO and unburned hydrocarbons due to incomplete combustion.

Newer gas turbines usually apply steam injection since it does not increase the heat rate as much as water. Further, carbon monoxide emissions are lower, pressure oscillations are less severe, and maintenance is reduced relative to water injection.

Water injection typically results in a NO_X reduction efficiency in the range 30 - 70 %, with emissions below 42 ppmvd NO_X at 15 % O_2. Steam injection has generally been more successful in reducing NO_X emissions and can achieve emissions of 25 ppmvd NO_X at 15 % O_2 (30 - 82 % control efficiency range). Water/steam injection is not further reviewed in this BACT analysis because it results in NO_X emissions that are in excess of those achieved by advanced DLN combustors. In addition, the water consumption and sludge treatment/disposal requirements associated with water/steam injection do not exist for DLN combustors.

Selective Non-Catalytic Reduction (Thermal $DeNO_X$™)

Selective non-catalytic reduction (SNCR), also known as Thermal $DeNO_X$ uses ammonia or urea agent which reduces the NO_X in the flue gas to N_2 and H_2O. In practice, this technology has been applied in boilers by injecting ammonia into the high temperature region of the exhaust stream (e.g., 1,300 ºF to 2,000 ºF). Incorrect location of injection points, insufficient residence times and injection rate calibration error may result in excess emissions of ammonia (ammonia slip). However, when successfully applied, SNCR has shown reduction efficiency in NO_X emissions from boilers of 35 to 60 %.

The only known commercial applications of Thermal $DeNO_X$™ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800 ºF. There are no known applications on or experience with combustion turbines. Temperatures of 1,800 ºF require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased. Since this control option has not been demonstrated on combustion turbines, it is not considered technically feasible and is precluded from further consideration in this BACT analysis.

CO Control Technologies

Carbon monoxide is formed as a result of incomplete combustion of fuel. CO emissions from gas turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Control of CO is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors however tend to result in high NO_X emissions. Therefore, a low NO_X emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve lowest NO_X emissions rate possible while also optimizing CO emission rates.

A review of EPA's RACT/BACT/LAER Clearinghouse indicated that CO emission control methods include exhaust gas cleanup methods such as catalytic oxidation, and front-end methods such as combustion control wherein CO formation is suppressed within the combustors.

Good Combustion Practices
According to the EPA's RBLC database, more than 2/3 of the recent BACT determinations for CO were use of good combustion practices. Efficient burners can minimize the formation of CO by providing excess oxygen, mixing the fuel thoroughly with air and by employing general good combustion practices. The CO emission limits set for installations with good combustion practices BACT are in the range of 2 to 40 ppmvd at 15% O_2.

Catalytic Oxidation
Another CO control technology for natural gas fired combined-cycle turbines is an oxidation catalyst system. Just like with SCR catalyst technology for NO_X control, oxidation catalyst systems seek to remove pollutants from the turbine exhaust gas rather than limiting pollutant formation at the source. Unlike an SCR catalyst system, which requires the use of ammonia as a reducing agent, oxidation catalyst technology does not require the introduction of additional chemicals for the reaction to proceed. Rather, the oxidation utilizes the excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. The oxidation is carried out by the following overall reaction:

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2$$

This reaction is promoted by several noble metal-enriched catalysts at high temperatures. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM_{10}. Under ideal operating conditions, this technology can achieve an 80% reduction in CO emissions.

As with SCR, CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700°F to 1,100°F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1,200°F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the HRSG for proper turbine exhaust lateral distribution. It is important that the gas flow is evenly distributed across the catalyst and that proper operating temperature at base load design conditions is maintained. Operation with duct burners, at part load, or during start-up/shutdown will result in less than optimum temperatures and reduced control efficiency.

Catalyst systems are subject to loss of activity over time. Catalyst fouling occurs slowly under normal operating conditions and may be accelerated by even moderate sulfur concentrations in the exhaust gas. The catalyst can be chemically washed to restore its effectiveness, but eventually, irreversible degradation occurs. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical

3-year guarantee to a 5 to 7 year predicted life. Periodic testing of catalyst material is necessary to predict actual catalyst life for a given installation. The following economic analysis assumes that catalyst will be replaced every 3 years per vendor guarantee. This system also would be expected to control a small percent (5-40%) of hydrocarbon (VOC) emissions.

A CO catalyst also will oxidize other species within the turbine exhaust. For example, sulfur in natural gas (fuel sulfur and mercaptans added as an odorant) is oxidized to gaseous SO_2 within the combustor, but is further oxidized to SO_3 across a catalyst (30% conversion is assumed). SO_3 will then be emitted and/or combined to form H_2SO_4 (sulfuric acid mist) from the exhaust stack. These sulfates condense in the gas stream or within the atmosphere as additional PM_{10} (and $PM_{2.5}$). Thus, an oxidation catalyst would reduce emissions of CO and to some extent VOC, but would increase emissions of PM_{10} and $PM_{2.5}$. Also, the increased backpressure of the catalyst bed would require additional fuel firing to produce the same amount of electricity output, resulting in associated emission increases in other criteria pollutants.

According to the EPA's RBLC database, a number of combined cycle gas fired turbines have been issued permits where oxidation catalysis systems are selected as the BACT. The CO emission limits for these BACT determinations are in the range of 1.3 to 25 ppmvd at 15% O_2.

VOC Control Technologies

A review of the EPA's RBLC indicates that VOC emissions from large gas-fired turbines are controlled either via the use of good combustion practices or the use of oxidation catalyst.

Catalytic Oxidation

As mentioned earlier, an oxidation catalyst designed to control CO would provide a side benefit of controlling 5 to 40 % of the VOC emissions. However, the same technical factors that apply to the use of oxidation catalyst technology for control of CO emissions apply to the use of this technology for collateral control of VOC. Some of them are narrow operating temperature range, loss of catalyst activity over time, and system pressure losses leading to increased fuel consumption. According to the EPA's RBLC database, the emission limits for facilities with good combustion practices BACT were set in the range 0.4-23 ppmvd at 15% O_2.

Good Combustion Practices

Another VOC control option is the employment of combustion controls where VOC emissions are minimized by optimizing fuel mixing, excess air, and combustion temperature to assure complete combustion of the fuel. According to the EPA's RBLC database the VOC emission limits for the facilities with oxidation catalyst BACT are in the range 0.4-34 ppmvd at 15% O_2.

PM Control Technologies

Some total suspended particulates (TSP) and particulate matter less than 10 micrometers will occur from the combustion of natural gas. The EPA's AP-42, Fifth Edition, Supplement D, Section 1, considers that particulate matter from natural gas combustion is less than 1 micron; therefore it is considered as PM_{10}. The PM_{10} emissions from the combustion of natural gas will result primarily from inert solids contained in the unburned fuel hydrocarbons, which agglomerate to form particles. PM_{10} emission rates from natural gas combustion are inherently low because of very high combustion efficiencies and the clean burning nature of natural gas. Therefore, the use of natural gas is in and of itself a highly efficient method of controlling emissions.

A review of the EPA's RBLC database indicates that there are no BACT precedents that have included an add-on TSP/PM_{10} control requirement for natural gas-fired combustion turbines. The lowest PM_{10} BACT emission limit has been set at 4.1 lb/hr, while the range of emission limits is from 4.1 to 45 lb/hr.

Step 3 – Ranking of control technologies by control effectiveness

All identified controlled technologies and their control efficiencies are presented below. The technologies are ranked in order of decreasing effectiveness and the technologies determined as non-feasible are indicated as such.

Ranked controlled technologies by control efficiency

Pollutant	Control Technology	Control Efficiency (%)	Technical Feasibility
NO_X	Selective Catalytic Reduction (SCR)	50 - 95	Feasible
	Dry Low-NO_X (DLN) Combustors	40 - 95	Feasible
	Water/Steam Injection	30 - 82	Feasible
	Selective Non-Catalytic Reduction (SNCR)	35 - 60	Non-Feasible
	$SCONO_X$™	N/A	Unproven
	XONON™	N/A	Unproven
	Good combustion practices	Base Case	Feasible
CO	Oxidation Catalyst	60 - 80	Feasible
	Good combustion practices	Base Case	Feasible
VOC	Oxidation Catalyst	5 - 40	Feasible
	Good combustion practices	Base Case	Feasible
PM	Good combustion practices	Base Case	Feasible

Step 4 – Evaluation of the most effective controls

NO_X Control Technologies

A technology review showed that currently the most effective control technology for NO_X, which has been commercially proven, is Selective Catalytic Reduction (SCR). The use of a Dry-Low NO_X (DLN) combustion process has also been established as another very effective technology to control NO_X emissions from large gas-fired turbines.

The combined use of SCR (with a maximum ammonia slip of 10 ppmvd at 15% O_2) and DLN combustors is selected as BACT for NO_X for the proposed facility expansion, with NO_X emission limit of 2 ppmvd at 15% O_2 (1-hour average). A review of the EPA's RBLC indicates that the proposed emission limit is well within the range of the NO_X emission limits determined for other large combustion turbines in the last few years.

CO Control Technologies

There is no "Bright Line" cost effectiveness threshold for CO; rather, the cost presented for a specific project for control of CO are compared with the cost per ton that have been required of other sources in the same geographical area. For example, a project located in a rural attainment area where dispersion modeling shows less than significant air quality impacts would have a different cost criteria than a project located in or near an urban CO non-attainment area where there is a legitimate need to minimize emissions of CO. It should also be noted that cost effectiveness is a pollutant specific standard. For instance, the cost effectiveness of controlling the more pervasive pollutant NO_X (an acid rain pollutant, a precursor to the formation of regional haze, and a precursor to the formation of ozone) is aptly higher than for the more benign stack level emissions of CO. Areas of CO non-attainment are primarily urban and exceedances of the CO NAAQS are dominated by ground level releases due to automobiles. CO emitted from a power plant stack is quickly dispersed (as shown in the modeling analysis) and is an unstable molecule that naturally is converted to CO_2 in the atmosphere.

The use of an oxidation catalyst to control emissions of CO would result in collateral increases in PM_{10} (and $PM_{2.5}$) emissions. Further, the catalyst bed would create an increased backpressure which would require additional fuel firing to produce the same amount of electricity output, resulting in associated emission increases in other criteria pollutants. In addition, the cost effectiveness of a catalyst system to control emissions of CO is estimated at $9,600 per ton of removed CO, which is well above the benchmark of $2,000 per ton removed pollutant. Capital and annual costs associated with installation of an oxidation catalyst system were calculated using vendor quotes.

The fact that the use of oxidation catalyst for CO reduction would be associated with increase in other emissions, the very high cost per ton of this technology, as well as the regional air quality conditions, leads to the determination that combustion controls represent BACT for large gas-fired turbines. In addition, the resulting CO emissions do not exceed the Modeling Significance Levels (MSLs). There are no expected adverse economic, environmental or energy impacts associated with the use of the proposed control alternative. The proposed CO BACT limit is 8 ppmvd at 15% O_2.

VOC Control Technologies
Since the use of oxidation catalyst has been shown to not be cost effective for the control of CO, it could not be cost effective for control of 5-40 % of the VOC emissions. Therefore, an oxidation catalyst cannot be considered to represent BACT for VOC emissions. The proposed BACT is good combustion practices with emission limit of 0.3 ppmvd at 15% O_2.

PM Control Technologies
The established BACT for PM_{10} emissions from the large natural gas-fired combustion turbines is the use of a low ash fuel (natural gas) and efficient combustion. This BACT choice is protective of any reasonable opacity standard. Typically, plume visibility is not an issue for this type of facility as the exhaust plumes are nearly invisible except for the condensation of moisture during periods of low ambient temperature. There are no adverse environmental or energy impacts associated with the control alternative. The proposed PM_{10} emission limit for this facility expansion is 6.59 lb/hr (filterable plus condensable) which is in the range of the set BACT PM_{10} limits for similar facilities.

<u>Step 5 – Selection of BACT</u>

Summary of Selected BACT for Gas Turbines

Pollutant	Control Technology	Proposed Permit Limit
NO_X	SCR with Dry Low-NO_X combustors	2 ppmvd @ 15% O_2
CO	Good combustion practices	8 ppmvd @ 15% O_2
VOC	Good combustion practices	0.3 ppmvd @ 15% O_2
PM_{10}	Good combustion practices	10.56 lb/hr (filter + cond)

BACT Evaluation for Gas Turbines (Startup/Shutdown)
A review of the EPA's RBLC database in April 2008 did not identify any control technologies for gas turbines specifically during the startup and shutdown periods. Therefore, BACT is proposed as a limit on the quantity of emissions during startup and shutdown while minimizing the startup and shutdown periods.

Event	Maximum Duration (hr)	NO_X Emissions (lbs/event)	CO Emissions (lbs/event)
Startup	4	568	1,596
Shutdown	1	142	399

BACT Evaluation for Cooling Tower
The first step in the BACT analysis is to identify all control technologies for each pollutant. Search of the RBLC database was performed in April 2008 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for emission sources similar to those at the proposed Facility.

The performed research showed that the only PM control technology for cooling towers is the design of cooling towers to minimize/eliminate drift. The drift eliminators are specifically designed baffles that collect and remove condensed water droplets in the air stream. These drift eliminators, according to a review of the EPA's RBLC, can reduce drift to 0.0005 % of cooling water flow, which reduces particulate emissions. The use of drift eliminators to attain an emission rate of 0.40 lb/hr per cell is determined as BACT for cooling tower particulate emissions. This BACT does not have any adverse environmental or energy impacts.

BACT Evaluation for Auxiliary Boiler

The first step in the BACT analysis is to identify all control technologies for each pollutant. Search of the RBLC database was performed in April 2008 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for emission sources similar to those at the proposed Facility.

The boiler design will incorporate low-NO_X burners for NO_X control, which is common for natural gas-fired auxiliary boilers. Since the auxiliary boiler will fire natural gas, the same properties that applied to the combustion turbines will also apply to this application. The EPA's RACT/BACT/LAER Clearinghouse (RBLC) database research indicates that there are no BACT precedents for the other criteria pollutants requiring add-on controls. Therefore, BACT is proposed to be the use of low-NO_X burners and efficient combustion. Opacity is also not an issue with this type of application, except for the condensation of moisture during periods of low ambient temperature. There are no adverse environmental or energy impacts associated with the control alternative.

BACT Evaluation for Auxiliary Equipment

Prospective auxiliary equipment for the facility includes the following:

- Fuel Gas Water Bath Heater No. 2 (natural gas fired)
- Emergency Generator No. 2 (diesel fired)
- Emergency Fire Pump No. 2 (diesel fired)

Search of the RBLC database was performed in April 2008 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT for emission sources similar to those at the proposed Facility.

These units will incorporate modern combustion design to minimize emissions. Baseline emissions are based on the NSPS, if available. Baseline emissions for the compression ignition engines are based on NSPS, Subpart IIII emission limits. Fuel specifications will require "Clean-Burning Fuels" to further reduce emissions. The EPA's RACT/BACT/LAER Clearinghouse (RBLC) database research indicates that there are no BACT precedents for the criteria pollutants requiring add-on controls. Therefore, BACT is proposed to be the use of good combustion design, efficient combustion and fuel specification for clean burning fuels. Opacity is also not an issue with this type of application, except for the condensation of moisture during periods of low ambient temperature. There are no adverse environmental or energy impacts associated with the control alternative.

Summary of Selected BACT

Pollutant	Gas Turbine with Duct Burner (permit limit)	Gas Turbine Startup (permit limit)	Gas Turbine Shutdown (permit limit)
NO_X	SCR with dry low-NOx combustors (2.0 ppmvd @ 15% O_2 & 10 ppmvd ammonia slip)	568 lb/event & a maximum of 4 hours/event	142 lb/event & a maximum of 1 hour/event
CO	Good combustion control (8 ppmvd @ 15% O_2)	1,596 lb/event & a maximum of 4 hours/event	399 lb/event & a maximum of 1 hour/event
VOC	Good combustion practice (5.27 lb/hr)	N/A	N/A
SO_2	Low sulfur fuel – natural gas (1.06 lb/hr)	N/A	N/A
PM_{10}	Good combustion control & use of natural gas (6.59 lb/hr)	N/A	N/A

Summary of Selected BACT (Continued)

Pollutant	Auxiliary Boiler (permit limit)	Fuel Gas Heater (permit limit)	Diesel Engine/Fire Water Pump (permit limit)
NO_X	Low NO_X burners (2.36 lb/hr)	Good design & operating practices (2.70 lb/hr)	NSPS, Emission Limits[1] (23.15/4.59 lb/hr)
CO	Good combustion practices (5.02 lb/hr)	Good combustion practices (0.39 lb/hr)	NSPS, Emission Limits (12.66/1.53 lb/hr)
VOC	Good design & operating practices (0.54 lb/hr)	Good design & operating practices (0.10 lb/hr)	Good engine design (1.55/0.66 lb/hr)
SO_2	Low sulfur fuel – natural gas (0.03 lb/hr)	Low sulfur fuel – natural gas (0.01 lb/hr)	0.05% sulfur diesel (0.89/0.11 lb/hr)
PM_{10}	Good combustion practice (0.34 lb/hr)	Good combustion practice (0.10 lb/hr)	NSPS, Emission Limits (0.72/0.24 lb/hr)

[1] - NOX is inclusive of NMHC.

B. Air Quality Impacts

Prevention of Significant Deterioration (PSD) is a construction permitting program designed to ensure air quality does not degrade beyond the National Ambient Air Quality Standards (NAAQS) or beyond specified incremental amounts above a prescribed baseline level. The PSD rules set forth a review procedure to determine whether a source will cause or contribute to a violation of the NAAQS or maximum increment consumption levels. If a source has the potential to emit a pollutant above the PSD significance levels, then it triggers this review process.

EPA has provided significance impact levels (SIL) for the PSD review process to determine whether a source will cause or contribute to a violation of the NAAQS or consume increment. Air quality impact analyses were conducted for NO_2, CO, and PM_{10} to determine if ambient impacts would be above the SIL and monitoring significance levels (MSL). For NO_X, the total NO_X emissions were modeled and then the maximum predicted impacts were converted to NO_2 using the Ambient Ratio Method (ARM) for comparison SIL and MSL. If impacts are above the SIL, a radius of impact (ROI) is defined for the facility for each pollutant out to the farthest receptor at or above the SIL. If a ROI is established for a pollutant, then a full impact analysis is required for that pollutant. If the air quality analysis does not indicate a ROI, no further air quality analysis is required for the Class II area.

The ROI is used to determine the distance out to which nearby sources need to be reviewed for inclusion in the NAAQS and increment modeling. The nearby source inventories for each pollutant that exceeded the SIL were obtained from the AQD using the determined ROI. Inventory sources included in the full impact analysis are generally sources that are within the ROI plus 50 km.

AERMOD (07026) was used for the modeling analyses. AERMOD is a refined, steady-state, multiple source, Gaussian dispersion model and is the preferred model for these analyses. The modeling analysis was performed using the regulatory default models settings, which include stack heights adjusted for stack-tip downwash and missing data processing.

Source and building elevations were obtained from engineering elevation drawings. Receptor terrain elevations entered into the model were the highest elevations extracted from USGS 7.5 minute digital elevation model (DEM) data of the area surrounding the proposed site. For each receptor elevation, the maximum terrain elevation associated with the four DEM points surrounding the receptor will be selected.

In order to account for building wake effects, direction-specific building dimensions used as input to the model were calculated using the algorithms of the Building Profile Input Program (BPIP). BPIP is designed to incorporate the concepts and procedures expressed in the GEP Technical Support document, and the Building Downwash Guidance document while incorporating the enhancements to improve prediction of ambient impacts in building cavities and wake regions.

As described in the *Air Dispersion Modeling Guidelines for Oklahoma Air Quality Permits*, meteorological data was derived from Oklahoma Mesonet surface data, National Climactic Data Center (NCDC) Integrated Surface Hourly (ISH) data, and FSL/NCDC Radiosonde upper air data. Oklahoma Mesonet data was provided to the AQD courtesy of the Oklahoma Mesonet, a cooperative venture between Oklahoma State University and The University of Oklahoma and supported by the taxpayers of Oklahoma. The model runs were performed using 2001-2005 meteorological data using NWS surface observations from Tulsa, upper air measurements from Springfield, Missouri, and adjusting the surface data using the Oklahoma Mesonet data from Pryor, OK. The 2001-05 data set used in this analysis was provided by the AQD.

Three Cartesian grids for the modeling analyses were defined as follows:

1. A Fence Line Grid containing receptors spaced at 50 meter intervals along the facility fence line.
2. A Fine Grid containing receptors spaced at 100 meter intervals extending approximately 3.0 km from the fence line, exclusive of the Fence Line Grid.
3. A Coarse Grid containing receptors spaced at 1.0 km intervals extending approximately 17.0 km beyond the Fine Grid.

Significance Analyses

In addition to emissions from normal operations, the modeling analysis included emissions from startup and shutdown periods of operation. The combustion turbines operate under several different types of startup conditions, as described below. During these startup and shutdown periods, the combustion turbine typically exhibits NO_X and CO emission levels greater than what is listed in the manufacturer's emission guarantee, which corresponds to normal operations. The facility has made very conservative estimates regarding the duration of each of these startup events and their expected emission rates based on a combination of manufacturer-provided data and the operating performance of the existing turbines. Emissions of other criteria pollutants, such as PM_{10}, SO_2, and VOC, are considered unaffected by startup/shutdown conditions. Modeled NO_X and CO emissions are based on the specific event durations.

For NO_X, the total annual emissions for a single turbine including startup and shutdown emissions are 164.38 TPY and were average over an 8,760 hour operating year. The modeled PM_{10} emission rates are based on the maximum hourly emission rate of 6.59 lb/hr. The modeled one hour CO emissions represent the maximum amount of emissions released over a one hour period, which corresponds to a shutdown period. The modeled eight hour CO emission rates represent the maximum amount of emissions released over an eight hour period. This would correspond to a cold start (four hours), followed by four hours of normal operation. A summary of eight hour CO emissions calculation is shown on the following page.

CO EMISSION SUMMARY (8-HRAVERAGING PERIOD)

Operating Mode	Duration (hours)	Emission Rate (lb/hr)	Total Emissions (lbs)
Cold Startup	4	399	1,596
Normal Operations	4	64	256
Total	8	--	1,852[1]

[1] - This corresponds to an 8-hr average emission rate of 231.5 lb/hr. Modeling was conducted at 304.75 lb/hr. If the facility is in compliance at the higher emission rate the facility will be in compliance at the lower emission rate.

The remaining sources, including the cooling tower, auxiliary boiler, and fuel gas water bath heater are not affected by any startup/shutdown issues. The modeled emissions for these sources were based on the short term (lb/hr) emission rate. Source parameters for the proposed new units are based on the designs of the comparable existing units and are shown below.

Modeled Source Parameters

EU #	EU Description	UTM Coordinates (meters) East	West	Stack Height (m)	Stack Temp. Kelvin	Exit Velocity (m/s)	Stack Diameter (m)
1-03	Turbine No.3	295504	4011041	39.63	366	19.95	5.69
1-04	Turbine No.4	295535	4011041	39.63	366	19.95	5.69
2-02	Auxiliary Boiler No.2	295519	4011064	7.62	478	14.15	0.70
3-02	Fuel Gas Heater No.2	295281	4011093	4.27	383	9.75	0.52
6-02-1	Cooling Tower, Cell 1	295635	4010951	12.80	299	8.89	16.46
6-02-2	Cooling Tower, Cell 2	295635	4010968	12.80	299	8.89	16.46
6-02-3	Cooling Tower, Cell 3	295635	4010985	12.80	299	8.89	16.46
6-02-4	Cooling Tower, Cell 4	295635	4011002	12.80	299	8.89	16.46
6-02-5	Cooling Tower, Cell 5	295635	4011018	12.80	299	8.89	16.46
6-02-6	Cooling Tower, Cell 6	295635	4011035	12.80	299	8.89	16.46
6-02-7	Cooling Tower, Cell 7	295635	4011052	12.80	299	8.89	16.46
6-02-8	Cooling Tower, Cell 8	295635	4011068	12.80	299	8.89	16.46
6-02-9	Cooling Tower, Cell 9	295635	4011085	12.80	299	8.89	16.46

Modeled Source Emissions

EU #	EU Description	NO_X (Annual) (g/s)	CO (1-hour) (g/s)	CO (8-hour) (g/s)	PM_{10} (24-hr, Annual) (g/s)
1-03	Turbine No.3	4.73[1]	70	38.4	1.330
1-04	Turbine No.4	4.73[1]	70	38.4	1.330
2-02	Auxiliary Boiler No.2	0.30	0.63	0.63	0.043
3-02	Fuel Gas Heater No.2	0.34	0.05	0.05	0.013

[1] - Turbine NO_X emissions modeled are greater than what was permitted.

Modeled Source Emissions

EU #	EU Description	NO_X (Annual) (g/s)	CO (1-hour) (g/s)	CO (8-hour) (g/s)	PM_{10} (24-hr, Annual) (g/s)
6-02-1	Cooling Tower, Cell 1	----	----	----	0.050
6-02-2	Cooling Tower, Cell 2	----	----	----	0.050
6-02-3	Cooling Tower, Cell 3	----	----	----	0.050
6-02-4	Cooling Tower, Cell 4	----	----	----	0.050
6-02-5	Cooling Tower, Cell 5	----	----	----	0.050
6-02-6	Cooling Tower, Cell 6	----	----	----	0.050
6-02- 7	Cooling Tower, Cell 7	----	----	----	0.050
6-02-8	Cooling Tower, Cell 8	----	----	----	0.050
6-02-9	Cooling Tower, Cell 9	----	----	----	0.050

A summary of results from the significance analysis is shown below. For the PM_{10} 24-hour standard the emissions were modeled using five years of combined meteorological data. The PM_{10} 24-hour average emission result shown below is the sixth highest high over the five-year period modeled.

Class II Area Significance Analysis Results

Pollutant	Averaging Period	SIL $\mu g/m^3$	Max Impact $\mu g/m^3$	Full Impact Analysis Required?
NO_2	Annual	1	6.5	Yes
CO	1-hr	2,000	885.6	No
	8-hr	500	151.8	No
PM_{10}	24-hr	5	10.5	Yes
	Annual	1	0.8	No

As seen above, NO_2 (annual) and PM_{10} (24-hr) exceeded their respective SIL and requires a full impact analysis. The modeling results were then compared to the Class I area SIL. This was done to determine if a Class I Increment Analysis is required. If the Class I SIL were not exceeded within the modeling domain, then a Class I Area Increment analysis is not required.

Class I Area Significance Analysis Results

Pollutant	Averaging Period	SIL $\mu g/m^3$	Distance km	Full Impact Analysis Required?
NO_2	Annual	0.1	1.0	No
PM_{10}	24-hr	0.3	6.6	No
	Annual	0.2	0.5	No

The modeling results were then compared to the MSL. If the impacts from the proposed project exceed the MSL then the facility might be required to do pre-construction monitoring.

Monitoring Significance Level Comparison

Pollutant	Averaging Period	MSL $\mu g/m^3$	Max Impact $\mu g/m^3$
NO_2	Annual	14	7
CO	8-hr	575	152
PM_{10}	24-hr	10	11
VOC/Ozone	8-hr	100 TPY	50 TPY

The PM_{10} impacts exceed the MSL. However, since there is an existing monitoring site located approximately 2.3 km ESE of the facility, no pre-construction monitoring is required of the facility.

NAAQS Analysis

Significance results indicated that the furthest significance receptor for either NO_X or PM_{10} was located approximately 8 km from the plant, resulting in an ROI of 58 kilometers. The inventory source data provided by the AQD included review of major sources located 65 km from the plant, and minor sources within 10km. To complete the NAAQS Analysis, the proposed emissions from the facility were modeled simultaneously with the emissions from the NAAQS sources identified in the inventory provided by the AQD. A full list of the sources used in the modeling was provided in the application. Permit allowable emission rates were modeled for all short-term averaging periods. For annual averaging periods, the potential emissions were multiplied by an operating factor which was based on the past actual 2-year average of operating hours reported in the emission inventory data. The background concentrations were added to the modeled concentration for comparison with the NAAQS.

Monitoring data from the state's network of ambient monitors was utilized to develop background concentrations for use in NAAQS analysis. The Mayes County monitors were used as the most representative monitoring data and are approximately 2.3 km ESE of the facility.

NAAQS Background Concentrations

	Averaging	Concentrations		Monitor	
Pollutant	**Period**	**ppm**	**$\mu g/m^3$**	**Site ID**	**Year**
NO_2	Annual	0.004	8	400979014	2007
PM_{10}	24- hr[1]	----	58	400979014	2007-5

[1] – The fourth highest concentration over the most recent three years of data.

The results of the NAAQS analysis, after accounting for the ARM and including background concentrations are summarized below.

NAAQS Analyses Results

Pollutant	Averaging Period	Impact $\mu g/m^3$	Background $\mu g/m^3$	Total $\mu g/m^3$	NAAQS $\mu g/m^3$
NO_2	Annual	18	8	26	100
PM_{10}	24- hr[1]	93	58	151	150

As seen above, the modeling predicts a single exceedance of the PM_{10} NAAQS. As described in the NSR/PSD Workshop Manual, when an exceedance is predicted at one or more receptors in the impact area, the applicant must:

> "[..] determine if the net emissions increase from the proposed source will result in a significant ambient impact at the point (receptor) of the predicted violation, <u>and</u> at the time the violation is predicted to occur. The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation."

The modeling was reviewed to determine if the emissions from the Chouteau Plant expansion had a significant impact at the specific receptor when the modeled exceedance occurred. The impact of the PM_{10} emissions from the Chouteau Plant expansion was less than 5 $\mu g/m^3$ (3.1 $\mu g/m^3$) at the specific receptor when the modeled exceedance occurred. Therefore, the emissions from the modification of the Chouteau Plant do not cause or contribute to the modeled PM_{10} NAAQS violation.

PSD INCREMENT ANALYSIS

The PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The major source baseline date depends upon the county in which the facility is located and on the pollutant in question. Sources that contribute to emissions increases after the baseline date are obtained from the AQD, and total facility-wide potential emissions are modeled simultaneously with the PSD Increment inventory sources provided by the AQD. As with the NAAQS analysis, permit allowable emission rates were modeled for all short-term averaging periods. For annual averaging periods, the potential emissions were multiplied by an operating factor which was based on the past actual 2-year average of operating hours reported in the emission inventory data.

Class II PSD Increment Analyses Results

Pollutant	Averaging Period	Impact $\mu g/m^3$	Allowable $\mu g/m^3$
NO_2	Annual	15	25
PM_{10}	24- hr[1]	380	30

The increment modeling was reviewed to determine if the emissions from the Chouteau Plant expansion had a significant impact at the specific receptor when the modeled exceedance occurred. The impact of the PM_{10} emissions from the Chouteau Plant expansion was less than 5 $\mu g/m^3$ at the specific receptors when the modeled exceedance occurred. Therefore, the emissions from the modification of the Chouteau Plant do not cause or contribute to the modeled PM_{10} Increment violation.

Class I Area Visibility Analysis

The nearest Class I areas are the Caney Creek Wilderness in western-central Arkansas, the Hercules Glades Wilderness in southwestern Missouri, and Upper Buffalo Wilderness located in north-central Arkansas. AECI strives to comply with the most current guidelines and utilized the method recommended by the Federal Land Managers (FLM) for Class I Area impact analysis. The FLM have proposed new guidance that uses the 10D Rule (Q/D<10). In this equation, Q is equal to the sum of the emission increases of NO_X, SO_2, and PM_{10} that will result from the proposed project (in TPY). The variable D is the distance from the source to the Class I Area (in km), and must be greater than 50 km. If the calculated Q/D value exceeds 10, then a Class I area analysis evaluating Air Quality Related Values (AQRV) (deposition and visibility) must be conducted. Otherwise, no additional analyses are required. As shown below, since Q/D is less than 10 no AQRV analyses need to be conducted.

10D Rule Screening Analysis

	Distance	Emissions	
Class I Area	**km**	**TPY**	**Q/D**
Caney Creek	200	486	2.4
Hercules Glade	215	486	2.3
Upper Buffalo	260	486	1.9

F. Evaluation of Source-Related Impacts on Growth, Soils, Vegetation, Visibility

Mobile Sources

The facility currently employs no more than 30 workers. The expansion will not result in additional employees beyond a total of 30, and will therefore result in a negligible increase in mobile source emissions.

Growth Impacts

A growth analysis is intended to quantify the amount of new growth that is likely to occur in support of the facility and to estimate emissions resulting from that associated growth. Associated growth includes residential and commercial/industrial growth resulting from the new facility. Residential growth depends on the number of new employees and the availability of housing in the area, while associated commercial and industrial growth consists of new sources providing services to the new employees and the facility. As mentioned previously, staffing of new permanent jobs is expected to be limited and the facility will likely employ fewer than 30 individuals over all shifts. As a result, additional growth impacts are expected to be minimal.

Soils and Vegetation Impact

The following discussion will review the project's potential to impact its agricultural surroundings based on the facility's allowable emission rates and resulting ground level concentrations of NO_2, VOC, CO, and PM_{10}.

The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than 1 month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism, whereas long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

NO_2 may affect vegetation either by direct contact of NO_2 with the leaf surface or by solution in water drops, becoming nitric acid. PM can impact vegetation through deposition and removal. The effects of this deposition include depleting nutrients in soils, damaging sensitive forests and farm crops, and affecting ecosystem diversity. These effects are generally associated with the removal of large quantities of soils from ecosystems, not with the possible addition of smaller quantities of fine materials. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents. This protection extends to agricultural soil. As described previously, the Chouteau plant expansion is not predicted to cause or contribute to a violation of the NO_2 or PM_{10} primary NAAQS. As a result, compliance with the secondary NAAQS is also expected.

At the levels of CO that occur in urban air, there are no detrimental effects on materials or plants, however human health may be adversely affected at such levels. The secondary NAAQS are intended to protect the public welfare from the adverse effects of airborne effluents, and extends to agricultural soil. Modeled CO impacts do not trigger modeling significance levels (MSLs). As a result, no significant adverse impact on soil and vegetation due to CO emissions is anticipated due to the proposed power plant.

Visibility Impairment

A screening analysis was conducted in order to evaluate the Chouteau Plant expansion's impact on Class II visibility. VISCREEN, the screening tool recommended for Class I visibility screening analyses, was used per guidance provided by the Oklahoma DEQ. In the absence of any guidance on the topic of Class II visibility screening analysis, default values and screening parameters for Class I visibility screening were used as recommended by U.S. EPA.

VISCREEN allows for two levels of visibility impact screening. Level 1 screening involves a series of conservative calculations designed to identify those emissions sources that have little potential for adversely affecting visibility. If visibility impairments are indicated, a Level 2 analysis, which allows for modification of default parameters including meteorological data, is performed. Both Level 1 and Level 2 analyses were performed for this study.

The default meteorological conditions of F-stability and 1 m/s wind speed were used. For emission rates, only annual emissions of NO_2 and PM_{10} from the combustion turbines were input into the model. The default values were chosen for primary NO_2, soot, and primary sulfate emissions. A background visual range of 40 km was used.

Based upon a geographic analysis of the local area, the closest large population center (Pryor, OK), is located 10 km from the Chouteau Plant. This distance was used for source-observer input distance. In addition, since this Class II analysis does not involve a formal Class I area boundary, a Class II boundary was selected (per DEQ guidance) extending from 1 km to 10 km from the source.

VISCREEN analyzes a matrix of conditions for regions within and outside the Class I area boundaries (in this case, the "Class II" boundaries). This matrix includes forward scattering and backward scattering impacts viewed against the sky and the surrounding terrain (e.g., mountains, hills, etc.). The forward scattering case assumes that the sun is in front of the observer at an angle of 10° above the horizon. The backward scatter case assumes that the sun is at the observer's back at an angle of 140° above the horizon.

Results from the VISCREEN model are expressed in terms of perceptibility (ΔE) and contrast. The EPA default Class I screening criteria for perceptibility and contrast are 2.0 and 0.05, respectively. For a Class II analysis, the AQD guidance suggests that 3 × the screening criteria be used, resulting in perceptibility and contrast thresholds of 6.0 and 0.15.

VISCREEN RESULTS

		Azimuth	Dist.	Alpha	ΔE		Contrast	
Background	**(degrees)**	**(degrees)**	**(km)**	**(degrees)**	**Critical**	**Plume**	**Critical**	**Plume**
SKY	10	10	4.8	159	6	6.793	0.15	0.004
SKY	140	10	4.8	159	6	2.574	0.15	-0.039
TERRAIN	10	1	1	168	6	9.697	0.15	.111
TERRAIN	140	1	1	168	6	2.089	0.15	.077

As seen from these results, the perceptibility threshold is marginally exceeded when viewed against a sky background, and exceeded when viewed against terrain. Although the modeled visibility impact is greater than 3 × the EPA default Class I threshold, AECI believes that the predicted impact will not result in actual visibility impairment.

Endangered Species Act (ESA)

An endangered species analysis was conducted for Mayes County in order to demonstrate compliance with the ESA. Based upon the latest County Species List for Mayes County, OK, there are five species present on the county species list for Mayes County:

- the American peregrine falcon (bird),
- Arkansas darter (fish),

- bald eagle (bird),
- Ozark cavefish (fish), and
- piping Plover (bird, endangered).

Of these five species, the U.S. Fish and Wildlife Service's (FWS) critical habitat mapper does not indicate the presence of any critical habitat in Mayes County. As a result, the proposed expansion at the Chouteau plant is not expected to adversely affect endangered species.

SECTION VI. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards. Compliance with the NAAQS is addressed in the "PSD Review" section.

OAC 252:100-5 (Registration, Emission Inventory, And Annual Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. This facility has recently submitted the required emission inventories and has paid the applicable or fees.

OAC 252:100-8 (Major Source/Part 70 Permits) [Applicable]
Part 5 includes the general administrative requirements for Part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual emission units that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

> 5 TPY of any one criteria pollutant
> 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule

Emissions limitations have been established for each emission unit based on information from the permit application and Permit No. 98-270-TV (PSD) (M-2).

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
In the event of any release that results in excess emissions, the owner or operator of such facility shall notify the Air Quality Division as soon as the owner or operator of the facility has knowledge of such emissions, but no later than 4:30 p.m. the next working day. Within ten (10) working days after the immediate notice is given, the owner or operator shall submit a written report describing the extent of the excess emissions and response actions taken by the facility. In addition, if the owner or operator wishes to be considered for the exemption established in 252:100-9-3.3, a Demonstration of Cause must be submitted within 30 calendar days after the occurrence has ended.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-19 (Particulate Matter) [Applicable]
Subchapter 19 regulates emissions of particulate matter from fuel-burning equipment. Particulate emission limits are based on maximum design heat input rating. The units listed below are subject to the requirements of this subchapter and will be in compliance as shown in the following table.

Equipment	**Max. Heat Input (MMBTUH) (HHV)**	**Allowable PM Emission Rate (lb/MMBTU) (HHV)**	**Potential PM Emissions (lb/MMBTU) (HHV)**
Each New Turbine	1,882	0.17	<0.01
Each Existing Turbine	1,783	0.17	<0.01
Auxiliary Boiler (2)	33.5	0.45	0.01
Fuel Gas Water Bath Heater (2)	18.8	0.52	0.01
Backup Generators (2)	<10	0.60	0.10
Diesel Fire Water Pump (2)	<10	0.60	0.31

OAC 252:100-25 (Visible Emissions and Particulates) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity. All of the emission units are subject to this subchapter. The turbines, Auxiliary Boiler, and Fuel Gas Water Bath Heater will assure compliance with this rule by ensuring "complete combustion" and utilizing pipeline-quality natural gas as fuel. The Backup Diesel Generator and the Diesel Fire Water Pump assure compliance with this rule by ensuring "complete combustion."

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originated in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or to interfere with the maintenance of air quality standards. No activities are expected that would produce fugitive dust beyond the facility property line.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 5 limits sulfur dioxide emissions from new equipment (constructed after July 1, 1972). For gaseous fuels, the limit is 0.2 lb/MMBTU heat input, three-hour average. The permit will require the new/existing turbines to be fired with pipeline-grade natural gas with SO_2 emissions of 2.2/2.0 lb/hr, which is equivalent to 0.001 lb/MMBTU. The auxiliary boiler and fuel gas heater emissions are approximately 0.0009 and 0.004 lb/MMBTU, respectively. The backup diesel generator and diesel fire water pump fire diesel fuel with a maximum sulfur content of 0.05 % by weight. This fuel will produce emissions of approximately 0.05 lbs/MMBTU, which is well below the allowable emission limitation of 0.8 lb/MMBTU for liquid fuels.
Part 5 also requires an opacity monitor and sulfur dioxide monitor for equipment rated above 250 MMBTU. Equipment burning gaseous fuel is exempt from the opacity monitor requirement, and equipment burning gaseous fuel containing less than 0.1 percent sulfur is exempt from the sulfur dioxide monitoring requirement, so the turbines do not require such monitoring.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
This subchapter limits emissions of NO_X from new gas-fired fuel-burning equipment with rated heat input greater than or equal to 50 MMBTUH to a three-hour average of 0.2 lb/MMBTU. Listed below is the 3-hr average emission limit (lb/hr) of NO_X for each combustion turbine and the equivalent emission rates (lb/MMBTU) based on the maximum heat input, which are below the standard of 0.2 lb/MMBTU. However, for operational flexibility, the permit will establish a limit based on the Subchapter 33 allowable of 0.2 lb/MMBTU, three-hour average. The Auxiliary Boiler, Fuel Gas Water Bath Heater, Backup Diesel Generator, and the Diesel Fire Water Pump are below 50 MMBTUH heat input and are, therefore, not subject to this regulation.

	MMBTUH	**lb/hr**	**lb/MMBTU**
New Turbines	1,882	15.25	0.012
Existing Turbines	1,783	86.70	0.050

OAC 252:100-35 (Carbon Monoxide) [Not Applicable]
None of the following affected processes are located at this facility: gray iron cupola, blast furnace, basic oxygen furnace, petroleum catalytic cracking unit, or petroleum catalytic reforming unit.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 3 requires storage tanks constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. The anticipated diesel tanks will be below the 1.5 psia threshold.
Part 5 limits the VOC content of coatings used in coating lines or operations. This facility will not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.
Part 7 requires fuel-burning equipment to be operated and maintained so as to minimize emissions of VOC. Temperature and available air must be sufficient to provide essentially complete combustion. The turbines are designed to provide essentially complete combustion of VOC.

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained unless a modification is approved by the Director. Since no Area of Concern (AOC) has been designated anywhere in the state, there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-17	Incinerators	not type of emission unit
OAC 252:100-23	Cotton Gins	not type of emission unit
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Municipal Solid Waste Landfills	not in source category

SECTION VI. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]
The facility is a listed source as a fossil fuel-fired electric plant of more than 250 MMBTU heat input with emissions greater than 100 TPY. PSD review has been completed in Section IV.

NSPS, 40 CFR Part 60 [Subparts Dc and GG are Applicable]
Subpart Da, Electric Steam Generating Units. This subpart affects electric steam generating units with a design capacity greater than 250 MMBTUH constructed after September 18, 1978. The duct burners in the new HRSG are rated at 90 MMBTUH (LHV), and therefore are not subject to Subpart Da. Furthermore, since the turbines are subject to NSPS, Subpart GG, they would be exempt from this subpart as per § 60.40a(b).

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects electric steam generating units with a design capacity greater than 100 MMBTUH constructed after June 19, 1984. The duct burners in the new HRSG are rated at 90 MMBTUH (LHV), and therefore are not subject to Subpart Db. Furthermore, since the turbines are subject to NSPS, Subpart GG, they would be exempt from this subpart as per § 60.40b(i).

Subpart Dc, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects industrial-commercial-institutional steam generating units with a design capacity between 10 and 100 MMBTUH heat input and which commenced construction or modification after June 9, 1989. For gaseous-fueled units, the only applicable standard of Subpart Dc is a requirement to keep records of the fuels used. The duct burners in the new HRSG are rated at 90 MMBTUH (LHV). However, since the turbines are subject to NSPS, Subpart GG, the duct burners are exempt from this subpart as per § 60.40c(e). The 33 MMBTUH (LHV) gas-fired auxiliary boilers are affected units as defined in the subpart since the heating capacity is above the de minimis level. Recordkeeping will be specified in the permit.

Subpart GG, Stationary Gas Turbines. This subpart affects combustion turbines which commenced construction, reconstruction, or modification after October 3, 1977, and which have a heat input rating of 10 MMBTUH or more. Each of the new turbines has a rated heat input of greater than 10 MMBTUH and is subject to this subpart.

EPA guideline document EMTIC, GD-009 advises to use zero for the value of F with gas turbines. So, the lowest NO_X limit is 0.0075% or 75 ppmdv when Y = 14.4. The NO_X emission limitation for turbines EU 1-01 and 1-02 is 12 ppmdv at 15% O_2 and is therefore more stringent than the Subpart GG standards. Similarly, the NO_X emission limitation for proposed turbines EU 1-03 and 1-04 is 2 ppmdv at 15% O_2 and puts them at an even greater compliance margin compared to the Subpart GG standard. Performance testing by Reference Method 20 was required. Monitoring fuel for nitrogen content is not required if the owner or operator does not claim an allowance for fuel bound nitrogen per § 60.334(h)(2).

Sulfur dioxide standards specify that no fuel shall be used which exceeds 0.8% by weight sulfur or the exhaust gases shall not contain SO_2 in excess of 150 ppm. The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted if the gaseous fuel is demonstrated to meet the definition of "natural gas" using either the gas quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or using representative fuel sampling data. The maximum total sulfur content of "natural gas" is 20 grains/100 SCF (680 ppmw or 338 ppmv) or less.

Subpart IIII, Stationary Compression Ignition Internal Combustion Engines. This subpart affects stationary compression ignition (CI) internal combustion engines (ICE) based on power and displacement ratings, depending on date of construction, beginning with those constructed after July 11, 2005. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator. The existing backup diesel generator (EU 4-01) was manufactured prior to the applicability date of this subpart and is not subject to this subpart. However, the proposed backup diesel generator (EU 4-02) will likely have been manufactured after the April 1, 2006 date (for units procured after July 11, 2005). Therefore, the new unit will be subject to the requirements in Subpart IIII. It is expected that the unit will have a displacement of less than 30 liters and a heat input rating of 1,640.5 kW. According to the NSPS, this unit must meet the following emission limitations:

NSPS Emission Limits for Emergency Engines

NMHC + NO_X	CO	PM	Opacity		
g/kW-hr (lb/hr)	g/kW-hr (lb/hr)	g/kW-hr (lb/hr)	Acceleration	Lugging	Peak
6.4 (23.15)	3.5 (12.66)	0.2 (0.72)	20%	15%	50%

Similarly, the proposed emergency Fire-Water Pump (EU 5-02) will likely be subject to the emissions limitations found in Table 4 of Subpart IIII. Assuming a similar horsepower rating as the existing fire pump (EU 5-01 is 267 hp), the following limitations would apply:

NSPS Emission Limits for Fire Pump Engines[1]

NMHC + NO_X	CO	PM
g/hp-hr (lb/hr)	g/hp-hr (lb/hr)	g/hp-hr (lb/hr)
7.8 (4.59)	2.6 (1.53)	0.40 (0.24)

[1] – Based on 2008 & earlier emissions.

Subpart KKKK, Stationary Combustion Turbines. This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBTU) per hour, based on the higher heating value of the fuel, that commenced construction, modification, or reconstruction after February 18, 2005. The new stationary combustion turbines in this permit were constructed prior the applicability date of this subpart and therefore are not subject to this subpart.

NESHAP, 40 CFR Part 61 [Not Applicable]
There are no emissions of any of the regulated pollutants: arsenic, asbestos, benzene, beryllium, coke oven emissions, mercury, radionuclides, or vinyl chloride except for trace amounts of benzene. Subpart J, Equipment Leaks of Benzene, concerns only process streams that contain more than 10% benzene by weight. Analysis of Oklahoma natural gas indicates a maximum benzene content of less than 1%.

NESHAP, 40 CFR Part 63 [Subpart ZZZZ is Applicable]
Subpart YYYY, Stationary Combustion Turbines. This subpart was promulgated on March 5, 2004 and affects stationary combustion turbines that are located at major source of HAP. On August 18, 2004, the EPA stayed the effectiveness of two subcategories of this subpart: lean premix gas-fired turbines and diffusion flame gas-fired turbines pending the outcome of EPA's proposal to delete these subcategories from the source category list. This facility is a major source but the turbines located at this facility are in the lean pre-mix gas-fired turbine category and are expected to be deleted from the source category list.

Subpart ZZZZ, Reciprocating Internal Combustion Engines (RICE). This subpart affects RICE with a site-rating greater than 500 brake horsepower and which are located at a major source of HAP emissions. The subpart establishes emission and operating limitations for each affected source. This facility is a major source of HAPs. Existing emergency stationary RICE are exempt from this subchapter. The existing emergency generator at this facility is exempt from this subpart. The new emergency generator is subject to this subpart and must meet the requirements of this part by meeting the requirements of 40 CFR Part 60, Subpart IIII, for compression ignition engines.

Subpart DDDDD, Industrial Boilers and Process Heaters. Subpart DDDDD regulated HAP emissions from industrial boilers and process heaters. In March, 2007, the DC Circuit Court of Appeals filed a motion to vacate and remand this rule back to the agency. The rule was vacated by court order, subject to appeal, on June 8, 2007. No appeals were made and the rule was vacated on July 30, 2007. Existing and new small gaseous fuel boilers and process heaters (less than 10 MMBTUH heat rating) were not subject to any standards, recordkeeping, or notifications under Subpart DDDDD.

EPA is planning on issuing guidance (or a rule) on what actions applicants and permitting authorities should take regarding MACT determinations under either Section112(g) or Section 112(j) for sources that were affected sources under Subpart DDDDD and other vacated MACTs. It is expected that the guidance (or rule) will establish a new timeline for submission of section 112(j) applications for vacated MACT standards. Until such time as more guidance is received, AQD has determined that a 112(j) determination is not needed for sources potentially subject to a vacated MACT, including Subpart DDDDD. This permit may be reopened to address Section 112(j) when necessary.

CAM, 40 CFR Part 64 [Not Applicable]
Compliance Assurance Monitoring (CAM), as published in the Federal Register on October 22, 1997, applies to any pollutant specific emission unit at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

- It is subject to an emission limit or standard for an applicable regulated air pollutant
- It uses a control device to achieve compliance with the applicable emission limit or standard
- It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source levels.

The turbines use a control device to meet an applicable emission limit and have the potential to emit greater than major source levels. However, the turbines are subject to a continuous monitoring requirement and are exempt from this part per § 64.2(b)(vi).

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Not Applicable At This Time]
There will be no regulated substances used, stored or processed at the facility above threshold levels as a result of this project except possibly ammonia. If ammonia will be stored above the applicable threshold, the facility will need to comply with the requirements of this part by the date on which the regulated substance (ammonia) is present above the threshold quantity. More information on this federal program is available on the web page: *www.epa.gov/ceppo*.

Acid Rain, 40 CFR Part 72 (Permit Requirements) [Applicable]
This facility is an affected source since it will commence operation after November 15, 1990, and is not subject to any of the exemptions under 40 CFR 72.7, 72.8 or 72.14. Paragraph 72.30(b)(2)(ii) requires a new source to submit an application for an Acid Rain permit at least 24 months prior to the start of operations. However, Mr. Dwight Alpern, U.S. EPA, has confirmed that this requirement was for the benefit of the regulating agency (Oklahoma DEQ) which can waive this requirement and has done so. The applicant submitted a Phase II Acid rain permit application on June 2, 2008.

Acid Rain, 40 CFR Part 73 (SO_2 Requirements) [Applicable]
This part provides for allocation, tracking, holding, and transferring of SO_2 allowances.

Acid Rain, 40 CFR Part 75 (Monitoring Requirements) [Applicable]
The facility shall comply with the emission monitoring and reporting requirements of this Part.

Acid Rain, 40 CFR Part 76 (NO_X Requirements) [Not Applicable]
This part provides for NO_X limitations and reductions for coal-fired utility units only.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to

Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).

Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.

Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

Conditions are included in the standard conditions of the permit to address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; § 82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

The standard conditions of the permit address the requirements specified at § 82.156 for persons opening appliances for maintenance, service, repair, or disposal; § 82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; § 82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; § 82.166 for recordkeeping; § 82.158 for leak repair requirements; and § 82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

SECTION VII. COMPLIANCE

Tier Classification and Public Review of Modified Construction Permit

This application has been determined to be Tier II based on the request for a construction permit for an existing major stationary source. The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant has option to purchase the land.

The applicant published the "Notice of Filing a Tier II Application" and the "Notice of Tier II Draft Permit" in *The Daily Times* a daily newspaper in Mayes County on October 30, 2008. The "Notice of Filing a Tier II Application" stated that the application was available for public review at the Pryor Public Library located at 505 E Graham Ave., Pryor, Oklahoma and the Air Quality Division's main office at 707 North Robinson, Oklahoma City, Oklahoma. The "Notice of Tier II Draft Permit" stated that the draft permit was available for public review at the Pryor Public Library located at 505 E Graham Ave., Pryor, Oklahoma, the Air Quality Division's main office at 707 North Robinson, Oklahoma City, Oklahoma, and on the Air Quality section of the DEQ Web Page: http://www.deq.state.ok.us/. No comments were received from the public.

This site is within 50 miles of the Oklahoma – Arkansas and Oklahoma – Missouri borders. The states of Arkansas and Missouri were notified of the draft permit. No comments were received from the states of Arkansas or Missouri.

This permit was approved for concurrent public and EPA review. The draft permit was forwarded to EPA for a 45-day review period. Since there were no comments received from the public the draft permit was deemed the proposed permit. The EPA submitted comments concerning the proposed permit in a letter dated December 8, 2009. Listed below are the comments from the EPA from the December 8, 2009 letter, responses from the applicant (AECI), and the final determination made by the AQD.

EPA's 1st Comment:

> "COMMENT 1: In the Preliminary Determination Summary, the State, in its analysis did not provide a detailed administrative record documenting appropriate best available control technology (BACT) determinations for the new emissions of nitrogen oxide (NO_X), particulate matter nominally 10 microns and less (PM_{10}), and carbon monoxide (CO). In particular, there is no comparison of emission rates/control units with other similar types of operations nationwide. Please provide the State's rationale for the BACT determinations and your analysis of federal /state /1ocal NSR permits, including an analysis of the technical and economic feasibility of available control technologies."

Response from the Applicant:

> "In the original permit application and in the draft permit, a number of control technologies were considered and determinations were made on either a technical or economic basis. Although a comparison to specific facilities was not included, the technologies selected in the BACT determinations for NO_X, CO, and PM_{10} are consistent with other RBLC entries for combined cycle turbines. EPA's comments make clear that they do not consider the emission levels proposed as BACT to be sufficiently stringent. As discussed in the responses below [to the remaining comments], the proposed emission limits represent the lowest emission rates the turbine manufacturer indicated these turbines could reasonably be expected to achieve. Further, it should be noted that the proposed units are of a similar vintage to the existing units constructed nearly ten (10) years ago.

Despite the presence of RBLC entries indicating lower emission rates, AECI is not comfortable with reducing the proposed emission limits considering that the permit limits are enforceable for the life of the plant. AECI believes the permit limits are firmly within the RBLC range."

AQD's Final Determination:
The permit memorandum does contain a detailed analysis of BACT for NO_X, PM_{10}, and CO including an analysis of the technical and economic feasibility of available control technologies and also compares the originally established BACT levels to those established nationwide. However, after further review the BACT determinations have been revised based on the remaining comments from EPA.

EPA's 2nd Comment:

"COMMENT 2: In the permit Special Condition No. 1, the proposed BACT used to control the emissions of NO_X from the new gas-fired combined cycle establishes an emission rate of 3 ppmvd at 15% O_2 annual average. A recent final permitting action by the State of Arizona for the Gila Bend Power Generation Station, RBLC ID: AZ-0038 regarding a similar size natural gas turbine specified 2 ppmvd at 15% O_2 1-hr average. In addition, there are similar rates for other facilities in the Clearinghouse database with lower then 3.0 ppmvd limits on 1-hr average. Furthermore, the Texas Commission on Environmental Quality (TCEQ) has recently changed its BACT guidance for natural gas combustion turbines in combined cycle mode to be 2 ppmvd at 15% oxygen for NO_X, on a 24-hour average basis. A search of recent TCEQ air permits that have been issued for natural gas turbines as well as the EPA's RBLC revealed that in several permits, BACT for NO_X was the use of DLN combustors in combination with SCR. Please provide the State's rationale for why, after analyzing the technical and economic feasibility of available control technologies, a 2 ppmvd at 15% O_2 1-hr average NO_X limit cannot be achieved by this facility."

Response from the Applicant:

Initial Response

"While preparing the permit application, a review of RBLC search results and current TCEQ BACT determinations did indicate instances of new combined-cycle turbines operating at NO_X emission rates less than the proposed 3 ppmvd @ 15% O2. For several reasons, the Chouteau turbines cannot achieve a lower emission rate:

- The turbines at the Chouteau plant, while new to the facility, are not newly manufactured units. The proposed Siemens V84.3A units are of late-1990s vintage/manufacture. While combined cycle turbines have achieved lower emission rates in the intervening ten (10) years through improved DLN burner efficiency and improvements in catalyst technology, the age of these units precludes them from meeting the BACT requirements established in recent years. The proposed emission level will require AECI to operate sufficiently

below 3 ppmvd NO_X to comply with the rolling average limitation. We believe the proposed limitation is at the point of testing the technological limits of the equipment and a more aggressive use of the SCR system would certainly increase the likelihood of creating higher levels of ammonia slip.

- The majority of the RBLC entries that commit to a 2 ppmvd NO_X limit also contain ammonia permit limits of 10 ppm, including the permit commented upon by the EPA, Gila Bend Power Generating Station (AZ-0038). As discussed in Comment 5, several of the most recent permits (such as the CPV Warren Plant, RBLC ID VA-0304, Permit Date 6/5/2007). AECI is already proposing a 10 ppm ammonia slip limit; based upon technical assessments provided by the turbine manufacturer, we do not believe further NO_X reductions can be achieved without operating the SCR system more aggressively (i.e. with greater levels of ammonia injection).

AECI believes that a twelve-month rolling average is sufficiently protective given that the NAAQS specifies an annual standard for NO_X. Even so, AECI is agreeable to a thirty (30) day rolling average to address the agency's concern."

<u>Letter dated December 30, 2008, addressing AQD letter to AECI concerning NO_X limit</u>:
"The NO_X emission rate in question (i.e. 3.0 PPM corrected to 15% O_2; as listed in Table 5-4 of the BACT analysis) was developed to represent a federally enforceable BACT permit limit over the life of the plant. Therefore, as allowed by the NSR Manual and upheld by the Environmental Appeals Board, the BACT emission rates should include an operating margin to allow a reasonable chance of achieving compliance on a consistent basis[1]. The information provided here is intended to address your request and to further support the NO_X limit as presented in the BACT and in the draft permit.

<u>Setting the PPM Limit for NO_X</u>
The main emission sources of the proposed 2-on-1 combined-cycle plant are the V84.3A combustion turbines with duct burners. You are correct in citing the new nomenclature as SCC6-4000F. The proposed units were constructed in the late 90s and it is our understanding that this model is no longer actively sold in the 60 Hz market. The proposed units are subject to the New Source Performance Standards found at 40 CFR Part 60 Subpart GG and are sited in Mayes County. Mayes County is an attainment/non-classified area for ozone.

These units, along with most other major components of the plant were originally purchased for installation in the state of Arizona. The project was eventually dropped by the original owner and the equipment became available for purchase on the secondary market. Attachment 1 to this submittal is from the equipment guarantee to the original owner. Please note that the NO_X guarantee is for 2.5 PPM @ 15% O_2 and for "new and clean" equipment.

Associated has been advised that an additional row of catalyst would be required to continuously achieve an emission rate in compliance with the suggested limit of 2.0 PPM NO_X @ 15% O_2. We are working on the incremental cost adder on a dollars-per-ton basis to determine the financial impact of controlling to the lower limit. At a minimum, the relevant cost factors will include a) the need for increased catalyst surface area, b) power loss due to increased back-pressure on the system, c) the increased cost of adding more ammonia, and d) the cost of purchasing replacement power due to the increase in unit heat rate.

While the financial impact is important to AECI and our member-owners, of notable consequence is the increase in emissions that would result from adding another obstruction (i.e. catalyst) to the effluent gas stream. The additional row of catalyst will increase the back-pressure to the system and force the system operator to burn more fuel to achieve the same electrical output from the generator. The increase in heat rate will result in an increase of all emissions on a lb/MWh basis as well as forcing AECI to generate or purchase electricity from a higher emitting source. AECI owns 38% of GRDA Unit 2 located upwind approximately 2.4 (linear miles) from the Chouteau facility. It is quite possible that the lost megawatts from the Chouteau facility would be replaced with energy dispatched from GRDA Unit 2. The average emission rate for GRDA unit 2 during all of 2007 was 154 PPM NO_X - or, about 7,700% higher than the suggested permit limit of 2.0 PPM for the Chouteau project. Associated is working to obtain the information regarding the heat rate penalty as expeditiously as possible.

In your letter you also mention the limitations of monitoring NO_X at these low levels. To this point, we believe that there are two factors that may introduce error into the CEM readings. These factors have less impact where the instruments are spanned at much higher levels, but at lower spans may interject a significant degree of uncertainty. The NO_X CEMS at Chouteau would be monitored per instrumental test Method 7E as described in 40 CFR Part 60 Appendix A-4. The method indicates process sensitivity as high as 2% of the instrument span. Where facilities must monitor very low levels of stack pollutants, the instrumentation department prefers to set the span as high as possible. To meet the annual requirement to monitor more than 50% of hourly emissions at or above 20% of instrument span (and less than 80% of span), we would expect to set the upper limit of the analyzer to 9 ppm for a limit of 2 or 3 ppm NO_X. Therefore, the implied error of the method could be as high as 0.18 PPM for a span set at 9 PPM. This would be almost 10% of the permit limit were it set at 2 PPM.

Similarly, Appendix A of 40 CFR Part 75 at 5.1.4(b) stipulates that EPA protocol reference gases must have a producer-certified uncertainty of no more that 2.0 percent of the certified concentration. Again, the implied error is 0.18 PPM if the high span gas is set at 9 PPM. The cumulative uncertainty due to allowed measurement error (i.e. Method 7E and EPA Protocol reference gases) would be 0.36 PPM - nearly 20%

of a permit limit at 2 PPM and almost twice the measurement error if one were to assume a permit limit of 3 PPM.

Averaging Time

To begin addressing the concern regarding the averaging period of the NO_X limit, AECI identified the Blythe facility located in the Mohave Desert Air Quality Maintenance District (MDAQMD) in California[2]. The Blythe facility is nearly identical to the proposed project at Chouteau. The facility was permitted at 2.5 PPM NO_X (corrected to 15% O2) on a three (3)-hour average basis. To evaluate the performance of the unit with respect to permit limit, we downloaded the most recent quarterly CEM report from the EPA web site at http://camddataandmaps.epa.gov/gdm/ and corrected the hourly NO_X emissions to 15% O_2. We then compared the hourly data to the permit limit of 2.5 PPM and the suggested and draft limits of 2.0 and 3.0 PPM, respectively. The results are listed in the table below:

Table 1 – Blythe Units 1 and 2 (Blythe, CA)

Blythe Unit	Permit Limit (NO_X PPM[1])	Hours of Valid QA NO_X Data	Hours > Permit Limit	Hours > 2 PPM[1]	Hours > 3 PPM[1]
1	2.5	1,301	102	1,287	43
2	2.5	1,194	80	1,193	46

[1] Corrected to 15% O_2 on a 1-hour basis.

While one might argue that the facility was only concerned with meeting the limit of 2.5 PPM on a 3-hour basis, we believe that the data is still instructive. Considering the comparison of emissions data to the higher limit of 2.5 PPM, it is apparent that the facility struggled to meet the limit on a continuous basis. It is also instructive to note the magnitude of many of these hours where unit emissions are >2.5 PPM. This information is included electronically with this transmittal.

It is the goal of AECI to comply with the permit conditions one-hundred percent of the time. We do not believe it is wise to create a situation where the ODEQ Enforcement Section is faced with continuously applying enforcement discretion toward a facility that is not capable of continuously achieving a federally enforceable permit limit.

Summary

Associated is providing this initial transmittal to respond to the Notice of Deficiency dated December 23, 2008. As indicated above, AECI is investigating the financial and environmental impacts of further reducing NO_X emissions to 2.0 PPM @ 15% O_2. We maintain that the limit of 3.0 PPM @ 15% O2 as presented in the draft permit is already at the threshold at which the facility can comply on a continuous basis. Further, AECI believes that the draft permit limit is sufficiently protective of the NAAQS and is not a major consumer of increment. At this time, we would like to request that the ODEQ AQD advise AECI of further data collection (i.e. similar to the Blythe analysis or other such efforts) that would be useful for your determination."

AQD's Final Determination:
Even though the specific facility that is referenced in the EPA comment was not built and is not operating, there are other facilities in the RBLC database that do have a NO_X emission limit of 2.0 ppmdv @ 15% O_2, 1-hr average which are operating. After review of all the data submitted, there is not enough data to indicate that the NO_X emission limit of 2.0 ppmdv @ 15% O_2, 1-hr average is not technically or economically infeasible. The BACT analyses submitted by the applicant indicate that the overall cost effectiveness of controlling NOX emission to 2 ppmdv with the use of an additional row of catalyst is approximately $2,000/ton. Therefore, the permit has established 2.0 ppmdv @ 15% O_2, 1-hr average as the BACT emission limit for this facility.

EPA's 3rd Comment:

> "COMMENT 3: In the permit Special Condition No.1, the proposed BACT used to control the emissions of CO from the new gas-fired combined cycle establishes an emission rate of 10 ppmvd at 15% O_2 annual average. A recent final permitting action by the State of Arizona for the Gila Bend Power Generation Station, RBLC ID: AZ-0038 regarding a similar size natural gas turbine specified 4 ppmvd at 15% O_2, 3-hr average. In addition, there are similar rates for other facilities in the Clearinghouse database with lower then 4.0 ppmvd limits on 3-hr average. Please provide the State's rationale for why, after analyzing the technical and economic feasibility of available control technologies, a 4 ppmvd at 15% O_2 1-hr average CO limit cannot be achieved by this facility."

Response from the Applicant:

> As presented in the attached economic analysis, Catalytic Oxidation is considered economically infeasible. Although other facilities have committed to 4 ppmvd CO limits based upon good combustion practices as BACT, discussions with the turbine manufacturer indicated that CO emission levels lower than 10 ppm cannot be guaranteed for the entire operating range. Based on stack testing from similar combustion turbines in AECI's generation fleet, we believe that we can achieve a CO emission limit of 5 ppmvd at 75% of the load range and above. Below 75% load, CO emissions may be expected to climb as the burner flame is more dependent upon the more stable (but less efficient) pilot flame and less dependent upon the lower emitting pre-mix flame.
>
> The new combustion turbine NSPS at 40 CFR 60 Subpart KKKK (note: these older units are subject to Subpart GG) appropriately recognizes that the emissions profile of such units can be considerably different at lower loads. For natural gas fired combustion turbines > 850 MMBTUH, the NSPS at Subpart KKKK assigns an emission rate (maximum) of 15 ppm NO_X for loads > 75% of peak load. At loads less than 75%, the turbine may emit up to 96 ppm NO_X. This amounts to a difference of 640% percent from one load range to the other for a pollutant with a much tighter ambient standard than CO.

Historically, AECI's combined cycle gas plants have operated between the morning-evening peak cycle. However, this is changing with the inclusion of wind generation on the AECI system. Because of the unpredictable nature of wind generation and to maintain a stable supply of electricity on the grid, AECI must "chase" the output from the wind farms with output from prompt-response resources. For AECI, this means regulating output from our gas fleet to stabilize the impact of the wind farms on the distribution system. This may be accomplished with either simple or combined-cycle units and must be addressed around the clock. The combined-cycle units at the Chouteau facility are a better option than peaking units for chasing wind generation. This is true both environmentally and economically.

Environmentally Preferred:
With the combined-cycle units at the Chouteau plant, AECI can reduce consumption of fuel by backing down the combustion turbine output while still maintaining operation of the steam turbine. This is not possible with a simple-cycle gas turbine EGU. At a combined-cycle plant, the heat recovery steam generating (HRSG) units greatly increase the efficiency of the plant. This means that the facility can put out more electricity per unit of pollutant. This is true because the steam turbine operates from the waste-heat captured at the HRSGs and can generate electricity without emitting pollutants. Further, because the combined cycle unit has a selective catalytic reduction (SCR) system to control NO_X emissions, these units can operate at a lower lb/MWh than can a simple-cycle gas turbine peaking unit that does not have SCR.

In addition, it is better (for the environment) to reduce the fuel consumption on a unit that is operating at maximum efficiency (e.g. a combined-cycle unit at base load) than to start up a cold peaking unit that will create its highest emissions during startup.

Economically Preferred:
By balancing the system output from the wind farms with a combined-cycle plant vs. a less efficient peaking plant, AECI should realize a lower $/MWh charge that will help keep rates as low as possible for our member-owners. A 2007 survey of AECI's member systems revealed 46 percent of respondents live in households earning annual gross incomes of $40,000 or less, and 32 percent are age 65 or older. About 17 percent live in households earning $20,000 or less. The survey also revealed 43 percent of members earning $40,000 or less pay on average more than $100 per month for electricity alone.

Summary:
Low load operations will be relatively infrequent and will typically occur only between the evening-morning peak (e.g. between 10PM and 8AM) and to avoid elevated startup/shutdown emissions and equipment startup penalties (e.g. from the effects of metal fatigue over time, lower efficiency at ramp-up, etc.) from brief unit shutdowns when the generation is not needed. In addition, lower load operations may occur as system dispatchers work to counteract the effect of wind generation and stabilize the grid.

> AECI proposes to limit emissions of CO from the proposed units to 5 ppm at loads ≥ 75%. At loads < 75%, CO emissions would be allowed without condition except where operation is limited by the startup and shutdown conditions found at Specific Condition 1.d and 1.e. Low load operations shall not be less than 40% of the rated unit load of the combustion turbine in question. Alternatively, AECI proposes to maintain the limit of 10 ppm CO as written in the draft permit."

AQD's Final Determination:
Again, the specific facility that is referenced in the EPA comment was not built and is not operating. However, there are other facilities in the RBLC database that do have lower CO emission limits which are operating but these facilities are permitted with the requirement for oxidation catalyst. Based on the information submitted by the applicant, it was determined that installation of an oxidation catalyst is considered economically infeasible for this particular facility at approximately $9,000/ton. The applicant submitted data from the turbine manufacturer guaranteeing an emission rate of 8 ppmdv @ 15% O_2. Therefore, after taking into account the EPA's comments and responses from the applicant AQD has established the CO emission limit at 8 ppmdv @ 15% O_2, 3-hr average.

EPA's 4th Comment:

> "COMMENT 4: The EPA is concerned that no short term emission limits based on 3-hr or 24-hr averaging periods for VOC and PM_{10} have been included in the draft permit. The EPA believes that short-term limits are necessary to ensure protection of the NAAQS and to adequately assess and protect increment consumption. A recent final permitting action by the State of Arizona for the Gila Bend Power Generation Station, RBLC ID: AZ-0038 regarding a similar size natural gas turbine specified 4 ppmvd at 15% O_2 3-hr average for VOC and 0.011 lb/mmBtu 3-hr average. Please provide the State's rationale for why, short term limits are not achievable for VOC and PM_{10}."

Response from the Applicant:
AECI is willing to establish PM_{10} and VOC emission limits on a three (3) hour average basis. The averaging times for the test methods (i.e. methods 5, 17, or 201 and 202 for PM_{10} and method 25 for VOC) are on a three (3) hour basis (i.e. three one (1) hour runs equals one test). Compliance with the applicable test method and a result equal to or less than the permit limit will equate to compliance with the emission limit in the permit.

AQD's Final Determination:
Based on EPA's comment and response from the applicant the PM_{10} and VOC emission limits were based on a 3-hr average.

EPA's 5th Comment:

"COMMENT 5: ODEQ should consider permit conditions to reduce the ammonia slip from the SCR used by the facility to control NO_X. According to the RBLC database, some recently approved combined cycle projects with NO_X limits of 2.0 ppm also included Ammonia (NH_3) limits of 5 ppm in those determinations to address ammonia slip. However, such limits are not necessarily required by the PSD regulations. With the use of the SCR, the facility may consider adding an enhancer to the ammonia, in its pure form, which tends to reduce the ammonia slip and utilizes ammonia better than other processes. Another process would be to mix the ammonia with urea or with urea and water. In either case, the urea would act as a catalyst, and the mixture would tend to be more effective than its components alone.

In addition, the "Technical Support Document for the Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule): Reconsideration Notice of Proposed Rule," December 2005, states that recent SCR technology developments have emphasized minimization of ammonia slip, along with SO_2-to-SO_3 conversion levels. The new SCR installations are routinely being designed to maintain ammonia slip at a 2 to 3 ppmv level (see 7 referenced documents within the TSD for further information on the related technology)."

Response from the Applicant:

"As discussed in the notes to Comment 2, the Chouteau units are not newly manufactured turbines. Maintaining low NO_X concentrations potentially requires very aggressive use of ammonia in the SCR system, as in the case of the Chouteau turbines. Most combined-cycle turbines that commit to 2-3 ppmvd NO_X emission levels by necessity require relatively high limits for ammonia slip (5-10 ppm). Although newer SCR designs are optimized to reduce ammonia slip, it is only the most recent entries that contain very low limits on both NO_X and Ammonia. Older projects (pre-2005) that commit to 2-3 ppmvd NO_X and 5 ppm Ammonia slip were either not constructed, or are located in California (and are more reflective of LAER and not BACT). Based upon the assessment of the manufacturer, 10 ppm Ammonia slip is the lowest level attainable while maintaining 3 ppmvd NO_X. Given the age of the turbines, this ammonia level should be considered the best achievable emission rate."

AQD's Final Determination:

While ammonia is not regulated by PSD, it could be regulated by state BACT if the emissions exceeded 100 TPY but they are less than 100 TPY. There is no documentation that indicates that use of urea with anhydrous ammonia would act as a catalyst and increase the reduction efficiency of anhydrous ammonia. The seven reference documents referenced by EPA are not accessible through the EPA web site and are generally related to SCR where control of NO_X is not as stringent as the limits established by the current permit. Based on the applicant's comments and other available data the ammonia emission limits listed in the proposed permit have not been changed.

Fees Paid
Construction permit application fee of $2,000.

SECTION VIII. SUMMARY

The applicant has demonstrated the ability to comply with the requirements of the applicable Air Quality rules and regulations. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance and enforcement issues concerning this facility. Issuance of the permit is recommended.

PERMIT TO CONSTRUCT
AIR POLLUTION CONTROL FACILITY
SPECIFIC CONDITIONS

Associated Electric Cooperative, Inc.
Chouteau Power Plant **Permit No. 2007-115-C (M-1) PSD**

The permittee is authorized to construct in conformity with the specifications submitted to Air Quality on July 1, 2008 and all supplemental materials. The Evaluation Memorandum dated January 20, 2009, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating permit limitations or permit requirements. Commencing construction or operations under this permit constitutes acceptance of, and consent to, the conditions contained herein:

1. Points of emissions and emissions limitations for each point: [OAC 252:100-8-6(a)]

EUG 1. Electric Generating Units.

Emission limits and standards for Emission Units (EUs) 1-01 and 1-02 (Turbines with Duct Burners); The emission limits for each EU include but are not limited to the following:

Pollutant	lb/hr	TPY[3]	ppmvd[1]	lb/MMBTU[5]
NO_X	86.70[2]	379.75	12[3]	0.20[2]
CO	59.00	258.42	10	
VOC	4.99	21.87		
SO_2	1.00	4.38		
PM_{10}	6.24	27.33		0.0035
Ammonia	18.14[4]	79.46		
H_2SO_4	0.15[4]	0.61		

[1] All concentrations are corrected to 15% O_2, per turbine.
[2] Three-hour rolling average, based on contiguous operating hours.
[3] Twelve-month rolling total.
[4] 24-hour average.
[5] Based on HHV.

Emission limits and standards for EU 1-03 and 1-04 (Turbines with Duct Burners); The emissions limits for each EU include but are not limited to the following:

Pollutant	lb/hr	TPY[3]	ppmvd[1]	lb/MMBTU[5]
NO_X	15.25[2]	125.45	2.0[2]	0.20[4]
CO	51.32[3]	385.43	8.0	
VOC	5.27[3]	23.08		
SO_2	1.06[3]	4.62		
PM_{10}	6.59[3]	28.86		0.0035[6]
Ammonia	18.14[4]	79.46		
H_2SO_4	0.15[4]	0.61		

[1] All concentrations are corrected to 15% O_2, per turbine.
[2] One-hour average.
[3] Three-hour average.
[4] Three-hour rolling average, based on contiguous operating hours.
[6] 24-hour average.
[7] Based on HHV.

a. The turbines shall only be fired with natural gas as defined in New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart GG having 20.0 grains or less of total sulfur per 100 standard cubic feet. Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

b. The turbines shall be equipped with dry low-NO_X burners. [OAC 252:100-8-34]

c. Emissions from each turbine and duct burner shall be controlled by a properly operated and maintained SCR. [OAC 252:100-8-34]

d. During startups and shutdowns, alternate short term emission limits apply to the combustion turbines. The short term emission limits for each combustion turbine during startup and shutdown are shown below:

Event	Maximum Duration (hr)	NO_X Emissions (lbs/event)	CO Emissions (lbs/event)
Startup	4	568	1,596
Shutdown	1	142	399

e. To demonstrate compliance with the startup and shutdown emission limits for NO_X, the permittee shall calculate the total emissions during the event and compare it to the table above. Startup ends when the turbine reaches normal operating mode and the SCR is operational. Compliance with the CO emission limits shall be based on the duration of the event and compliance with the NO_X emission limit. The existing units shall have ninety (90) days from the issuance of this permit to comply with this condition. [OAC 252:100-8-6(a)(1)]

f. Turbines 1-01, 1-02, 1-03, and 1-04 are subject to the NSPS for Stationary Gas Turbines, 40 CFR Part 60, Subpart GG, and shall comply with all applicable requirements. [40 CFR § 60.330 to § 60.335]
   i. § 60.332: Standard for nitrogen oxides
   ii. § 60.333: Standard for sulfur dioxide
   iii. § 60.334: Monitoring of operations
   iv. § 60.335: Test methods and procedures
   v. Monitoring of the fuel sulfur content is not required if the permittee can demonstrate that the gaseous fuel meets the definition of "natural gas" with a maximum total sulfur content of less than 20 grains/100 SCF (680 ppmw or 338 ppmv) or less using either a current valid purchase contract, tariff sheet, or transportation contract or representative fuel sampling. Monitoring of fuel nitrogen content under NSPS, 40 CFR Part 60, Subpart GG shall not be required unless the permittee claims an allowance for fuel bound nitrogen.

EUG 2. Auxiliary Boilers. Emission limits and standards for EU 2-01 and 2-02 include but are not limited to the following:

	NO_X		CO		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
2-01	2.36	10.34	5.02	21.99	0.54	2.37
2-02	2.36	10.34	5.02	21.99	0.54	2.37

a. The Auxiliary Boilers shall be equipped with low-NO_X burners. [OAC 252:100-8-34]
b. The Auxiliary Boilers shall only be fired with natural gas as defined in NSPS, 40 CFR Part 60, Subpart GG having 20.0 grains or less of total sulfur per 100 standard cubic feet. Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]
c. The permittee shall maintain a record of the amount of natural gas burned in the Auxiliary Boilers for compliance with NSPS, 40 CFR Part 60, Subpart Dc. [40 CFR § 60.48c(g) & § 60.13(i)]

EUG 3. Fuel Gas Water Bath Heaters. Emission limits and standards for EU 3-01 and 3-02 include but are not limited to the following:

	NO_X		CO	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**
3-01	2.70	11.83	0.39	1.71
3-02	2.70	11.83	0.39	1.71

a. The Fuel Gas Water Bath Heaters shall only be fired with natural gas as defined in NSPS, 40 CFR Part 60, Subpart GG having 20.0 grains or less of total sulfur per 100 standard cubic feet. Compliance can be shown by the following methods: for gaseous fuel, a current gas company bill, lab analysis, stain-tube analysis, gas contract, tariff sheet, or other approved methods. Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

b. The permittee shall maintain a record of the amount of natural gas burned in the Fuel Gas Water Bath Heaters for compliance with NSPS, 40 CFR Part 60, Subpart Dc. [40 CFR § 60.48c(g) & § 60.13(i)]

EUG 4A. Backup Diesel Generator. Emission limits and standards for EU 4-01 include but are not limited to the following:

	NO_X		CO	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**
4-01	52.80	13.20	12.10	3.03

a. EU 4-01 the Backup Diesel Generator shall not operate more than 500 hours per in any 12-month period. [OAC 252:100-8-6(a)(1)]

b. EU 4-01 the Backup Diesel Generators shall each be fitted with a non-resettable hour-meter. [OAC 252:100-8-6(a)(3)]

c. EU 4-01 the Backup Diesel Generators shall only be fired with fuel oil with a maximum sulfur content of 0.05% S by weight. Compliance can be shown by the following methods: for fuel oil, supplier's latest delivery ticket(s). Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

d. Replacement (including temporary periods of 6 months or less for maintenance purposes), of the internal combustion engine associated with the Backup Diesel Generator with an engine of lesser or equal emissions of each pollutant (in lbs/hr and TPY) are authorized under the following conditions:

   i. The permittee shall notify AQD in writing not later than 7 days in advance of the start-up of the replacement engine. Said notice shall identify the equipment removed and shall include the new engine make, model, and horsepower; date of the change, fuel usage, stack flow (ACFM), stack temperature (^oF), stack height (feet), stack diameter (inches), and pollutant emission rates (g/hp-hr, lbs/hr, and TPY) at maximum rated horsepower for the altitude/location and any change in emissions.

   ii. Replacement equipment and emissions are limited to equipment and emissions which do not subject the engine/turbine to an applicable requirement not already included in this permit.

   iii. The permittee shall calculate the net emissions increase resulting from the replacement to document that it does not exceed significance levels and submit the results with the notice required by Specific Condition 1, EUG 4A, (d). [OAC 252:100-8-6 (f)]

EUG 4B. Backup Diesel Generator Subject to NSPS, Subpart IIII. Emission limits and standards for EU 4-02 include but are not limited to the following:

EU	NO_X		CO		PM_{10}	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
4-02	23.15	5.79	12.66	3.16	0.72	0.18

a. EU 4-02 the Backup Diesel Generator is subject to the federal NSPS for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE), 40 CFR Part 60, Subpart IIII, and shall comply with all applicable requirements:

[40 CFR § 60.4200 - § 60.4219]

What This Subpart Covers

i. 60.4200 Am I subject to this subpart?

Emission Standards for Owners and Operators

ii. 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

iii. 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

iv. 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Fuel Requirements for Owners and Operators

v. 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

Other Requirements for Owners and Operators

vi. 60.4208 What is the deadline for importing and installing stationary CI ICE produced in the previous model year?

vii. 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

Compliance Requirements

viii. 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

Testing Requirements for Owners and Operators

ix. 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Notification, Reports, and Records for Owners and Operators

x. 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

General Provisions

xi. 60.4218 What parts of the General Provisions apply to me?

Definitions

xii. 60.4219 What definitions apply to this subpart?

b. EU 4-02 the Backup Diesel Generator shall not operate more than 500 hours per in any 12-month period. [OAC 252:100-8-6(a)(1)]

c. The Backup Diesel Generators shall each be fitted with a non-resettable hour-meter. [OAC 252:100-8-6(a)(3)]

EUG 5A. Emergency Fire Water Pump (Diesel). EU 5-01 is considered an insignificant activity and is limited to the following:

EU	Make/Model	Hp
5-01	Caterpillar/3306- A552598	267

a. EU 5-01 the Emergency Fire Water Pump shall not operate more than 500 hours in any 12-month period. [OAC 252:100-8-6(a)(1)]

b. EU 5-01 the Emergency Fire Water Pump shall be fitted with a non-resettable hour-meter. [OAC 252:100-8-6(a)(3)]

c. The Emergency Fire Water Pump shall only be fired with a fuel oil with a maximum sulfur content of 0.05% S by weight. Compliance can be shown by the following methods: for fuel oil, supplier's latest delivery ticket(s). Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

EUG 5B. Emergency Fire Water Pump (Diesel) Subject to NSPS, Subpart IIII. Emission limits and standards for EU 5-02 include but are not limited to the following:

EU	Make/Model	Hp
5-02	To Be Determined	267

a. EU 5-02 the Emergency Fire Water Pump is subject to the NSPS for Stationary CI-ICE, 40 CFR Part 60, Subpart IIII, and shall comply with all applicable requirements: [40 CFR § 60.4200 - § 60.4219]

What This Subpart Covers

i. 60.4200 Am I subject to this subpart?

Emission Standards for Owners and Operators

ii. 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

iii. 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

iv. 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Fuel Requirements for Owners and Operators

v. 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

Other Requirements for Owners and Operators

vi. 60.4208 What is the deadline for importing and installing stationary CI ICE produced in the previous model year?

vii. 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

Compliance Requirements

viii. 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

Testing Requirements for Owners and Operators

ix. 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Notification, Reports, and Records for Owners and Operators

x. 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

General Provisions

xi. 60.4218 What parts of the General Provisions apply to me?

Definitions

xii. 60.4219 What definitions apply to this subpart?

b. The Emergency Fire Water Pump shall not operate more than 500 hours in any 12-month period. [OAC 252:100-8-6(a)(1)]

c. The Emergency Fire Water Pump shall be fitted with a non-resettable hour-meter. [OAC 252:100-8-6(a)(3)]

d. The Emergency Fire Water Pump shall only be fired with a fuel oil with a maximum sulfur content of 0.05% S by weight. Compliance can be shown by the following methods: for fuel oil, supplier's latest delivery ticket(s). Compliance shall be demonstrated at least once annually. [OAC 252:100-31 & 8-34]

EUG 6. Cooling Towers. EU 6-01 and 6-02 are considered insignificant activities and are limited to the following standards:

EU	Make/Model	No. of Towers
6-01	Psychometrics, Inc	9
6-02	To be determined	9

a. The Cooling Towers shall be equipped with drift eliminators. [OAC 252:100-8-34]

2. Upon issuance of an operating permit, the permittee shall be authorized to operate the turbines, auxiliary boiler, and fuel gas water bath heater continuously (24 hours per day, every day of the year). [OAC 252:100-8-6]

3. The turbines, Auxiliary Boiler, Fuel Gas Water Bath Heater, Backup Diesel Generator, and Emergency Fire Water Pump shall have a permanent (non-removable) identification plate attached which shows the make, model number, and serial number. [OAC 252:100-43]

4. The permittee shall comply with all acid rain control permitting requirements and SO_2 emissions allowances and SO_2, NO_X, and O_2 continuous emissions monitoring and reporting. SO_2 emissions shall be monitored in accord with Part 75, Appendix D.

5. When monitoring shows concentrations or emissions in excess of the limits of Specific Condition No. 1, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions including during start-up, shutdown, and malfunction of air pollution control equipment. Due to technological limitations on emissions during turbine start-up and shutdown, the owner or operator may submit an initial written notification of this condition and thereafter immediate notice and quarterly reports as provided in Paragraph 3.1(b)(2). Requirements for periods of other excess emissions include prompt notification to Air Quality and prompt commencement of repairs to correct the condition of excess emissions. [OAC 252:100-9]

6. The following records shall be maintained on-site to verify Insignificant Activities. No recordkeeping is required for those operations that qualify as Trivial Activities.
[OAC 252:100-8-6 (a)(3)(B)]

a. For stationary reciprocating engines burning natural gas, gasoline, aircraft fuels, or distillate fuel oil which are used exclusively for emergency power generation: records of hours of operation, size of engines, and type of fuel.
b. For fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia: records of capacity of the tanks and contents.
c. For activities that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions from that activity (annual).

7. The permittee shall maintain records of operations as listed below. These records shall be maintained on-site or at a local field office for at least five years after the date of recording and shall be provided to regulatory personnel upon request. [OAC 252:100-8-6 (a)(3)(B)]

a. Total fuel consumption for each turbine, the Auxiliary Boilers and the Fuel Gas Water Bath Heaters (monthly and 12-month rolling totals).
b. Operating hours for the Backup Diesel Generators and Emergency Fire Water Pumps (monthly and 12-month rolling totals).
c. For fuel(s) burned, the appropriate document(s) as described in Specific Condition No. 1.
d. Diesel fuel consumption for the Backup Diesel Generators and Emergency Fire Water Pumps (12-month rolling totals).
e. CEMS data required by the Acid Rain program.
f. Records required by NSPS, Subparts Dc and GG.

8. No later than 30 days after each anniversary date of the issuance of the original Title V operating permit (December 6, 2002), the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit. [OAC 252:100-8-6 (c)(5)(A) & (D)]

9. Within 60 days of achieving maximum power output from each new turbine generator set (1-03 and 1-04), not to exceed 180 days from initial start-up, and at other such times as directed by Air Quality, the permittee shall conduct performance testing as follows and furnish a written report to Air Quality. Such report shall document compliance with Subpart GG for the combustion turbines and Subpart Dc for the auxiliary boiler. [OAC 252:100-8-6(a)]

10. The permittee shall conduct NO_X, CO, PM_{10}, and VOC testing on the new turbines (1-03 and 1-04) at the 60% and 100% operating rates, with testing at the 100% turbine load to include testing at both a 70% and 100% duct burner operating rate. NO_X and CO testing shall also be conducted on the turbines at two additional intermediate points in the operating range, pursuant to 40 CFR §60.335(c)(2). Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(d).

The permittee shall conduct sulfuric acid mist testing on the new turbines and duct burners (1-03 and 1-04) at the 100% operating rate of both the turbine and duct burner. Performance testing shall include determination of the sulfur content of the gaseous fuel using the appropriate ASTM method per 40 CFR 60.335(d).

The permittee shall conduct formaldehyde testing on the new turbines (1-03 and 1-04) at the 50% and 100% operating rates, without the duct burners operating.

The permittee may report all PM emissions measured by USEPA Method 5 as PM_{10}, including back half condensable particulate. If the permittee reports USEPA Method 5 PM emissions as PM_{10}, testing using USEPA Method 201 or 201A need not be performed.

Performance testing shall be conducted while the new units are operating within 10% of the desired testing rates. Testing protocols shall describe how the testing will be performed to satisfy the requirements of the applicable NSPS. The permittee shall provide a copy of the testing protocol, and notice of the actual test date, to AQD for review and approval at least 30 days prior to the start of such testing.

The following USEPA methods shall be used for testing of emissions, unless otherwise approved by Air Quality:

Method 1:	Sample and Velocity Traverses for Stationary Sources.
Method 2:	Determination of Stack Gas Velocity and Volumetric Flow Rate.
Method 3:	Gas Analysis for Carbon Dioxide, Excess Air, and Dry Molecular Weight.

Method 4:	Determination of Moisture in Stack Gases.
Method 5:	Determination of Particulate Emissions from stationary sources.
Method 8:	Sulfuric Acid Mist.
Method 10:	Determination of Carbon Monoxide Emissions from Stationary Sources.
Method 6C	Quality Assurance procedures (Range and Sensitivity, Measurement System Performance Specification, and Measurement System Performance Test Procedures) shall be used in conducting Method 10.
Method 20:	Determination of Nitrogen Oxides and Oxygen Emissions from Stationary Gas Turbines.
Method 25/25A:	Determination of Non-Methane Organic Emissions From Stationary Sources.
Method 201/201A	Determination of PM_{10} Emissions
Method 320:	Vapor Phase Organic & Inorganic Emissions by Extractive FTIR

14. The permittee shall apply for a modification of their current Title V operating permit and an Acid Rain permit within 180 days of operational start-up.

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(December 22, 2008)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:
(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any document submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." However, an exceedance report that must be submitted within ten days of the exceedance under Section II (Reporting Of Deviations From Permit Terms) or Section XIV (Emergencies) may be submitted without a certification, if an appropriate certification is provided within ten days thereafter, together with any corrected or supplemental information required concerning the exceedance.

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1) and OAC 252:100-9-3.1(c)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.

[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.

[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a

certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.
[OAC 252:100-8-6(c)(5)(A) and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period; and a statement that the facility will continue to comply with all applicable requirements. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source. [OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.
[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances:

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

[OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.
[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(18) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.
[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.
[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that:

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;
(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit. [OAC 252:100-8-6 (e)(2)]

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.
[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter.
[OAC 252:100-13]
(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for:
   (a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
   (b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
   (c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
   (d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property. [OAC 252:100-25]

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances:

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;

(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and

(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs. [40 CFR 82, Subpart A]

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term

"motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B:

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;
(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166. [40 CFR 82, Subpart F]

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).

(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).
(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 C.F.R. § 70.8(d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).
(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.[OAC 252:100-43-6]

Associated Electric Cooperative, Inc.
Attn: Mr. Todd Tolbert
Environmental Specialist
2814 S. Golden, P.O. Box 754
Springfield, MO 65801-0754

Re: Permit Number 2007-115-C (M-1) (PSD)
Chouteau Power Plant
Location: Mid America Industrial Park, Mayes County

Dear Mr. Tolbert:

Enclosed is the construction permit authorizing installation of the referenced facility. Please note that this permit is issued subject to the standard and specific conditions, which are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

Thank you for your cooperation in this matter. If we may be of further service, please contact me at eric.milligan@deq.state.ok.us or (405) 702-4217.

Sincerely,

Eric L. Milligan, P.E.
Engineering Section
AIR QUALITY DIVISION

Enclosures

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 NORTH ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2007-115-C (M-1) PSD

Associated Electric Cooperative, Inc.,

having complied with the requirements of the law, is hereby granted permission to construct/modify/operate the Chouteau Power Plant located in Section 10, T20N, R19E, Mayes County, Oklahoma, subject to the Standard Conditions dated December 22, 2008, and Specific Conditions, both of which are attached.

In the absence of construction commencement, this permit shall expire 18 months from the issuance date, except as authorized under Section VIII of the Standard Conditions.

Division Director, Air Quality Division

1-23-09
Date

Attachment 7

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

PIEDMONT REGIONAL OFFICE

Douglas W. Domenech
Secretary of Natural Resources

4949A Cox Road, Glen Allen, Virginia 23060
(804) 527-5020 Fax (804) 527-5106
www.deq.virginia.gov

David K. Paylor
Director

Michael P. Murphy
Regional Director

March 12, 2013

Mr. Robert McKinley
Vice President of Generation and Construction
Virginia Electric and Power Company
5000 Dominion Blvd.
Glen Allen, VA 23060

Location: Brunswick County
Registration No.: 52404

Dear Mr. McKinley:

Attached is a permit to construct and operate an electric power generation facility in accordance with the provisions of the Virginia State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution.

In the course of evaluating the application and arriving at a final decision to approve the project, the Department of Environmental Quality (DEQ) deemed the application complete on December 21, 2012 and solicited written public comments by placing a newspaper advertisement in the Brunswick Times Gazette and Independent Messenger (Emporia) on January 2, 2013. A public hearing was held on February 4, 2013. The required comment period, provided by 9 VAC 5-80-1775 F expired on February 19, 2013.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and/or civil charges. Please read all permit conditions carefully.

This permit approval to construct and operate shall not relieve Virginia Electric and Power Company of the responsibility to comply with all other local, state, and federal permit regulations. Please note that your proposed emergency generator (EG-1) and emergency fire water pump (FWP-1) may be affected facilities under 40 CFR 60, New Source Performance Standard (NSPS), Subpart IIII and the propane emergency generator (EG-2) may be an affected facility under NSPS, Subpart JJJJ. Therefore, these units may be subject to owner/operator requirements of the NSPS and 40 CFR 63, Maximum Achievable Control Technology, (MACT), Subpart ZZZZ,. In summary, the units could be required to comply with certain federal emission standards and operating limitations over their useful life. The DEQ advises you to review the attached NSPS and MACT to ensure compliance with applicable emission and operational limitations. As the owner/ operator you are also responsible for monitoring, notification, reporting and recordkeeping requirements of the NSPS and MACT. Notifications for these regulations and the results of performance tests required by 40 CFR 60, Subparts Dc, IIII, JJJJ and KKKK shall to be sent to:

Associate Director
Office of Air Enforcement (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

The Board's Regulations as contained in Title 9 of the Virginia Administrative Code 5-170-200 provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this case decision notice was mailed or delivered to you. 9 VAC 5-170-200 provides that you may request direct consideration of the decision by the Board if the Director of the DEQ made the decision. Please consult the relevant regulations for additional requirements for such requests.

As provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal of this decision by filing a Notice of Appeal with:

David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

If this permit was delivered to you by mail, three days are added to the thirty-day period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for information on the required content of the Notice of Appeal and for additional requirements governing appeals from decisions of administrative agencies.

If you have any questions concerning this permit, please contact the regional office at (804) 527-5020.

Sincerely,

Kyle Ivar Winter, P.E.
Deputy Regional Director

KIW/AMS/52404_001_13_PSD.docx

Attachments: Permit
NSPS, Subparts Dc, IIII, JJJJ, and KKKK,
MACT Subpart ZZZZ
Source Testing Report Format

cc: Director, OAPP (electronic file submission)
Chief, Office of Air Enforcement and Compliance Assistance, U.S. EPA, Region III (electronic file submission)
Inspector, Air Compliance

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

PIEDMONT REGIONAL OFFICE

Douglas W. Domenech
Secretary of Natural Resources

4949A Cox Road, Glen Allen, Virginia 23060
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www.deq.virginia.gov

David K. Paylor
Director

Michael P. Murphy
Regional Director

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
This permit includes designated equipment subject to
New Source Performance Standards (NSPS).

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, Virginia 23060
Registration No.: 52404
County-Plant ID: 025-0037

is authorized to construct and operate

an electric power generation facility

located at

20100 Governor Harrison Parkway, Freeman, VA 23856
(south of Rte 58, approximately 1.3 mi NE of Racume, Brunswick Co., VA)

in accordance with the Conditions of this permit.

Approved on March 12, 2013.

_____

Deputy Regional Director
Department of Environmental Quality

Permit consists of 28 pages.
Permit Conditions 1 to 84.

INTRODUCTION

This permit approval is based on the permit application dated December 20, 2011, including amendment information dated March 7, 2012, September 7, 2012, November 5, 2012 and December 21, 2012. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

PROCESS REQUIREMENTS

1. **Equipment List** - Equipment at this facility consists of the following:

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
Three on one power block with three natural gas-fired combustion turbine generators, each with a duct-fired heat recovery steam generator (HRSG) , providing steam to a common steam turbine generator			
T-1M	Mitsubishi M501 GAC combustion turbine generator with HRSG duct burner (natural gas-fired)	3,442 MMBtu/hr	NSPS Subpart KKKK NOx trading Subparts AA-II, AAA-III, and AAAA-IIII
T-2M	Mitsubishi M501 GAC combustion turbine generator with HRSG duct burner (natural gas-fired)	3,442 MMBtu/hr	NSPS Subpart KKKK NOx trading Subparts AA-II, AAA-III, and AAAA-IIII
T-3M	Mitsubishi M501 GAC combustion turbine generator with HRSG duct burner (natural gas-fired)	3,442 MMBtu/hr	NSPS Subpart KKKK NOx trading Subparts AA-II, AAA-III, and AAAA-IIII
Ancillary Equipment			
B-1	Auxiliary Boiler (natural gas-fired)	66.7 MMBtu/hr	NSPS Subpart Dc
GH-1, 2, 3	Three Fuel Gas Heaters (natural gas-fired)	8 MMBtu/hr each	None

Equipment to be Constructed			
Ref. No.	**Equipment Description**	**Rated Capacity**	**Federal Requirements**
EG-1	Emergency Generator (diesel)	2200 kW	NSPS Subpart IIII (non-delegated) MACT Subpart ZZZZ (non-delegated)
EG-2	Emergency Generator (propane)	80 kW	NSPS Subpart JJJJ (non-delegated) MACT Subpart ZZZZ (non-delegated)
FWP-1	Fire Water Pump (diesel)	305 bhp	NSPS Subpart IIII (non-delegated) MACT Subpart ZZZZ (non-delegated)
AEC-1	Delugeable Auxiliary Equipment Cooler	69,600 gallons of water/hr	None
IC-1 through 4	Four Turbine Inlet Air Chillers (mechanical draft cooling towers)	690,000 gallons of water/hr each	None
CB-1 through CB-11	Eleven Electrical Circuit Breakers	18,095 lb SF_6	None
ST-1	Distillate fuel oil tank	6000 gallons	None

Specifications included in the permit under this Condition are for informational purposes only and do not form enforceable terms or conditions of the permit.
(9 VAC 5-80-1180 D 3)

<u>Combined-cycle gas turbine generators and duct-fired HRSG (T-1M, T-2M, T-3M)</u>

2. **Emission Controls: Nitrogen Oxides** - Nitrogen oxide (NO_x) emissions from each of the combined cycle gas turbine generators and associated duct-fired heat recovery steam generators (HRSG) (T-1M, T-2M, T-3M) shall be controlled by dry, low NO_x burners and selective catalytic reduction (SCR) with a NO_X performance of 2.0 ppmvd at 15% O_2 for natural gas. The low NO_X burners shall be installed and operated in accordance with manufacturer's specifications. The SCR shall be provided with adequate access for inspection and shall be in operation when the combined cycle gas turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 12).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

3. **Monitoring Devices: SCR** - Each SCR system shall be equipped with devices to continuously measure or be calculated and record ammonia feed rate, gas stream flow rate, and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating.
(9 VAC 5-50-20 C and 9 VAC 5-80-1705 B)

4. **Monitoring Device Observation: SCR** -To ensure good performance, the devices used to continuously measure or be calculated and record the ammonia feed rate, gas stream flow rate, and catalyst bed inlet temperature on the SCR shall be observed by the permittee with a frequency sufficient to ensure good performance of the SCR system, but not less than once per day of operation.
(9 VAC 5-50-50H and 9 VAC 5-80-1705 B)

5. **Emission Controls: Carbon Monoxide** – Carbon monoxide (CO) emissions from each of the combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M) shall be controlled by an oxidation catalyst and good combustion practices. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combined cycle gas turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 12).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

6. **Emission Controls: Volatile Organic Compounds** – Volatile organic compound (VOC) emissions from each of the combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M) shall be controlled by an oxidation catalyst and good combustion practices. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the combined cycle gas turbine generators are operating (at all times except during startup and shutdown, as defined in Condition 12).
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

7. **Monitoring Devices: Oxidation Catalyst** - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating.
(9 VAC 5-50-20 C, 9 VAC 5-50-280, and 9 VAC 5-80-1705 B)

8. **Monitoring Device Observation: Oxidation Catalyst -** To ensure good performance, the device used to continuously measure and record the catalyst bed inlet and outlet gas temperature on the oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst system, but not less than once per day of operation.
(9 VAC 5-50-50H and 9 VAC 5-80-1705 B)

9. **Emission Controls: Sulfur dioxide and sulfuric acid mist** – Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions from each of the combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

10. **Emission Controls: Particulate Matter** – Particulate Matter (PM_{10}, $PM_{2.5}$) emissions from each of the combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M) shall be controlled by good combustion practices and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

11. **Emission Controls: Greenhouse Gases** – Greenhouse gas emissions (including carbon dioxide, methane, and nitrous oxide), as CO_2e from the combined cycle gas turbine

generators and associated duct-fired HRSG (T-1M, T-2M, T-3M) shall be controlled by the use of low carbon fuel (natural gas) and high efficiency design and operation of the combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M and steam turbine generator). The combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M and steam turbine generator) shall operate at a higher heating value heat rate, at full load and corrected to ISO conditions, not to exceed 7,500 Btu/kWh net (HHV) output. Compliance with this limit shall be demonstrated as contained in Conditions 67 and 69.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

12. **Startup/Shutdown** – The short-term emission limits contained in Condition 40 apply at all times except during periods of startup and shutdown.

    a. Startup and shutdown periods are defined as follows:

        i. Cold Startup – refers to restarts made 72 hours or more after shutdown. Exclusion from the short-term emissions limits for cold startup periods shall not exceed an annual average of 169 minutes per occurrence.

        ii. Warm Startup – refers to restarts made more than 8 but less than 72 hours after shutdown. Exclusion from the short-term emissions limits for warm startup periods shall not exceed an annual average of 93 minutes per occurrence.

        iii. Hot Startup – refers to restarts made 8 hours or less after shutdown. Exclusion from the short-term emissions limits for hot startup periods shall not exceed an annual average of 43 minutes per occurrence.

        iv. Shutdown – refers to the period between the time the turbine load drops below 50 percent operating level and the fuel supply to the turbine is cut. Exclusion from the short-term emissions limits for shutdown shall not exceed an annual average of 11 minutes per occurrence.

    b. The permittee shall operate the CEMS during periods of startup and shutdown.

    c. The permittee shall record the time, date and duration of each startup and shutdown event. The records must include calculations of NO_x and CO emissions during each event based on the CEMS data. These records must be kept for five years following the date of such event.

    d. During startup, the combustion turbine SCR system, including ammonia injection, shall be operated in a manner to minimize emissions, as technologically feasible, and not later than when the load reaches 50% of unit output.

    e. The permittee shall operate the facility so as to minimize the frequency and duration of startup and shutdown events.

    (9 VAC 5-50-280 and 9 VAC 5-80-1705)

Auxiliary boiler (B-1) and fuel gas heaters (GH-1 through GH-3)

13. **Emission Controls: Nitrogen Oxides** – NO_x emissions from the auxiliary boiler (B-1) and three fuel gas heaters (GH-1 through GH-3) shall be controlled by ultra low-NO_x burners with a NO_x performance of 9 ppmvd at 3% O_2 for natural gas. The low NO_x burners shall be installed and operated in accordance with manufacturer's specifications.
(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

14. **Emission Controls: Carbon Monoxide and Volatile Organic Compounds** – CO and VOC emissions from the auxiliary boiler (B-1) and fuel gas heaters (GH-1 through GH-3) shall be controlled by good combustion practices, operator training, and proper emissions unit design, construction and maintenance to achieve a maximum CO emission rate of 50 ppmvd at 3% O_2. Boiler and heater operators shall be trained in the proper operation of all such equipment. Training shall consist of a review and familiarization of the manufacturer's operating instructions, at a minimum. The permittee shall maintain records of the required training including a statement of time, place and nature of training provided. The permittee shall have available good written operating procedures and a maintenance schedule for the boiler and heater. These procedures shall be based on the manufacturer's recommendations, at a minimum. All records required by this condition shall be kept on site and made available for inspection by the DEQ.
(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

15. **Emission Controls: Sulfur dioxide and sulfuric acid mist** – SO_2 and H_2SO_4 emissions from auxiliary boiler (B-1) and three fuel gas heaters (GH-1 through GH-3) shall be controlled by the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

16. **Emission Controls: Particulate Matter** – PM_{10} and $PM_{2.5}$ emissions from the auxiliary boiler (B-1) and three fuel gas heaters (GH-1 through GH-3) shall be controlled by good combustion practices and the use of pipeline-quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf), on a 12-month rolling average.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

17. **Emission Controls: Greenhouse Gases** – CO_2e from the auxiliary boiler (B-1) and three fuel gas heaters (GH-1 through GH-3) shall be controlled by the use of natural gas fuel and high efficiency design and operation.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

Emergency Units (EG-1, EG-2 and FWP-1)

18. **Emission Controls: EG-1, FWP-1** - PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, VOC, and H_2SO_4 emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by good combustion practices and the use of ultra low sulfur diesel fuel oil with a maximum sulfur content of 15 ppmw.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

19. **Emission Controls: EG-2** - PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, VOC, and H_2SO_4 emissions from the propane emergency unit (EG-2) shall be controlled by good combustion practices.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

20. **Emission Controls: Greenhouse gasses** – CO_2e emissions from the diesel emergency units (EG-1 and FWP-1) shall be controlled by the use of low carbon fuel and high efficiency design and operation.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

21. **Monitoring Devices –** The permittee must install a non-resettable hour meter on the emergency generators (EG-1 and EG-2) and the emergency fire water pump (FWP-1) prior to the startup of each unit. The hour meters shall be provided with adequate access for inspection.
(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

22. **Maintenance and Operation –** The permittee must maintain and operate the emergency generators (EG-1 and EG-2) and the emergency fire water pump (FWP-1) according to the manufacturer's written instructions, or procedures developed by the permittee that are approved by the manufacturer, over the entire life of the engine. In addition, the permittee may only change those settings that are approved by the manufacturer or DEQ.
(9 VAC 5-50-280 and 9 VAC 5-80-1705 B)

<u>Miscellaneous Processes</u>

23. **Emission Controls: Inlet Chillers** – Particulate matter emissions from the four, 11,500-gallon/minute inlet chillers (CH-1 through CH-4) shall be controlled to a drift rate of 0.0005 percent of the circulating water flow and a total dissolved solids content of the cooling water of no more than 1000 mg/l. The permittee shall keep a log of weekly testing for total dissolved solids content of the cooling water.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

24. **Emission Controls: Delugeable Auxiliary Equipment Cooler** – Particulate matter emissions from the 1,160 gallon/minute delugeable auxiliary equipment cooler (AEC-1) shall be controlled to a drift rate of 0.010 percent of the circulating water flow and a total dissolved solids content of the cooling water of no more than 300 mg/l. The permittee shall keep a log of weekly testing for total dissolved solids content of the cooling water.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

25. **Emission Controls: Electrical breakers –** Greenhouse gas emissions (including SF_6) from the electrical circuit breakers (CB-1 through CB-11) shall be controlled by an enclosed-pressure circuit breaker, with a maximum annual leakage rate of 1.0 percent, and a low pressure detection system (with alarm). The low pressure detection system shall be in operation when the circuit breakers are in use.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

OPERATING LIMITATIONS

26. **Fuel: Gas turbines and auxiliary boiler** - The approved fuel for the combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M), fuel gas heaters (GH-1 through GH-3) and the auxiliary boiler (B-1) is pipeline quality natural gas with a maximum sulfur content of 0.4 grains per 100 standard cubic feet (scf). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

27. **Fuel Throughput: Gas turbines** -The three combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M) combined shall consume no more than a total of 88,682 x 10^6 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

28. **Fuel Monitoring: Gas turbines** – The permittee shall conduct tests for the total sulfur content of the natural gas being fired at the electric power generation facility to verify that the sulfur content of the natural gas is 0.4 grains of total sulfur per 100 scf on a 12-month rolling average in order to demonstrate that potential sulfur dioxide emissions shall not exceed the limits specified in Condition 40. The permittee shall demonstrate compliance with the sulfur content limit in Condition 26 using one of the following:

    a. Determine and record the total sulfur content of the natural gas each month. A monthly sample is not required for months when the turbines operated for 48 hours or less, or

    b. Develop custom schedules for determination of the sulfur content of the natural gas based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in 40 CFR 60.4370(c)(1) and (c)(2), custom schedules shall be substantiated with data and shall receive prior EPA approval.

    (9 VAC 5-50-410, 9 VAC 5-50-280, 40 CFR 60.4365(a), 40 CFR 60.4370(b), and 40 CFR 60.4370(c))

29. **Fuel Throughput: Auxiliary boiler** -The auxiliary boiler (B-1) shall consume no more than 573 x 10^6 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

30. **Fuel: Diesel fire water pump and emergency diesel generator** - The approved fuel for the emergency diesel fire water pump (FWP-1) and emergency diesel generator (EG-1) is ultra low sulfur diesel (ULSD). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

31. **Fuel: propane-fired emergency generator** - The approved fuel for the emergency generator (EG-2) is liquid petroleum gas (LPG)(as propane). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

32. **Fuel: Fire water pump and emergency generators**- The fuels for the fire pump (FWP-1) and generators (EG-1 and EG-2) shall meet the specifications below:
DIESEL FUEL (ULSD) which meets the ASTM D975-10b specification for S15 fuel oil:
Maximum sulfur content per shipment: 0.0015%

    LPG, including butane and propane, which meets ASTM specification D1835.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

33. **Operating Hours: Fire water pump** - The emergency fire water pump (FWP-1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

34. **Operating Hours: Emergency generators** - The emergency generators (EG-1 and EG-2) shall not operate more than 500 hours each per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

35. **Emergency Operation: Generators and fire water pump** – The operation of the emergency generators (EG-1 and EG-2) and fire water pump (FWP-1) is limited to emergency situations. Emergency situations include a) emergency generator use to produce power for critical networks or equipment (including power supplied to portions of the facility) when electric power from the local utility (or the normal source, if the facility runs on its own power production) is interrupted and b) emergency engine use to pump water in the case of fire or flood, etc. The emergency generators (EG-1 and EG-2) and fire water pump (FWP-1) may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by federal, state, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per calendar year for each unit.
(9 VAC 5-80-1705 B and 9 VAC 5-50-280)

36. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of ULSD oil. Each fuel supplier certification shall include the following:

    a. The name of the fuel supplier;

b. The date on which the ULSD oil was received;

c. The quantity of ULSD oil delivered in the shipment;

d. A statement that the ULSD oil complies with the American Society for Testing and Materials specifications ASTM D975 for Grades 1 or 2 Ultra Low Sulfur fuel oil, or other DEQ approved fuel specifications;

e. The sulfur content of the ULSD oil;

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 32. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-50-280)

37. **Maintenance and Operation: Fire water pump and emergency generators** – The permittee must maintain and operate the emergency fire pump (FWP-1) and emergency generators (EG-1 and EG-2) according to the manufacturer's written instruction, or procedures developed by the permittee that are approved by the manufacturer, over the entire life of the engine. In addition, the permittee may only change those settings that are approved by the manufacturer.
(9 VAC 5-50-280)

38. **Fuel Throughput: Fuel gas heater** -The three fuel gas heaters (GH-1 through GH-3) combined shall consume no more than a total of 206 x 10^6 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-50-280)

39. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the NSPS equipment as described in Condition 1shall be operated in compliance with the requirements of 40 CFR 60, Subparts Dc and KKKK.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

EMISSION LIMITS

40. **Short-Term Emission Limits: Gas Turbines -**Emissions from the operation of each combined-cycle gas turbine generator and associated HRSG duct burner (T-1M, T-2M, T-3M), shall not exceed the limits specified below:

Pollutant	Short term emission limits
PM_{10} (including condensable PM)	0.0033 lb/MMBtu and 9.7 lb/hr as a three-hour average without duct burner firing 0.0047 lb/MMBtu and 16.3 lb/hr as a three-hour average with duct burner firing.
$PM_{2.5}$ (including condensable PM)	0.0033 lb/MMBtu and 9.7 lb/hr as a three-hour average without duct burner firing 0.0047 lb/MMBtu and 16.3 lb/hr as a three-hour average with duct burner firing.
Sulfur dioxide	00.00112 lb/MMBtu
Nitrogen Oxides (as NO_2)	2.0 ppmvd @ 15% O_2 as a one-hour rolling average
Carbon monoxide	1.5 ppmvd @ 15% O_2 as a three-hour rolling average without duct burning 2.4 ppmvd @ 15% O_2 as a three-hour rolling average with duct burning
Volatile organic compounds	0.7 ppmvd @ 15% O_2 without duct burner firing 1.6 ppmvd @ 15% O_2 with duct burner firing
Sulfuric acid mist	0.00058 lb/MMBtu without duct burner firing 0.00067 lb/MMBtu with duct burner firing

Where:

ppmvd = parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short-term emission limits represent averages for a three-hour sampling period except for nitrogen oxides, which shall be calculated as a one-hour average.

Unless otherwise specified, limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 12 of this permit.

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these limits may be determined as stated in Conditions 2, 5, 6, 26, 49, 52, 61, and 62

(9 VAC 5-50-280, 9 VAC 5-80-1705, 9 VAC 5-80-1715)

41. **Emission Limits: Combustion Turbines** – CO_2e emissions from the combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M) shall not exceed 920 lbs/MWh (net HHV) calculated monthly on a 12-operating month annual average basis. Compliance may be determined each month by summing the CO_2e emissions for all hours in which power is being generated to the grid during the previous 12 months and dividing that value by the sum of the electrical energy output over that same period.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

42. **Annual Process Emission Limits** – Emissions from the operation of <u>each</u> of the three combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M) shall not exceed the limits specified below:

PM_{10} (including condensable)	71.4	tons/yr	(on a 12-month, rolling total)
$PM_{2.5}$ (including condensable)	71.4	tons/yr	(on a 12-month, rolling total)
Sulfur Dioxide	16.9	tons/yr	(on a 12-month, rolling total)
Nitrogen Oxides (as NO_2)	110.3	tons/yr	(on a 12-month, rolling total)
Carbon Monoxide	150.3	tons/yr	(on a 12-month, rolling total)
Volatile Organic Compounds	101.3	tons/yr	(on a 12-month, rolling total)
Sulfuric Acid Mist	10.2	tons/yr	(on a 12-month, rolling total)
CO_2e	1,763,902	tons/yr	(on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 2, 5, 6, 9, 10, 11, 27, 28, 51, 52 and 55.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

43. **Process Emission Limits** – Emissions from the operation of the auxiliary boiler (B-1) shall not exceed the limits specified below:

PM_{10} (including condensable)	0.5 lbs/hr	2.2 tons/yr	(on a 12-month, rolling total)
$PM_{2.5}$ (including condensable)	0.5 lbs/hr	2.2 tons/yr	(on a 12-month, rolling total)
Nitrogen Oxides (as NO_2)	0.8 lb/hr	3.2 tons/yr	(on a 12-month, rolling total)
Carbon Monoxide	2.5 lbs/hr	10.8 tons/yr	(on a 12-month, rolling total)
Volatile Organic Compounds	0.4 lbs/hr	1.5 tons/yr	(on a 12-month, rolling total)
CO_2e	34,182 tons/yr		(on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 13, 14, 26 and 29.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

44. **Process Emission Limits** - Emissions from the operation of the electrical circuit breakers (CB-1 through CB-11) shall not exceed the limits specified below:

CO_2e	2,162	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 1 and 25.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

45. **Process Emission Limits** - Emissions from the operation of the fire water pump (FWP-1) shall not exceed the limits specified below:

PM (filterable only)	0.54	g/kW-hr
PM_{10}(including condensable)	0.4	g/kW-hr
$PM_{2.5}$(including condensable)	0.4	g/kW-hr
Sulfur Dioxide	0.00154	lb/MMBtu
Nitrogen Oxides (as NO_2) + Non-methane hydrocarbons	4.0	g/kW-hr
Carbon Monoxide	3.5	g/kW-hr
CO_2e	91.2	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 30, 32, 33, 35, 37 and 51.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

46. **Process Emission Limits** - Emissions from the operation of the diesel emergency generator (EG-1) shall not exceed the limits specified below:

PM (including condensable)	0.2	g/kW-hr		
PM_{10}(including condensable)	0.4	g/kW-hr		
$PM_{2.5}$(including condensable)	0.4	g/kW-hr		
Sulfur Dioxide	0.00154	lb/MMBtu		
Nitrogen Oxides (as NO_2) + Non-methane hydrocarbons	6.4	g/kW-hr	7.8	tons/yr (on a 12-month rolling total)

Carbon Monoxide	3.5	g/kW-hr	4.3	tons/yr (on a 12-month rolling total)
CO_2e			814.0	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 30, 32, 34, 35, 37, and 51.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

47. **Process Emission Limits** - Emissions from the operation of the propane emergency generator (EG-2) shall not exceed the limits specified below:

PM_{10}(including condensable)	0.12	g/kW-hr		
$PM_{2.5}$(including condensable)	0.12	g/kW-hr		
Sulfur Dioxide	0.00059	lb/MMBtu		
Nitrogen Oxides (as NO_2)	5.84	g/kW-hr		
Carbon Monoxide	174.4	g/kW-hr	7.7	tons/yr (on a 12-month rolling total)
CO_2e			37.4	tons/yr (on a 12-month rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 30, 32, 34, 35, 37, and 51.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

48. **Process Emission Limits** – Emissions from the operation of the fuel gas heaters (GH-1 through GH-3) combined shall not exceed the limits specified below:

PM_{10} (including condensable)	0.007 lbs/MMBtu	0.8	tons/yr (on a 12-month, rolling total)
$PM_{2.5}$ (including condensable)	0.007 lbs/MMBtu	0.8	tons/yr (on a 12-month, rolling total)
Nitrogen Oxides (as NO_2)	0.011 lb/MMBtu	1.2	tons/yr (on a 12-month, rolling total)
Carbon Monoxide	0.9 lbs/hr	3.9	tons/yr (on a 12-month, rolling total)
Volatile Organic Compounds		0.6	tons/yr (on a 12-month, rolling total)
CO_2e		12,299	tons/yr (on a 12-month, rolling total)

These emissions are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits. Compliance with these emission limits may be determined as stated in Conditions 2, 5, 6, 9, 10, 11, 27, 28, and 51.
(9 VAC 5-50-280, 9 VAC 5-80-1705, and 9 VAC 5-80-1715)

49. **Visible Emission Limit** - Visible emissions from the combined cycle gas turbine generators and associated duct-fired HRSG (T-1M, T-2M, T-3M) shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown (as defined in Condition 12), and malfunction.
(9 VAC 5-50-80 and 9 VAC 5-50-280)

50. **Visible Emission Limit** - Visible emissions from the fuel gas heaters (GH-1 through GH-2) and auxiliary boiler (B-1) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-50-80 and 9 VAC 5-50-280)

51. **Visible Emission Limit** - Visible emissions from the emergency fire water pump (FWP-1) and emergency generators (EG-1 and EG-2) shall not exceed 10 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown, and malfunction.
(9 VAC 5-50-80 and 9 VAC 5-50-280)

<u>CEMS/</u>

52. **CEMS -** Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of NO_x (measured as NO_2), CO_2 and CO from each combined cycle combustion turbine and associated duct-fired HRSG (T-1M, T-2M, T-3M) in ppmvd, corrected to 15 percent O_2. CEMS for NO_x shall meet the design specifications of 40 CFR Part 75 whereas CEMS for CO shall be installed, evaluated, and operated according to the monitoring requirements in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_x and CO emissions are monitored and measure heat input and power output. A CEMS or alternative method as allowed by 40 CFR 75 shall be used to measure sulfur dioxide emissions to comply with the requirements of 40 CFR 75 (acid rain program monitoring). For compliance with the emission limits contained in Condition 40, NO_x data and CO data shall each be reduced to 1-hour block averages. The relative accuracy test audit (RATA) of the NO_x CEMS shall be performed on a lb/MMBtu basis.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

53. **CEMS Performance Evaluations -** Performance evaluations of the NO_x and, if applicable, SO_2 CEMS shall be conducted in accordance with 40 CFR Part 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter.

Two copies of the performance evaluations report shall be submitted to the Piedmont Region within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30 day notification, prior to the demonstration of continuous monitoring system's performance, and subsequent notifications shall be submitted to the Piedmont Region.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

54. **CEMS Quality Control Program -** A CEMS quality control program which is equivalent to the requirements of 40 CFR 75 Appendix B shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-350 and 9 VAC 5-50-40)

55. **CEMS Emissions Data** – CEMS data shall be used to report annual emissions of NO_x, CO and CO_2 from the stack of each combined cycle combustion turbine and associated duct-fired HRSG (T-1M, T-2M, T-3M) in tons/yr for the purpose of emission inventory.
(9 VAC 5-50-50)

56. **Excess Emissions and Monitor Downtime for NO_x - Continuous Monitoring Systems**
For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 58 are defined as follows:

    a. An excess emission period is any unit operating period in which the average one-hour NO_x emission rate exceeds the applicable emission limit in Condition 40; and

    b. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_x concentration, O_2 concentration, fuel flow rate, steam pressure, or megawatts. The steam flow rate is only required if the permittee uses this information for compliance purposes.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4380)

57. **Excess Emissions and Monitor Downtime for SO_2 -** Continuous Monitoring Systems
Excess emissions and monitoring downtime are defined, for the purpose of this permit, as follows:

    a. For samples of gaseous fuel obtained using daily sampling or for proportional sampling, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit; and

    b. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4385)

58. **Reports for Continuous Monitoring Systems -** The permittee shall furnish written reports to the Piedmont Region of excess emissions from any process monitored by a continuous monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

    b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

    c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

    d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

    e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.

    (9 VAC 5-50-50)

59. **Excess Emissions for Continuous Monitoring Systems** – For purposes of identifying excess emissions:

    a. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h);

    b. For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both NO_x and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_x emission rate in units of ppm, using the appropriate equation in 40 CFR Part 60, Appendix A, Method 19. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations; and

    c. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), and 40 CFR 60.4350)

INITIAL COMPLIANCE DETERMINATION

60. **Emissions Testing** - The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from excessive cyclonic flow as defined in 40 CFR 60 Appendix A. Sampling ports shall be provided at the appropriate locations (in accordance with the applicable performance specification in 40 CFR Part 60, Appendix B) and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30 F and 9 VAC 5-80-1675)

61. **Stack Test: Turbines -** Initial performance tests shall be conducted for CO, PM_{10} (including condensable PM_{10}), $PM_{2.5}$, and total VOC from each combustion turbine and associated duct burner (T-1M, T-2M, and T-3M) to determine compliance with the emission limits contained in Condition 40. The tests shall be performed and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. Tests shall be conducted for two different operating scenarios: natural gas firing with the duct burners off; and natural gas firing with the duct burners on. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 45 days of test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1675, and 9 VAC 5-50-410)

62. **Initial Performance Test – Combustion Turbines –** Initial performance tests shall be conducted on each combustion turbine and associated duct burner (T-1M, T-2M, and T-3M) for NO_x (as NO_2) to determine compliance with the limits contained in Condition 40 as follows:

    a. 40 CFR 60, Appendix A, Methods 7E or 20 shall be used to measure the NO_x concentration (in ppm). Sampling traverse points for NO_x and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

    b. Notwithstanding Condition 62 a. above, the permittee may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met: The permittee may perform a stratification test for NO_x and diluent pursuant to the procedures specified

in 40 CFR 75, Appendix A, Section 6.5.6.1(a) through (e). Once the stratification sampling is completed, the permittee may use the following alternative sample point selection criteria for the performance test:

i. If each of the individual traverse point NO_x concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent O_2 from the mean for all traverse points, three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall) may be used. The three points must be located along the measurement line that exhibited the highest average NO_x concentration during the stratification test; or

ii. The permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_x concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent O_2 from the mean for all traverse points.

c. The performance test must be done at any load condition as required by 40 CFR 60.4400(b). Testing maybe performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. Three separate test runs for each performance test must be conducted. The minimum time per run is 20 minutes.

d. The permittee must measure the total NO_x emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

e. Compliance with the applicable emission limit in Condition 40 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_x emission rate at each tested level meets the applicable emission limit in Condition 40.

f. The performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit.

g. The ambient temperature must be greater than 0°F during the performance test.

h. The permittee may use the following as alternatives to the reference methods and procedures specified in this condition:

i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, as required by 40 CFR 60.4400(b). The ambient temperature must be greater than 0°F during the RATA runs.

ii. Compliance with the applicable emission limit in Condition 40 is achieved if the arithmetic average of all of the NO_x emission rates for the RATA runs, expressed in units of ppm at 15% O_2, does not exceed the emission limit.

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 45 days after test completion but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-50-410, and 9 VAC 5-80-1675)

63. **Initial Performance Test – Combustion Turbines –** Initial performance tests shall be conducted on each combustion turbine and associated duct burner (T-1M, T-2M, and T-3M) for SO_2 to determine compliance with the limits contained in Condition 40. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manually sampling using Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported

and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-50-410 and 9 VAC 5-80-1675)

64. **Stack Test: Auxiliary boiler and fuel gas heater -** Initial performance tests shall be conducted for NO_x and CO from the auxiliary boiler (B-1) and fuel gas heaters (GH-1 through GH-2) to determine compliance with the emission limits contained in Conditions 43 and 48. The tests shall be performed, reported and demonstrate compliance within 60 days after the boiler or fuel gas heater, as applicable, reach the maximum load level at which the unit will be operated but in no event later than 180 days after its initial start-up. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 45 days of test completion but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1985 E, and 9 VAC 5-50-410)

65. **Visible Emissions Evaluation – Combustion Turbines -** Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combustion turbine and associated duct burner (T-1M, T-2M, and T-3M). Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. At least one VEE shall be conducted for each of the operating conditions and loads for which emissions tests are required for the stack tests contained in Condition 61. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit.

    Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Piedmont Regional Office within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

66. **Visible Emissions Evaluation - Auxiliary Boiler and fuel gas heaters -** Concurrently with the initial performance tests in Condition 64, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on the auxiliary boiler (B-1) and fuel gas heaters (GH-1 through GH-3). Each test shall consist of 10 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the boiler will be operated but in no event later than 180 days after start-up of the boiler.

    Should conditions prevent concurrent opacity observations, the Piedmont Regional Office shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Piedmont Regional Office within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
    (9 VAC 5-50-30 and 9 VAC 5-80-1675)

67. **Testing: Heat Rate Limit -** Initial compliance testing, using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996) or equivalent method approved by the Piedmont Regional Office, shall be conducted for the heat rate limit of the power blocks (i.e., a combination of T-1M, T-2M, and T-3M and the steam turbine generator) to show compliance with the heat rate limit contained in Condition 11. The testing shall be performed, reported and demonstrate compliance within 90 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Testing shall be conducted when combusting natural gas. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office within 45 days of test completion and shall conform to the test report format enclosed with this permit. An exceedance of the heat rate limit is not considered a violation of this permit, but triggers a requirement for the permittee to submit a maintenance plan to DEQ which specifies the actions the permittee plans to take in order to achieve the heat rate limit contained in Condition 11. The details of this plan are to be arranged with the Piedmont Regional Office.
    (9 VAC 5-50-30 and 9 VAC 5-80-1675)

CONTINUING COMPLIANCE DETERMINATION

68. **Annual Performance Test – Combustion Turbines –** Annual performance tests shall be conducted on each combustion turbine and associated duct burner (T-1M, T-2M, and T-3M) for SO_2 to determine compliance with the limits contained in Condition 40. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17 or by manual sampling using the Gas Process Association Standard 2166) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the SO_2 concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the SO_2 and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Piedmont Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Piedmont Regional Office, within 45 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-50-410)

69. **Periodic Testing: Heat Rate Limit** – Every five years after initial evaluation of the heat rate limit of the power blocks, the permittee shall conduct a heat rate evaluation of the power blocks to show compliance with the heat rate limit contained in Condition 11. The details of the evaluation are to be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 and 9 VAC 5-80-1675)

70. **Stack Tests** – Upon request by DEQ, the permittee shall conduct additional performance tests to determine compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the Piedmont Regional Office.
(9 VAC 5-50-30 G)

RECORDS

71. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Region. These records shall include, but are not limited to:

    a. Annual hours of operation of the emergency fire water pump (FWP-1) and emergency generators (EG-1 and EG-2) for emergency purposes and for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

    b. All fuel supplier certifications for the ULSD fuel used in the emergency units (EG-1and FWP-1);

    c. Monthly and annual throughput of natural gas to the three combustion turbines and associated duct burners (T-1M, T-2M, and T-3M), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

    d. Time, date and duration of each startup, shutdown, and malfunction period for each combustion turbine and associated duct burner (T-1M, T-2M, and T-3M);

    e. Monthly and annual throughput of natural gas to the auxiliary boiler (B-1) and the fuel gas heaters (GH-1 through GH-3), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

    f. Fuel quality records for natural gas combusted in the combustion turbine and associated duct burner (T-1M, T-2M, and T-3M), auxiliary boiler (B-1), and fuel gas heaters (GH-1 through GH-3);

    g. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions;

    h. Operation and control device monitoring records for each SCR system and oxidation catalyst as required in Conditions 3 and 7;

    i. Weekly logs of dissolved solids content of cooling water to the four inlet coolers (IC-1 through IC-4) and the auxiliary equipment chiller (AEC-1).

    j. Scheduled and unscheduled maintenance, and operator training.

k. Results of all stack tests, visible emission evaluations, and performance evaluations.

l. Manufacturer's instructions for proper operation of equipment.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50)

72. **Emissions Testing** - The electric generating facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from excessive cyclonic flow as defined in 40 CFR 60 Appendix A. Sampling ports shall be provided when requested at the appropriate locations and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30 F and 9 VAC 5-80-1180)

NOTIFICATIONS

73. **Initial Notifications** - The permittee shall furnish written notification to the Piedmont Regional Office of:

a. The actual date on which construction of the electric power generation facility commenced within 30 days after such date.

b. The anticipated start-up date of the electric power generation facility postmarked not more than 60 days nor less than 30 days prior to such date.

c. The actual start-up date of the electric power generation facility within 15 days after such date.

d. The anticipated date of continuous monitoring system performance evaluations postmarked not less than 30 days prior to such date.

e. The anticipated date of performance tests of the combustion turbines (T-1M, T-2M, and T-3M), auxiliary boiler (B-1), and fuel gas heaters (GH-1 through GH-3), postmarked at least 30 days prior to such date.

Copies of the written notification referenced in items a through e above are to be sent to:

Associate Director
Office of Air Enforcement and Compliance Assistance (3AP20)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-50-50 and 9 VAC 5-50-410)

GENERAL CONDITIONS

74. **Permit Invalidation** –This permit to construct the electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

    a. A program of continuous construction or modification is not commenced within 18 months from the date of this permit.

    b. A program of construction or modification is discontinued for a period of 18 months or more, or is not completed within a reasonable time, except for a DEQ approved period between phases of the phased construction of a new stationary source or project.

    (9 VAC 5-80-1985)

75. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

    a. Knowingly makes material misstatements in the permit application or any amendments to it;

    b. Fails to comply with the conditions of this permit;

    c. Fails to comply with any emission standards applicable to a permitted emissions unit, ;

    d. Causes emissions from the stationary source which result in violations of , or interfere with the attainment and maintenance of, any ambient air quality standard; or

    e. Fails to operate in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

    (9 VAC 5-80-1985 F)

76. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

    a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

    b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

    c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

    d. To sample or test at reasonable times.

    For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
    (9 VAC 5-170-130 and 9 VAC 5-80-1180)

77. **Maintenance/Operating Procedures** – At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

    The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment and process equipment which affect such emissions:

    a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

    b. Maintain an inventory of spare parts.

    c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

    d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

    Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
    (9 VAC 5-50-20 E)

78. **Record of Malfunctions** – The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
    (9VAC 5-20-180 J)

79. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Piedmont Regional Office of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Piedmont Regional Office.
    (9 VAC 5-20-180 C)

80. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating

any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I)

81. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Piedmont Regional Office of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1985 E)

82. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1985 E)

STATE-ONLY ENFORCEABLE REQUIREMENTS

The following terms and conditions are included in this permit to implement the requirements of 9 VAC 5-40-130 et seq., 9 VAC 5-50-130 et seq., 9 VAC 5-60-200 et seq. and/or 9 VAC 5-60-300 et seq. and are enforceable only by the Virginia Air Pollution Control Board. Neither their inclusion in this permit nor any resulting public comment period make these terms federally enforceable.

83. **Emission Limits – E**missions from the electric power generation facility shall not exceed the limits specified below:

Pollutant	CAS#	Lb/hr	Tons/yr
Acrolein	107-02-8	0.040 lb/hr	0.16 tons/yr
Formaldehyde	50-00-0	1.370 lb/hr	5.88 tons/yr
Cadmium	7440-43-9	0.011 lb/hr	0.05 tons/yr
Chromium	7440-47-3	0.014 lb/hr	0.06 tons/yr
Nickel	7440-02-0	0.021 lb/hr	0.09 tons/yr

Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-60-320 and 9 VAC 5-80-1625G)

84. **On Site Records –** The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Regional Office. These records shall include, but are not limited to the average hourly, monthly, and annual emissions (in pounds and tons) of each toxic compound listed in Condition 83. Hourly emissions shall be calculated monthly. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. These records shall be available for inspection by DEQ and current for at least the most recent five years.
(9 VAC 5-50-50, and 9 VAC 5-80-1625G)

SOURCE TESTING REPORT FORMAT

Report Cover

1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Test Dates.
4. Tester; name, address and report date

Certification

1. Signed by team leader/certified observer (include certification date)
2. Signed by responsible company official
3. *Signed by reviewer

Copy of approved test protocol

Summary

1. Reason for testing
2. Test dates
3. Identification of unit tested & the maximum rated capacity
4. *For each emission unit, a table showing:
   a. Operating rate
   b. Test Methods
   c. Pollutants tested
   d. Test results for each run and the run average
   e. Pollutant standard or limit
5. Summarized process and control equipment data for each run and the average, as required by the test protocol
6. A statement that test was conducted in accordance with the test protocol or identification & discussion of deviations, including the likely impact on results
7. Any other important information

Source Operation

1. Description of process and control devices
2. Process and control equipment flow diagram
3. Sampling port location and dimensioned cross section Attached protocol includes: sketch of stack (elevation view) showing sampling port locations, upstream and downstream flow disturbances and their distances from ports; and a sketch of stack (plan view) showing sampling ports, ducts entering the stack and stack diameter or dimensions

Test Results

1. Detailed test results for each run
2. *Sample calculations
3. *Description of collected samples, to include audits when applicable

Appendix

1. *Raw production data
2. *Raw field data
3. *Laboratory reports
4. *Chain of custody records for lab samples
5. *Calibration procedures and results
6. Project participants and titles
7. Observers' names (industry and agency)
8. Related correspondence
9. Standard procedures

_____

* Not applicable to visible emission evaluations

Attachment 8

ENGINEERING EVALUATION
AUTHORITY TO CONSTRUCT

Facility Name:	SDG&E Palomar Energy Center
Equipment Type:	20F – Combined Cycle Gas Turbine Power Plant
Application #:	APCD2015-APP-003970 (PTO-000623)
	APCD2015-APP-003971 (PTO-000625)
ID#:	APCD2001-SITE-04276
Equipment/Facility Address:	2300 Haverson Place
	Escondido, CA 92029
Facility Contact:	Jason Bowman, (760)432-2547
Permit Engineer:	4/14/2016 X Nicholas Horres Air Pollution Control Engineer Signed by: Nicholas Horres
Senior Engineer Signature:	4/14/2016 X John Annicchiarico John Annicchiarico Senior Air Pollution Control Engineer Signed by: John Annicchiarico

1.0 Background

1.1 Type of application.
These applications are to modify existing gas turbine engines as part of an engine overhaul. Improved engine components will allow a small increase in gas turbine heat input, energy output and efficiency.

1.2 Permit History.
This equipment was originally applied for in 2006. The initial permits were issued in 2011. The equipment was modified in 2014 by APCD2013-APP-003153 to replace the control software.

1.3 Facility Description.
This is a combined cycle gas turbine power plant used to produce power for the grid. The only other permitted equipment at this facility other than the two gas turbines includes 2011-PTO-000873 which is a 1945 hp emergency natural gas fired engine.

1.4 Other background info.
This is a title V site.

2.0 Process Description

2.1 Equipment Description.

PTO-000623: Power Station Unit No.1 (West or Unit No.1) consisting of: one 176 MW rated natural-gas fired combined-cycle General Electric Power Systems Frame 7FA gas turbine generator (combustion turbine), max heat input 1765 MMBtu/hr, S/N 298258, with dry low-NOx combustors, a heat recovery steam generator, a 195 MMbtu/hr (HHV) auxiliary duct burner, a Peerless Selective Catalytic Reduction unit (SCR) [with a Cormetech catalyst block, a Peerless Ammonia Vaporizer Skid], an Engelhart oxidation catalyst, a steam turbine generator shared with Power Station Unit No. 2, and an Emerson Ovation control system with low-load emissions and startup fuel gas heating capability.

Centralized chiller plant of 9800 ton refrigeration capacity or less, potentially including a thermal energy storage tank (3 to 5 million gallons), fixed and variable speed pumps and four (4) York chillers, Model YKZ1Z3J7-DHF, S/N's SATM-7832-20, SATM-7834-20, SATM-7920-40 and SATM-9722-70.

PTO-000625: Power Station Unit No.2 (East or Unit No.2) consisting of: one 176 MW rated natural-gas fired combined-cycle General Electric Power Systems Frame 7FA gas turbine generator (combustion turbine), max heat input 1765 MMBtu/hr, S/N 298257, with dry low-NOx combustors, a heat recovery steam generator, a 195 MMbtu/hr (HHV) auxiliary duct burner, a Peerless Selective Catalytic Reduction unit (SCR) [with a Cormetech catalyst block, a Peerless Ammonia Vaporizer Skid], an Engelhart oxidation catalyst, a steam turbine generator shared with Power Station Unit No. 1, and an Emerson Ovation control system with low-load emissions and startup fuel gas heating capability.

Centralized chiller plant of 9800 ton refrigeration capacity or less, potentially including a thermal energy storage tank (3 to 5 million gallons), fixed and variable speed pumps and four (4) York chillers, Model YKZ1Z3J7-DHF, S/N's SATM-7832-20, SATM-7834-20, SATM-7920-40 and SATM-9722-70.

A shared 130,000 gallons per minute (GPM) wet cooling tower system and high efficiency drift eliminators.

2.2 Process Description.

Combined cycle gas turbine power plant with two combustion turbines and one steam turbine. The purpose of this application is to modify the gas turbines using a hot gas path modification during the next planned overhaul. This modification allows the gas turbines to fire slightly more fuel while using slightly less cooling air resulting in increased power output and increased efficiency.

2.3 Emissions Controls.

These turbines are equipped with DLN combustors to control emissions at the point of generation. Additionally emissions are further lowered by in-stack controls including an oxidation catalyst for CO and VOC control and an SCR catalyst with ammonia injection for NOx control. This application does not affect the emission controls since the small

increase in fuel input will not affect the ability of the controls to meet emission requirements.

2.4 Attachments.

None.

3.0 Emissions

3.1 Emissions estimate summary.

Estimated emissions from the process are shown below.

Table 1: Estimated PTE for criteria pollutants (Post-project)

	lb/hr	lb/day	ton/yr
NOx	400	796.0	99
CO	2000	4108	99
VOC	14.6	392	49
PM-10	28	672.0	99
SOx	8.1	221.1	33.9

Table 2: Pre-Project Emissions

	Combined PTE			Pre-Project Actual Emissions*
	lb/hr	lb/day	ton/yr	ton/yr
NOx	400	796.0	104.3	59.8
CO	2000	4108	313.7	7.1
VOC	14.6	392	50	28.8
PM-10	28	672	104.8	8.1
SOx	8.0	190.9	33.1	23.6

Table 3: Emission Increase

	Emission Increase			actual->potential
	lb/hr	lb/day	ton/yr	ton/yr
NOx	0	0.0	-5.3	-5.3
CO	0	0.0	-214.7	91.9
VOC	0	0.0	-1	20.2
PM-10	0	0.0	-5.8	90.9
SOx	0.19	30.2	0.78	10.3
NH3	0.57	13.8	2.51	36.9

3.2 Estimated Emissions Assumptions.

Post-Project PTE

-Calculated based on combination of permit limits and calculations. NOx, CO, VOC and PM-10 lb/hr emissions are limited by pre-project permit conditions which will not change as part of this modification.
-Post-Project Emissions of NOx, CO, VOC and PM-10 are further limited on an annual basis (ton/yr) by permit limits.
-Daily emissions of PM-10, NOx, CO and SOx are effectively limited by hourly permit conditions.
-Daily post-project emissions of SOx assumed to increase proportionally according to the increase in maximum hourly fuel use (1938.29MMBtu/hr / 1893.58MMBtu/hr)=1.0236 → 2.36% increase.

Pre-Project PTE

Based on current permit limits when available and for other pollutants and time-periods copied from the original FDOC prepared for these turbines with the exception of SOx emissions. Assumptions are the same as those used in the FDOC and account for permit limitations.

Emission Increase

-SOx emissions assume pre-modification fuel use of 1893.58 MMBtu/hr (HHV) and post-modification fuel use of 1938.29 MMBtu/hr (HHV) both including duct burner heat input.
-For all criteria pollutants, hourly and daily emission increases are assessed on a potential to potential basis.
-As will be discussed in section 4.2, the emission increase for this project is calculated by comparing pre-project potential to post project potential emissions. These calculations are contained in the emission increase column. Calculations of emission increase on an "actual->potential" (actual to potential) basis were also calculated and shown for reference. However, as will be explained in section 4.2, this calculation methodology was found not to be necessary for permit evaluation.
-The emission increase for toxic emissions was calculated based on the estimated increase in hourly and annual maximum fuel use. Default emission factors for turbines and an assumed control efficiency of 50% were used to calculate toxic emissions.

General

-Fuel is assumed to contain 0.75 grains total sulfur per 100 dscf natural gas.
-Natural gas heat content (HHV) of 1020 btu/scf. Ratio of HHV/LHV=1.1.
-Default F-factor of 8710 dscf/MMBtu natural gas.
-Maximum heat input for each turbine-duct burner combo of 1893.6 MMBtu/hr before project and 1938.3 MMBtu/hr after project (Both on an HHV basis)
-Other assumptions and procedures may be contained in the individual calculation sheets.

3.3 Emissions Calculations.

See original FDOC and attached spreadsheets. The emission increase shown in the tables above was calculated according to the methods described by District rules 20.1-20.3. Generally, potential emissions are calculated by multiplying maximum fuel use for an hour, day and annually by the emission rate (lb/MMBtu) calculated from converting the emission concentration using EPA method 19 equations. Elevated emissions during startup and shutdown are added to these emission rates. Finally if permit conditions further limit the emissions of any pollutant, potential to emit is lowered to match to corresponding emission limit.

3.4 Attachments.
None.

4.0 Applicable Rules

4.1 District Prohibitory Rules

District prohibitory rules that apply to this equipment have not changed since the issuance of the permit. The only requirement affected by the modification is the NOx emission concentration limit of Rule 69.3.1 which depends on efficiency; however, since this modification will result in an increase in efficiency, the allowable emission concentration under the rule will increase. The emission limit on the applicable permit condition is not proposed to be changed as part of this modification, and therefore the equipment is expected to comply with all applicable prohibitory rules if current permit conditions are complied with.

4.2 New Source Review (NSR) Rule 20.1-20.4

1. Applicability. *20.3(a)*: This rule applies to any new or modified major stationary source, to any new or modified emission unit and to any relocated emission unit being moved from a stationary source if, after completion of the project, the stationary source will be a major stationary source or a Prevention of Significant Deterioration (PSD) Stationary Source.
This equipment is located a major source, and therefore rule 20.3 applies to the equipment. After completion of the project the stationary source is expected to be a major source of NOx and will not be a PSD stationary source. This will be ensured through permit conditions limiting emissions of NOx, CO and PM-10 to 99 ton/yr for both turbines and 49 ton/yr VOC for both turbines combined.

2. Best Available Control Technology (BACT). 20.3(d)(1)(i): Except as provided in Subsection (d)(1)(v), any new or modified emission unit which has any increase in its potential to emit particulate matter (PM10), oxides of nitrogen (NOx), volatile organic compounds (VOC), or oxides of sulfur (SOx) and which unit has a post-project potential to emit 10 pounds per day or more of PM10, NOx, VOC or SOx shall be equipped with BACT for each such air contaminant.
Emissions from each unit exceed 10 lb/day for PM-10, NOx, VOC and SOx. However, BACT requirements are triggered for a modification only if there is an emission increase for that pollutant. To determine the correct procedure for calculating the emission increase for the project, the following considerations applied:
a. This equipment was installed under the terms of an A/C that was evaluated according to the District's NSR rules including the requirement to install BACT for NOx, VOC, PM-10 and SOx.

b. Emissions of NOx were previously offset during the initial application phase and annual emissions have not subsequently been increased beyond this level

c. Annual emissions of NOx, VOC and PM-10 will be limited by enforceable permit conditions

d. The emission calculation procedures described in rule 20.1 apply on an "air-contaminant specific" basis, so the procedures for calculating emissions described in rule 20.1 for major sources apply only to NOx emissions.

These considerations result in the District finding that there is no emission increase for NOx, VOC or PM-10 as shown in the emission calculation section. There is a minor increase in SOx emissions, so BACT requirements are triggered for SOx.

SOx: Emissions of SOx increase for this application based on the estimated increase in fuel use. Therefore BACT requirements are triggered and apply only to the potential to emit increase. The increase in fuel use results in an increase in SOx of less than 1 ton per year and therefore no add on controls are cost-effective. As determined in the previous analysis, BACT for SOx is the use of PUC quality natural gas with no more than 0.75 gr S/scf.

<u>3. Lowest Achievable Emission Rate (LAER).</u> *20.3(d)(1)(v).* …LAER shall be required for each new, modified, relocated or replacement emission unit which results in an emissions increase which constitutes a new major source or major modification. LAER shall be required only for those air contaminants and their precursors for which the stationary source is major and for which the District is classified as non-attainment of a national ambient air quality standard.
The District is classified as non-attainment of ozone (both NOx and VOC are ozone precursors), and therefore the project must be analyzed to determine whether it results in a major modification. Since this source is only major for NOx, only the emission increase of NOx must be reviewed.

To determine if the increase of NOx emissions results in a major modification, the "contemporaneous emission increase" of NOx must be determined. The contemporaneous emission increase includes all emission increase expected to occur within the 4 years preceding the modification and the year following. These applications are the only modifications occurring within this time frame. The contemporaneous emission increase of NOx emissions is determined to be 0. This is because the annual potential to emit is decreasing, and since more than the 99 ton/yr NOx PTE was previously offset Rule 20.1(d)(1)(i) defines the emission increase as post-project minus pre-project PTE (the decrease in permitted emissions is not considered part of the contemporaneous increase because it is not an actual emission reduction).

This project does not result in a new major source or major modification and therefore LAER is not required.

<u>4. Air Quality Impact Analysis (AQIA)</u>. *20.3(d)(2)(i)*: This rule requires new/modified sources that exceed the emissions limits in the table below to perform an AQIA.

Table 3: AQIA Emission Limits

	Emission Rate		
Air Contaminant	(lb/hr)	(lb/day)	(tons/yr)
Particulate Matter (PM10)	---	100	15
Oxides of Nitrogen (NOx)	25	250	40
Oxides of Sulfur (SOx)	25	250	40
Carbon Monoxide (CO)	100	550	100
Lead and Lead Cmpds.	---	3.2	0.6

-As shown in the emission calculation section and described under the BACT section above, the project does not result in an increase in potential to emit above these levels, and therefore an AQIA is not required.

5. Prevention of Significant Deterioration (PSD). *20.3(d)(3)*: The Air Pollution Control Officer shall not issue an Authority to Construct or modified Permit to Operate for any project which is expected to have a significant impact on any Class I area, as determined by an AQIA required pursuant to Subsection (d)(2), unless the following requirements are satisfied...
Previously this source was considered to be a PSD source based on the assumptions used to calculate emissions and the annual NOx emission limit that resulted in Potential to emit of NOx, CO and PM-10 in excess of 100 ton/yr. However, based on review of the actual operating history of the facility the applicant and the District have determined that the facility can be operated with a PTE of less than 99 ton/yr of each of these pollutants. To ensure enforceability, permit conditions will ensure that emissions from this source do not exceed 99 ton/yr and include appropriate monitoring and recordkeeping conditions. Therefore, this source is not considered a PSD source under District rules.

6. Public Notice and Comment. *20.3(d)(4)*: The Air Pollution Control Officer shall not issue an Authority to Construct or modified Permit to Operate for any project subject to the AQIA or notification requirements of Subsection (d)(2) or (d)(3), nor for any project which results in an emissions increase of VOCs equal to or greater than 250 pounds per day or 40 tons per year, unless the following requirements are satisfied...
This modification did not require an AQIA, did not result in an emission increase of VOC in excess of this level and did not result in a PSD modification. Therefore, no public notice is required under this section. However, as discussed in the title V section below, this application will be processed under the "enhanced A/C" procedure which will include the same public notice requirement that would have been required under this section.

7. LAER and Federal Offset Requirements. 20.3(d)(8). The determination that a project at an existing major stationary source is a major modification and is subject to the LAER and federal emission offsets provisions of this Subsection (d)(8) shall be based on the stationary source's contemporaneous emission increases.
As described under the discussion of LAER above, this project is a major source of NOx, but is not considered a major modification because the contemporaneous emission

increase of NOx is 0 which does not result in a major modification. Therefore, LAER and federal offsets are not required.

4.3 Toxic New Source Review – Rule 1200

1. Applicability. *1200(a)*: Except as provided in Section (b) of this rule, this rule applies to any new, relocated, or modified emission unit which may increase emissions of one or more toxic air contaminant(s) and for which an Authority to Construct or Permit to Operate is required pursuant to Rule 10…
-*This application may result in an increase in emissions of toxic air contaminants, and therefore a health risk assessment was required to evaluate compliance with Rule 1200.*

<u>Standards</u>

<u>2. Cancer Risk</u>. *1200(d)(1)*:
Cancer Risk
(i) T-BACT Not Applied. The increase in maximum incremental cancer risk at every receptor location is equal to or less than one in one million for any project for which new, relocated, or modified emission units that increases maximum incremental cancer risk are not equipped with T-BACT; and
(ii) T-BACT Applied. Except as provided in (d)(1)(iii), the increase in maximum incremental cancer risk at every receptor location is equal to or less than 10 in one million for any project for which all new, relocated, or modified emission units that increases maximum incremental cancer risk are equipped with T-BACT.
-*The increase in maximum incremental cancer risk from this project is below one in one million based on results of the HRA, and therefore this requirement is satisfied.*

<u>3. Total Acute Non-Cancer Risk</u>. *1200(d)(2).* The increase in the total acute noncancer health hazard index at every receptor location as a result of the project is equal to or less than one unless the Air Pollution Control Officer, after consulting with the state OEHHA, determines that an alternate total acute noncancer health hazard index is sufficiently health protective…
-The increase in total acute non cancer health effects (HHI) determined by the results of the HRA is below one which satisfies this requirement.

<u>4. Total Chronic Non-Cancer Risk</u>. *1200(d)(3).* The increase in the total chronic noncancer health hazard index at every receptor location as a result of the project is equal to or less than one unless the Air Pollution Control Officer, after consulting with the state OEHHA, determines that an alternate total chronic noncancer health hazard index is sufficiently health protective…
-The increase in total chronic non cancer health effects (HHI) determined by the results of the HRA is below one which satisfies this requirement.

4.4 AB3205

This application does not result in an emission increase within 1000 feet of a school, and therefore no public notice is required under this section.

4.5 State and Federal Regulations.

This equipment is subject to NSPS GG and if the turbines were considered "modified", would be subject to NSPS KKKK. This application is not expected to affect requirements of these rule. This is for two reasons:

1. The applications do not constitute a "modification" as defined in the NSPS general provisions and do not result in the turbines being subject to NSPS subpart KKKK instead of GG. A modification would occur if the emission rate of a pollutant for which the rule has a standard (NOx and SO_2) may increase in terms of kg/hr. This application only results in an increase in hourly SOx emissions, however when converted to units of kg/hr, based on emissions of 3.98 lb/hr compared to 4.07 lb/hr and a conversion factor of 2.205 lb/kg, the kg/hr emission rate would not change from 1.8 kg/hr (the standard is assumed to have two significant figures).

2. Even if the increase was sufficient to be considered a modification, the modified turbines would only be subject to the sulfur standards under NSPS KKKK. The current natural gas sulfur limit of 0.75 gr S/ 100 scf ensures compliance with the KKKK sulfur standard as well.

4.6 Title V.

The District determined that the proposed changes to the equipment and permit conditions will constitute a significant modification to the Title V permit as defined in District Rule 1401(c)(44)(iv) since the revised permit will contain additional and lowered annual emission limits that have been voluntarily accepted to qualify as exempt from District PSD and other potentially applicable requirements of District NSR rules. To streamline the procedure to modify the Title V permit once the modifications have been completed, the District processed the application under procedures to issue an "enhanced A/C". An enhanced A/C allows for public notice to be conducted as would be required for a significant modification at the time the A/C is issued allowing the Title V permit to be modified using an administrative amendment at the proper time. District Rule 1410(q) contains the requirements and procedures for enhanced authorities to construct as follows:

1. Application Requirements. *Rule 1410(q)(1).*This section requires the submittal of a compliance plan for the modified unit, the submittal of a description of the methods the applicant proposes to use to determine compliance, a schedule for the submission of initial compliance certifications and any other information.
In accordance with District policy for enhanced authorities to construct, the compliance plan is outlined within the application submittal documents and subsequent correspondence with the permittee. This information is further discussed in this evaluation demonstrating that all applicable requirements are satisfied. The methods that will be used to demonstrate compliance are specified in permit. Permit conditions specify the schedule for submittal of compliance certifications.

2. Authority to Construct Requirements. *Rule 1410(q)(2)*. This section specifies that the authority to construct must include a compliance schedule if the source is not already in compliance and require the submission of an initial compliance certification no later than one year following the completion of the modification.
This source is expected to be in compliance and does not require a compliance schedule. Permit conditions specify the submittal of an initial compliance certification.

3. Noticing Requirements (Prior to A/C Issuance). *Rule 1410(q)(3)-(6)*. This section essentially requires the fulfillment of the same noticing requirements that would apply to a significant Title V modification:

Part (i) requires that a public notice be conducted
A notice (attached) will be published in the San Diego Union Tribune and all relevant documents posted on the District's website allowing for a 30 day public comment period. The notice will also be distributed through the District's applicable listserv's.

Part(ii) requires that a public hearing be conducted if requested by petitioning the APCO.
This is specified in the public notice to be distributed and a hearing will be conducted if so petitioned.

Part (iii) requires the submittal of a draft of the proposed A/C to affected states and EPA region IX for a 45 day period.
A copy of the draft A/C, this evaluation and its attachments will be distributed to interested parties including the EPA and affected states including tribal agencies (SCAQMD, ICAPCD, Pechanga and Pala) and ARB.
If any comments are received, this section may be updated prior to the issuance of the ATC to reflect the comment response.

5.0 Recommendations

This modified equipment is expected to comply with all rules and regulations. Therefore, I recommend that an authority to construct be issued with the following

6.0 Recommended Conditions

See attached proposed draft conditions (attachment 2) and draft A/C.

ENGINEERING EVALUATION
ATTACHMENTS

Attachment 1: Relevant Emission Calculation Tables

Table A-1: Annual NOx and Fuel/Heat Input Data from EPA Acid Rain Database and calculation of pre-project NOx emissions

	Data from EPA Acid Rain Database					
	NOx (ton/yr)			Heat input (MMBtu)		
	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total
2010	35.0	31.0	66.0	11080341	11384149	22464489
2011	20.4	24.9	45.2	7087249	8396559	15483808
2012	25.9	27.4	53.3	9767287	9922832	19690118
2013	34.1	35.6	69.6	13353188	13166659	26519847
2014	25.7	24.2	49.9	9560522	8796482	18357005
13-'14 AVG[1]			59.8			22438426
5-yr AVG[2]			56.8			20503053

Table A-2: Annual CO and PM-10 Emissions calculated from actual heat input reported to EPA

	Calculated from Acid Rain HI and ST Results					
	CO (ton/yr)			PM-10 (ton/yr)		
	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total
2010	9.61	5.58	15.20	17.66	17.19	34.85
2011	0.98	4.08	5.06	2.43	7.67	10.10
2012	2.67	0.73	3.39	3.06	1.33	4.39
2013	4.51	3.78	8.29	1.54	3.68	5.22
2014	4.70	1.13	5.83	5.00	6.06	11.06
13-'14 AVG[1]			7.1			8.1
5-yr AVG[2]			7.6			13.1

Table A-3: Max calendar day NOx emissions reported to EPA

	Max NOx (lb/day)			
	Unit 1	Unit 2	Total	Combined (time-specific)[3]
2010	328	350	678	658
2011	388	398	786	572
2012	270	302	572	502
2013	318	270	588	480
2014	392	338	730	620

Table A-4: Max calendar day heat input reported to EPA

	Max Fuel (MMBtu/day)			
	Unit 1	Unit 2	Total	Combined (time-specific)[3]
2010	44368.4	44597.6	88966	88966
2011	43345	43393.8	86738.8	86738.8

2012	45051.5	45218	90269.5	90269.5
2013	44210.2	44259	88469.2	88469.2
2014	46386.6	46111.9	92498.5	92134.4

Table A-5: CO and PM-10 source test results for each unit during the pre-project calculation period

	CO (lb/MMBtu)		PM-10 (lb/MMBtu)	
	Unit 1	Unit 2	Unit 1	Unit 2
2010	1.73E-03	9.81E-04	3.19E-03	3.02E-03
2011	2.77E-04	9.71E-04	6.85E-04	1.83E-03
2012	5.46E-04	1.46E-04	6.27E-04	2.68E-04
2013	6.76E-04	5.75E-04	2.31E-04	5.59E-04
2014	9.83E-04	2.58E-04	1.05E-03	1.38E-03

Calculation Notes:

1. The average for 2013-2014 for NOx and Fuel Input is shown since this was the basis for pre-project actual emission calculations.
2. The 5-year rolling average is shown for comparison purposes
3. "Combined (time-specific)" refers to the maximum value for the two units combined in a specific day, whereas "total" indicates the sum of the maximum daily values for each individual unit that may occur on different calendar days.

Table A-6: Table of emission limits and maximum PTE.

	Based on Current Permit										
		PTE (unadjusted)			Special limits				Combined		
	Conc. (ppmvd @ 15% O2)	lb/hr	lb/day	ton/yr	lb/hr[b]	lb/hr[c]	lb/hr[d]	ton/yr[e]	lb/hr	lb/day	ton/yr
NOx	2	13.96	335.1	61.2	13.4	14.9	400	104.3	400	796.0	104.3
CO	4	17.0	407.9	74.4	16.3	18.1	2000	NA	2000	4108	313.7
VOC	2	4.9	116.5	21.3	4	7.3	NA	50	14.6	392	50
PM-10	NA	14	336.0	61.3	NA	NA	NA	NA	28	672	104.8
SOx	NA	3.98	95.5	17.4	NA	NA	NA	NA	8.0	190.9	33.1
NH3	5	12.1	291.4	53.2	NA	NA	NA	NA	24.3	582.7	106.3
	Proposed Permit										
		PTE (unadjusted)			Special limits				Combined		
	Conc. (ppmvd @ 15% O2)	lb/hr	lb/day	ton/yr	lb/hr[a]	lb/hr[b]	lb/hr[c]	ton/yr[d]	lb/hr	lb/day	ton/yr
NOx	2	14.29	343.0	62.6	13.4	14.9	400	99	400	814.8	99
CO	4	17.4	417.5	76.2	16.3	18.1	2000	99	2000	4205	99
VOC	2	5.0	119.3	21.8	4	7.3	NA	49	14.6	401	49
PM-10	NA	14	336.0	61.3	NA	NA	NA	99	28	672	99
SOx	NA	4.07	97.7	17.8	NA	NA	NA	NA	8.1	221	33.9
NH3	5	12.4	298.2	54.4	NA	NA	NA	NA	24.9	596	108.9

Notes:
a. Shaded cells are values defined by permit conditions. Unshaded values are values calculated by converting emission concentrations to emission factors using EPA method 19 equations and multiplying by the maximum heat input over the appropriate time period (values within the 'PTE (unadjusted)' columns) or as otherwise described in emission calculations section (lb/day combined emissions).
b. Limit based on 3-hour average with Duct Burner < 19.5 MMBtu/hr (startup, shutdown, low-load exempt)
c. Limit based on 3-hour average with Duct Burner > 19.5 MMBtu/hr (startup, shutdown, low-load exempt)
d. Combined limit for both turbines during startups, shutdowns, low-load and tuning operations
e. Combined annual limits for both turbines including all emissions

Attachment 2: Draft Conditions for Palomar Energy Center

The following are the draft permit conditions for the Palomar Energy Center enhanced A/C.

1. This equipment shall be properly maintained and kept in good operating condition at all times. [C584]

2. The unit shall be fired on Public Utility Commission (PUC) quality natural gas only. The permittee shall maintain quarterly records of sulfur content (grains/100 dscf) and higher and lower heating values (Btu/dscf) of the natural gas and provide such records to the District personnel upon request. [C25580]

3. The permittee shall comply with all the applicable provisions of 40 CFR 73, including requirements to offset, hold and retire SO2 allowances. [C29512]

4. For purposes of determining compliance based on source testing, the average of three subtests shall be used. For purposes of determining compliance with emission limits based on the CEMS, data collected in accordance with the CEMS protocol shall be used and averaging periods shall be as specified herein. [C40181]

5. When the unit is combusting fuel (operating), the concentration of oxides of Nitrogen (NOx), calculated as nitrogen dioxide (NO2) and measured in the exhaust stack, shall not exceed 2.0 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen, except during periods of startup, shutdown, low load operation, or tuning. The following averaging periods shall apply to CEMS data:

   A. During any clock hour when duct firing above 19.5 MMBTU/hr heat input is occurring (a "duct-fired hour"): 3-clock hour average, calculated as the average of the duct fired hour, the clock hour immediately prior to and the clock hour immediately following the duct-fired hour.
   B. For any clock hour during which the change in gross electrical output produced by the combustion turbine exceeds 50 MW per minute for one minute or longer (transient hour): 3-clock hour average, calculated as the average of the transient hour, the clock hour immediately prior to and the clock hour immediately following the transient hour.
   C. All other hours: 1-clock-hour average. (NSR) [C40182]

6. When the unit is operating, the concentration of CO measured in the exhaust stack shall not exceed 4.0 ppmvd corrected to 15% oxygen, except during periods of startup, shutdown, low load operation, or tuning. A 3-clock hour averaging period shall apply to CEMS data. (NSR) [C40183]

7. When the unit is operating, the VOC concentration, calculated as methane and measured in the exhaust stack, shall not exceed 2.0 ppmvd corrected to 15% oxygen, except during periods of startup, shutdown, low load operation, or tuning. For purposes of determining compliance based on

the CEMS, the District approved VOC/CO surrogate relationship, the CO CEMS data, and a 3-clock hour average shall be used in accordance with the CEMS protocol. The VOC/CO surrogate relationship shall be verified and/or modified, if necessary, based on source testing. (NSR) [C40184]

8. When the unit is operating, the Ammonia concentration (Ammonia slip) measured in the exhaust stack, shall not exceed 5.0 ppmvd corrected to 15% oxygen, except during periods of startup, low load, or tuning. [C40185]

9. When the unit is operating, the concentration of Oxides of Nitrogen (NOx), calculated as nitrogen dioxide (NO2) and measured in the exhaust stack, shall not exceed 11.8 ppmvd corrected to 15% oxygen, averaged over each clock hour period, except for exempt periods of operation during startup, combined-cycle gas turbine extended startup, shutdowns, and low load operation, as defined in Rule 69.3.1. All CEMS calculations and averages shall be performed in accordance with the CEMS protocol approved by the District. [Rule 69.3.1(d)(1)] [C40186]

10. When the unit is operating, the concentration of Oxides of Nitrogen (NOx), calculated as Nitrogen Dioxide (NO2) and measured in the exhaust stack, shall not exceed 42 ppmvd corrected to 15% oxygen, calculated over each clock hour period except for periods of Startup or Shutdown, as defined in Rule 69.3. All CEMS calculations, averages shall be performed in accordance with the CEMS protocol approved by the District. [Rule 69.3.] [C40187]

11. The emissions of particulate matter less than 10 microns (PM-10) shall not exceed 14.0 lbs/hr for each unit with and without duct burner firing. [C40188]

12. The discharge of particulate matter from the exhaust stack of the unit shall not exceed 0.10 grains per dry standard cubic foot (0.23 grams/dscm). The District may require periodic testing to verify compliance with this standard. (Rule 53) [C40189]

13. Visible emissions from the lube oil vents and the exhaust stack of the unit shall not exceed 20% opacity for more than three (3) minutes in any period of 60 consecutive minutes. (Rule 50) [C40190]

14. When operating with the duct burner at or below 19.5 MMBTU/hr heat input, mass emissions from each unit shall not exceed the following limits, except during periods of startup, shutdown, low load operation, or tuning. A 3 clock-hour averaging period for these limits shall apply to CEMS data except for NOx emissions during non-transient hours when a 1 clock-hour averaging period shall apply.

Pollutant	Emission Limit, lbs/hr
A) Oxides of Nitrogen, NOx (calculated as NO2)	13.4
B) Carbon Monoxide, CO	16.3
C) Volatile Organic Compounds, VOC	4.0

[C40191]

15. When operating with the duct burner firing above 19.5 MMBTU/hr heat input, mass emissions from each unit shall not exceed the following emission limits, except during periods of startup, shutdown, low load operation, or tuning. A 3-clock-hour averaging period shall apply to CEMS data

Pollutant	Emission Limit, lbs/hr
A) Oxides of Nitrogen, NOx (calculated as NO2)	14.9
B) Carbon Monoxide, CO	18.1
C) Volatile Organic Compounds, VOC	7.3

[C40192]

16. Total combined NOx emissions from both units shall not exceed 400 pounds per hour, calculated as Nitrogen Dioxide and measured over each 1-clock-hour period. These emission limits shall apply during all times during which one or both units are operating, including, but not limited to, emissions during periods of startup, shutdown, low load operation and tuning. In addition, Unit No. 1 shall not begin operating while Unit No. 2 is already operating in a startup period nor shall Unit No. 2 begin operating while Unit No. 1 is already operating in a startup period unless the unit already operating in a startup period meets all of the following in the clock-minute immediately preceding the clock-minute that the other unit begins operating:
A) has been operating with a gross electrical output from the combustion turbine of 64 MW or more during the preceding 10 consecutive-clock-minute period;
B) the concentration of NOx, calculated as NO2 and measured in the exhaust stack, does not exceed 2.0 ppmvd corrected to 15% oxygen; and
C) the concentration of CO measured in the exhaust stack does not exceed 4.0 ppmvd corrected to 15% oxygen. (Rule 20.3(d)(2)(i)) [C40193]

17. Total combined CO emissions from both units shall not exceed 2,000 pounds per hour measured over each 1-clock-hour period. This emission limit shall apply during all times that one or both units are operating, including, but not limited to emissions during periods of startup, shutdown, low load operation and tuning. (Rule 20.3(d) (2)(i)) [C40194]

18. Total emissions from all stationary emission units at this stationary source, except emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d)(1) as it exists on the date the permit to operate for this equipment is approved, shall not exceed the following limits for each rolling 12-calendar-month period:

Pollutant	**Emission Limit, tons per year**
a. Oxides of Nitrogen, NOx (calculated as NO2)	**99**
b. Carbon Monoxide, CO	**99**
c. Volatile Organic Compounds, VOC	**49**
d. PM10	**99**

The aggregate emissions of each pollutant shall include emissions during all times that the equipment is operating. All calculations performed to show compliance with this limit shall be performed according to a protocol approved in advance by the District. [Rules 20.3(d)(1)-20.3(d)(5), 20.3(d)(8), and 21] [NEW1]

19. The owner or operator shall obtain written authorization from the District prior to making any changes to the annual emission calculation protocol. Any approved changes to the protocol shall take effect no earlier than 30 days after requesting approval of the modified protocol unless an alternative is stated in writing by the District. [NEW2]

20. For each calendar month and each rolling 12-calendar-month period, the Permittee shall maintain records, as applicable, on a calendar monthly basis, of mass emissions during each calendar month and rolling 12-calendar-month period of NOx (calculated as NO2), CO, VOC (calculated as methane), PM10, and SOx (calculated as SO2), in tons, from each emission unit located at this stationary source, except for emissions or emission units excluded from the calculation of aggregate potential to emit as specified in Rule 20.1 (d)(1) as it exists on the date the permit to operate for this equipment is approved. These records shall be made available for inspection within 30 calendar days after the end of each calendar month. [Rules 20.3(d)(5), 20.3(d)(8) and 21] [Modified C40197]

21. The emissions of any single Federal Hazardous Air Pollutant (HAP) shall not equal or exceed 10 tons, and the aggregate emissions of all Federal HAPs shall not equal or exceed 25 tons in any rolling 12-calendar month period. Compliance with these single and aggregate HAP limits shall be based on a methodology approved by the District for the purpose of calculating HAP emissions for this permit. If emissions exceed these limits, the permittee shall apply to amend permit to reflect applicable Federal Maximum Achievable Control Technology (MACT) standards and requirements in accordance with applicable provisions (including timing requirements) of 40 CFR Part 63. [C40198]

22. The maximum total dissolved solids (TDS) concentration of the water used in the cooling towers shall not exceed 4,000 mg/l. This concentration shall be verified through quarterly testing of the water by a certified lab using EPA approved methods. [C40199]

23. When combusting fuel, Ammonia shall be injected at all times that the SCR outlet temperature is 510 degrees Fahrenheit or greater. [C40200]

24. The Ammonia injection flow rate shall be continuously measured, recorded and controlled. The Ammonia injection flow control equipment shall be installed, calibrated and maintained in accordance with a District approved protocol. [C40201]

25. Except during periods when the Ammonia injection system is being tuned or one or more Ammonia injection systems is in manual control (for compliance with applicable permits), the automatic Ammonia injection system serving the SCR shall be in operation in accordance with manufacturer's specifications at all times when Ammonia is being injected into the SCR. Manufacturer specifications shall be maintained on site and made available to District personnel upon request. [C40202]

26. The concentration of Ammonia solution used in the Ammonia injection system shall be less than 20% ammonia by weight. Records of Ammonia solution concentration shall be maintained on site and made available to District personnel upon request. [C40203]

27. For purposes of determining compliance with the emission limits of this permit, a shutdown period is the period of time that begins with the lowering of the gross electrical output of the combustion turbine below 64 MW and that ends five minutes after fuel flow to the combustion turbine ceases, not to exceed 65 consecutive minutes. [C40204]

28. A startup period is the period of time that begins when fuel flows to the combustion turbine following a non-operational period. For purposes of determining compliance with the emission limits of this permit, the duration of a startup period shall not exceed 120 consecutive minutes if the steam turbine reheat bowl temperature is above 500° F when the startup period begins and shall not exceed 360 consecutive minutes if the steam turbine reheat bowl temperature is less than or equal to 500° F when the startup period begins. [C40205]

29. Low load operation is a period of time that begins when the gross electrical output (load) of the combustion turbine is reduced below 64 MW from a higher load and that ends 10 consecutive minutes after the combustion turbine load next exceeds 64 MW provided that fuel is continuously combusted during the entire period and one or more clock hour concentration emission limits specified in this permit are exceeded as a result of the low-load operation. Periods of operation at low load shall not exceed 130 minutes in any calendar day nor an aggregate of 780 minutes in any calendar year, and no period of operation at low load shall begin during a startup period. [C40206]

30. Tuning is defined as adjustments to the combustion system that involves operating the unit in a manner such that the emissions control equipment may not be fully effective or operational. Only one combustion turbine will be tuned at any given time. Tuning events shall not exceed 480 minutes in a calendar day nor exceed 40 hours in a calendar year. The District compliance division shall be notified at least 24 hours in advance of any tuning event. [C40207]

31. A CEMS Protocol is a document approved in writing by the APCD M&TS division that describes the Quality Assurance and Quality Control procedures for monitoring, calculating and recording stack emissions from the unit. [C40208]

32. This unit shall be source tested to demonstrate compliance with the NOx, CO, VOC, PM-10, and Ammonia emission standards of this permit, using District approved methods. The source test and the NOx and CO Relative Accuracy Test Audit (RATA) tests shall be conducted in accordance with the applicable RATA frequency requirements of 40 CFR75, appendix B, sections 2.3.1 and 2.3.3. [C40209]

33. A Relative Accuracy Test Audit (RATA) and all other required certification tests shall be performed and completed on the CEMS in accordance with applicable provisions of 40 CFR part 75 Appendix A and B performance specifications. At least 30 days prior to the test date, the permittee shall submit a test protocol to the District for approval. Additionally, the District shall be notified a minimum of 21 days prior to the test so that observers may be present. [C40210]

34. If source testing will be performed by an independent contractor and witnessed by the District, a source test protocol shall be submitted to the District for written approval at least 30 days prior to source testing. The source test protocol shall comply with the following requirements:
A. Measurements of NOX, CO, and O2 emissions shall be conducted in accordance with U.S. Environmental Protection Agency (EPA) methods 7E, 10, and 3A, respectively, and District Source Test, method 100, or alternative methods approved by the District and EPA.
B. Measurement of VOC emissions shall be conducted in accordance with EPA Methods 25A and/or 18, or alternative methods approved by the District and EPA.
C. Measurements of ammonia emissions shall be conducted in accordance with Bay Area Air Quality Management District ST-1B or an alternative method approved by the District and EPA.
D. Measurements of PM-10 emissions shall be conducted in accordance with EPA Methods 201A and 202 or alternative methods approved by the district and EPA.
E. Source testing shall be performed with both the combustion turbine and the duct burner in operation. Each duct burner shall operate with a minimum heat input of 97 MMBTU/hr.
F. Source testing shall be performed at the most frequently used load level, as specified in 40 CFR Part 75 Appendix A Section 6.5.2.1.d, provided it is not less than 80% of the unit's rated load unless it is demonstrated to the satisfaction of the district that the unit cannot operate under these conditions . If the demonstration is accepted, then emissions source testing shall be performed at the highest achievable continuous level power level.
G. Measurements of particulate matter emissions shall be conducted in accordance with SDAPCD Method 5 or an alternative method approved by the District and EPA.
H. Measurements of opacity shall be conducted in accordance with EPA Method 9 or an alternative method approved by the District and EPA.
I. Measurement of fuel flow shall be conducted in accordance with an approved test protocol. [C40211]

35. Within 45 days after completion of the renewal source test or RATA, a final test report shall be submitted to the District for review and approval. [C40212]

36. The Oxides of Nitrogen (NOx) and Oxygen (O2) CEMs shall be certified and maintained in accordance with applicable federal regulations including the requirements of Sections 75.10 and 75.12 of Title 40, Code of Federal Regulations Part 75 (40 CFR75), the performance specifications of Appendix A of 40 CFR 75, the quality assurance procedures of Appendix B of 40 CFR 75 and the CEMs protocol approved by the District. The Carbon Monoxide (CO) CEMs shall be certified and maintained in accordance with 40 CFR 60, Appendices B and F, unless otherwise specified in this permit. [C26608]

37. Continuous emission monitoring system (CEMS) shall be installed and properly maintained and calibrated to measure, calculate and record the following, in accordance with the District approved CEMS protocol:
A. Hourly average concentration of Oxides of Nitrogen (NOX) corrected to 15% oxygen, in parts per million (ppmvd);
B. Concentration of Carbon Monoxide (CO) corrected to 15% oxygen, in parts per million (ppmvd);
C. Percent oxygen (O2) in the exhaust gas (%) for each clock hour period;
D. Average concentration of Oxides of Nitrogen (NOX) for each rolling 3-hour period, in parts per million (ppmv) corrected to 15% oxygen;
E. Hourly and Monthly mass emissions of Oxides of Nitrogen (NOX), in pounds;
F. Rolling 12 month mass emissions of Oxides of Nitrogen (NOX), in tons;
G. Hourly and monthly mass emissions of Carbon Monoxide (CO), in pounds;
H. Annual mass emissions of Carbon Monoxide (CO), in tons.
I. Natural gas flow rate to combustion turbine in scf/hr.
J. Natural gas flow rate to duct burner in scf/hr.
K. Concentration of Volatile Organic Compounds (VOC) corrected to 15% oxygen, in parts per million (pmvd) for each rolling 3-hour period, based upon the approved VOC/CO surrogate relationship.
M. Hourly and monthly mass emissions of VOC in pounds
N. Rolling 12-month mass emissions of VOC in tons.
The CEMS shall be in operation in accordance with the District approved CEMS monitoring protocol at all times when the combustion turbine is in operation. A copy of the District approved CEMS monitoring protocol shall be maintained on site and made available to District personnel upon request. [C40214]

38. When the CEMs is not recording data and the unit is operating, hourly NOx emissions annual calculations shall be determined in accordance with 40 CFR 75 Appendix C. Additionally, hourly CO emissions for the annual emission calculations shall be determined using the hourly emission rate recorded by the CEMs during the most recent hours in which the unit operated 3 continuous hours at no less than 80% of full power rating. Alternate CO emission factors shall be determined from compliance source test emissions data. The alternate hourly CO emission rate shall be reviewed and approved by the District, in writing. [C29524]

39. Any violation of any emission standard as indicated by the CEMs shall be reported to the District's Compliance Division within 96 hours after such occurrence. [C28009]

40. The CEMs shall be maintained and operated, and reports submitted, in accordance with the requirements of Rule 19.2 sections (d), (e), (f)(2),(f)(3), (f)(4) and (f)(5) and CEMs protocol approved by the District. [C24368]

41. The District shall be notified at least two weeks prior to any changes made in CEMS software that affect the measurement, calculation or correction of data displayed and/or recorded by the CEMS. [C26609]

42. Fuel flowmeters with an accuracy of +/- 2% shall be maintained to measure the volumetric flow rate corrected for temperature and pressure. Correction factors and constants shall be maintained on site and made available to the District upon request. The fuel flowmeters shall meet the applicable quality assurance requirements of 40 CFR Part 75, Appendix D, and Section 2.1.6. [C40215]

43. The unit shall be equipped with continuous monitors to measure, calculate and record the following operational characteristics:
A. Ammonia injection rate in lb/hr of solution.
B. Outlet temperature of SCR in degrees Fahrenheit.
C. Combustion turbine power output (MW).
D. Steam turbine reheat bowl temperature in degrees Fahrenheit.
The monitors shall be installed, calibrated, and maintained in accordance with a protocol approved by the District, which shall include any relevant calculation methodologies. The monitors shall be in full operation at all times when the combustion turbine is in operation. Calibration records for the continuous monitors shall be maintained on site and made available to the District upon request. [C40216]

44. Operating logs or Data Acquisition System (DAS) records shall be maintained to record the beginning and end times and durations of all startups, shutdowns, low load operations, and tuning periods to the nearest minute; quantity of fuel used (in each clock hour, calendar month, and 12 calendar month period) in standard cubic feet; hours of daily operation; and total cumulative hours of operation during each calendar year. [C40217]

45. All records required by this written permit shall be maintained on site for a minimum of five years and made available to the District upon request. (Title V) [C40218]

46. Access, facilities, utilities and any necessary safety equipment for source testing and inspection shall be provided upon request of the Air Pollution Control District. [CHW001]

47. The District may require one or more of the following compounds, or additional compounds to be quantified through source testing periodically to ensure compliance with rule 1200:
A) Acetaldehyde
B) Acrolein
C) Benzene
D) Formaldehyde
E) Toluene
F) Xylenes
If the District requires the permittee to perform this source testing, the District shall request the testing in writing a reasonable period of time prior to the testing date, and the permittee shall submit a source test protocol to the District for written approval at least 30 days prior to the testing date. [C40213]

48. This Air Pollution Control District Permit does not relieve the holder from obtaining permits or authorizations required by other governmental agencies. [CHW002]

49. The permittee shall, upon determination of applicability and written notification by the District, comply with all applicable requirements of the Air Toxics "Hot Spots" Information and Assessment Act (California Health and Safety Code Section 44300 et seq.) [CHW003]

Proposed A/C Only Conditions:

50. The conditions stated in this authorization shall take effect upon completion of construction of the modified equipment as described in applications APCD2015-APP-003970 and APCD2015-APP-003971. Any conditions referring to hour, day, month, year, clock hour, calendar day, calendar month or calendar year shall apply to the entire duration of that period if the equipment is operated for any portion of the corresponding period under this authorization. This condition does not relieve the owner or operator from complying with any other applicable conditions of other permits or authorizations.

51. Prior to operating the modified emission unit, the permittee shall submit an initial certification of compliance, To the District and EPA, for the modified emission unit, in accordance with Rule 1414(f)(3)(ix), and 40 CFR 70.5(c)(9), that includes the identification of each applicable term or condition of the final permit for which the compliance status is being certified, the current compliance status and whether the modified equipment was in continuous or intermittent compliance during the certification period, identification of the applicable permitted method used to determine compliance during the certification period, and any other information required by the District to determine the compliance status. This requirement may be fulfilled by submitting District form 1401-I along with the construction completion notice. The modified equipment shall not be operated until written

authorization is received from the District in accordance with Rule 1410(b)(2) or the permittee has submitted an application for an administrative amendment in accordance with Rule 1410(q)(6).

52. Not later than 60 calendar days after completion of construction for each combustion turbine, an Initial Emissions Source Test shall be conducted on that turbine to demonstrate compliance with the NOx, CO, VOC, PM10, and ammonia emission standards of this permit. The source test shall be conducted according to an approved protocol if testing is not performed by the District and the protocol shall comply with all applicable requirements dictated in this permit for routine source tests and/or RATAs. The protocol shall be submitted to the District for approval at least 60 days prior to the proposed test date.

53. After completion of construction, the NOx and O_2 CEMs described in this permit shall be recertified according to the timelines and applicable requirements of Sections 75.10 and 75.12 of Title 40, Code of Federal Regulations Part 75 (40 CFR75), the performance specifications of Appendix A of 40 CFR 75, the quality assurance procedures of Appendix B of 40 CFR 75 and the CEMs protocol approved by the District. The Carbon Monoxide (CO) CEMs shall be recertified in accordance with 40 CFR 60, Appendices B and F, unless otherwise specified in this permit.

54. After completion of construction, a Relative Accuracy Test Audit (RATA) and all other required certification tests shall be performed and completed on the CEMS in accordance with applicable provisions of 40 CFR part 75 Appendix A and B performance specifications. At least 30 days prior to the test date, the permittee shall submit a test protocol to the District for approval. Additionally, the District shall be notified a minimum of 21 days prior to the test so that observers may be present.

55. At least 30 days prior to completion of construction of this equipment, the owner or operator shall submit a protocol to the District for approval to be used in calculating emissions to show compliance with all annual (ton/yr) emission limits of this permit. The protocol must contain the following information/meet the following requirements:

a. The protocol must provide procedures for calculating annual emissions of NOx, CO, VOC and PM10.
b. NOx and CO emissions from the combustion turbine shall be calculated using CEMS data during all periods CEMS data is valid. For all other times the protocol must specify data substitution procedures or other calculation methodology.
c. During all times except periods of startup, shutdown, low load operation and tuning, VOC and PM10 emissions from the combustion turbine shall be calculated using measured fuel flow and/or operating time and the results of the most recent District witnessed source tests. The protocol shall specify procedures for calculating emissions during all other times for these pollutants.
d. Total emissions from the combustion turbines shall include the sum of all emissions during all periods of operation.
e. The protocol shall also specify procedures for calculating annual emissions from emission units located at this source, other than the combustion turbines, if they are subject to the annual emission limit included in this permit. These emissions shall be added to the totals for the combustion turbines to determine emissions from the stationary source.
f. For any parameter used in calculating emissions that is measured in more than one location (e.g. fuel flow) or using more than one monitoring protocol or procedure, an indication of which monitoring location, protocol or procedure will be used for this calculation.
g. Averaging times or other aggregation procedures for CEMS data if different than those specified in the applicable CEMS protocol.
h. For any instance where the CEMS protocol provides for correcting raw CEMS data prior to reporting, an indication of whether corrected or uncorrected data will be used for the calculation.