Commonwealth of Kentucky
Division for Air Quality

PERMIT STATEMENT OF BASIS

TITLE V/PSD/PHASE II ACID RAIN DRAFT PERMIT NO. V-01-018

WESTLAKE ENERGY CORPORATION
CALVERT CITY, KY.

NOVEMBER 2, 2001
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PLANT I.D. # 21-157-00054
APPLICATION LOG # 51381 (G601)

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A. **SOURCE DESCRIPTION**

The Westlake Energy Corporation facility will consist of 2 natural gas-fired combustion turbine units and associated equipment for electricity generation in Calvert City in Marshall County, Kentucky. The turbines will operate in combined cycle mode, in which heat from the combustion turbine will be recovered in a heat recovery steam generator (HRSG), producing steam which will be used to run a steam turbine. The HRSGs have natural gas-fired duct burners for supplemental firing. Other emission units will be cooling towers, a diesel-fired emergency fire pump, and a diesel fuel storage tank. The facility is to be a baseload plant that produces electricity on a consistent basis year-round (8760 hours per year). The facility will have an electric generating capacity of 520 megawatts (MW) in combined cycle mode. Although some of the electricity generated will be used at other nearby Westlake facilities, most of the electrical output will be for sale to the power grid.

Turbine Manufacturer
The 2 combustion turbines will be either GE 7FA , Siemens-Westinghouse 501F, or Siemens V84.3A turbines with a nominal output capacity of 170-180 MW each. The PSD review and permit limitations have taken into consideration the differences in emissions and operating parameters for each manufacturer.

2-on-1 or 2-on-2 layout
The facility will be constructed in either "2-on-1" layout consisting of two combustion turbines with supplemental duct-fired HRSGs routing to one 160 MW steam turbine, or in "2-on-2" layout consisting of two separate units, each with a combustion turbine with supplemental duct-fired HRSGs routing to an 80 MW steam turbine. The layout does not affect emission rates or permit conditions, only the arrangement of equipment and exhaust stacks and number of cooling towers. Each combustion turbine is to be equipped with its own exhaust stack.

B. **PROJECT DESCRIPTION**

This permit is a sourcewide, initial-issuance Title V, PSD, and Phase II Acid Rain permit authorizing construction and operation of this new facility.

The proposed facility meets the definition of a major source in state regulation 401 KAR 51:017, Prevention of significant deterioration (PSD) of air quality, and is subject to evaluation and review under the provisions of the PSD regulation for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2) and volatile organic compounds (VOC). The PSD preliminary determination is provided in this statement of basis for the Title V permit. This review demonstrates that all regulatory requirements will be met and includes a draft permit which establishes the enforceability of all applicable requirements.

The Division received a Title V/PSD/Acid Rain permit application (log # 51381/G601) to construct and operate the following affected facilities for electricity generation from Westlake Energy Corporation on March 8, 2000. Additional information was requested on numerous occasions and responses received on June 12, 2000; March 1, June 15, June 18, June 21, July 18, July 25, August 28, and August 29, 2001. The application was logged complete on August 9, 2000.
A copy of the application was sent to EPA on June 7, 2001. A copy of the application was sent to the Federal Land Manager by the source's consultant and by EPA Region 4.

Affected Emission Units:
- (2) 170-180 MW, 1515 MMBtu/hr natural gas-fired combined cycle combustion turbine units with 585 MMBtu/hr natural gas-fired duct burners for supplemental firing in the HRSGs with exhaust gases routed to (1) 160 MW or (2) 80 MW steam turbine(s).
- 300 hp diesel-fired emergency fire pump
- diesel fuel storage tank
- (1) 8-cell or (2) 4-cell cooling towers
- paved roads

Types of controls and efficiencies:

- Selective Catalytic Reduction (SCR) and Dry Low-NO_x Burners on the combustion turbines for NO_x
- Catalytic Oxidation for CO, VOC, and HAPs

Emissions analysis:

The electricity generation operations will consist of (2) natural gas-fired combined cycle combustion turbines (nominally 170 MW each) equipped with dry low NOx burners, and (1) 160 MW or (2) 80 MW steam turbines. Emissions from the combustion turbines are from natural gas products of combustion and are based on operating conditions of 61°F ambient temperature and a natural gas lower heating value of 1003 Btu/scf. The turbine operating schedule is a maximum of 2221 hours of startup and shutdown time (defined as less than 70% load) consisting of 10 cold starts, 50 warm starts, 100 hot starts, and associated shutdowns and downtime, and 6539 hours of operation (at or above 70% load) at 100% load with supplemental duct firing. All maximums are federally-enforceable permit conditions. Emission rates for NO_x, CO, PM/PM_{10}, SO_2, and VOC were taken from manufacturers' estimates using proposed BACT limits and an SO_2 emission rate of 2.0 gr S/100 dscf. HAP emissions were calculated using factors derived from the California Air Toxics Emission Factors (CATEF) database and 8760 hours/year of operation at 100% load with supplemental duct firing. Ammonia (NH_3) emissions are based on an ammonia slip of 10 ppmvd at 15% O_2 from the SCR. There are no pollutant emissions from the steam turbine(s) since there is no fuel combustion.

Emissions from the cooling tower are from entrained liquid droplets, known as drift, that are carried out the tower exhaust fan duct. Dissolved solids in the drift may become particulate after evaporation of the drift water droplets. Particulate emissions are based on the calculation procedures in AP-42 Section 13.4 (Fifth edition, 1995) modified to account for high-efficiency drift eliminators which limit drift to 0.0006% of the circulating water rate. PM_{10} emissions are further calculated using the dissolved solids properties and drift particle size tests from high efficiency drift eliminators similar to what will be installed at Westlake Energy.

A diesel-fired emergency fire pump will operate 500 hours or less per year during emergencies and weekly testing. Criteria pollutant emissions are based on manufacturer's rated capacity and emission rate data for an example unit, the Caterpillar Model 3306B.

Fugitive particulate emissions from vehicle traffic on paved roads were calculated using AP-42 Section 13.2.1 (October 1997) calculation procedures and an estimation of the vehicle traffic on the roads.

Potential to emit:

Sourcewide potential emissions, including the permitted operational limitations and BACT limits, are as listed in the following Tables 1, 2, and 3.

Table 1. Emissions using GE 7FA turbine

Pollutant	Emission rate (tpy)					
	CT/HRSG 1	CT/HRSG 2	Cooling Towers	Fire Pump	Paved Roads	**Sourcewide Total**
NO_x	66.46	66.46	--	1.86	--	**134.78**
CO	84.51	84.51	--	0.16	--	**169.18**
PM_{10}	44.14	44.14	1.01	0.013	0.011	**89.32**
SO_2	39.09	39.09	--	0.03	--	**78.20**
VOC	73.48	73.48	--	0.16	--	**147.11**
Total HAP	4.70	4.70	--	--	--	**9.40**
1,3-Butadiene 106-99-0	0.0004	0.0004	--	--	--	**0.0009**
Acetaldehyde 75-07-0	0.98	0.98	--	--	--	**1.96**
Acrolein	0.23	0.23	--	--	--	**0.46**

107-02-8						
Benzene 71-43-2	0.17	0.17	--	--	--	**0.33**
Formaldehyde 50-00-0	2.34	2.34	--	--	--	**4.68**
Napthalene 91-20-3	0.03	0.03	--	--	--	**0.05**
Propylene Oxide 75-56-9	0.19	0.19	--	--	--	**0.39**
Toluene 108-88-3	0.56	0.56	--	--	--	**1.11**
Total Xylene 1330-20-7	0.21	0.21	--	--	--	**0.41**
Ammonia	88.86	88.86	--	--	--	**177.72**

Table 2. Emissions using Siemens-Westinghouse 501F turbine

Pollutant	Emission rate (tpy)					
	CT/HRSG 1	CT/HRSG 2	Cooling Towers	Fire Pump	Paved Roads	**Sourcewide Total**
NO_x	85.48	85.48	--	1.86	--	**172.83**
CO	221.01	221.01	--	0.16	--	**442.19**
PM_{10}	51.10	51.10	1.01	0.013	0.011	**103.24**
SO_2	40.49	40.49	--	0.03	--	**81.00**
VOC	108.21	108.21	--	0.16	--	**216.57**
Total HAP	4.70	4.70	--	--	--	**9.40**
1,3-Butadiene 106-99-0	0.0004	0.0004	--	--	--	**0.0009**
Acetaldehyde 75-07-0	0.98	0.98	--	--	--	**1.96**
Acrolein 107-02-8	0.23	0.23	--	--	--	**0.46**
Benzene 71-43-2	0.17	0.17	--	--	--	**0.33**
Formaldehyde 50-00-0	2.34	2.34	--	--	--	**4.68**
Napthalene 91-20-3	0.03	0.03	--	--	--	**0.05**
Propylene Oxide 75-56-9	0.19	0.19	--	--	--	**0.39**
Toluene 108-88-3	0.56	0.56	--	--	--	**1.11**
Total Xylene 1330-20-7	0.21	0.21	--	--	--	**0.41**
Ammonia	88.86	88.86	--	--	--	**177.72**

Table 3. Emissions using Siemens V84.3A turbine

Pollutant	Emission rate (tpy)					
	CT/HRSG 1	CT/HRSG 2	Cooling Towers	Fire Pump	Paved Roads	**Sourcewide Total**

NO_x	86.43	86.43	--	1.86	--	**174.73**
CO	40.07	40.07	--	0.16	--	**80.30**
PM_{10}	8.85	8.85	1.01	0.013	0.011	**18.73**
SO_2	29.80	29.80	--	0.03	--	**59.62**
VOC	25.69	25.69	--	0.16	--	**51.54**
Total HAP	4.70	4.70	--	--	--	**9.40**
1,3-Butadiene 106-99-0	0.0004	0.0004	--	--	--	**0.0009**
Acetaldehyde 75-07-0	0.98	0.98	--	--	--	**1.96**
Acrolein 107-02-8	0.23	0.23	--	--	--	**0.46**
Benzene 71-43-2	0.17	0.17	--	--	--	**0.33**
Formaldehyde 50-00-0	2.34	2.34	--	--	--	**4.68**
Napthalene 91-20-3	0.03	0.03	--	--	--	**0.05**
Propylene Oxide 75-56-9	0.19	0.19	--	--	--	**0.39**
Toluene 108-88-3	0.56	0.56	--	--	--	**1.11**
Total Xylene 1330-20-7	0.21	0.21	--	--	--	**0.41**
Ammonia	88.86	88.86	--	--	--	**177.72**

Applicable regulations:

The following air quality regulations are applicable to this project.

- 401 KAR 51:017 (40 CFR 52.21), Prevention of significant deterioration (PSD) of air quality, applies to the proposed plant which will be located in Marshall County which is currently designated as “attainment” or “unclassified” for each of these pollutants pursuant to Regulation 401 KAR 51:010, Attainment status designations, and 40 CFR 81.318. The proposed plant has the potential to emit more than 100 tons per year of one or more regulated criteria pollutants. Since the proposed Westlake Energy facility is to be located in an area designated as attainment or unclassified for all criteria pollutants and since its emissions of at least one regulated pollutant will exceed 100 tons per year, it is a major source subject to the PSD regulations.

- 401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, for emissions units with a heat input at peak load equal to or greater than 10 MMBTU/hour for which construction commences after October 3, 1977, applies to each of the gas-fired combustion turbines. The BACT requirements of PSD are more stringent than the NO_x and SO_2 emission standards in Subpart GG , and therefore BACT will supercede these standards.

- 401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart Da, Standards of Performance For Electric Utility Steam Generating Units, for emissions units capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel for which construction or modification is commenced after September 18, 1978, applies to each of the heat recovery steam generating units (HRSG). Each HRSG meets the definition of electric utility steam generating unit since it has a capacity of 585 MMBtu/hr (171 MW) and a potential electric output capacity of 56 MW, all or most of which will be for sale to the power grid.

- Acid Rain regulations, 40 CFR 72 through 40 CFR 78 apply. This source is required to apply for a phase II acid rain permit. Part 75 requires continuous emission monitoring.

Multiple applicable requirements:
Streamlining multiple applicable requirements per White Paper 2 was performed in order to allow the permittee to comply with the more stringent PSD limits instead of all the requirements in PSD and the NSPS regulations. In addition, compliance will be determined at a single sampling point (in the HRSG exhaust duct) instead of at 2 sampling points (at the inlet and outlet of the duct burner).

For Subpart Da:
1. For NO_x, using the procedure in 40 CFR 60.46a (k)(2) with a BACT limit of 2.5 ppmvd gives an emission rate of 0.02 lb/MWh, which is less than the Da standard of 1.6 lb/MWh. This procedure itself accounts for a single sampling point instead of multiple sampling points.
2. For SO_2, the BACT emission rates of 3.7, 3.6, and 0.6 lb/hr (for each turbine model) from just the duct burners are less than the Da standard of 0.02 lb/MMBtu * 585 MMBtu.hr = 11.7 lb/hr.
3. For PM_{10}, the BACT emission rates of 10.4, 10.4, and 2.0 lb/hr (for each turbine model) from just the duct burners are less than the Da standard of 0.03 lb/MMBtu * 585 MMBtu.hr = 17.6 lb/hr.

For Subpart GG:
1. For NO_x, using the procedure in 40 CFR 60.46a (k)(1) with a BACT limit of 2.5 ppmvd and zero pollutant contribution from the duct burner gives an emission rate of 3.46 ppmvd which is less than the GG standard of 75 ppmvd.
2. For SO_2, the BACT limit of 2 gr/100 dscf = 0.01% is less than the GG standard of 0.8%. The location of the sampling point does not affect this limit.

Since compliance with the PSD BACT limits ensures compliance with the NSPS limits, compliance methods developed for PSD supercede the compliance methods in Subparts Da and GG. The compliance methods developed for PSD include testing, monitoring, recordkeeping, and reporting requirements for all PSD pollutants.

Non-Applicable regulations:
Regulation 401 KAR 50:012 does not apply to the proposed facility because it is subject to other standards specified in the Kentucky Administrative Regulations.

Emission and Operating Caps description:
N/A

Operational Flexibility:
N/A

Credible Evidence:
This permit contains provisions which require that specific test methods, monitoring or recordkeeping be used as a demonstration of compliance with permit limits. On February 24, 1997, the U.S. EPA promulgated revisions to the following federal regulations: 40 CFR Part 51, Sec. 51.212; 40 CFR Part 52, Sec. 52.12; 40 CFR Part 52, Sec. 52.30; 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12, that allow the use of credible evidence to establish compliance with applicable requirements. At the issuance of this permit, Kentucky has not incorporated these provisions in its air quality regulations.

C. **PSD REVIEW**

1. APPLICABILITY

The proposed plant will be a major source as defined in state regulation 401 KAR 51:017, Prevention of significant deterioration (PSD) of air quality, because it belongs to one of the 28 source categories and has potential emissions of nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2) and volatile organic compounds (VOC) in excess of 100 tons per year. Potential emissions of NO_x, CO, PM/PM_{10}, SO_2 and VOC are emitted in quantities greater than the PSD significant emission rates as presented in Regulation 401 KAR 51:017, Section 22. The source will be located in Marshall County, which is classified as "attainment" or "unclassified" for each of these pollutants pursuant to Regulation 401 KAR 51:010, Attainment status designations. Consequently, the proposed facility meets the definition of a major stationary source and is subject to evaluation and review under Sections 9 through 17 of the PSD regulation for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2) and volatile organic compounds (VOC).

2. BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

Pursuant to Regulation 401 KAR 51:017, Section 9(1) and (2), a major stationary source subject to a PSD review shall meet the following requirements:

1. The proposed source shall apply the best available control technology (BACT) for each pollutant that it will have the potential to emit in significant amounts.
2. The proposed source shall meet each applicable emissions limitation under Title 401, KAR 50 to 68, and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63.

Westlake Energy has presented in the permit application a study of the best available control technology for pollutants NO_x, CO, PM/PM_{10}, SO_2, and VOC from each emissions unit in the proposed source. The source used EPA methodologies in EPA Best Available Control Technology Draft Guidance Document (October 1990), EPA Region 9 BACT Guidelines, and the OAQPS Control Cost Manual (4th Edition), and budgetary quotations from equipment manufacturers (not included in the application) and other engineering estimates to determine capital and annual costs of feasible technologies and control levels.

The Division has reviewed the proposed control technology in conjunction with information available in the U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database. A summary of the control technology determined to be the best available control technology for each pollutant and each emissions unit is presented below:

Table 4. Combined Cycle Natural Gas Combustion Turbines without supplemental duct firing

Pollutant	Best Available Control Technology	GE 7FA BACT limits	WEC 501F BACT limits	SiemensV84.3A BACT limits
NO_x	Selective Catalytic Reduction (SCR) with Dry Low NO_x Burners (DLNB) with emission rate of 2.5 ppmvd @ 15% O_2	2.5 ppmvd at 15 % oxygen 14.3 lb/hr (3-hour average)	2.5 ppmvd at 15 % oxygen 14.7 lb/hr (3-hour average)	2.5 ppmvd at 15 % oxygen 14.5 lb/hr (3-hour average)
CO	Catalytic Oxidation with 80% reduction	1.5 ppmvd at 15 % oxygen 5.1 lb/hr (3-hour average)	2.0 ppmvd at 15 % oxygen 7.2 lb/hr (3-hour average)	1.0 ppmvd at 15 % oxygen 3.5 lb/hr (3-hour average)
PM/PM_{10}	Good combustion practices	10.7 lb/hr (3-hour average)	16.9 lb/hr (3-hour average)	6.5 lb/hr (3-hour average)
SO_2	Pipeline quality natural gas combustion	2.0 gr/100 dscf fuel sulfur content 8.3 lb/hr (3-hour average)	2.0 gr/100 dscf fuel sulfur content 8.6 lb/hr (3-hour average)	2.0 gr/100 dscf fuel sulfur content 8.4 lb/hr (3-hour average)

VOC	Catalytic Oxidation with 50% reduction	0.7 ppmvd at 15 % oxygen 1.3 lb/hr (3-hour average)	1.5 ppmvd at 15 % oxygen 3.1 lb/hr (3-hour average)	0.6 ppmvd at 15 % oxygen 1.1 lb/hr (3-hour average)

Table 5. Combined Cycle Natural Gas Combustion Turbines with supplemental duct firing

Pollutant	Best Available Control Technology	GE 7FA BACT limits	WEC 501F BACT limits	SiemensV84.3A BACT limits
NO_x	Selective Catalytic Reduction (SCR) with Dry Low NO_x Burners (DLNB) with emission rate of 2.5 ppmvd @ 15% O_2	2.5 ppmvd at 15 % oxygen 19.1 lb/hr (3-hour average)	2.5 ppmvd at 15 % oxygen 19.7 lb/hr (3-hour average)	2.5 ppmvd at 15 % oxygen 15.6 lb/hr (3-hour average)
CO	Catalytic Oxidation with 80% reduction	3.1 ppmvd at 15 % oxygen 14.4 lb/hr (3-hour average)	3.4 ppmvd at 15 % oxygen 16.5 lb/hr (3-hour average)	1.5 ppmvd at 15 % oxygen 5.9 lb/hr (3-hour average)
PM/PM_{10}	Good combustion practices	21.1 lb/hr (3-hour average)	27.3 lb/hr (3-hour average)	7.5 lb/hr (3-hour average)
SO_2	Combustion of pipeline-quality natural gas	2.0 gr/100 dscf fuel sulfur content 11.9 lb/hr (?-hour average)	2.0 gr/100 dscf fuel sulfur content 12.3 lb/hr (?-hour average)	2.0 gr/100 dscf fuel sulfur content 9.0 lb/hr (?-hour average)
VOC	Catalytic Oxidation with 50% reduction	4.9 ppmvd at 15 % oxygen 13.0 lb/hr (3-hour average)	5.4 ppmvd at 15 % oxygen 14.8 lb/hr (3-hour average)	1.1 ppmvd at 15 % oxygen 2.4 lb/hr (3-hour average)

Table 6. Diesel-fired Emergency (< 500 hours/year) Fire Pump

Pollutant	Best Available Control Technology	BACT limits
NO_x	Good combustion practices	7.45 lb/hour
CO	Good combustion practices	0.65 lb/hour
PM/PM_{10}	Inlet air filtering, Good combustion practices	0.053 lb/hour
SO_2	Good combustion practices	0.10 lb/hour
VOC	Good combustion practices	0.63 lb/hour

Table 7. Cooling Tower

Pollutant	Best Available Control Technology	BACT limits

PM_{10}	High efficiency drift eliminators (0.0006% drift)	0.029 lb/hour per cell

a. BACT for Combined Cycle Natural Gas-Fired Combustion Turbines

This project is being proposed as a combined cycle, baseload power plant. Combined cycle turbines usually supply baseload power and represent the majority of listings in the EPA RACT/BACT/LAER Clearinghouse. A detailed discussion of the BACT determination submitted by Westlake Energy is located in the permit application. Following is a summary of the control technologies examined and final controls approved as BACT. Individual BACT limits were developed for each turbine model and, for some pollutants, for operating with and without supplemental duct firing.

NO_x

The following table lists potential NO_x control technology options that are included in the BACT analysis:

Table 8. Available NO_x Control Technologies for Westlake Energy

Control Technology	Determination
Combinations of control technologies	
Selective Catalytic Reduction (SCR) with Dry Low-NO_x Burner (DLNB)	**Suitable, selected;** Technically feasible, good temperature range, acceptable NO_x reduction. $2,485/ton removed for 2.5 ppmvd.
In-combustion controls	
XONON	**Not suitable;** Technical feasibility not demonstrated at this scale. Proprietary system means no market system to regulate costs and enforce product reliability.
Dry Low-NO_x Burner (DLNB)	**Suitable;** Technically feasible, good temperature range, good NO_x reduction. Standard equipment on some turbines. Considered to be baseline for evaluation.
Diluent Injection	**Suitable, but not considered**; Typically used only in fuel oil-fired units. May degrade reliability and operational life. NO_x reduction similar to or below DLNB.
Post-combustion controls	
$SCONO_x$™ 90+% reduction	**Suitable, but not cost-effective;** Technically feasible, good temperature range, acceptable NO_x reduction. $7,220/ton removed for 2.5 ppmvd.
Selective Catalytic Reduction (SCR) 70-90% reduction	**Suitable;** Technically feasible, good temperature range, good NO_x reduction.
Selective Non-catalytic Reduction (SNCR)	**Not suitable;** Not technically feasible since the turbine exhaust gas temperature is below the SNCR required temperature range.

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

Dry-low NO_x Burner (DLNB) – Dry low NO_x burners are in-combustor burners designed to reduce thermal NO_x emissions. The process involves using a two-stage combustor which ensures improved air/fuel mixing, reduced flame temperatures, and minimal excess air.

Selective Catalytic Reduction (SCR) – Selective catalytic reduction (SCR) systems involve the post-combustion removal of NO_x from flue gas with a catalytic reactor. These systems selectively reduce NO_x by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. The ammonia reacts with NO_x in the presence of the catalyst to form molecular nitrogen (N_2) and water. The portion of the unreacted ammonia that passes through the catalyst and is emitted from the stack is called ammonia slip. This control technique reduces both thermal NO_x and fuel NO_x in the exhaust streams. The performance and effectiveness of SCR systems are directly dependent on the temperature of the turbine exhaust gas when it passes through the catalyst. The temperature range is dictated by the catalyst, which is typically made from metals, or zeolite-based material. The typical

temperature range for base-metal catalysts is 600 to 800 °F. Keeping the exhaust gas temperature within this range is important. For combined cycle units, the ideal temperature window occurs at a point within the heat recovery steam generator.

SCONO$_x$ – SCONO$_x^{TM}$ is a catalytic oxidation and absorption system developed by Goal Line Environmental Technologies that uses a coated oxidation catalyst to remove both NO_x and CO. NO is oxidized to NO_2 and absorbed onto the catalytic surface. A regenerative gas periodically passes through the catalyst and de-sorbs the NO_2 and reduces it to N_2. CO is oxidized to CO_2. SCONO$_x^{TM}$ is a low-temperature back-end control system that operates effectively from 300 to 700 °F.

The source has proposed Dry Low-NO_x Burners and add-on SCR control system that reduces NO_x emissions to 2.5 ppmvd at 15% oxygen as BACT. The cost effectiveness of this emission rate over the Dry Low-NO_x Burner emission rate of 25.7 ppmvd at 15% oxygen is $2,485/ton. The energy and environmental impacts do not eliminate this control technology. The source has rejected SCONO$_x$ as BACT since the cost effectiveness of this control technology using an emission rate of 2.5 ppmvd over the Dry Low-NO_x Burner emission rate of 25.7 ppmvd at 15% oxygen is $7,220/ton. The division agrees that BACT is Dry Low-NO_x Burner with add-on SCR control system with an emission rate of 2.5 ppmvd at 15% oxygen. This control technology, emission rate, and cost effectiveness agree with or are more stringent than BACT for currently permitted similar projects.

CO

The following table lists potential CO control technology options are included in the BACT analysis:

Table 9. Available CO Control Technologies for Westlake Energy

Control Technology	Technical Feasibility Determination
Post-combustion controls	
Catalytic Oxidation	**Suitable, selected**; Technically feasible, acceptable CO reduction. Cost analysis not performed.
SCONO$_x^{TM}$	**Suitable, but not cost-effective for NO$_x$;** Technically feasible, good temperature range, acceptable CO reduction. Cost analysis not performed for CO.
In-combustion controls	
Good combustion practices	**Suitable, but not selected**; Technically feasible. Considered to be baseline for evaluation.

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

Good combustion practices – Good combustion practices in gas turbines involve combusting the fuel as efficiently as possible to reduce CO emissions. This requires proper air-to-fuel ratio and turbine design to achieve good mixing and turbulence, high combustion temperature and residence time. Note that the high combustion temperature for CO reduction is counterproductive to lowering the combustion temperature with NO_x control technology.

Catalytic Oxidation – Catalytic oxidation systems involve the post-combustion removal of CO from flue gas as it passes through a catalyst bed (typically a precious metal) where oxidation of CO to CO_2 takes place. The catalyst has an operating temperature of 500°F - 1500°F and an optimum temperature range of 650°F - 1100°F. The process is capable of reducing CO levels by 80 to 90 percent.

SCONO$_x$ – see description under the BACT review for NO_x.

The source has proposed a catalytic oxidation control system that reduces CO emissions by 80% as BACT. A cost effectiveness of this emission rate over a baseline of good combustion practices was not performed. Energy and environmental impacts analyses were not performed. The division agrees that BACT is catalytic oxidation with 80%

CO emissions reduction. This control technology agrees with or is more stringent than BACT for currently permitted similar projects.

PM/PM_{10}

The following table lists potential particulate matter control technology options that are included in the BACT analysis:

Table 10. Available PM/PM_{10} Control Technologies for Westlake Energy	
Control Technology	**Determination**
In-combustion controls	
Good combustion practices	**Suitable, selected;** Technically feasible. Standard operating procedures on some turbines.

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

> ***Good combustion practices*** – Standard operating procedures for the turbines include filtering inlet air and good combustion controls. Firing natural gas which contains only trace quantities of non-combustible material minimizes particulate emissions. This design includes optimum operational efficiency and the use of NO_x controls to limit NO_x emissions as particulate.

The source has proposed good combustion practices as BACT. A cost effectiveness of this emission rate was not performed. Energy and environmental impacts analyses were not performed. The division agrees that BACT is good combustion practices given that the emission unit will be combusting natural gas. This control technology agrees with or is more stringent than BACT for currently permitted similar projects, which do not require add-on particulate controls.

SO_2

The following table lists potential SO_2 control technology options that are included in the BACT analysis:

Table 11. Available SO_2 Control Technologies for Westlake Energy	
Control Technology	**Determination**
In-combustion controls	
Combustion of pipeline-quality natural gas	**Suitable, selected;** Technically feasible. Evaluated at 2.0 gr sulfur/100 dscf

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

> ***Combustion of pipeline-quality natural gas*** – Firing natural gas which qualifies as pipeline quality. Pipeline natural gas as defined in the Acid Rain Program means natural gas that is provided by a supplier through a pipeline and that contains 0.3 grains or less of hydrogen sulfide per 100 standard cubic feet and the hydrogen sulfide in content of the gas constitutes at least 50% (by weight) of the total sulfur in the fuel

The source has proposed combustion of pipeline-quality natural gas as BACT. A cost effectiveness of this emission rate was not performed. Energy and environmental impacts analyses were not performed. The division agrees that BACT is combustion of pipeline-quality natural gas with a maximum sulfur content of 2.0 grains of sulfur per 100 dscf. This control technology agrees with or is more stringent than BACT for currently permitted similar projects.

VOC

The following table lists potential VOC control technology options that are included in the BACT analysis:

Table 12. Available VOC Control Technologies for Westlake Energy

Control Technology	Technical Feasibility Determination
Post-combustion controls	
Catalytic Oxidation	**Suitable, selected**; Technically feasible, acceptable VOC reduction. Cost analysis not performed.
In-combustion controls	
Good combustion practices	**Suitable, but not selected**; Technically feasible. Considered to be baseline for evaluation.

See the CO BACT analysis for descriptions of the technically feasible control options listed in the table above. Measures to reduce CO emissions can also be used to reduce VOC emissions, although only the removal efficiency is much lower for VOC.

The source has proposed a catalytic oxidation control system that reduces VOC emissions by 50% as BACT. A cost effectiveness of this emission rate over a baseline of good combustion practices was not performed. Energy and environmental impacts analyses were not performed. The division agrees that BACT is catalytic oxidation with 50% VOC emissions reduction. This control technology agrees with or is more stringent than BACT for currently permitted similar projects.

b. BACT for Diesel-fired Emergency (< 500 hours/year) Fire Pump

A detailed discussion of the BACT determination submitted by Westlake Energy is located in the permit application. Following is a summary of the control technologies examined and final controls approved as BACT.

NO_x

The following table lists potential NO_x control technology options that are included in the BACT analysis:

Table 13. Available NO_x Control Technologies for Westlake Energy	
Control Technology	**Determination**
In-combustion controls	
Fuel Injection Timing Retardation (FITR)	**Suitable, but not selected**; Technically feasible, but reduces combustion efficiency and pump usefulness, which is counterproductive to maximum usefulness needed in emergency situations.
Good combustion practices	**Suitable, selected**; Technically feasible. Considered to be baseline for evaluation.
Post-combustion controls	
Selective Catalytic Reduction (SCR)	**Suitable, but not selected**; Technically feasible, but may not operate properly since optimal temperature range and emissions reductions may not reached during short operational periods. Not cost-effective since fire pump will not operate continuously.

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

Fuel Injection Timing Retardation (FITR) – FITR is an in-combustion process designed to reduce thermal NO_x emissions. The process involves delaying the start of fuel injection in order to reduce the engine's maximum combustion pressure and, therefore, lower the combustion temperature.

Good combustion practices – Good combustion practices in engines involves combusting the fuel as efficiently as possible to reduce NO_x emissions.

Selective Catalytic Reduction (SCR) – see description under the combustion turbine BACT review for NO_x.

The source has proposed good combustion practices as BACT. The energy and environmental impacts do not eliminate this control technology. The source has rejected FITR and SCR as BACT since the cost effectiveness of these control technologies over the baseline of good combustion practices is considered to be excessive, although cost effectiveness calculations were not performed. Both FITR and SCR have undesirable environmental impacts that contribute to their elimination as BACT. FITR increases the emissions of other pollutants. SCR has emissions of ammonia. The division agrees that BACT is good combustion practices. This control technology, emission rate, and cost effectiveness agree with or are more stringent than BACT for currently permitted similar projects.

CO

The following table lists potential CO control technology options are included in the BACT analysis:

Table 14. Available CO Control Technologies for Westlake Energy	
Control Technology	**Technical Feasibility Determination**
Post-combustion controls	
Catalytic Oxidation	**Suitable, but not selected**; Technically feasible, but may not operate properly since optimal temperature range and emissions reductions may not reached during short operational periods. Not cost-effective since fire pump will not operate continuously.
In-combustion controls	
Good combustion practices	**Suitable, selected**; Technically feasible. Considered to be baseline for evaluation.

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

Catalytic Oxidation – see description under the combustion turbine BACT review for CO
Good combustion practices – Good combustion practices in engines involves combusting the fuel as efficiently as possible to reduce CO emissions.

The source has proposed good combustion practices as BACT. The energy and environmental impacts do not eliminate this control technology. The source has rejected CatOx as BACT since the cost effectiveness of these control technologies over the baseline of good combustion practices is considered to be excessive, although cost effectiveness calculations were not performed. The division agrees that BACT is good combustion practices. This control technology, emission rate, and cost effectiveness agree with or are more stringent than BACT for currently permitted similar projects.

SO_2

The following table lists potential SO_2 control technology options that are included in the BACT analysis:

Table 15. Available SO_2 Control Technologies for Westlake Energy	
Control Technology	**Determination**
In-combustion controls	
Good combustion practices	**Suitable, selected;** Technically feasible.

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

Good combustion practices – Good combustion practices in engines involves combusting the fuel as efficiently as possible to reduce CO emissions.

The source has proposed good combustion practices as BACT. Energy and environmental impacts do not eliminate this control technology. The division agrees that BACT is good combustion practices. This control technology,

emission rate, and cost effectiveness agree with or are more stringent than BACT for currently permitted similar projects.

PM/PM_{10}

The following table lists potential particulate matter control technology options that are included in the BACT analysis:

Table 16. Available PM/PM_{10} Control Technologies for Westlake Energy	
Control Technology	**Determination**
In-combustion controls	
Good combustion practices	**Suitable, selected;** Technically feasible.

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

Good combustion practices – Standard operating procedures include filtering inlet air and as complete combustion of fuel as possible.

The source has proposed good combustion practices as BACT. Energy and environmental impacts do not eliminate this control technology. The division agrees that BACT is good combustion practices. This control technology, emission rate, and cost effectiveness agree with or are more stringent than BACT for currently permitted similar projects.

VOC

The following table lists potential VOC control technology options are included in the BACT analysis:

Table 17. Available VOC Control Technologies for Westlake Energy	
Control Technology	**Technical Feasibility Determination**
Post-combustion controls	
Catalytic Oxidation	**Suitable, but not selected**; Technically feasible, but may not operate properly since optimal temperature range and emissions reductions may not reached during short operational periods. Not cost-effective since fire pump will not operate continuously.
In-combustion controls	
Good combustion practices	**Suitable, selected**; Technically feasible. Considered to be baseline for evaluation.

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

Catalytic Oxidation – see description under the combustion turbine BACT review for CO

Good combustion practices – Good combustion practices in engines involves combusting the fuel as efficiently as possible to reduce VOC emissions.

The source has proposed good combustion practices as BACT. The energy and environmental impacts do not eliminate this control technology. The source has rejected CatOx as BACT since the cost effectiveness of these control technologies over the baseline of good combustion practices is considered to be excessive, although cost effectiveness calculations were not performed. The division agrees that BACT is good combustion practices. This control technology, emission rate, and cost effectiveness agree with or are more stringent than BACT for currently permitted similar projects.

c. BACT for Cooling Tower

PM/PM_{10}

The following table lists potential particulate matter control technology options that are included in the BACT analysis:

Table 18. Available PM/PM_{10} Control Technologies for Westlake Energy	
Control Technology	**Determination**
High efficiency drift eliminators (0.0006% drift)	**Suitable, selected;** Technically feasible.

The following are descriptions of the technically feasible control options that are considered in the BACT analysis:

High efficiency drift eliminators – Drift eliminators minimize drift, therefore reducing the dissolved/suspended solids particulate emissions formed as the water evaporates during the evaporative cooling. This proposed high-efficiency drift eliminator has a design rate of 0.0006% drift.

The source has proposed high-efficiency drift eliminators as BACT. A cost effectiveness of this emission rate was not performed. Energy and environmental impacts analyses were not performed. The division agrees that BACT is high-efficiency drift eliminators with a maximum drift rate of 0.006%. This control technology agrees with or is more stringent than BACT for currently permitted similar projects.

3. AIR QUALITY ANALYSIS

Pursuant to Regulation 401 KAR 51:017, Sections 10 - 12, Westlake Energy must demonstrate that allowable emission increases from the proposed source will not cause or contribute to air pollution in violation of a national ambient air quality standard (NAAQS) in an air quality control region, or an applicable maximum allowable increase over the baseline concentration in an area (Ambient Air Increment). Estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR Part 51, Appendix W ("Guideline on Air Quality Models (Revised)" (1986), Supplement A (1987), Supplement B (1993), and Supplement C (1996)).

The application contains an air quality analysis of the ambient impacts in the area that the proposed facility will affect for nitrogen oxides, carbon monoxide, particulate/particulate-10, sulfur dioxide, and volatile organic compounds. Modeling is not required for volatile organic compounds which have a BACT determination.

a. Dispersion Modeling Methodology

The application contains an air dispersion modeling analysis for criteria pollutants (nitrogen oxides, particulate/particulate-10, sulfur dioxide, and carbon monoxide) to determine the maximum ambient concentrations attributable to the proposed plant for each of these pollutants for comparison with:

1. The significant impact levels (SIL) found in 40 CFR 51.165 (b)(2).
2. The significant air quality impact/significant monitoring concentrations (SMC) found in Regulation 401 KAR 51:017, Section 24.
3. The Class I and Class II PSD increments found in Regulation 401 KAR 51:017, Section 23.
4. The National Ambient Air Quality Standards (NAAQS) found in Regulation 401 KAR 53:010, Ambient air quality standards.

All of the applicable air quality criteria are presented in the following table. Based on the U.S. EPA suggested procedures, if the maximum predicted impacts for any pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling would be required for such a pollutant. The applicant may also be exempted from the ambient monitoring data requirements if the impacts are below the significant monitoring concentrations.

Table 19. Air Quality Criteria

Pollutant	Averaging	SIL	SMC	PSD Class II	PSD Class I	NAAQS

	Period	(μg/m^3)	(μg/m^3)	Increments (μg/m^3)	Increments (μg/m^3)	(μg/m^3)
NO_2	Annual	1	14	25	2.5	100
CO	8-hour 1-hour	500 2000	575 NA	NA NA	NA NA	10000 40000
PM_{10}	Annual 24-hour	1 5	NA 10	17 30	4 8	50 150
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	20 91 512	2 5 25	80 365 1300

The permittee used the Industrial Source Complex Short Term model (ISCST3, Version 00101) in the analysis. The ISCST3 model fulfills the requirements of Supplement C of the Guideline on Air Quality Models (Appendix W to 40 CFR 51). All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with the prescribed usage for this model. Per EPA guidance, the ISCST3 model was run with the regulatory default using five consecutive years of meteorological data. ISC-ready surface data was taken from National Weather Station (NWS) at the Paducah, Kentucky, airport and concurrent upper air data taken from Salem, Illinois, from 1990 to 1994. See section 4.2 of the PDS application for details on the model selection and setup.

b. Dispersion Modeling results - Class II Area Impacts

The proposed facility will be located in Marshall County, a Class II area. The permittee modeled the impact of the emissions from the proposed facilities on the ambient air quality using emission rates that are higher than the permitted emission rates. The results of the modeled impacts on the Class II area have been presented in the Tables 20 and 21. The results for NO_x, PM_{10} (24-hour), and CO are from the application update submitted to the division on July 18, 2001. The results for PM_{10} (annual) and SO_2 are from the application update submitted to the division on August 28, 2001.

The modeling results show that the maximum impacts from the proposed facility for NO_x, CO, PM_{10}, and SO_2 are less than the EPA prescribed significant ambient impact levels (SIL) and the significant monitoring concentrations (SMC). Since the maximum predicted impacts for each pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling is required at this time. The applicant is also exempted from the ambient monitoring data requirements since the impacts are shown to be below the SMC.

Table 20. 2-on-1 Configuration Modeled Impacts

Pollutant	Averaging Period	SIL (μg/m^3)	SMC (μg/m^3)	Max Impact of Source Emissions (μg/m^3)
NO_2	Annual	1	14	0.95
CO	8-hour 1-hour	500 2000	575 NA	152 835
PM_{10}	Annual 24-hour	1 5	NA 10	0.379 4.86
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	0.23 4.93 11.29

Table 21. 2-on-2 Configuration Modeled Impacts

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	SMC ($\mu g/m^3$)	Max Impact of Source Emissions ($\mu g/m^3$)
NO_2	Annual	1	14	0.82
CO	8-hour 1-hour	500 2000	575 NA	60 994
PM_{10}	Annual 24-hour	1 5	NA 10	0.435 3.11
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	0.30 4.18 9.60

c. Dispersion Modeling Results - Class I Area Impacts

The nearest federally designated Class I areas to the proposed facility are Mammoth Cave National Park, Kentucky (200 km east) and Mingo National Wildlife Refuge, Missouri (145 km west-southwest). The permittee modeled the impact of the emissions from the proposed facilities on the ambient air quality in these Class I Areas using ISCST356 and emission rates that are higher than the permitted emission rates. The results of the modeled impacts on the Class I areas have been presented in the Table 22. The results are from the original application submitted to the division.

The modeling results show that the maximum impacts from the proposed facility for NO_x, PM_{10}, and SO_2 are less than the EPA prescribed significant ambient impact levels (SIL) and the significant monitoring concentrations (SMC). These concentrations are also much less than the PSD Increments for Class I Areas. Since the maximum predicted impacts for each pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling is required at this time. The applicant is also exempted from the ambient monitoring data requirements since the impacts are shown to be below the SMC.

Table 22. Class I Areas Modeled Impacts

Pollutant	Averaging Period	SIL ($\mu g/m^3$)	SMC ($\mu g/m^3$)	PSD Class I Increments ($\mu g/m^3$)	Mingo NWR Max Impact ($\mu g/m^3$)	Mammoth Cave NP Max Impact ($\mu g/m^3$)
NO_2	Annual	1	14	2.5	0.09	0.05
PM_{10}	Annual 24-hour	1 5	NA 10	4 8	0.04 0.38	0.03 0.27
SO_2	Annual 24-hour 3-hour	1 5 25	NA 13 NA	2 5 25	0.001 0.009 0.03	0.001 0.006 0.02

4. ADDITIONAL IMPACTS ANALYSIS

Pursuant to Regulation 401 KAR 51:017, Section 14, Westlake Energy shall provide an analysis of the impairment to visibility, soils and vegetation and an analysis of the air quality impact projected for the area that would occur as a result of the source and general commercial, residential, industrial and other growth associated with the source.

a. Growth Analysis

Growth impacts resulting from the Westlake Energy Facility will be insignificant. The facility will require only 20 full-time employees, which will come from 8 Purchase Area counties, therefore additional housing schools, and commercial growth will not occur. The Calvert City Industrial Complex has a sufficient infrastructure of suppliers in Calvert City, Paducah, and St. Louis and will not need additional support facilities.

b. Soils and Vegetation Impacts Analysis

The secondary NAAQS are documented to generally protect soils and vegetation. Ambient concentrations of criteria pollutants below this level are not generally expected to cause harmful affects to soil and vegetation. Since the facility's impacts for NO_x, CO, PM_{10}, and SO_2 are below PSD significant impact levels, it is assumed that the proposed facility cannot cause or contribute to a violation of the national ambient air quality standards (NAAQS). Therefore, an adverse effects for soils and vegetation should not occur.

c. Ambient Air Quality Impacts Analysis

The facility's impact for NO_x, CO, PM_{10}, and SO_2 are below PSD significant impact levels, therefore it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). There is no growth expected to occur which would also contribute to an impact on air quality in the area. Therefore any impact on the air quality in the area from the Westlake Energy Facility and resultant growth should be insignificant.

d. Visibility Impairment Analysis

See 5. CLASS I AREAS for the visibility analysis for Class I Areas. The permittee did not perform any other visibility analyses.

5. CLASS I AREAS

Pursuant to Regulation 401 KAR 51:017, Section 15, the division must provide written notice of this permit application to the Federal Land Managers (FLM) Mammoth Cave National Park, Kentucky (200 km east) and Mingo National Wildlife Refuge, Missouri (145 km west-southwest). The permittee and EPA Region 4 have sent copies of the permit application to the FLM at Mingo and Mammoth Cave.

The PSD regulations also require a demonstration that the proposed source's emissions would not adversely affect a Class I area's air quality related values (AQRV). The permittee performed visibility and deposition analyses using the Calpuff modeling system and PCRAMMET meteorological preprocessor. All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with IWAQM Phase 2 Summary Report. Calpuff evaluation was used in screening mode with 6 years of surface data and concurrent upper air data from Evansville, Indiana, and Peoria, Illinois, from 1985 to 1990. See the "Class I Impacts Analysis" section of the PSD application for model setup, calculations, and detailed results. The results predict one 24-hour change for 1985-1990 in extinction greater than 5%. The results indicate that a visibility reduction greater than 5% may occur on one day out of a 2,191 day period (about 0.04% of the time). Based on the results of that analysis, no significant adverse impact of a Class I area's air quality related values (AQRV) is projected.

6. CONCLUSION AND RECOMMENDATION

In conclusion, considering the information presented in the application, the Division has made a preliminary determination

that the proposed source should meet all applicable requirements:

1. All the emissions units are expected to meet the requirements of BACT for each significant pollutant. Additionally, each applicable emission limitation under 401 KAR Chapters 50 to 68 and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63 will also be met.

2. Ambient air quality impacts on Class II areas are expected to be below the significant impact levels. No impact is expected on any Class I area.

3. Impacts on soil, vegetation, and visibility have been predicted to be minimal.

A draft permit containing conditions which may ensure compliance with all the applicable requirements listed above has been prepared by the Division. The Division recommends the issuance of the permit following the public notice period, and after the resolution of any adverse comments received by the Division. A copy of this preliminary determination will be made available for public review at the following locations:

1. Affected public at the Marshall County Clerk's office
2. Division for Air Quality, 803 Schenkel Lane, Frankfort
3. Division for Air Quality, Paducah Regional Office, 4500 Clarks River Road, Paducah, KY 42003