INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Eric J. Holcomb
Governor

Brian C. Rockensuess
Commissioner

To:	Interested Parties
Date:	June 27, 2024
From:	Jenny Acker, Chief Permits Branch Office of Air Quality
Source Name:	Lakeshore Terminal Railroad LLC
Permit Level:	Registration
Permit Number:	089-47845-00732
Source Location:	1150 E 145th St, East Chicago, IN 46312
Type of Action Taken:	Initial Permit

Notice of Decision: Approval - Registration

Please be advised that on behalf of the Commissioner of the Department of Environmental Management, I have issued a decision regarding the matter referenced above.

The final decision is available on the IDEM website at: http://www.in.gov/apps/idem/caats/
To view the document, choose Search Option **by Permit Number**, then enter permit 47845. This search will also provide the application received date and **final** permit issuance date.

The final decision is also available via IDEM's Virtual File Cabinet (VFC). Please go to: https://www.IN.gov/idem and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria.

(continues on next page)

If you would like to request a paper copy of the permit document, please contact IDEM's Office of Records Management:

IDEM - Office of Records Management
Indiana Government Center North, Room 1207
100 North Senate Avenue
Indianapolis, IN 46204
Phone: (317) 232-8667
Fax: (317) 233-6647
Email: IDEMFILEROOM@idem.in.gov

Pursuant to IC 4-21.5-3-4(d) this order is effective when it is served. When served by U.S. mail, the order is effective three (3) calendar days from the mailing of this notice pursuant to IC 4-21.5-3-2(e).

If you wish to challenge this decision, IC 4-21.5-3-7 requires that you file a petition for administrative review. This petition may include a request for stay of effectiveness and must be submitted to the Office of Environmental Adjudication, 100 North Senate Avenue, Government Center North, Room N103, Indianapolis, IN 46204, **within eighteen (18) calendar days of the mailing of this notice**. The filing of a petition for administrative review is complete on the earliest of the following dates that apply to the filing:
(1) the date the document is delivered to the Office of Environmental Adjudication (OEA);
(2) the date of the postmark on the envelope containing the document, if the document is mailed to OEA by U.S. mail; or
(3) The date on which the document is deposited with a private carrier, as shown by receipt issued by the carrier, if the document is sent to the OEA by private carrier.

The petition must include facts demonstrating that you are either the applicant, a person aggrieved or adversely affected by the decision or otherwise entitled to review by law. Please identify the permit, decision, or other order for which you seek review by permit number, name of the applicant, location, date of this notice and all of the following:
(1) the name and address of the person making the request;
(2) the interest of the person making the request;
(3) identification of any persons represented by the person making the request;
(4) the reasons, with particularity, for the request;
(5) the issues, with particularity, proposed for considerations at any hearing; and
(6) identification of the terms and conditions which, in the judgment of the person making the request, would be appropriate in the case in question to satisfy the requirements of the law governing documents of the type issued by the Commissioner.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178. Callers from within Indiana may call toll-free at 1-800-451-6027, ext. 3-0178.

Enclosures

REGISTRATION
OFFICE OF AIR QUALITY

Lakeshore Terminal Railroad LLC
1150 East 145th Street
East Chicago, Indiana 46312

Pursuant to 326 IAC 2-5.1 (Construction of New Sources: Registrations) and 326 IAC 2-5.5 (Registrations), (herein known as the Registrant) is hereby authorized to construct and operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this registration.

Registration No. R089-47845-00732 Master Agency Interest ID.: 12627	
Issued by: Madhurima Das Madhurima D. Moulik, Ph.D., Section Chief Permits Branch Office of Air Quality	Issuance Date: June 27, 2024

SECTION A SOURCE SUMMARY

This registration is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 and A.2 is descriptive information and does not constitute enforceable conditions. However, the Registrant should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Registrant to obtain additional permits pursuant to 326 IAC 2.

A.1 General Information

The Registrant owns and operates a liquid transloading operation.

Source Address:	1150 East 145th Street, East Chicago, IN 46312
General Source Phone Number:	(219) 314-6796
SIC Code:	4731 (Arrangement of Transportation of Freight & Cargo)
County Location:	Lake (North Township)
Source Location Status:	Nonattainment for ozone Attainment for all other criteria pollutants
Source Status:	Registration

A.2 Emission Units and Pollution Control Equipment Summary

This stationary source consists of the following emission units and pollution control devices:

(a) One liquid transloading operation, identified as EU1, approved in 2024 for construction, handling a maximum of 60,000 gal/day of liquid commodity, without control, and exhausting outside.

(b) One diesel fuel dispensing operation (DFDS), approved in 2024 for construction, with maximum storage capacity 10,500 gallons and dispensing 3,500 gal/day or less diesel.

(c) One (1) natural gas-fired boiler, identified as B1, approved in 2024 for construction, with a maximum heat input capacity of 5.02 MMBtu per hour, and exhausting outside.

(d) One (1) natural gas-fired boiler, identified as B2, approved in 2024 for construction, with a maximum heat input capacity of 25.106 MMBtu per hour, and exhausting outside.

Under 40 CFR 60, Subpart Dc, this unit is considered an affected facility.

(e) Two (2) natural gas-fired HVAC units, approved in 2024 for construction, each with a maximum heat input capacity of 0.05 MMBtu per hour, and exhausting outside.

(f) Five (5) natural gas-fired heaters, approved in 2024 for construction, each with a maximum heat input capacity of 0.25 MMBtu per hour, and exhausting outside.

(g) Paved roads.

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-1.1-1]

Terms in this registration shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, the applicable definitions found in the statutes or regulations (IC 13-11, 326 IAC 1-2 and 326 IAC 2-1.1-1) shall prevail.

B.2 Effective Date of Registration [IC 13-15-5-3]

Pursuant to IC 13-15-5-3, this registration R089-47845-00732 is effective immediately, unless a petition for stay of effectiveness is filed and granted according to IC 13-15-6-3, and may be revoked or modified in accordance with the provisions of IC 13-15-7-1.

B.3 Registration Revocation [326 IAC 2-1.1-9]

Pursuant to 326 IAC 2-1.1-9 (Revocation), this registration to operate may be revoked for any of the following causes:

(a) Violation of any conditions of this registration.

(b) Failure to disclose all the relevant facts, or misrepresentation in obtaining this registration.

(c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this registration shall not require revocation of this registration.

(d) For any cause which establishes in the judgment of IDEM the fact that continuance of this registration is not consistent with purposes of this article.

B.4 Prior Permits Superseded [326 IAC 2-1.1-9.5]

(a) All terms and conditions of permits established prior to Registration No. R089-47845-00732 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised, or

(3) deleted.

(b) All previous registrations and permits are superseded by this registration.

B.5 Annual Notification [326 IAC 2-5.1-2(f)(3)] [326 IAC 2-5.5-4(a)(3)]

Pursuant to 326 IAC 2-5.1-2(f)(3) and 326 IAC 2-5.5-4(a)(3):

(a) An annual notification shall be submitted by an authorized individual to the Office of Air Quality stating whether or not the source is in operation and in compliance with the terms and conditions contained in this registration.

(b) The annual notice shall be submitted in the format attached no later than March 1 of each year to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, IN 46204-2251

(c) The notification shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

B.6 Source Modification Requirement [326 IAC 2-5.5-6(a)]

Pursuant to 326 IAC 2-5.5-6(a), an application or notification shall be submitted in accordance with 326 IAC 2 to the Office of Air Quality (OAQ) if the source proposes to construct new emission units, modify existing emission units, or otherwise modify the source.

B.7 Registrations [326 IAC 2-5.1-2(i)]

Pursuant to 326 IAC 2-5.1-2(i), this registration does not limit the source's potential to emit.

B.8 Preventive Maintenance Plan [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this registration, the Registrant shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this registration or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Registrant’s control, the PMPs cannot be prepared and maintained within the above time frame, the Registrant may extend the date an additional ninety (90) days provided the Registrant notifies:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The Registrant shall implement the PMPs.

(b) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Registrant to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions.

(c) To the extent the Registrant is required by 40 CFR Part 60 or 40 CFR Part 63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such OMM Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

Emission Limitations and Standards [326 IAC 2-5.1-2(g)] [326 IAC 2-5.5-4(b)]

C.1 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-1 (Applicability) and 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this registration:

(a) Opacity shall not exceed an average of twenty percent (20%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

C.2 Fugitive Dust Emissions [326 IAC 6-4]

The Registrant shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions).

SECTION D.1 EMISSION UNIT OPERATION CONDITIONS

Emission Unit Description:

(c) One (1) natural gas-fired boiler, identified as B1, approved in 2024 for construction, with a maximum heat input capacity of 5.02 MMBtu per hour, and exhausting outside.

(d) One (1) natural gas-fired boiler, identified as B2, approved in 2024 for construction, with a maximum heat input capacity of 25.106 MMBtu per hour, and exhausting outside.

Under of 40 CFR 60, Subpart Dc, this unit is considered an affected facility.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

Emission Limitations and Standards [326 IAC 2-5.1-2(f)(1)] [326 IAC 2-5.5-4(a)(1)]

D.1.1 Particulate Emissions [326 IAC 6-2-4]

Pursuant to 326 IAC 6-2-4 (Particulate Emission Limitations for Sources of Indirect Heating), the PM emissions from the following units shall be limited to the PM emission limit (Pt) in pounds per MMBtu heat input as specified in the following table:

Emission Unit	Pt (lb/MMBtu)
Natural Gas-fired Boiler B1	0.45
Natural Gas-fired Boiler B2	0.45

D.1.2 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan is required for these facilities and their control devices. Section B - Preventive Maintenance Plan contains the Registrant's obligation with regard to the preventive maintenance plan required by this condition.

SECTION E.1 **NSPS**

Emission Unit Description:

(d) One (1) natural gas-fired boiler, identified as B2, approved in 2024 for construction, with a maximum heat input capacity of 25.12 MMBtu per hour, and exhausting outside.

Under 40 CFR 60, Subpart Dc, this unit is considered an affected facility.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

E.1.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Registrant shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Dc.

(b) Pursuant to 40 CFR 60.4, the Registrant shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region 5
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

E.1.2 Small Industrial-Commercial-Institutional Steam Generating Units NSPS [326 IAC 12] [40 CFR Part 60, Subpart Dc]

The Registrant shall comply with the following provisions of 40 CFR Part 60, Subpart Dc (included as Attachment A to the registration), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.40c (a)
(2) 40 CFR 60.41c
(3) 40 CFR 60.48c (a) and (g)(2)

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH

REGISTRATION
ANNUAL NOTIFICATION

This form should be used to comply with the notification requirements under 326 IAC 2-5.1-2(f)(3) and 326 IAC 2-5.5-4(a)(3).

Company Name:	Lakeshore Terminal Railroad LLC
Source Address:	1150 East 145th Street, East Chicago, IN 46312
City:	East Chicago, Indiana, 46312
Phone Number:	(219) 314-6796
Registration No.:	R089-47845-00732

I hereby certify that Lakeshore Terminal Railroad LLC is:
☐ still in operation.
☐ no longer in operation.

I hereby certify that Lakeshore Terminal Railroad LLC is:
☐ in compliance with the requirements of Registration No. R089-47845-00732.
☐ not in compliance with the requirements of Registration No. R089-47845-00732.

Authorized Individual (typed):	
Title:	
Signature:	**Date:**
Email Address:	**Phone:**

If there are any conditions or requirements for which the source is not in compliance, provide a narrative description of how the source did or will achieve compliance and the date compliance was, or will be achieved.

Noncompliance:

Attachment A

Registration No: R089-47845-00732

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Source: 72 FR 32759, June 13, 2007, unless otherwise noted.

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators, fuel heaters, and other affected facilities that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/h) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/h) heat input of fossil fuel. If the heat recovery steam generator, fuel heater, or other affected facility is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

(i) Temporary boilers are not subject to this subpart.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.41c Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal not meeting the definition of natural gas, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

Combined cycle system means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

Combustion research means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.* , the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for other units, generating electricity, or any other purpose).

Conventional technology means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

Distillate oil means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17), diesel fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17), kerosine, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17), biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17), or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Dry flue gas desulfurization technology means a SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO_2 control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum design heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

Potential sulfur dioxide emission rate means the theoretical SO_2 emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Wet flue gas desulfurization technology means an SO_2 control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO_2 .

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9461, Feb. 16, 2012]

§ 60.42c Standard for sulfur dioxide (SO2).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain SO_2 in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential SO_2 emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input SO_2 emissions limit or the 90 percent SO_2 reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of SO_2 emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 50 percent (0.50) of the potential SO_2 emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent SO_2 reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/h) or less;

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area; or

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input from oil; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of the following:

(1) The percent of potential SO_2 emission rate or numerical SO_2 emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/h); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

E_s = SO_2 emission limit, expressed in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (1.2 lb/MMBtu);

K_b = 260 ng/J (0.60 lb/MMBtu);

K_c = 215 ng/J (0.50 lb/MMBtu);

H_a = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

H_b = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

H_c = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential SO_2 emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential SO_2 emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion SO_2 control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(4) Other fuels-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/h).

(i) The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) For affected facilities located in noncontinental areas and affected facilities complying with the percent reduction standard, only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5090, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.43c Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c).

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification

after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) An owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or SO_2 emissions is not subject to the PM limit in this section.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 77 FR 9462, Feb. 16, 2012]

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

(a) Except as provided in paragraphs (g) and (h) of this section and § 60.8(b), performance tests required under § 60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and SO_2 emission limits under § 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and § 60.8, compliance with the percent reduction requirements and SO_2 emission limits under § 60.42c is based on the average percent reduction and the average SO_2 emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and SO_2 emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission rate (E_{ho}) and the 30-day average SO_2 emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate E_{ao} when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted E_{ho} (E_{ho} o) is used in Equation 19-19 of Method 19 of appendix A of this part to compute the adjusted E_{ao} (E_{ao} o). The E_{ho} o is computed using the following formula:

$$E_{ho}o = \frac{E_{ho} - E_w(1 - X_1)}{X_1}$$

Where:

E_{ho} o = Adjusted E_{ho} , ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume $E_w = 0$.

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters E_w or X_k if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the SO_2 emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential SO_2 emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$ = Potential SO_2 emission rate, in percent;

$\%R_g$ = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_g$ o) is computed from E_{ao} o from paragraph (e)(1) of this section and an adjusted average SO_2 inlet rate (E_{ai} o) using the following formula:

$$\%R_g o = 100\left(1 - \frac{E_{ao}^{o}}{E_{ai}^{o}}\right)$$

Where:

$\%R_g$ o = Adjusted $\%R_g$, in percent;

E_{ao} o = Adjusted E_{ao} , ng/J (lb/MMBtu); and

E_{ai} o = Adjusted average SO_2 inlet rate, ng/J (lb/MMBtu).

(ii) To compute E_{ai} o, an adjusted hourly SO_2 inlet rate (E_{hi} o) is used. The E_{hi} o is computed using the following formula:

$$E_{hi}o = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

E_{hi} o = Adjusted E_{hi} , ng/J (lb/MMBtu);

E_{hi} = Hourly SO_2 inlet rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure E_w if the owner or operator elects to assume E_w = 0; and

X_k = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in § 60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the SO_2 standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid SO_2 emissions data in calculating $\%P_s$ and E_{ho} under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or E_{ho} pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

§ 60.45c   Compliance and performance test methods and procedures for particulate matter.

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3A or 3B of appendix A-2 of this part shall be used for gas analysis when applying Method 5 or 5B of appendix A-3 of this part or 17 of appendix A-6 of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen (O_2) or carbon dioxide (CO_2) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A-4 of this part shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(14) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (c)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (c)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (c)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O_2 (or CO_2) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and performance tests conducted using the following test methods.

(i) For PM, Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall be used; and

(ii) For O2 (or CO_2), Method 3A or 3B of appendix A-2 of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(14) As of January 1, 2012, and within 90 days after the date of completing each performance test, as defined in § 60.8, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.,* reference method) data and performance test (*i.e.,* compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities between 2.9 and 8.7 MW (10 to 30 MMBtu/h).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.46c Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the SO_2 emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring SO_2 concentrations and either O_2 or CO_2 concentrations at the outlet of the SO_2 control device (or the outlet of the steam generating unit if no SO_2 control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure SO_2 concentrations and either O_2 or CO_2 concentrations at both the inlet and outlet of the SO_2 control device.

(b) The 1-hour average SO_2 emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average SO_2 emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under § 60.13(h)(2). Hourly SO_2 emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under § 60.42c, the span value of the SO_2 CEMS at the inlet to the SO_2 control device shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted, and the span value of the SO_2 CEMS at the outlet from the SO_2 control device shall be 50 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the SO_2 CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) shall be 125 percent of the maximum estimated hourly potential SO_2 emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the SO_2 control device (or outlet of the steam generating unit if no SO_2 control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO_2 emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO_2 input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when

calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure SO_2 at the inlet or outlet of the SO_2 control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO_2 and CO_2 measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, as described under § 60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

§ 60.47c Emission monitoring for particulate matter.

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a continuous opacity monitoring system (COMS) for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard in § 60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in § 60.11 to demonstrate compliance with the applicable limit in § 60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.* , 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in § 60.45c(a)(8).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) All COMS shall be operated in accordance with the applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO2 or PM emissions and that are subject to an opacity standard in § 60.43c(c) are not required to operate a COMS if they follow the applicable procedures in § 60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in § 60.45c(c). The CEMS specified in paragraph § 60.45c(c) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) Owners and operators of an affected facility that is subject to an opacity standard in § 60.43c(c) and that does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2 , or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO discharged to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section; or

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (e)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in § 60.13(h)(2).

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An owner or operator of an affected facility that is subject to an opacity standard in § 60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section.

(1) The affected facility uses a fabric filter (baghouse) as the primary PM control device and, the owner or operator operates a bag leak detection system to monitor the performance of the fabric filter according to the requirements in section § 60.48Da of this part.

(2) The affected facility uses an ESP as the primary PM control device, and the owner or operator uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the requirements in section § 60.48Da of this part.

(3) The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.48c(c).

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009; 76 FR 3523, Jan. 20, 2011; 77 FR 9463, Feb. 16, 2012]

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits in § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period and maintain records according to the requirements specified in paragraphs (c)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (c)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator

(d) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c; and

(iii) The sulfur content or maximum sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate or maximum potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in § 60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[72 FR 32759, June 13, 2007, as amended at 74 FR 5091, Jan. 28, 2009]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Registration

Source Description and Location

Source Name: Lakeshore Terminal Railroad LLC
Source Location: 1150 East 145th Street, East Chicago, IN 46312
County: Lake (North Township)
SIC Code: 4731 (Arrangement of Transportation of Freight & Cargo)
Registration No.: R089-47845-00732
Permit Reviewer: Mehul Sura

On May 15, 2024, the Office of Air Quality (OAQ) received an application from Lakeshore Terminal Railroad LLC related to the construction and operation of a new liquid transloading operation.

Existing Approvals

There have been no previous approvals issued to this source.

County Attainment Status

The source is located in Lake (North Township) County.

Pursuant to amendments to Indiana Code IC 13-17-3-14, effective July 1, 2023, a federal regulation that classifies or amends a designation of attainment, nonattainment, or unclassifiable for any area in Indiana under the federal Clean Air Act is effective and enforceable in Indiana on the effective date of the federal regulation.

Pollutant	Designation
SO_2	Unclassifiable or attainment effective April 9, 2018, for the 2010 primary 1-hour SO_2 standard. Better than national secondary standards effective March 3, 1978.
CO	Attainment effective February 18, 2000, for the part of the city of East Chicago bounded by Columbus Drive on the north; the Indiana Harbor Canal on the west; 148th Street, if extended, on the south; and Euclid Avenue on the east. Unclassifiable or attainment effective November 15, 1990, for the remainder of East Chicago and Lake County.
O_3	Attainment effective May 20, 2022, for the 2008 8-hour ozone standard.
O_3	Moderate nonattainment effective November 7, 2022, for the 2015 8-hour ozone standard for Calumet, Hobart, North, Ross, and St. John townships. Unclassifiable or attainment effective August 3, 2018, for the remainder of the county.
$PM_{2.5}$	Unclassifiable or attainment effective January 28, 2019, for the 2012 annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 2006 24-hour $PM_{2.5}$ standard.
PM_{10}	Attainment effective March 11, 2003, for the cities of East Chicago, Hammond, Whiting, and Gary. Unclassifiable effective November 15, 1990, for the remainder of Lake County.
NO_2	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO_2 standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.

(a) Ozone Standards
U.S. EPA, in the Federal Register Notice 87 FR 60897 dated October 7, 2022, designated Lake County (North Township), as moderate nonattainment for the 2015 8-hour ozone standard effective November 7, 2022. Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the

National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to ozone. Therefore, VOC and NOx emissions were evaluated pursuant to the requirements of Emission Offset, 326 IAC 2-3.

(b) $PM_{2.5}$
Lake County (North Township) has been classified as attainment for $PM_{2.5}$. Therefore, direct $PM_{2.5}$, SO_2, and NOx emissions were reviewed pursuant to the requirements of Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
Lake County (North Township) County has been classified as attainment or unclassifiable in Indiana for all the other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

The fugitive emissions of regulated air pollutants and hazardous air pollutants (HAP) are counted toward the determination of Registration (326 IAC 2-5.1-2) applicability and source status under Section 112 of the Clean Air Act (CAA).

Greenhouse Gas (GHG) Emissions

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

Background and Description of Emission Units and Pollution Control Equipment

The Office of Air Quality (OAQ) has reviewed an application, submitted by Lakeshore Terminal Railroad LLC on May 15, 2024, relating to the operation of a new transloading operation.

The source consists of the following emission unit(s):

(a) One liquid transloading operation, identified as EU1, approved in 2024 for construction, handling a maximum of 60,000 gal/day of liquid commodity, without control, and exhausting outside.

(b) One diesel fuel dispensing operation (DFDS), approved in 2024 for construction, with maximum storage capacity 10,500 gallons and dispensing 3,500 gal/day or less diesel.

(c) One (1) natural gas-fired boiler, identified as B1, approved in 2024 for construction, with a maximum heat input capacity of 5.02 MMBtu per hour, and exhausting outside.

(d) One (1) natural gas-fired boiler, identified as B2, approved in 2024 for construction, with a maximum heat input capacity of 25.106 MMBtu per hour, and exhausting outside.

(e) Two (2) natural gas-fired HVAC units, approved in 2024 for construction, each with a maximum heat input capacity of 0.05 MMBtu per hour, and exhausting outside.

(f) Five (5) natural gas-fired heaters, approved in 2024 for construction, each with a maximum heat input capacity of 0.25 MMBtu per hour, and exhausting outside.

(g) Paved roads.

Enforcement Issues

There are no pending enforcement actions related to this source.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Permit Level Determination – Registration

This table reflects the unrestricted potential emissions of the source. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Unrestricted Source-Wide Emissions (ton/year)									
	PM[1]	PM_{10}[1]	$PM_{2.5}$[1, 2]	SO_2	NO_X	VOC	CO	Total HAPs	Single HAP[3]	
Total PTE of Entire Source Including Source-Wide Fugitives	**2.13**	**2.90**	**2.90**	**0.08**	**13.52**	**10.37**	**11.35**	**9.88**	**9.87**	methanol
Exemptions Levels	< 5	< 5	< 5	< 10	< 10	< 5/10	< 25	< 25	< 10	
Registration Levels	< 25	< 25	< 25	< 25	< 25	< 25	< 100	< 25	< 10	

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."
[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.
[3]Single highest source-wide HAP.

(a) The potential to emit (as defined in 326 IAC 2-1.1-1) of NOx and VOC, each, is within the ranges listed in 326 IAC 2-5.1-2(a)(1). The potential to emit of all other regulated air pollutants are less than the ranges listed in 326 IAC 2-5.1-2(a)(1). Therefore, the source is subject to the provisions of 326 IAC 2-5.1-2 (Registrations). The source will be issued a Registration.

(b) The potential to emit (as defined in 326 IAC 2-1.1-1) of any single HAP is less than ten (10) tons per year and the potential to emit (as defined in 326 IAC 2-1.1-1) of a combination of HAPs is less than twenty-five (25) tons per year. Therefore, this source is an area source under Section 112 of the Clean Air Act (CAA) and not subject to the provisions of 326 IAC 2-7.

Federal Rule Applicability Determination

Federal rule applicability for this source has been reviewed as follows:

(a) Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

The natural gas-fired boiler B1 is not subject to the requirements of this NSPS because this boiler has a maximum design heat input capacity less than 10 MMBtu/hr.

The natural gas-fired boiler B2 is subject to the requirements of this NSPS because this boiler has a maximum design heat input capacity more than 10 MMBtu/hr and less than 100 MMBtu per hour.

The natural gas-fired boiler B2 is subject to the following portions of Subpart Dc.

(1) 40 CFR 60.40c (a)
(2) 40 CFR 60.41c
(3) 40 CFR 60.48c (a) and (g)(1)

The requirements of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated as 326 IAC 12-1, apply to the natural gas-fired boiler B2 except as otherwise specified in 40 CFR 60, Subpart Dc.

(b) Subpart XX—Standards of Performance for Bulk Gasoline Terminals

The liquid transloading operation EU1 is not subject to the requirements of this NSPS because the source does not receive gasoline by pipeline, ship or barge.

<u>New Source Performance Standards (NSPS):</u>

(a) Subpart R—National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)

The source is not subject to the requirements of this NESHAP because this source is not a major source of HAPs.

(b) Subpart EEEE—National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)

The source is not subject to the requirements of this NESHAP because this source is not a major source of HAPs.

(c) Subpart BBBBBB —National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities

The source is not subject to the requirements of this NESHAP because this source does not receive gasoline by pipeline, ship or barge, or cargo tank.

(d) Subpart CCCCCC—National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

The diesel fuel dispensing operation is not subject to the requirements of this NESHAP because it does not dispense gasoline

(e) Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

The natural gas-fired boilers B1 and B2 are considered gas-fired boilers under this NESHAP, therefore, these boilers are not subject to the requirements of this NESHAP.

The natural gas-fired HVAC units and heaters are not water heaters or process heaters; therefore, these natural gas-fired units are not subject to the requirements of this NESHAP.

(f) There are no NESHAPs (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) included in the permit.

Compliance Assurance Monitoring (CAM):

Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is not included in the registration, because the unlimited potential to emit of the source is less than the Title V major source thresholds and the source is not required to obtain a Part 70 or Part 71 permit.

State Rule Applicability - Entire Source

State rule applicability for this source has been reviewed as follows:

326 IAC 2-5.1-2 (Registrations)
Registration applicability is discussed under the Permit Level Determination – Registration section above.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of this source will emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 2-6 (Emission Reporting)
This source is not subject to 326 IAC 2-6 (Emission Reporting), because it is not required to have an operating permit pursuant to 326 IAC 2-7 (Part 70), it is located in Lake County (North Township), it does not emit NOx and VOC into the ambient air at levels equal to or greater than twenty-five (25) tons per year, and it does not emit lead into the ambient air at levels equal to or greater than 5 tons per year. Therefore, 326 IAC 2-6 does not apply.

326 IAC 5-1 (Opacity Limitations)
Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in the registration:

(1) Opacity shall not exceed an average of twenty percent (20%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(2) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes (sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute nonoverlapping integrated averages for a continuous opacity monitor) in a six (6) hour period.

326 IAC 6-4 (Fugitive Dust Emissions Limitations)
The source is subject to the requirements of 326 IAC 6-4, because the paved roads have the potential to emit fugitive particulate emissions. Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions Limitations), the source shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)
This source is not subject to the requirements of 326 IAC 6-5, because the source has potential fugitive particulate emissions of less than twenty-five (25) tons per year.

326 IAC 6.8 (Particulate Matter Limitations for Lake County)
This source (located in Lake County) is not one of the sources specifically listed in 326 IAC 6.8-4, 326 IAC 6.8-5, or 326 IAC 6.8-8 through 326 IAC 6.8-11. The source-wide unlimited PTE of PM is less than 10 tons per year; therefore, the source-wide actual emissions of PM are less than 10 tons per year. This source is not subject to the requirements of 326 IAC 6.8-1-2 because the source-wide PTE of PM is less than 100 tons per year and source-wide actual emissions of PM are less than 10 tons per year.

326 IAC 6.8 (Lake County: Fugitive Particulate Matter)
Pursuant to 326 IAC 6.8-10-1, this source (located in Lake County) is not subject to the requirements of

326 IAC 6.8-10 because it is not one of the sources specifically listed in 326 IAC 6.8-10-1(2)(A) through (V) and the source-wide PTE of fugitive PM and PM10 is less than 5 tons per year, each.

326 IAC 6-2-4 (Particulate Matter Emission Limitations for Sources of Indirect Heating)

(a) Two (2) natural gas-fired HVAC units and five (5) natural gas-fired heaters are direct-fired units. Therefore, these emission units are not subject to the requirements of this rule.

(b) Pursuant to 326 IAC 6-2-1(d), indirect heating facilities which received permit to construct after September 21, 1983 are subject to the requirements of 326 IAC 6-2-4.

The particulate matter emissions (Pt) shall be limited by the following equation:

$$Pt = \frac{1.09}{Q^{0.26}}$$

Where:

Pt = Pounds of particulate matter emitted per million British thermal units (lb/MMBtu).

Q = Total source maximum operating capacity rating in MMBtu/hr heat input. The maximum operating capacity rating is defined as the maximum capacity at which the facility is operated or the nameplate capacity, whichever is specified in the facility's permit application, except when some lower capacity is contained in the facility's operation permit; in which case, the capacity specified in the operation permit shall be used.

Indirect Heating Units Which Began Operation After September 21, 1983						
Unit	Construction Date	Operating Capacity (MMBtu/hr)	Q (MMBtu/hr)	Calculated Pt (lb/MMBtu)	Particulate Limitation, (Pt) (lb/MMBtu)	PM PTE based on AP-42 (lb/MMBtu)
Natural Gas-fired Boiler B1	2024	5.02	30.126	0.45	0.45	0.002
Natural Gas-fired Boiler B2	2024	25.106	30.126	0.45	0.45	0.002
Where: Q = Includes the capacity (MMBtu/hr) of the new unit(s) and the capacities for those unit(s) which were in operation at the source at the time the new unit(s) was constructed.						

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)
Liquid and gaseous fuels are not considered as part of the process weight pursuant to 326 IAC 1-2-59 (Process weight; weight rate). Therefore, natural gas-fired units are not subject to the requirements of 326 IAC 6-3.

326 IAC 7-1.1 (Sulfur Dioxide Emission Limitations)
All emission units at this source have potential to emit sulfur dioxide (SO2) less than 25 tons per year or less than 10 pounds per hour. Therefore, 326 IAC 7-1.1 rule does not apply.

326 IAC 8-4-4 (Petroleum Sources: Bulk Gasoline Terminals)
This source is not subject to the requirements 326 IAC 8-4-4, because this source is not a bulk gasoline terminal.

326 IAC 8-4-6 (Petroleum Sources: Gasoline Dispensing Facilities)
This source is not subject to the requirements 326 IAC 8-4-6, because this source does not include a gasoline dispensing facility.

326 IAC 8-1-6 (VOC Rules: General Reduction Requirements for New Facilities)
All emission units at this source have VOC potential emissions less than twenty-five (25) tons per year. Therefore, 326 IAC 8-1-6 rule does not apply.

326 IAC 9-1 (Carbon Monoxide Emission Limits)
The requirements of 326 IAC 9-1 do not apply to the source, because this source does not operate a catalyst regeneration petroleum cracking system or a petroleum fluid coker, grey iron cupola, blast furnace, basic oxygen steel furnace, or other ferrous metal smelting equipment.

326 IAC 10-3 (Nitrogen Oxide Reduction Program for Specific Source Categories)
The requirements of 326 IAC 10-3 do not apply to the source, since this source does not operate any blast furnace gas-fired boiler, a Portland cement kiln, or a facility specifically listed under 326 IAC 10-3-1(a)(2).

326 IAC 12 (New Source Performance Standards)
See Federal Rule Applicability Section of this TSD.

326 IAC 20 (Hazardous Air Pollutants)
See Federal Rule Applicability Section of this TSD.

Conclusion and Recommendation

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on May 15, 2024.

The construction and operation of this source shall be subject to the conditions of the attached proposed Registration No. R089-47845-00732. The staff recommends to the Commissioner that the Registration be approved.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Mehul Sura, Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251, or by telephone at (317) 233-6868 or (800) 451-6027, and ask for Mehul Sura or (317) 233-6868.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Appendix A: Emissions Calculations
Facility-wide Emissions

Company Name: Lakeshore Terminal Railroad LLC
Source Address: 1150 East 145th Street, East Chicago, IN 46312
Permit Number: R089-47845-00732
Reviewer: Mehul Sura

Potential Emissions (tons/yr)

Process/Emission Unit	PM	PM10	PM2.5	SO2	NOx	VOC	CO	Total HAPs	Max. Single HAP	
Transloading Operation	--	--	--	--	--	8.97	--	8.97	8.97	methanol
Transloading (Fugitive)	--	--	--	--	--	0.66	--	0.66	0.66	methanol
Diesel Dispensing (DFDS)	--	--	--	--	--	*negligible*	--	--	--	
Natural Gas-fired Units	0.26	1.03	1.03	0.08	13.52	0.74	11.35	0.26	0.24	
Paved Roads (Fugitive)	1.88	1.88	1.88	--	--	--	--	--	--	
Total (Including Fugitives):	**2.13**	**2.90**	**2.90**	**0.08**	**13.52**	**10.37**	**11.35**	**9.88**	**9.62**	

Appendix A: Emissions Calculations
Transloading Operation - VOC and HAP Emissions

Company Name:	**Lakeshore Terminal Railroad LLC**
Source Address:	**1150 East 145th Street, East Chicago, IN 46312**
Permit Number:	**R089-47845-00732**
Reviewer:	**Mehul Sura**

Parameters:

Maximum Throughput =	60,000	gal/day
Maximum Annual Operating days =	365	days/yr

Loading Loss calculations based on AP-42, Chapter 5.2 Transportation And Marketing Of Petroleum Liquids

LL = 12.46 * SPM/T

where:
LL = loading loss (lb/10^3 gal)
S = saturation factor (from AP-42 Table 5.2-1)
P = true vapor pressure (psia)
M = molecular weight of vapors
T = temperature of liquid (°R)

Worst Case Loading (Methanol)

S =	0.6	
P =	1.780	psia
M =	32.0	lb/lb-mole
T =	520	R
LL =	0.82	lb/Kgal
Maximum Throughput =	60,000	gal/day
Potential VOC/Single HAP/Combined HAPS Emissions =	8.97	TONS/YR

Notes:

Potential VOC/Single HAP/Combined HAPS Emissions = Loading Loss LL (lb/Kgal) x Maximum Throughput (gal/day) x Maximum Annual Operating days (days/yr) x1/2000 (ton/lb)

The throughput information was provided by the facility. Maximum throughput is based on a worst-case assumption of transloading ten (10) 6,000-gallon tank truck loads of liquid per day. Expected throughput is based on transloading four (4) 6,000-gallon truck loads of liquid per day.

For a worst-case estimate, it was assumed that all the material transloaded is methanol. This was based on the loading loss parameters for the materials transloaded in Q1 of the 2024 calendar year (see following pages) by Lakeshore Railcar & Tanker Services LLC. Methanol is 100% HAP.

Appendix A: Emissions Calculations

Company Name: Lakeshore Terminal Railroad LLC
Source Address: 1150 East 145th Street, East Chicago, IN 46312
Permit Number: R089-47845-00732
Reviewer: Mehul Sura

2024 Q1 Transloading

January 2024[1] *(Based on LSRS Records)*

Month/Date [1]	Permit Substance Name	Permit Substance Category	CAS Number	VOC (Yes/No)	HAPs (Yes/No)	Volume Loaded Per Day (Kgal/day)	Number of Cars (cars/day)	Loading Loss Factor [2] (lbs/Kgal)	VOC Content (wt.%)	HAPs Content (wt.%)	VOC Emissions (lbs/day)	HAPs Emissions (lbs/day)	Other Emissions (lbs/day)	Saturation Factor, S (No unit)	True Vapor Pressure, P (psia)	Vapor Molecular Weight, MW (lb/lb mole)	worst case S*P*MW	Bulk Liquid Temperature, T (˚R)
1/2/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	7.000	2	0.8207	100%	100.00%	5.75	5.75	0.00	0.60	1.78	32.00	34.25	520
1/4/2024	Diesel Fuel, generic (used for Spirdane D15)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	7.039	1	0.0168	100%	1.28%	0.12	1.51E-03	0.00	0.60	0.01	130.00	0.70	520
1/5/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	5.633	1	0.0002	100%	17.00%	9.23E-04	1.57E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/5/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.565	1	0.0002	100%	17.00%	1.24E-03	2.11E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/5/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.670	1	0.0002	100%	17.00%	1.09E-03	1.86E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/5/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.800	1	0.0002	100%	17.00%	1.11E-03	1.89E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/8/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	5.500	3	0.0001	100%	17.84%	2.82E-04	5.02E-05	0.00	0.60	4.45E-05	80.00	0.00	520
1/8/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	6.506	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
1/9/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	6.940	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
1/10/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.056	1	0.0002	100%	17.00%	1.16E-03	1.97E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/10/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.534	1	0.0002	100%	17.00%	1.07E-03	1.82E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/10/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.300	1	0.0002	100%	17.00%	1.03E-03	1.76E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/10/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.202	1	0.0002	100%	17.00%	1.02E-03	1.73E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/11/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	5.500	1	0.0001	100%	17.84%	2.82E-04	5.02E-05	0.00	0.60	4.45E-05	80.00	0.00	520
1/11/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	6.900	1	0.8207	100%	100.00%	5.66	5.66	0.00	0.60	1.78	32.00	34.25	520
1/11/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	6.913	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
1/11/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.659	1	0.0002	100%	17.00%	1.26E-03	2.13E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/11/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	5.590	1	0.0002	100%	17.00%	9.16E-04	1.56E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/11/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.851	1	0.0002	100%	17.00%	1.29E-03	2.19E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/16/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	5.500	1	0.0001	100%	17.84%	2.82E-04	5.02E-05	0.00	0.60	4.45E-05	80.00	0.00	520
1/16/2024	Diesel Fuel, generic (used for Spirdane D15)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	7.021	1	0.0168	100%	1.28%	0.12	1.51E-03	0.00	0.60	0.01	130.00	0.70	520
1/16/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	2.020	1	0.0025	100%	100.00%	0.01	0.01	0.00	0.60	1.16E-03	150.00	0.10	520
1/16/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.548	1	0.0002	100%	17.00%	1.07E-03	1.82E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/17/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	4.000	1	0.0025	100%	100.00%	0.01	0.01	0.00	0.60	1.16E-03	150.00	0.10	520
1/17/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.800	1	0.0002	100%	17.00%	1.11E-03	1.89E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/17/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.470	1	0.0002	100%	17.00%	1.06E-03	1.80E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/17/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	5.637	1	0.0002	100%	17.00%	9.24E-04	1.57E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/17/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.548	1	0.0002	100%	17.00%	1.07E-03	1.82E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/18/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	5.845	1	0.0002	100%	17.00%	9.58E-04	1.63E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/18/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.548	2	0.0002	100%	17.00%	1.07E-03	1.82E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/18/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.909	1	0.0002	100%	17.00%	1.30E-03	2.20E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/19/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	6.787	1	0.8207	100%	100.00%	5.57	5.57	0.00	0.60	1.78	32.00	34.25	520
1/19/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	3.076	1	0.0025	100%	100.00%	0.01	0.01	0.00	0.60	1.16E-03	150.00	0.10	520
1/19/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	5.686	1	0.0002	100%	17.00%	9.32E-04	1.58E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/19/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.025	1	0.0002	100%	17.00%	1.15E-03	1.96E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/19/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.909	1	0.0002	100%	17.00%	1.30E-03	2.20E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/19/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.025	1	0.0002	100%	17.00%	1.15E-03	1.96E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/22/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	8.093	1	0.0002	100%	17.00%	1.33E-03	2.25E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/22/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.800	2	0.0002	100%	17.00%	1.11E-03	1.89E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/22/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	5.420	1	0.0002	100%	17.00%	8.88E-04	1.51E-04	0.00	0.60	6.00E-05	190.00	0.01	520
1/23/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	6.940	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
1/25/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	7.383	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
1/26/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	7.073	1	0.0001	100%	17.84%	3.62E-04	6.46E-05	0.00	0.60	4.45E-05	80.00	0.00	520
1/26/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	7.500	1	0.0001	100%	17.84%	0.00	0.00	0.00	0.60	4.45E-05	80.00	0.00	520
1/26/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	7.000	1	0.8207	100%	100.00%	5.75	5.75	0.00	0.60	1.78	32.00	34.25	520
1/29/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	4.000	1	0.0001	100%	17.84%	2.05E-04	3.65E-05	0.00	0.60	4.45E-05	80.00	0.00	520
1/29/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	6.100	1	0.0001	100%	17.84%	3.12E-04	5.57E-05	0.00	0.60	4.45E-05	80.00	0.00	520
1/30/2024	EPON Resin 828 (used for Hot Resin Solution)	Non-List 1 Individual	25068-38-6	Yes	No	5.976	1	0.0041	100%	0.00%	0.02	0.00E+00	0.00	0.60	4.35E-04	650.00	0.17	520
1/30/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	6.930	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
1/31/2024	EPON Resin 828 (used for Hot Resin Solution)	Non-List 1 Individual	25068-38-6	Yes	No	5.976	1	0.0041	100%	0.00%	0.02	0.00E+00	0.00	0.60	4.35E-04	650.00	0.17	520

(Kgal/month)	Total Cars
351.051	55

Monthly Total	VOC E_{TO}	HAP E_{TO}	Other E_{TO}
(lbs)	23.166	22.859	0.000
(tons)	**0.012**	**0.011**	**0.000**

February 2024[1] *(Based on LSRS Records)*

Month/Date [1]	Permit Substance Name	Permit Substance Category	CAS Number	VOC (Yes/No)	HAPs (Yes/No)	Volume Loaded Per Day (Kgal/day)	Number of Cars (cars/day)	Loading Loss Factor [2] (lbs/Kgal)	VOC Content (wt.%)	HAPs Content (wt.%)	VOC Emissions (lbs/day)	HAPs Emissions (lbs/day)	Other Emissions (lbs/day)	Saturation Factor, S (No unit)	True Vapor Pressure, P (psia)	Vapor Molecular Weight, MW (lb/lb mole)	worst case S*P*MW	Bulk Liquid Temperature, T (˚R)
2/1/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	7.000	1	0.8207	100%	100.00%	5.75	5.75	0.00	0.60	1.78	32.00	34.25	520
2/1/2024	EPON Resin 828 (used for Hot Resin Solution)	Non-List 1 Individual	25068-38-6	Yes	No	6.184	1	0.0041	100%	0.00%	0.03	0.00E+00	0.00	0.60	4.35E-04	650.00	0.17	520
2/2/2024	EPON Resin 828 (used for Hot Resin Solution)	Non-List 1 Individual	25068-38-6	Yes	No	5.524	1	0.0041	100%	0.00%	0.02	0.00E+00	0.00	0.60	4.35E-04	650.00	0.17	520
2/5/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	3.846	1	0.0025	100%	100.00%	0.01	0.01	0.00	0.60	1.16E-03	150.00	0.10	520
2/5/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	7.374	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
2/9/2024	EPON Resin 828 (used for Hot Resin Solution)	Non-List 1 Individual	25068-38-6	Yes	No	5.976	1	0.0041	100%	0.00%	0.02	0.00E+00	0.00	0.60	4.35E-04	650.00	0.17	520
2/9/2024	EPON Resin 828 (used for Hot Resin Solution)	Non-List 1 Individual	25068-38-6	Yes	No	6.184	1	0.0041	100%	0.00%	0.03	0.00E+00	0.00	0.60	4.35E-04	650.00	0.17	520
2/9/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	7.000	1	0.8207	100%	100.00%	5.75	5.75	0.00	0.60	1.78	32.00	34.25	520
2/12/2024	EPON Resin 828 (used for Hot Resin Solution)	Non-List 1 Individual	25068-38-6	Yes	No	6.184	1	0.0041	100%	0.00%	0.03	0.00E+00	0.00	0.60	4.35E-04	650.00	0.17	520
2/12/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	6.000	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
2/13/2024	EPON Resin 828 (used for Hot Resin Solution)	Non-List 1 Individual	25068-38-6	Yes	No	4.782	1	0.0041	100%	0.00%	0.02	0.00E+00	0.00	0.60	4.35E-04	650.00	0.17	520
2/13/2024	Diesel Fuel, generic (used for VM & P Max 12)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	7.194	1	0.0168	100%	1.28%	0.12	1.54E-03	0.00	0.60	0.01	130.00	0.70	520
2/14/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	5.000	1	0.0001	100%	17.84%	2.56E-04	4.57E-05	0.00	0.60	4.45E-05	80.00	0.00	520
2/14/2024	Diesel Fuel, generic (used for Spirdane D15)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	6.800	1	0.0168	100%	1.28%	0.11	1.46E-03	0.00	0.60	0.01	130.00	0.70	520
2/14/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	6.937	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
2/14/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	7.402	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
2/15/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	7.000	1	0.8207	100%	100.00%	5.75	5.75	0.00	0.60	1.78	32.00	34.25	520
2/15/2024	Diesel Fuel, generic (used for VM & P Max 12)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	7.194	1	0.0168	100%	1.28%	0.12	1.54E-03	0.00	0.60	0.01	130.00	0.70	520
2/16/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	5.866	1	0.0002	100%	17.00%	9.61E-04	1.63E-04	0.00	0.60	6.00E-05	190.00	0.01	520
2/16/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.548	1	0.0002	100%	17.00%	1.07E-03	1.82E-04	0.00	0.60	6.00E-05	190.00	0.01	520
2/16/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.659	1	0.0002	100%	17.00%	1.09E-03	1.86E-04	0.00	0.60	6.00E-05	190.00	0.01	520
2/16/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.900	1	0.0002	100%	17.00%	1.13E-03	1.92E-04	0.00	0.60	6.00E-05	190.00	0.01	520
2/19/2024	Diesel Fuel, generic (used for Spirdane D15)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	7.039	1	0.0168	100%	1.28%	0.12	1.51E-03	0.00	0.60	0.01	130.00	0.70	520
2/21/2024	Diesel Fuel, generic (used for Spirdane D15)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	3.000	1	0.0168	100%	1.28%	0.05	6.44E-04	0.00	0.60	0.01	130.00	0.70	520
2/23/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	7.000	1	0.8207	100%	100.00%	5.75	5.75	0.00	0.60	1.78	32.00	34.25	520
2/27/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	5.300	1	0.0001	100%	17.84%	2.71E-04	4.84E-05	0.00	0.60	4.45E-05	80.00	0.00	520
2/29/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	5.200	1	0.0001	100%	17.84%	2.66E-04	4.75E-05	0.00	0.60	4.45E-05	80.00	0.00	520
2/29/2024	Diesel Fuel, generic (used for VM & P Max 12)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	7.194	1	0.0168	100%	1.28%	0.12	1.54E-03	0.00	0.60	0.01	130.00	0.70	520
2/29/2024	Diesel Fuel, generic (used for VM & P Max 12)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	6.005	1	0.0168	100%	1.28%	0.10	1.29E-03	0.00	0.60	0.01	130.00	0.70	520

(Kgal/month)	Total Cars
180.292	29

Monthly Total	VOC E_{TO}	HAP E_{TO}	Other E_{TO}
(lbs)	23.953	23.070	0.000
(tons)	**0.012**	**0.012**	**0.000**

March 2024[1] *(Based on LSRS Records)*

Month/Date [1]	Permit Substance Name	Permit Substance Category	CAS Number	VOC (Yes/No)	HAPs (Yes/No)	Volume Loaded Per Day (Kgal/day)	Number of Cars (cars/day)	Loading Loss Factor [2] (lbs/Kgal)	VOC Content (wt.%)	HAPs Content (wt.%)	VOC Emissions (lbs/day)	HAPs Emissions (lbs/day)	Other Emissions (lbs/day)	Saturation Factor, S (No unit)	True Vapor Pressure, P (psia)	Vapor Molecular Weight, MW (lb/lb mole)	worst case S*P*MW	Bulk Liquid Temperature, T (˚R)
3/8/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	7.402	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
3/12/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.029	1	0.0002	100%	17.00%	1.15E-03	1.96E-04	0.00	0.60	6.00E-05	190.00	0.01	520
3/12/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	7.028	1	0.0002	100%	17.00%	1.15E-03	1.96E-04	0.00	0.60	6.00E-05	190.00	0.01	520
3/12/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	5.567	1	0.0002	100%	17.00%	9.12E-04	1.55E-04	0.00	0.60	6.00E-05	190.00	0.01	520
3/12/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.495	1	0.0002	100%	17.00%	1.06E-03	1.81E-04	0.00	0.60	6.00E-05	190.00	0.01	520
3/14/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	7.000	1	0.8207	100%	100.00%	5.75	5.75	0.00	0.60	1.78	32.00	34.25	520
3/15/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	7.000	1	0.8207	100%	100.00%	5.75	5.75	0.00	0.60	1.78	32.00	34.25	520
3/18/204	Diesel Fuel, generic (used for Spirdane D15)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	7.031	1	0.0168	100%	1.28%	0.12	1.51E-03	0.00	0.60	0.01	130.00	0.70	520
3/18/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.577	1	0.0002	100%	17.00%	1.08E-03	1.83E-04	0.00	0.60	6.00E-05	190.00	0.01	520
3/18/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.905	1	0.0002	100%	17.00%	1.13E-03	1.92E-04	0.00	0.60	6.00E-05	190.00	0.01	520
3/19/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	3.000	1	0.0025	100%	100.00%	0.01	0.01	0.00	0.60	1.16E-03	150.00	0.10	520
3/19/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.910	1	0.0002	100%	17.00%	1.13E-03	1.93E-04	0.00	0.60	6.00E-05	190.00	0.01	520
3/19/2024	Used Oil	List 1 RPP Motor Oil	68553-00-4	Yes	Yes	6.056	1	0.0002	100%	17.00%	0.00	0.00	0.00	0.60	6.00E-05	190.00	0.01	520
3/22/2024	Methanol	List 1 Methanol	67-56-1	Yes	Yes	7.000	1	0.8207	100%	100.00%	5.75	5.75	0.00	0.60	1.78	32.00	34.25	520
3/24/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	5.600	1	0.0001	100%	17.84%	2.87E-04	5.11E-05	0.00	0.60	4.45E-05	80.00	0.00	520
3/24/2024	Distillate, generic (used for Distillation Feedstock)	List 1 RPP Distillate	64741-59-9	Yes	Yes	5.500	1	0.0001	100%	17.84%	2.82E-04	5.02E-05	0.00	0.60	4.45E-05	80.00	0.00	520
3/25/2024	Diesel Fuel, generic (used for Spirdane D40)	List 1 Individual	68334-30-5	Yes	Yes	6.940	1	0.0025	100%	100.00%	0.02	0.02	0.00	0.60	1.16E-03	150.00	0.10	520
3/26/2024	Diesel Fuel, generic (used for VM & P Max 12)	List 1 RPP Diesel Fuel	68334-30-5	Yes	Yes	7.246	2	0.0168	100%	1.28%	0.12	1.56E-03	0.00	0.60	0.01	130.00	0.70	520

(Kgal/month)	Total Cars
123.532	19

Monthly Total	VOC E_{TO}	HAP E_{TO}	Other E_{TO}
(lbs)	17.528	17.283	0.000
(tons)	**0.009**	**0.009**	**0.000**

Footnotes:
1. The operation date, substance name, and transloading volume loaded were based on the monthly transload worksheets provided by the facility for January, February, and March of 2024.
2. The loading loss factor L_L(lbs/gal) was calculated based on the saturation factor (S) from AP-42 Table 5.2-1, true vapor pressure (P) in psia, molecular weight of vapors (MW), bulk liquid temperature of 520 R using the following equation from AP-42 Section 5.2.1:

Equation (1) : $L_L = 12.46\ S \times P \times MW / T$.

Appendix A: Emissions Calculations
Transloading Operation - Fugitive Emissions

Company Name: Lakeshore Terminal Railroad LLC
Source Address: 1150 East 145th Street, East Chicago, IN 46312
Permit Number: R089-47845-00732
Reviewer: Mehul Sura

Parameters:

Equipment Type [1]	Maximum No. of Units per Hour [1]	Emission Factor (kg/hr per source) [2]	VOC Fraction [6]
Valves	0	0.00403	1.0
Pump Seals	0	0.0199	1.0
Compressor Seals	0	0.228	1.0
Pressure Relief Valves	0.63	0.104	1.0
Connectors	1.67	0.00183	1.0
Open-ended Lines	0	0.0017	1.0
Sampling Connections	0	0.015	1.0

Maximum Annual Operating Hours [3] =	8,760	hrs/yr
Expected Actual Annual Operating Hours [4] =	4,160	hrs/yr
Conversion =	2.20462	lbs/kg

Calculations: [5]

$$E_{TOC} = F_A \times WF_{TOC} \times N$$

E_{TOC} = Emission rate of VOC from all equipment in the stream of a given equipment type (kg/hr).
F_A = Applicable average emission factor for the equipment type (kg/hr per source).
WF_{TOC} [6] = Average weight fraction of VOC in the stream.
N = Number of pieces of the applicable equipment in the stream.

Emissions:

Pollutant	Potential Emissions		Actual Emissions	
	(lbs/hr)	(TPY)	(lbs/hr)	(TPY)
VOC	0.15	0.66	0.15	0.31
Max. Single HAP [6]	0.15	0.66	0.15	0.31
Total HAPs [6]	0.15	0.66	0.15	0.31

Notes:
1. The maximum number of units per hour assumes a worse-case estimate of transloading ten (10) 6,000-gallon tank truck loads of liquid per day, one (1) pressure relief valve per transloading vessel [conservatively assuming a maximum of 15 transloading vessels are involved per day], four (4) connectors per transloading event, 365 days of transloading per year, and 8,760 operating hrs/yr.
2. The emission factors were taken from the EPA's Emission Inventory Improvement Program (EIIP), Volume II, Chapter 4 - *Preferred and Alternative Methods for Estimating Fugitive Emission from Equipment Leaks* , Table 4.5-1 - *SOCMI Average Emission Factors.*
3. The maximum annual operating hours are assumed to be 8,760 operating hrs/yr.
4. The expected actual annual operating hours are assumed to be 4,160 operating hrs/yr based on 16 operating hours per day, 5 operating days per week, and 52 operating weeks per year.
5. The VOC emissions were calculated based on the EIIP, Volume II, Chapter 4 - *Preferred and Alternative Methods for Estimating Fugitive Emission from Equipment Leaks* , Equation 4.5-1.
6. For a worst-case estimate, it was assumed that all the material transloaded is methanol. This was based on the loading loss parameters for the materials transloaded in Q1 of the 2024 calendar year (see previous pages) by Lakeshore Railcar & Tanker Services LLC. Methanol is 100% VOC and 100% HAP.

Appendix A: Emissions Calculations
Natural Gas Combustion (≤ 100 MMBtu/hr)

Company Name: Lakeshore Terminal Railroad LLC
Source Address: 1150 East 145th Street, East Chicago, IN 46312
Permit Number: R089-47845-00732
Reviewer: Mehul Sura

	Heat Input Capacity MMBtu/hr	HHV mmBtu / mmscf	Potential Throughput MMCF/yr
boiler B1	5.02		
boiler B2	25.106		
Two (2) natural gas-fired HVAC units	0.1		
Five (5) natural gas-fired heater	1.25		
	31.48	1020	270.3

	Pollutant						
	PM*	PM10*	direct PM2.5*	SO2	NOx	VOC	CO
Emission Factor in lb/MMCF	1.9	7.6	7.6	0.6	100 **see below	5.5	84
Total Potential Emission in tons/yr	0.26	1.03	1.03	0.08	13.52	0.74	11.35

*PM emission factor is filterable PM only. PM10 emission factor is filterable and condensable PM10 combined.
PM2.5 emission factor is filterable and condensable PM2.5 combined.
**Emission Factors for NOx: Uncontrolled = 100, Low NOx Burner = 50, Low NOx Burners/Flue gas recirculation = 32

Methodology
All emission factors are based on normal firing.
MMBtu = 1,000,000 Btu; MMCF = 1,000,000 Cubic Feet of Gas
Emission Factors are from AP 42, Chapter 1.4, Tables 1.4-1, 1.4-2, 1.4-3, SCC #1-02-006-02, 1-01-006-02, 1-03-006-02, and 1-03-006-03
Potential Throughput (MMCF) = Heat Input Capacity (MMBtu/hr) x 8,760 hrs/yr x 1 MMCF/1,020 MMBtu
Potential Emission (tons/yr) = Potential Throughput (MMCF/yr) x Emission Factor (lb/MMCF)/2,000 lb/ton

Hazardous Air Pollutants (HAPs)

	HAPs - Organics				
	Benzene	Dichlorobenzene	Formaldehyde	Hexane	Toluene
Emission Factor in lb/MMcf	2.1E-03	1.2E-03	7.5E-02	1.8E+00	3.4E-03
Total Potential Emission in tons/yr	2.8E-04	1.6E-04	1.0E-02	2.4E-01	4.6E-04

	HAPs - Metals				
	Lead	Cadmium	Chromium	Manganese	Nickel
Emission Factor in lb/MMcf	5.0E-04	1.1E-03	1.4E-03	3.8E-04	2.1E-03
Total Potential Emission in tons/yr	6.8E-05	1.5E-04	1.9E-04	5.1E-05	2.8E-04

Potential Emission of Combined HAPs (tons/yr)	**2.6E-01**	
Potential Emission of Highest Single HAP (tons/yr)	**2.4E-01**	**Hexane**

Methodology
Methodology is the same as above.
The five highest organic and metal HAPs emission factors are provided above.
Additional HAPs emission factors are available in AP-42, Chapter 1.4.

Appendix A: Emissions Calculations
Diesel Dispensing DFDS - VOC Emissions

Company Name: Lakeshore Terminal Railroad LLC
Source Address: 1150 East 145th Street, East Chicago, IN 46312
Permit Number: R089-47845-00732
Reviewer: Mehul Sura

Parameters:

Annual Operating Hours = 8,760 hr/yr

Emissions:

Emission Unit	Max. Throughput[1]	VOC Emissions[2,3]	VOC Emissions	
	(gal/yr)	(lb/yr)	(lb/hr)	(tons/yr)
10,500-gallon Diesel Dispensing	1,277,500	22.57	2.6E-03	0.01

Footnotes:

2. Working loss VOC emissions were estimated using the EIIP Equation for Material Loss (Volume II, Chapter 8, Equation 8.4-1).
3. Breathing loss VOC emissions were estimated using AP-42, Chapter 7.1, Equation 1-2. Tank dimensions were approximated.

Appendix A: Emissions Calculations
Paved Roads - PM Emissions

Company Name: Lakeshore Terminal Railroad LLC
Source Address: 1150 East 145th Street, East Chicago, IN 46312
Permit Number: R089-47845-00732
Reviewer: Mehul Sura

Paved Roads at Industrial Site:

The following calculations determine the amount of emissions created by paved roads, based on AP-42, Ch 13.2.1 (1/2011).

Vehicle Information (provided by the Facility):

Type	Maximum number of vehicles per day	Number of one-way trips per day per vehicle	Maximum trips per day (trip/day)	Maximum Weight Loaded (tons/trip)	Total Weight driven per day (ton/day)	Maximum one-way distance (feet/trip)	Maximum one-way distance (miles/trip)	Maximum one-way miles (miles/day)	Maximum one-way miles (miles/yr)
Truck Tankers (enter empty)	5.0	1.0	5.0	17	85	1300	0.246	1.2	449.3
Truck Tankers (leave full)	5.0	1.0	5.0	40	200	1300	0.246	1.2	449.3
Truck Tankers (enter full)	5.0	1.0	5.0	40	200	1300	0.246	1.2	449.3
Truck Tankers (leave empty)	5.0	1.0	5.0	17	85	1300	0.246	1.2	449.3
Light Duty Vehicles (enter with driver)	5.0	1.0	5.0	2.4	12	650	0.123	0.6	224.7
Light Duty Vehicles (leave with driver)	5.0	1.0	5.0	2.4	12	650	0.123	0.6	224.7
Totals			**30.0**		**594**			**6.2**	**2,247**

Average Vehicle Weight Per Trip = 19.8 tons/trip
Average Miles Per Trip = 0.21 miles/trip

Unmitigated Emission Factor, Ef = [k * (sL)^0.91 * (W)^1.02] (Equation 1 from AP-42 13.2.1)

	PM	PM10	PM2.5	
where k =	0.011	0.0022	0.00054	lb/VMT = particle size multiplier (AP-42 Table 13.2.1-1)
W =	19.8	19.8	19.8	tons = average vehicle weight (provided by source)
sL =	9.7	9.7	9.7	g/m^2 = silt loading value for paved roads for Steel and Iron Production - Table 13.2.1-3)

Taking natural mitigation due to precipitation into consideration, Mitigated Emission Factor, Eext = E * [1 - (p/4N)] (Equation 2 from AP-42 13.2.1)
Mitigated Emission Factor, Eext = Ef * [1 - (p/4N)]
where p = 125 days of rain greater than or equal to 0.01 inches (see Fig. 13.2.1-2)
N = 365 days per year

	PM	PM10	PM2.5	
Unmitigated Emission Factor, Ef =	1.828	0.366	0.0897	lb/mile
Mitigated Emission Factor, Eext =	1.671	0.334	0.0821	lb/mile
Dust Control Efficiency =	0.0%	0.0%	0.0%	

Process	Unmitigated PM Emissions (tons/yr)	Unmitigated PM10 Emissions (tons/yr)	Unmitigated PM2.5 Emissions (tons/yr)	Mitigated PM Emissions (tons/yr)	Mitigated PM10 Emissions (tons/yr)	Mitigated PM2.5 Emissions (tons/yr)	Actual PM Emissions (tons/yr)	Actual PM10 Emissions (tons/yr)	Actual PM2.5 Emissions (tons/yr)
Truck Tankers (enter empty)	0.41	0.08	0.02	0.38	0.08	0.02	0.38	0.08	0.02
Truck Tankers (leave full)	0.41	0.08	0.02	0.38	0.08	0.02	0.38	0.08	0.02
Truck Tankers (enter full)	0.41	0.08	0.02	0.38	0.08	0.02	0.38	0.08	0.02
Truck Tankers (leave empty)	0.41	0.08	0.02	0.38	0.08	0.02	0.38	0.08	0.02
Light Duty Vehicles (enter with driver)	0.21	0.04	0.01	0.19	0.04	0.01	0.19	0.04	0.01
Light Duty Vehicles (leave with driver)	0.21	0.04	0.01	0.19	0.04	0.01	0.19	0.04	0.01
Total (tons/yr)	**2.05**	**0.41**	**0.10**	**1.88**	**0.38**	**0.09**	**1.88**	**0.38**	**0.09**
Total (lbs/hr)	**0.47**	**0.09**	**0.02**	**0.43**	**0.09**	**0.02**	**0.43**	**0.09**	**0.02**

Methodology:

Total Weight driven per day (ton/day) = [Maximum Weight Loaded (tons/trip)] * [Maximum trips per day (trip/day)]
Maximum one-way distance (mi/trip) = [Maximum one-way distance (feet/trip) / [5280 ft/mile]
Maximum one-way miles (miles/day) = [Maximum trips per year (trip/day)] * [Maximum one-way distance (mi/trip)]
Average Vehicle Weight Per Trip (ton/trip) = SUM[Total Weight driven per day (ton/day)] / SUM[Maximum trips per day (trip/day)]
Average Miles Per Trip (miles/trip) = SUM[Maximum one-way miles (miles/day)] / SUM[Maximum trips per year (trip/day)]
Unmitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Unmitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Mitigated PTE (tons/yr) = [Maximum one-way miles (miles/yr)] * [Mitigated Emission Factor (lb/mile)] * (ton/2000 lbs)
Controlled PTE (tons/yr) = [Mitigated PTE (tons/yr)] * [1 - Dust Control Efficiency]

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Eric J. Holcomb
Governor

Brian C. Rockensuess
Commissioner

SENT VIA U.S. MAIL: CONFIRMED DELIVERY AND SIGNATURE REQUESTED

TO: Clint Morris
Lakeshore Terminal Railroad LLC
1150 E 145th St
East Chicago, IN 46312

DATE: June 27, 2024

FROM: Jenny Acker, Branch Chief
Permits Branch
Office of Air Quality

SUBJECT: Final Decision
Registration
089-47845-00732

This notice is to inform you that a final decision has been issued for the air permit application referenced above.

Our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person. In addition, the Notice of Decision has been sent to the OAQ Permits Branch Interested Parties List and, if applicable, the Consultant/Agent and/or Responsible Official/Authorized Individual.

The final decision and supporting materials are available electronically; the original signature page is enclosed for your convenience. The final decision and supporting materials available electronically at:

IDEM's online searchable database: http://www.in.gov/apps/idem/caats/ . Choose Search Option **by Permit Number**, then enter permit 47845

and

IDEM's Virtual File Cabinet (VFC): https://www.in.gov/idem. Enter VFC in the search box, then search for permit documents using a variety of criteria, such as Program area, date range, permit #, Agency Interest Number, or Source ID.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit. If you think you have received this document in error, or have difficulty accessing the documents online, please contact Joanne Smiddie-Brush of my staff at 1-800-451-6027 (ext 3-0185), or via e-mail at jbrush@idem.IN.gov.

Final Applicant Cover Letter 8/20/20-acces via website

June 27, 2024
Lakeshore Terminal Railroad LLC
089-47845-00732

To: Interested Parties

This notice is to inform you that a final decision has been issued for the air permit application referenced above. This notice is for informational purposes only. You are not required to take any action.

You are receiving this notice because you asked to be on IDEM's notification list for this company and/or county; or because your property is nearby the company being permitted; or because you represent a local/regional government entity.

The enclosed Notice of Decision Letter provides additional information about the final permit decision.

The final decision and supporting materials are available electronically at:

IDEM's online searchable database: http://www.in.gov/apps/idem/caats/ . Choose Search Option by Permit Number, then enter permit 47845

and

IDEM's Virtual File Cabinet (VFC): https://www.in.gov/idem. Enter VFC in the search box, then search for permit documents using a variety of criteria, such as Program area, date range, permit #, Agency Interest Number, or Source ID.

If you have technical questions regarding the enclosed documents, please contact the Office of Air Quality, Permits Branch at (317) 233-0178, or toll-free at 1-800-451-6027 (ext. 3-0178), and ask to speak to the permit reviewer who prepared the permit.

Please Note: *If you would like to be removed from the Air Permits mailing list, please contact Joanne Smiddie-Brush with the Air Permits Administration Section at 1-800-451-6027, ext. 3-0185 or via e-mail at JBRUSH@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.*

Enclosure
Final Interested Parties Cover Letter 10/13/2023

Mail Code 61-53

IDEM Staff	JLSCOTT 6/27/2024 Lakeshore Terminal Railroad LLC 089-47845-00732 Final Page 1 of 2			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Clint Morris Lakeshore Terminal Railroad LLC 1150 E 145th St East Chicago IN 46312 (Source CAATS) via UPS									
2		East Chicago City Council 4525 Indianapolis Blvd East Chicago IN 46312 *(Local Official)*									
3		Lake County Board of Commissioners 2293 N Main St, Bldg A, 3rd Floor Crown Point IN 46307 *(Local Official)*									
4		Barbara G Perez 506 Lilac St East Chicago IN 46312 *(Affected Party)*									
5		Mr. Robert Garcia 3733 Parrish Ave East Chicago IN 46312 *(Affected Party)*									
6		Ms. Karen Kroczek 8212 Madison Ave Munster IN 46321-1627 *(Affected Party)*									
7		Mr. Larry Davis 268 S 600 W Hebron IN 46341 *(Affected Party)*									
8		Jeff Mayes News-Dispatch 422 Franklin St Michigan City IN 46360 *(Affected Party)*									
9		East Chicago City Health Department 100 W Chicago Ave East Chicago IN 46312 *(Health Department)*									
10		Lake County Health Department 2900 W 93rd Ave Crown Point IN 46307 *(Health Department)*									
11		Kristina Lindborg League of Women Voters of Indiana 2213 S Sussex Dr Bloomington IN 47401 *(Affected Party)*									
12		Grayson Uhlir Weaver Consultants Group 35 E Wacker Dr Ste 1250 Chicago IL 60601 *(Consultant)*									
13		Menards 6300 Mississippi St Merrillville IN 46410 (Affected Party)									
14		Jesus A Gallegos II 6814 Prairie Path Ln Merrillville IN 46410 *(Affected Party)*									
15		Rebecca Dien-Johns Or Current Resident 612 N Temple Ave Indianapolis IN 46201 *(Affected Party)*									

Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.

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Mail Code 61-53

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<tr><td>IDEM Staff</td><td colspan="3">JLSCOTT 6/27/2024
Lakeshore Terminal Railroad LLC 089-47845-00732 Final Page 2 of 2</td><td rowspan="2">AFFIX STAMP
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OF MAILING</td></tr>
<tr><td>Name and address of Sender</td><td>▶</td><td>Indiana Department of Environmental Management
Office of Air Quality – Permits Branch
100 N. Senate
Indianapolis, IN 46204</td><td>Type of Mail:

CERTIFICATE OF MAILING ONLY</td></tr>
</table>

Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee / Remarks
1		John Wisconsin Department of Natural Resources 101 S. Webster Street Madison WI 53707 (Affected Party)									
2		Or Current Resident Kapital Steel 1215 E 143rd St East Chicago IN 46312 *(Affected Party)*									
3		Tradebe Environmental Services 4343 Kennedy Avenue East Chicago IN 46312 *(Affected Party)*									
4		ICO Polymers 4404 Euclid Avenue East Chicago IN 46312 *(Affected Party)*									
5		USA Pantas Tires LLC 1202 E Chicago Avenue East Chicago IN 46312 *(Affected Party)*									
6		C & P Auto Repair 1106e East Chicago Ave East Chicago IN 46312 *(Affected Party)*									
7		Mota Family Towing 1050 E Chicago Ave East Chicago IN 46312 *(Affected Party)*									
8		Macabi Auto Supply 1310 E Chicago Ave East Chicago IN 46312 *(Affected Party)*									
9		Caruthers Auto Sales 1218 E Chicago Ave #20 East Chicago IN 46312 *(Affected Party)*									
10		Friedman Industries Inc 4303 Kennedy Ave East Chicago IN 46312 *(Affected Party)*									
11											
12											
13											
14											
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